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L-MT-16-064
10 CFR 50.71(e)
Technical Specification 5.5.9

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

Monticello Nuclear Generating Plant
Docket No. 50-263
Renewed Facility Operating License No. DPR-22

Update to Technical Requirements Manual and Technical Specification Bases

The Northern States Power Company, a Minnesota Corporation (NSPM), doing business as Xcel Energy, hereby submits updates to the Monticello Nuclear Generating Plant (MNGP) Technical Requirements Manual (TRM) and Technical Specification (TS) Bases. The TRM is being provided in accordance with 10 CFR 50.71(e). The TS Bases are being provided in accordance with TS 5.5.9, "Technical Specifications (TS) Bases Control Program," on a frequency consistent with 10 CFR 50.71(e).

The TRM and TS Bases are provided as attachments to this letter. Current copies of the entire MNGP TRM, Revision 18, and the entire MNGP TS Bases, Revision 43 are provided. The previous update included MNGP TRM, Revision 17 and MNGP TS Bases, Revision 39. The affected TS Bases pages in the intervening revisions (Revisions 40, 41, and 42) are included in Revision 43. A list of changes to the TRM is provided in Table 2, "TRM Record of Revisions," located near the front of the TRM (001_TRM.pdf). A list of changes to the TS Bases is provided in Table 2, "Technical Specification Bases Record of Revisions," located near the front of the TS Bases (002_TS Bases.pdf). The following files are attached.

File Name	Document
001_TRM.pdf	TRM, Rev 18
002_TS Bases.pdf	TS Bases, Rev 43

Summary of Commitments

This letter makes no new commitments and no revisions to existing commitments.

Peter A. Gardner
Site Vice President, Monticello Nuclear Generating Plant
Northern States Power Company – Minnesota

Attachments

cc: Administrator, Region III, USNRC
Project Manager, Monticello, USNRC
Resident Inspector, Monticello, USNRC

MONTICELLO NUCLEAR GENERATING PLANT TECHNICAL REQUIREMENTS MANUAL

TABLE 1 (Page 1 of 1)
MONTICELLO NUCLEAR GENERATING PLANT
LIST OF EFFECTIVE SECTIONS FOR THE
TRM SPECIFICATIONS AND TRM BASES

TRM Section/ Specification	TRM Spec. Revision No.	TRM Bases Revision No.
Table of Contents	15	15
1.1	0	N/A
1.2	0	N/A
1.3	0	N/A
1.4	0	N/A
3.0	7	0
3.3.1.1	18	18
3.3.2.1	16	16
3.3.3.1	0	0
3.3.4.1	0	0
3.3.5.1	17	17
3.3.7.1	1	12
3.4.1	0	0
3.4.2	0	0
3.4.3	(Deleted)	(Deleted)
3.4.4	15	15
3.5.1	0	0
3.5.2	6	8
3.6.1.3	13	13
3.6.1.7	2	0
3.6.3.2	13	13
3.8.1	16	0
3.8.2	0	0
3.9.1	0	0
5.2	0	N/A
Appendix A	2	N/A
Appendix B	0	N/A
Appendix C	6	N/A

TABLE 2 (Page 1 of 3)
TRM SPECIFICATIONS AND TRM BASES RECORD OF REVISIONS

Revision Number	Affected TRM Spec. Section/ Specification	Affected TRM Bases Section/ Specification	Description of Revision
0	All	All	Original TRM Specification and Bases Issuance
1	3.3.7.1	B 3.3.7.1	Amendment 148 – Removed the Control Room Air Intake Radiation Monitors from Technical Specification 3.3.7.1. Monitors added to TRM as new Specification 3.3.7.1 as required by NRC Commitment M06030A.
2	Appendix A	N/A	Revised control rod scram time limits at 0 psig reactor pressure to reflect Calculation CA-01-231, Revision 1.
	3.6.1.7	---	Corrected typo. Changed Required Action B.1 to A.1 in Specification 3.6.1.7.
3	3.4.3	B 3.4.3	Revised Specification and Bases to incorporate ASME OM Code – 1995, 1996 Addenda, and Code Case OMN-13 for visual inspection of snubbers. Removed Table 3.4.3-2. Changed surveillance frequency from referring to Table 3.4.3-1 to the Snubber Inservice Inspection Program. Complete rewrite of existing TRM specification bases to TS bases standards.
4	3.4.3	---	Revised Specification 3.4.3 to remove incorrect MODE 4 restriction from Table 3.4.3-1 under Item C for functional testing of snubbers.
5	3.3.2.1	B 3.3.2.1	Amendment 159 – Incorporated PRNMS TRM changes. Revised APRM functions in Table 3.3.2.1-1 to include APRM STP – High and Neutron Flux – High (Setdown) rod blocks. Added new SR 3.3.2.1.6 and SR 3.3.2.1.7. Complete rewrite of existing TRM specification and bases to TS bases standards.
6	3.5.2	B 3.5.2	Revised specification to add a Note providing a 6-hour delay for entry into the Required Action solely for surveillance performance. Added complete TRM Bases for Specification 3.5.2 to TS bases standards.

TRM SPECIFICATIONS AND TRM BASES RECORD OF REVISIONS

Revision Number	Affected TRM Spec. Section/ Specification	Affected TRM Bases Section/ Specification	Description of Revision
6 (con't)	Appendix C	N/A	Amendments 159 and 161 – Revised appendix to clarify methodologies for the determination of the NSTP values for several PRNMS functions and the Recirculation Riser Differential Pressure – High function.
7	3.0	---	Replaced reference to Generic Letter 91-18 with correct current reference, i.e., Regulatory Issue Summary (RIS) 2005-020.
8	---	B 3.5.2	Each Core Spray sparger break detection instrumentation is associated with a single sparger. Removed incorrect statement in TRM Specification 3.5.2 Bases implying that monitoring capability is maintained when the instrumentation for that sparger is inoperable.
9	3.8.1	---	Removed Specification 3.8.1 Condition C to reflect separation of 1ARS and Bus 1.
10	3.6.1.3	B 3.6.1.3	Changed TSR 3.6.1.3.2 surveillance test frequency from 7 days to in accordance with the Inservice Testing Program. Added TRM Bases discussion.
11	3.4.3	B 3.4.3	Deleted specification and bases for Specification 3.4.3 – Snubbers. Addressed under ASME OM Code.
12	---	B 3.3.7.1	Corrected page numbers on TRM Specification 3.3.7.1 Bases pages.
13	TOC, 3.3.2.1, 3.6.1.3, 3.6.3.2	B TOC, B 3.6.1.3, B 3.6.3.2	Amendment 176 – Changes for EPU. Revised TS Bases for Specifications 3.3.2.1 and 3.6.1.3. Added Specification and Bases for 3.6.3.2, "Online Containment Leakage Check," with fully detailed TRM Bases written to TS bases standards.
14	---	B 3.3.5.1	Added complete Loss of Auxiliary Power Instrumentation bases for Specification 3.3.5.1 written to TS bases standards.

TABLE 2 (Page 3 of 3)
TRM SPECIFICATIONS AND TRM BASES RECORD OF REVISIONS

Revision Number	Affected TRM Spec. Section/ Specification	Affected TRM Bases Section/ Specification	Description of Revision
15	TOC, 3.3.2.1, 3.4.4	B TOC, B 3.3.2.1, B 3.4.4	Amendment 180 – Changes for MELLLA+. Added Specification and Bases for 3.4.4, “Safety/Relief Valves (S/RVs) Out-of-Service,” with fully detailed TRM Bases written to TS bases standards. Bases discuss limitation on an SRV being out of service in the MELLLA+ domain.
16	3.3.2.1	B 3.3.2.1	Increase Channel Calibration interval of SDV level switches for high level rod block trip from 92 days to 12 months. Correct the number of SDV water level rod block instrument channels and instruments in TRM Bases.
	3.8.1	---	Remove incorrect statement in TLCO for Specification 3.8.1 that 1AR must be powered from 10 Transformer when 1AR and 2R are the required offsite circuits.
17	3.3.5.1	B 3.3.5.1	Revised Applicability to Specification 3.3.5.1 to clarify that the Loss of Auxiliary Power instrumentation is required when the associated ECCS injection/spray subsystem is required OPERABLE per TS LCO 3.5.2.
18	3.3.1.1	B 3.3.1.1	Revised Condenser vacuum Allowable Value in TSR 3.3.1.1.2 to provide additional margin for summer readiness. Added complete “Turbine Condenser Vacuum – Low Instrumentation” Specification 3.3.1.1 TRM Bases written to TS bases standards.

1.0 USE AND APPLICATION

1.1 Definitions

---NOTES---

1. Definitions are defined in Section 1.1 of the Technical Specifications (TS) and are applicable throughout the Technical Requirements Manual (TRM) and Bases. Only definitions specific to the TRM will be defined in this section.

2. The defined terms of this section and the Technical Specifications (TS) appear in capitalized type and are applicable throughout the TRM and the TRM Bases.

3. When a term is defined in both the TS and the TRM, the TRM definition takes precedence within the TRM and the TRM Bases.

Term	Definition
ACTIONS	ACTIONS shall be that part of a Requirement that prescribes Required Actions to be taken under designated Conditions within specified Completion Times.
OPERABLE - OPERABILITY	A system, subsystem, division, component, or device shall be OPERABLE or have OPERABILITY when it is capable of performing its specified function(s) and when all necessary attendant instrumentation, controls, normal or emergency electrical power, cooling and seal water, lubrication, and other auxiliary equipment that are required for the system, subsystem, division, component, or device to perform its specified function(s) are also capable of performing their related support function(s).

1.0 USE AND APPLICATION

1.2 Logical Connectors

Logical Connectors are discussed in Section 1.2 of the Technical Specifications and are applicable throughout the Technical Requirements Manual and Bases.

1.0 USE AND APPLICATION

1.3 Completion Times

Completion Times are discussed in Section 1.3 of the Technical Specifications and are applicable throughout the Technical Requirements Manual and Bases.

1.0 USE AND APPLICATION

1.4 Frequency

Frequency is discussed in Section 1.4 of the Technical Specifications and is applicable throughout the Technical Requirements Manual and Bases.

3.0 TECHNICAL LIMITING CONDITION FOR OPERATION (TLCO) APPLICABILITY

TLCO 3.0.1	TLCOs shall be met during the MODES or other specified conditions in the Applicability, except as provided in TLCO 3.0.2.
TLCO 3.0.2	Upon discovery of a failure to meet a TLCO, the Required Actions of the associated Conditions shall be met, except as provided in TLCO 3.0.5. If the TLCO is met or is no longer applicable prior to expiration of the specified Completion Time(s), completion of the Required Action(s) is not required, unless otherwise stated.
TLCO 3.0.3	When a TLCO is not met and the associated ACTIONS are not met, an associated ACTION is not provided, or if directed by the associated ACTIONS, action shall be initiated within 1 hour to: a. Implement appropriate compensatory actions as needed; b. Verify that the plant is not in an unanalyzed condition; and c. Verify that a required safety function is not compromised by the inoperabilities. In addition, within 12 hours, obtain the Operation Manager's approval of the compensatory actions and plan for exiting TLCO 3.0.3. Exceptions to this TLCO are stated in the individual TLCOs. Where corrective measures are completed that permit operation in accordance with the TLCO or ACTIONS, completion of the actions required by TLCO 3.0.3 is not required. Actions a, b, and c shall be performed consistent with the Requirements of Regulatory Issue Summary 2005-020.
TLCO 3.0.4	When a TLCO is not met, entry into a MODE or other specified condition in the Applicability shall only be made: a. When the associated ACTIONS to be entered permit continued operation in the MODE or other specified condition in the Applicability for an unlimited period of time; b. After performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering the MODE or other specified condition in the Applicability, and establishment of risk management actions, if appropriate; exceptions to this TLCO are stated in the individual TLCOs; or

TLCO Applicability

TLCO 3.0.4 (continued)

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

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

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

TECHNICAL SURVEILLANCE REQUIREMENT (TSR) APPLICABILITY

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

TSR Applicability (continued)

TSR 3.0.4	Entry into a MODE or other specified condition in the Applicability of a TLCO shall only be made when the TLCO's TSRs have been met within their specified Frequency, except as provided by TSR 3.0.3. When a TLCO is not met due to TSRs not having been met, entry into a MODE or other specified condition in the Applicability shall only be made in accordance with TLCO 3.0.4. This provision shall not prevent entry into MODES or other specified conditions in the Applicability that are required to comply with TS or TRM ACTIONS or that are part of a shutdown of the unit.

3.3 INSTRUMENTATION

3.3.1.1 Turbine Condenser Vacuum - Low Instrumentation

TLCO 3.3.1.1 Two Turbine Condenser Vacuum - Low channels in each Reactor Protection System trip system shall be OPERABLE.

APPLICABILITY: MODE 1,
MODE 2 with reactor steam dome pressure $\geq$ 600 psig.

ACTIONS

---NOTE---

Separate Condition entry is allowed for each channel.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more channels inoperable.	A.1 Place channel in trip. <u>OR</u> A.2 Place associated trip system in trip.	12 hours 12 hours
B. One or more channels inoperable in both trip systems.	B.1 Place channel in one trip system in trip. <u>OR</u> B.2 Place one trip system in trip.	6 hours 6 hours
C. Turbine Condenser Vacuum - Low trip capability not maintained.	C.1 Restore Turbine Condenser Vacuum - Low trip capability.	1 hour
D. Required Action and associated Completion Time not met.	D.1 Enter TLCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

--NOTE--

When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided Turbine Condenser Vacuum - Low trip capability is maintained.

SURVEILLANCE		FREQUENCY
TSR 3.3.1.1.1	Perform CHANNEL FUNCTIONAL TEST.	31 days
TSR 3.3.1.1.2	Perform CHANNEL CALIBRATION. The Allowable Value is $\geq$ 20.8 inches vacuum Hg.	31 days

3.3 INSTRUMENTATION

3.3.2.1 Control Rod Block Instrumentation

TLCO 3.3.2.1 The control rod block instrumentation for each Function in Table 3.3.2.1-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.2.1-1

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. ------------NOTE------------- Only applicable to Functions 1, 2, 3 and 5. --------------------------------- One or more Functions with one required channel inoperable.	A.1 Restore channel to OPERABLE status.	7 days
B. ------------NOTE------------- Only applicable to Functions 1, 2, 3, and 5. --------------------------------- One or more Functions with two required channels inoperable.	B.1 Place channel in the tripped condition. OR B.2 Suspend control rod withdrawal.	Immediately Immediately
C. One or more required Function 4 channels inoperable.	C.1 Place channel in the tripped condition. <u>OR</u> C.2 Suspend control rod withdrawal.	Immediately Immediately

SURVEILLANCE REQUIREMENTS

--NOTE--

1. Refer to Table 3.3.2.1-1 to determine which TSRs apply for each Control Rod Block Function.

2. When a channel is placed in an inoperable status solely for performance of required Surveillance, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains control rod block capability.

SURVEILLANCE		FREQUENCY
TSR 3.3.2.1.1	Perform CHANNEL CHECK.	12 hours
TSR 3.3.2.1.2	-------------------------------NOTE------------------------------- 1. For Function 1.b, not required to be performed if SRM detectors are secured in the full-in position. 2. For Function 2.a and 2.b, not required to be performed when entering MODE 2 from MODE 1 until 12 hours after entering MODE 2. --- Perform CHANNEL FUNCTIONAL TEST.	7 days
TSR 3.3.2.1.3	Perform CHANNEL FUNCTIONAL TEST.	92 days
TSR 3.3.2.1.4	Perform CHANNEL CALIBRATION.	12 months
TSR 3.3.2.1.5	-------------------------------NOTE------------------------------- 1. Neutron detectors are excluded. 2. For Function 2.a and 2.b, not required to be performed when entering MODE 2 from MODE 1 until 12 hours after entering MODE 2. --- Perform CHANNEL CALIBRATION.	24 months
TSR 3.3.2.1.6	Perform CHANNEL CALIBRATION.	24 months
TSR 3.3.2.1.7	Perform CHANNEL FUNCTIONAL TEST.	184 days

Table 3.3.2.1-1 (Page 1 of 2)
Control Rod Block Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Source Range Monitors				
a. Upscale	2[(a)], 5	1	TSR 3.3.2.1.1 TSR 3.3.2.1.2 TSR 3.3.2.1.5	$\leq 1.16 \times 10^5$cps
b. Detector Not Fully Inserted	2[(b)], 5[(b)]	1	TSR 3.3.2.1.2 TSR 3.3.2.1.5	NA
2. Intermediate Range Monitors				
a. Downscale	2[(c)], 5[(c)]	2[(d)]	TSR 3.3.2.1.1 TSR 3.3.2.1.2 TSR 3.3.2.1.5	≥ 3/125 divisions of full scale
b. Upscale	2, 5	2[(d)]	TSR 3.3.2.1.1 TSR 3.3.2.1.2 TSR 3.3.2.1.5	≤ 109.5/125 divisions of full scale
3. Average Power Range Monitors				
a. Simulated Thermal Power – High	1	3[(f)]	TSR 3.3.2.1.6 TSR 3.3.2.1.7	≤ 0.61W + 61.2% RTP[(e)] and < 110% RTP
b. Downscale	1	3[(f)]	TSR 3.3.2.1.6 TSR 3.3.2.1.7	≥ 2/125 divisions of full scale
c. Neutron Flux – High (Setdown)	2	3[(f)]	TSR 3.3.2.1.6 TSR 3.3.2.1.7	≤ 15%
4. Scram Discharge Volume				
a. East Water Level High	1, 2	1	TSR 3.3.2.1.3 TSR 3.3.2.1.4	≤ 40 gal
b. West Water Level High	1, 2	1	TSR 3.3.2.1.3 TSR 3.3.2.1.4	≤ 40 gal

(a) With IRMs on Range 6 or below.

(b) With SRM channel count rate < 100 cps and IRMs on Range 2 or below.

(c) With IRMs on Range 2 or above.

(d) There must be at least one OPERABLE IRM channel monitoring each core quadrant.

(e) ≤ 0.55(W - Delta W) + 55.5% when Technical Specification 3.3.1.1 Function 2.b, is reset for single loop operation per LCO 3.4.1, “Recirculation Loops Operating.” The value of Delta W is defined in the COLR. Single loop operation is not permitted while operating in the MELLLA+ operating domain.

(f) Each APRM channel provides input to both trip systems.

Table 3.3.2.1-1 (Page 2 of 2)
Control Rod Block Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
5. Average Power Range Monitors (Automated Backup Stability Protection (BSP))				
a. Slope	1[(g)]	3[(f)]	TSR 3.3.2.1.6 TSR 3.3.2.1.7	≤ 1.3
b. Constant Power Line	1[(g)]	3[(f)]	TSR 3.3.2.1.6 TSR 3.3.2.1.7	≤ 30% RTP
c. Constant Flow Line	1[(g)]	3[(f)]	TSR 3.3.2.1.6 TSR 3.3.2.1.7	≥ 58.8% Rated Drive Flow (RDF)
d. Flow Breakpoint	1[(g)]	3[(f)]	TSR 3.3.2.1.6 TSR 3.3.2.1.7	≥ 34.5% RDF

(f) Each APRM channel provides input to both trip systems.

(g) Required only when the Automated BSP Scram Region is implemented in accordance with Technical Specification 3.3.1.1.

3.3 INSTRUMENTATION

3.3.3.1 Post Accident Monitoring (PAM) Instrumentation

TLCO 3.3.3.1 The PAM instrumentation for each Function in Table 3.3.3.1-1 shall be OPERABLE.

APPLICABILITY: MODES 1 and 2.

ACTIONS

---NOTE---

Separate Condition entry is allowed for each Function.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Functions with one required channel inoperable.	A.1 Restore required channel to OPERABLE status.	30 days
B. Required Action and associated Completion Time of Condition A not met.	B.1 Prepare an evaluation in accordance with the Corrective Action Program outlining the alternate method of monitoring, the cause of the inoperability, and the plans and schedule for restoring the channel to OPERABLE status.	30 days
C. One or more Functions with two required channels inoperable.	C.1 Enter the Condition referenced in Table 3.3.3.1-1 for the channel.	Immediately

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
D. As required by Required Action C.1 and referenced in Table 3.3.3.1-1.	D.1	Monitor torus temperature for signs of an open Safety/Relief Valve.	Once per 12 hours
	<u>AND</u>		
	D.2	Restore one required channel to OPERABLE status.	30 days
E. Required Action and associated Completion Time of Condition D not met. <u>OR</u> As required by Required Action C.1 and referenced in Table 3.3.3.1-1.	E.1	Initiate preplanned alternate method of monitoring appropriate parameters.	Immediately

SURVEILLANCE REQUIREMENTS

--NOTE--

When a channel is placed in an inoperable status solely for performance of the required Surveillance, entry into the associated Conditions and Required Actions may be delayed for up to 6 hours provided the other required channel in the associated Function is OPERABLE.

SURVEILLANCE		FREQUENCY
TSR 3.3.3.1.1	Perform CHANNEL CHECK for each required channel.	31 days
TSR 3.3.3.1.2	Perform CHANNEL CALIBRATION for each required channel.	24 months

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
TSR 3.3.3.1.3	For Function 1 channels, verify recorder traces or computer logs indicate sensor responses.	Following each S/RV actuation

Table 3.3.3.1-1 (page 1 of 1)
Post Accident Monitoring Instrumentation

FUNCTION	REQUIRED CHANNELS	CONDITIONS REFERENCED FROM REQUIRED ACTION C.1
1. Safety/Relief Valve (S/RV) Position	2 per S/RV [(a)]	D
2. Offgas Stack Wide Range Radiation	2	E
3. Reactor Building Vent Wide Range Radiation	2	E

(a) One pressure switch channel and one thermocouple position indication channel.

3.3 INSTRUMENTATION

3.3.4.1 Anticipated Transient Without Scram (ATWS) Alternate Rod Injection Instrumentation

TLCO 3.3.4.1 Two channels per trip system for each ATWS Alternate Rod Injection instrumentation Function listed below shall be OPERABLE:

a. Reactor Vessel Water Level - Low Low; and

b. Reactor Vessel Steam Dome Pressure - High.

APPLICABILITY: MODE 1.

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more channels inoperable.	A.1 Restore channel to OPERABLE status. <u>OR</u> A.2 ---------------NOTE-------------- Not applicable if inoperable channel is the result of an inoperable solenoid valve. ------------------------------------- Place channel in trip.	14 days 14 days
B. One Function with ATWS Alternate Rod Injection trip capability not maintained.	B.1 Restore ATWS Alternate Rod Injection trip capability.	72 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. Both Functions with ATWS Alternate Rod Injection trip capability not maintained.	C.1	Restore ATWS Alternate Rod Injection trip capability for one Function.	1 hour
D. Required Action and associated Completion Time not met.	D.1	Enter TLCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

---NOTE---

When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains ATWS Alternate Rod Injection trip capability.

SURVEILLANCE		FREQUENCY
TSR 3.3.4.1.1	------------------------------NOTE------------------------------ Not required for the time delay portion of the Reactor Vessel Water Level - Low Low Function. --- Perform CHANNEL CHECK.	12 hours
TSR 3.3.4.1.2	Perform CHANNEL FUNCTIONAL TEST.	92 days
TSR 3.3.4.1.3	Calibrate the trip units.	92 days

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
TSR 3.3.4.1.4	Perform CHANNEL CALIBRATION of Reactor Vessel Water Level - Low Low time delay relays. The Allowable Value shall be ≥ 6 seconds and ≤ 8.6 seconds.	184 days
TSR 3.3.4.1.5	Perform CHANNEL CALIBRATION. The Allowable Values shall be: a. Reactor Vessel Water Level - Low Low ≥ - 48 inches; and b. Reactor Vessel Steam Dome Pressure - High ≤ 1155 psig.	24 months

3.3 INSTRUMENTATION

3.3.5.1 Loss of Auxiliary Power Instrumentation

TLCO 3.3.5.1 Two channels (one channel is a circuit breaker contact and the other channel is an undervoltage relay) of Loss of Auxiliary Power instrumentation shall be OPERABLE in each of two trip systems.

APPLICABILITY: MODES 1, 2, and 3
When associated ECCS injection/spray subsystem(s) are required to be OPERABLE per LCO 3.5.2, "ECCS – Shutdown".

ACTIONS

---NOTE---

Separate Condition entry is allowed for each channel.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One Loss of Auxiliary Power instrument channel inoperable in one or more required trip systems.	A.1 Restore Loss of Auxiliary Power instrument channels to OPERABLE status.	12 hours
B. Required Action and associated Completion Time of Condition A not met. <u>OR</u> Two Loss of Auxiliary Power instrument channels inoperable in one or both required trip systems.	B.1 Declare associated low pressure ECCS pumps inoperable.	Immediately

SURVEILLANCE REQUIREMENTS

---NOTE---

When a channel is placed in an inoperable status solely for performance of the required Surveillance, entry into the associated Conditions and Required Actions may be delayed for up to 6 hours provided that at least one other OPERABLE channel in the same trip system is monitoring that parameter.

SURVEILLANCE		FREQUENCY
TSR 3.3.5.1.1	Perform CHANNEL CALIBRATION.	24 months

3.3 INSTRUMENTATION

3.3.7.1 Control Room Air Intake Radiation - High Instrumentation

TLCO 3.3.7.1 One channel per trip system of the Control Room Air Intake Radiation - High Function shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3,
During movement of recently irradiated fuel assemblies in the secondary containment,
During operations with a potential for draining the reactor vessel (OPDRVs).

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more channels inoperable.	A.1 Place the associated CREF subsystem in the pressurization mode of operation.	1 hour
	<u>OR</u>	
	A.2 Declare associated CREF subsystem inoperable.	1 hour

SURVEILLANCE REQUIREMENTS

---NOTE---
When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 8 hours provided the associated Function maintains CREF System initiation capability.

SURVEILLANCE		FREQUENCY
TSR 3.3.7.1.1	Perform CHANNEL CHECK.	12 hours
TSR 3.3.7.1.2	Perform CHANNEL FUNCTIONAL TEST.	31 days
TSR 3.3.7.1.3	Perform CHANNEL CALIBRATION. The Allowable Value shall be ≤ 2 mR/hour.	24 months

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.1 RCS Chemistry

TLCO 3.4.1 The chemistry of the reactor coolant system shall be maintained within the limits specified in Table 3.4.1-1.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. RCS chemistry not within required limits.	A.1 Enter TLCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.4.1.1	Analyze sample of reactor coolant for conductivity and chloride ion concentration.	4 hours during startup and at steaming rates < 100,000 lbs/hr <u>AND</u> 96 hours at steaming rates ≥ 100,000 lbs/hr <u>AND</u> Once when continuous conductivity monitor indicates abnormal conductivity (other than short term spikes) at steaming rates ≥ 100,000 lbs/hr
TSR 3.4.1.2	Analyze sample of reactor coolant for conductivity and chloride ion concentration.	Once within 12 hours if continuous conductivity monitor is inoperable and THERMAL POWER > 1% RTP <u>AND</u> 12 hours thereafter

Table 3.4.1-1 (page 1 of 1)
Reactor Coolant Chemistry Limits

Parameter	Steaming Rate < 100,000 lbs/hr [a]	Steaming Rate ≥ 100,000 lbs/hr [a]
Conductivity	$\leq$ 5 μmho/cm	$\leq$ 5 μmho/cm
Chloride ion concentration	$\leq$ 0.1 ppm	$\leq$ 0.5 ppm

(a) Upon commencing a reactor startup until 24 hours after THERMAL POWER is > 1% RTP, the conductivity shall be $\leq$ 10 μmho/cm and the chloride ion concentration shall be $\leq$ 0.1 ppm.

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.2 Safety/Relief Valve (S/RV) Bellows and Bellows Monitoring System

TLCO 3.4.2 The S/RV bellows and bellows monitoring system shall be OPERABLE for each required S/RV.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

--NOTE--
Separate Condition entry is allowed for each S/RV bellows and bellows monitoring system.

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or more required S/RV bellows inoperable.	A.1	Declare the associated S/RV inoperable.	Immediately
B. One or more required S/RV bellows monitoring system inoperable.	B.1	Enter TLCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.4.2.1	Verify the integrity of each required S/RV bellows.	12 hours
TSR 3.4.2.2	Verify each required bellows monitoring system is OPERABLE	24 months
TSR 3.4.2.3	------------------------------NOTE------------------------------ This TSR is a maintenance TSR only. Failure to perform this TSR does not result in the inoperability of the S/RV bellows or bellows monitoring system. --- Disassemble and inspect two S/RVs.	24 months

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.4 Safety/Relief Valves (S/RVs) Out-of-Service

TLCO 3.4.4 The safety function of eight S/RVs shall be OPERABLE.

APPLICABILITY: MODE 1, when operating in the MELLLA+ operating domain.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more S/RVs inoperable.	A.1 Restore eight S/RVs to OPERABLE status.	14 days
B. Required Action and associated Completion Time of Condition A not met.	B.1 Exit the Maximum Extended Load Line Limit Analysis Plus (MELLLA+) Operating Domain.	12 hours
C. Required Action and associated Completion Time of Condition B not met.	C.1 Enter TLCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

There are no additional surveillance requirements beyond those specified in Technical Specification 3.4.3.

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

3.5.1 Automatic Depressurization System (ADS) Inhibit Switch

TLCO 3.5.1 Both ADS Inhibit switches shall be OPERABLE.

APPLICABILITY: MODE 1,
MODES 2 and 3, with reactor steam dome pressure > 150 psig.

ACTIONS

---NOTE---

Separate Condition entry is allowed for each ADS inhibit switch.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. TSR 3.5.1.1 not met for one or more ADS Inhibit Switches.	A.1 Declare the associated ADS instrumentation trip system channels inoperable.	Immediately
B. TSR 3.5.1.2 not met for one or more ADS Inhibit Switches	B.1 Enter TLCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.5.1.1	Verify each ADS Inhibit Switch does not prevent the ADS initiation capability when in the "Auto" position.	24 months
TSR 3.5.1.2	Verify each ADS Inhibit Switch will inhibit ADS initiation when in the "Inhibit" position.	24 months

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

3.5.2 Core Spray (CS) System Nozzle Differential Pressure Instrumentation

TLCO 3.5.2 Two CS System nozzle differential pressure channels shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or both CS System nozzle differential pressure channels inoperable.	A.1	Initiate action to restore CS System nozzle differential pressure channel(s) to OPERABLE status.	Immediately

SURVEILLANCE REQUIREMENTS

---NOTES---

When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the other required channel is OPERABLE.

SURVEILLANCE		FREQUENCY
TSR 3.5.2.1	Perform CHANNEL CHECK.	24 hours
TSR 3.5.2.2	Perform CHANNEL FUNCTIONAL TEST.	31 days
TSR 3.5.2.3	Perform CHANNEL CALIBRATION.	92 days

3.6 CONTAINMENT SYSTEMS

3.6.1.3 Primary Containment Isolation Valves (PCIVs)

TLCO 3.6.1.3 TSR 3.6.1.3.1 and TSR 3.6.1.3.2 shall be met.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

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

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. TSR 3.6.1.3.1 not met for one or more PCIVs.	A.1	Enter the applicable Conditions and Required Actions of LCO 3.6.1.3, "Primary Containment Isolation Valves."	Immediately
B. TSR 3.6.1.3.2 not met for one or more PCIVs.	B.1	Enter TLCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.6.1.3.1	-------------------------------NOTE------------------------------- Only one main steam isolation valve (MSIV) should be tested at a time and THERMAL POWER must be < 1330 MWth. --- Test each normally open power operated PCIV in accordance with the Inservice Testing Program.	In accordance with the Inservice Testing Program

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
TSR 3.6.1.3.2	Exercise each MSIV by partial closure and subsequent reopening.	In accordance with the Inservice Testing Program

3.6 CONTAINMENT SYSTEMS

3.6.1.7 Suppression Chamber-to-Drywell Vacuum Breakers

TLCO 3.6.1.7 TSR 3.6.1.7.1 shall be met.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

--NOTE--
Separate Condition entry is allowed for each suppression chamber-to-drywell vacuum breaker.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. TSR 3.6.1.7.1 not met for one or more suppression chamber-to-drywell vacuum breakers.	A.1 Enter TLCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.6.1.7.1	-----------------------------NOTE----------------------------- Primary containment access is required to perform this Surveillance. -- Visually inspect each suppression chamber-to-drywell vacuum breaker.	24 months

3.6 CONTAINMENT SYSTEMS

3.6.3.2 Online Containment Leakage Check

TLCO 3.6.3.2 TSR 3.6.3.2.1 shall be met.

APPLICABILITY: MODE 1

ACTIONS

---NOTE---
This surveillance is performed once at the beginning of a cycle following refueling when containment and reactor conditions are stable.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. TSR 3.6.3.2.1 not met for allowable leakage criteria.	A.1 Enter TS 3.5.1 (ECCS – Operating) action statement for two or more ECCS injection/spray subsystems inoperable.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.6.3.2.1	Determine primary containment leakage rate. The allowable leakage is 150 scfm when tested at ≥ 44.1 psig.	Once per cycle following refueling

3.8 ELECTRICAL POWER SYSTEMS

3.8.1 Northern States Power (NSP) Transmission Lines

TLCO 3.8.1 Two NSP transmission lines and associated switchgear shall be OPERABLE to supply power to the offsite circuits required by LCO 3.8.1, "AC Sources - Operating."

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required NSP transmission line and associated switchgear inoperable.	A.1 Verify, by administrative means, both emergency diesel generators (EDGs) are OPERABLE. AND A.2 Restore required NSP transmission line and associated switchgear to OPERABLE status.	Immediately 7 days
B. Required Action and associated Completion Time of Condition A not met. OR Two required NSP transmission lines and associated switchgear inoperable.	B.1 Enter TLCO 3.0.3	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.8.1.1	The following Substation Switchyard Battery measurements shall be taken: a. Pilot cell specific gravity and voltage; b. Temperature of cells adjacent to the pilot cell; and c. Overall battery voltage.	7 days
TSR 3.8.1.2	The following Substation Switchyard Battery measurements shall be taken: a. Voltage of each cell (to the nearest 0.01 volt); b. Specific gravity of each cell; and c. Temperature of every fifth cell.	92 days

3.8 ELECTRICAL POWER SYSTEMS

3.8.2 24 VDC Battery Systems

TLCO 3.8.2 Two 24 VDC battery subsystems (each consisting of one 24 VDC battery and battery charger) shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or two 24 VDC battery systems inoperable.	A.1	Declare the associated supported equipment inoperable.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
TSR 3.8.2.1	For each 24 VDC battery subsystem, the following measurements shall be taken: a. Pilot cell specific gravity and voltage; b. Temperature of cells adjacent to the pilot cell; and c. Overall battery voltage.	7 days
TSR 3.8.2.2	For each 24 VDC battery subsystem, the following measurements shall be taken: a. Voltage of each cell (to the nearest 0.01 volt); b. Specific gravity of each cell; and c. Temperature of every fifth cell.	92 days

3.9 REFUELING OPERATIONS

3.9.1 Decay Time

TLCO 3.9.1 The reactor shall be shutdown ≥ 24 hours.

APPLICABILITY: During movement of fuel assemblies within the reactor pressure vessel (RPV).

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Reactor shutdown for < 24 hours.	A.1 Suspend movement of fuel assemblies within the RPV.	Immediately

SURVEILLANCE REQUIREMENTS

None.

5.0 ADMINISTRATIVE CONTROLS

5.2 Organization

5.2.1 Each duty shift shall be composed of at least the minimum licensed operator shift crew composition shown in Table 5.2-1.

Table 5.2-1 (Page 1 of 1)
Minimum Licensed Operator Shift Crew Composition

CATEGORY	APPLICABLE PLANT CONDITIONS	
	MODES 4 and 5	MODES 1, 2[b], and 3
Number of Senior Operators	1[a]	2[c]
Total number of Operators (Senior Operators and Operators)	2	4

(a) Does not include the Senior Operator or the Senior Operator limited to Fuel Handling who is supervising alterations of the reactor core.

(b) Except for momentary switching of the reactor mode switch to Startup/Hot Standby position for testing.

(c) One Senior Operator shall be in the control room or the shift supervisor's office at all times when the reactor is in MODE 1, 2, or 3. At least 50% of the time, a Senior Operator shall actually be in the control room proper when the reactor is in the MODE 1, 2, or 3.

APPENDIX A (Page 1 of 1)
Control Rod Scram Times Limits For Reactor Pressures at 0 psig

NOTCH POSITION	SCRAM TIMES[a] (seconds) WHEN REACTOR STEAM DOME PRESSURE AT 0 psig
46	0.414
36	0.803
26	1.297
06	2.293

(a) Maximum scram time from fully withdrawn position based on de-energization of scram pilot valve solenoids at time zero.

Appendix B (Page 1 of 2)
Secondary Containment Isolation Valves (SCIVs)

Valve	Location	Isolation Time (if applicable)
A. Automatic SCIVs		
V-D-11	Duct from SBGT Room (Division I)	10 seconds
V-D-12	Duct from SBGT Room (Division II)	10 seconds
V-D-13	Duct from SBGT Room (Division I)	10 seconds
V-D-14	Duct from SBGT Room (Division II)	10 seconds
V-D-23	Duct to V-EF-10 (Division I)	10 seconds
V-D-24	Duct to V-EF-10 (Division II)	10 seconds
V-D-25	Duct to V-EF-28 (Division I)	10 seconds
V-D-26	Duct to V-EF-28 (Division II)	10 seconds
V-D-39	Duct to V-EF-24A and V-EF-24B (Division I)	10 seconds
V-D-40	Duct to V-EF-24A and V-EF-24B (Division II)	10 seconds
V-D-57	Double Isolation Dampers on V-AC-10A (Division I)	10 seconds
V-D-58	Double Isolation Dampers on V-AC-10A (Division II)	10 seconds
V-D-59	Double Isolation Dampers on V-AC-10B (Division II)	10 seconds
V-D-60	Double Isolation Dampers on V-AC-10B (Division I)	10 seconds
V-D-61	Double Isolation Dampers on V-AH-4A (Division I)	10 seconds
V-D-62	Double Isolation Dampers on V-AH-4A (Division II)	10 seconds
V-D-63	Double Isolation Dampers on V-AH-4B (Division II)	10 seconds
V-D-64	Double Isolation Dampers on V-AH-4B (Division I)	10 seconds
BV-8203-4	Exhaust Pipe from C-1006A/C-1006B (Division I)	10 seconds
BV-8203-5	Exhaust Pipe from C-1006A/C-1006B (Division II)	10 seconds
AO-2982	Duct to Main Exhaust Plenum Room	10 seconds

Appendix B (Page 2 of 2)
Secondary Containment Isolation Valves (SCIVs)

Valve	Location	Isolation Time (if applicable)
B. Manual SCIVs		
V-D-65	Fuel Pool Filter/Demin (T-47A)	NA
V-D-66	Fuel Pool Filter/Demin (T-47A)	NA
V-D-67	Fuel Pool Filter/Demin (T-47B)	NA
V-D-68	Fuel Pool Filter/Demin (T-47B)	NA
V-D-69	Floor Drain Filter (T-27)	NA
V-D-70	Floor Drain Filter (T-27)	NA
V-D-71	Waste Collector Filter (T-25)	NA
V-D-72	Waste Collector Filter (T-25)	NA
V-D-73	Waste Collector Demineralizer (T-65)	NA
V-D-74	Waste Collector Demineralizer (T-65)	NA
V-D-75	Cleanup Filter/Demin (T-202A)	NA
V-D-76	Cleanup Filter/Demin (T-202A)	NA
V-D-77	Cleanup Filter/Demin (T-202B)	NA
V-D-78	Cleanup Filter/Demin (T-202B)	NA

APPENDIX C

I - Nominal Trip Setpoints

ITS Table and Function Number	Nominal Trip Setpoint (NTSP)	Am.
Table 3.3.1.1-1 – Reactor Protection System Instrumentation		
Function 2.c: APRM Neutron Flux – High	≤ 119.5 % RTP	159
Table 3.3.1.2-1 – Control Rod Block Instrumentation		
Functions 1.a, 1.b and 1.c:		
Rod Block Monitor – Low Power Range – Upscale (1.a)	As specified in COLR	159
Rod Block Monitor – Intermediate Power Range – Upscale (1.b)	As specified in COLR	159
Rod Block Monitor – High Power Range – Upscale (1.c)	As specified in COLR	159
Table 3.3.5.1-1 – Emergency Core Cooling System Instrumentation		
Functions 1.c, 2.c: Reactor Steam Dome Pressure – Low (Injection Permissive)	420 psig	146
Functions 1.d, 2.d: Reactor Steam Dome Pressure Permissive – Low (Pump Permissive)	420 psig	146

APPENDIX C

I - Nominal Trip Setpoints

ITS Table and Function Number	Nominal Trip Setpoint (NTSP)	Am.
Table 3.3.5.1-1 – Emergency Core Cooling System Instrumentation (con't)		
Function 2.j:		
Recirculation Riser Differential Pressure – High (Break Detection)	56.0 inches (water-column)	161
Functions 4.c, 5.c:		
Core Spray Pump Discharge Pressure – High	100 psig	146
Functions 4.d, 5.d:		
Low Pressure Coolant Injection Pump Discharge Pressure – High	100 psig	146

APPENDIX C

II - Nominal Trip Setpoint Methodology (for identified SL-LSSS digital functions)

II.A. ITS Table 3.3.1.1-1, Function 2.c [Am. 159]

- APRM Neutron Flux – High (2.c)

The Nominal Trip Setpoint (NTSP) for this Function was established in accordance with the guidance provided in ESM-03.02-APP-I. Calculation CA-08-050, Revision 0 (Ref. 4) discusses determination of the NTSP, using GE-Hitachi methods analogous to those below.

$NTSP_1$ = AL ± (1.645/2) (SRSS of random terms) ± bias terms for process variables which decrease (+) or increase (-) to trip

$NTSP_2$ = AV ± (desired margin) (Sigma (LER))

The more conservative of $NTSP_1$ or $NTSP_2$ is the governing value.

The PRNM System is a digital system. PRNM System setpoints are stored as numerical values within the PRNMS digital system database and are not subject to drift. The stored setpoint is the NTSP. There is no As Left tolerance (ALT) / As Found tolerance (AFT) associated with re-setting a digital instrument setpoint during surveillance.

II.B. ITS Table 3.3.1.2-1, Functions 1.a, 1.b and 1.c [Am. 159]

- Rod Block Monitor – Low Power Range – Upscale (1.a)
- Rod Block Monitor – Intermediate Power Range – Upscale (1.b)
- Rod Block Monitor – High Power Range – Upscale (1.c)

The NTSPs for these Functions were established in accordance with the guidance provided in ESM-03.02-APP-I. Calculation CA-08-051, Revision 0 (Ref. 5) discusses determination of the NTSP, using GE-Hitachi methods analogous to those below.

$NTSP_1$ = AL ± (1.645/2) (SRSS of random terms) ± bias terms for process variables which decrease (+) or increase (-) to trip

$NTSP_2$ = AV ± (desired margin) (Sigma (LER))

The more conservative of $NTSP_1$ or $NTSP_2$ is the governing value.

The PRNM System is a digital system. PRNM System setpoints are stored as numerical values within the PRNMS digital system database and are not subject to drift. These stored setpoints are the NTSP. There is no ALT/AFT associated with re-setting digital instrument setpoints during surveillances.

APPENDIX C

III - As-Left Methodology

III.a. ITS Table 3.3.5.1-1, Functions 1.c, 1.d, 2.c, 2.d, 4.d, and 5.d [Am. 146]

- Reactor Steam Dome Pressure – Low (Injection Permissive) (1.c and 2.c)
- Reactor Steam Dome Pressure Permissive – Low (Pump Permissive) (1.d and 2.d)
- Low Pressure Coolant Injection Pump Discharge Pressure – High (4.d and 5.d)

The As Left tolerances (ALT) for these Functions were established in accordance with the guidance provided in ESM-03.02-APP-I: "This is an arbitrary term that is used in the calibration or surveillance procedure. If not defined in procedures, the following equation can be used as a guideline: ALT = 3/2 X VA."

The selection of an ALT is not considered critical in the GE setpoint methodology as long as the established ALT is included when calculating the AV and NTSPs. Therefore the methodology provides only limited guidance on establishing ALTs. For these Functions, the existing plant ALTs were used in the setpoint calculations. These ALTs are within the ALTs that would be determined with the above guidance.

III.b. ITS Table 3.3.5.1-1, Function 2.j [Am. 161]

- Recirculation Riser Differential Pressure – High (Break Detection)

The ALT for this Function was established in accordance with the guidance provided in ESM-03.02-APP-I: The following equation was applied to determine the ALT in accordance with CA-04-098, Revision 2 (Ref. 6).

$$ALT = (VA^2 + C_1{}^2 + C_{1STD}{}^2)^{1/2}$$

The selection of an ALT is not considered critical in the GE setpoint methodology as long as the established ALT is included when calculating the AVs and NTSPs. Therefore the methodology provides only limited guidance on establishing ALTs. For this Function, the existing plant ALT was determined to be too restrictive and was increased in order to provide greater ease in the calibration process. The established ALT is within the ALT that would be determined with the above guidance.

III.c ITS Table 3.3.5.1-1 Functions 4.c, 5.c [Am. 146]

- Core Spray Pump Discharge Pressure – High (4.c and 5.c)

The ALTs for these Functions were established in accordance with the guidance provided in ESM-03.02-APP-I: "This is an arbitrary term that is used in the calibration or surveillance procedure. If not defined in procedures, the following equation can be used as a guideline: ALT = 3/2 X VA."

APPENDIX C

The selection of an ALT is not considered critical in the GE setpoint methodology as long as the established ALT is included when calculating the AVs and NTSPs. Therefore the methodology provides only limited guidance on establishing ALTs. For these Functions, the existing plant ALTs were determined to be too restrictive and were increased in order to provide greater ease in the calibration process. The established ALTs are within the ALTs that would be determined with the above guidance.

APPENDIX C

IV - As-Found Methodology

IV.a. ITS Table 3.3.5.1-1, Functions 1.c, 1.d, 2.c, and 2.d [Am. 146]

- Reactor Steam Dome Pressure – Low (Injection Permissive) (1.c and 2.c)
- Reactor Steam Dome Pressure Permissive – Low (Pump Permissive) (1.d and 2.d)

The AFT for these Functions were established in accordance with the guidance provided in ESM-03.02-APP-I: "As Found Tolerances (AFT) should be determined for each device in the instrument channel. The AFT should account for all effects measurable during calibration. Two suggested ways for determining the AFT are:

$$AFT_1 = (3/2)\ (VA^2 + VD^2 + DTE^2)^{1/2};\ \text{or}$$

$$AFT_2 = (VA^2 + VD^2 + DTE^2 + CL^2)^{1/2}.$$

When available, As Left/As Found trending data could be used to determine the AFT limits. The AFT for each device must bound the ALT, but must not exceed the AV. The AFT is normally an indication of expected instrument performance and not an indication of AV violation."

The selection of an AFT is not included in the GE setpoint methodology as the instrument is considered operational as long as the measured as-found value is more conservative than the AV. The above equations are included in the Monticello Nuclear Generating Plant (MNGP) methodology to provide an indication of expected instrument performance. The first equation provides an approximate 3-sigma AFT (as-found measurement expected to be within the AFT 99% of the time). The second equation provides an approximate 2-sigma AFT (as-found measurement expected to be within the AFT 95% of the time).

AFTs for these Functions were established using the AFT_1 equation.

IV.b. ITS Table 3.3.5.1-1, Function 2.j [Am. 161]

- Recirculation Riser Differential Pressure – High (Break Detection)

The AFTs for this Function was established in accordance with the guidance provided in ESM-03.02-APP-I: "As Found Tolerances (AFT) should be determined for each device in the instrument channel. The AFT should account for all effects measurable during calibration." Several suggested ways of determining the AFT are provided in ESM-03.02-APP-I. The following equation was applied to determine the AFT in accordance with CA-04-098, Revision 2 (Ref. 6).

$$AFT = (ALT^2 + AD^2)^{1/2} + D_{Bias}.$$

"When available, As Left/As Found trending data could be used to determine the AFT limits. The AFT for each device must bound the ALT, but must not exceed the AV.

APPENDIX C

The AFT is normally an indication of expected instrument performance and not an indication of AV violation."

The selection of an AFT is not included in the GE setpoint methodology as the instrument is considered operational as long as the measured as-found value is more conservative than the AV.

IV.c <u>ITS Table 3.3.5.1-1, Functions 4.c, 4.d, 5.c, and 5.d</u> [Am. 146]

- Core Spray Pump Discharge Pressure – High (4.c and 5.c)
- Low Pressure Coolant Injection Pump Discharge Pressure – High (4.d and 5.d)

The AFTs for these Functions were established in accordance with the guidance provided in ESM-03.02-APP-I: "As Found Tolerances (AFT) should be determined for each device in the instrument channel. The AFT should account for all effects measurable during calibration. Two suggested ways for determining the AFT are:

$AFT_1 = (3/2)\ (VA^2 + VD^2 + DTE^2)^{1/2}$; or

$AFT_2 = (VA^2 + VD^2 + DTE^2 + CL^2)^{1/2}$.

When available, As Left/As Found trending data could be used to determine the AFT limits. The AFT for each device must bound the ALT, but must not exceed the AV. The AFT is normally an indication of expected instrument performance and not an indication of AV violation."

The selection of an AFT is not included in the GE setpoint methodology as the instrument is considered operational as long as the measured as-found value is more conservative than the AV. The above equations are included in the MNGP methodology to provide an indication of expected instrument performance. The first equation provides an approximate 3-sigma AFT (as-found measurement expected to be within the AFT 99% of the time). The second equation provides an approximate 2-sigma AFT (as-found measurement expected to be within the AFT 95% of the time).

AFTs for these Functions were established using the AFT_2 equation.

APPENDIX C

REFERENCES

1. Amendment No. 146, “Monticello Nuclear Generating Plant (MNGP) - Issuance of Amendment for the Conversion to the Improved Technical Specifications with Beyond-Scope Issues (TAC Nos. MC7505, MC7597 through MC7611, and MC8887),” dated June 5, 2006. (ADAMS Accession No. ML061240241)

2. Amendment No. 159, “Issuance of Amendment Re: Request to Install Power Range Neutron Monitoring System,” dated February 3, 2009. (ADAMS Accession No. ML083440681)

3. Amendment No. 161, “Monticello Nuclear Generating Plant - Issuance of Amendment Regarding Recirculation Riser Differential Pressure (TAC No. MD6864),” dated April 7, 2009. (ADAMS Accession No. ML083040608)

4. CA-08-050, Revision 0, “Average Power Range Monitor (APRM) Non-Flow Biased PRNMS Setpoints for CLTP and EPU,” Attachment 4, DRF No. 0000-0076-2387, “Nuclear Management Company, LLC, Monticello Nuclear Generating Plant PRNM Licensing Setpoints - CLTP Operation,” December 2007.

5. CA-08-051, Revision 0, “Rod Block Monitor (RBM) PRNM Setpoints for CLTP and EPU Operation,” Attachment 4, DRF No. 0000-0076-2387, “Nuclear Management Company, LLC, Monticello Nuclear Generating Plant PRNM Licensing Setpoints - CLTP Operation,” December 2007.

6. CA-04-098, Revision 2, “Instrument Setpoint Calculation, Recirculation Riser Differential Pressure – High (LPCI Loop Select).”

MONTICELLO NUCLEAR GENERATING PLANT TECHNICAL REQUIREMENTS MANUAL BASES

TABLE 1 – MONTICELLO NUCLEAR GENERATING PLANT TRM BASES LIST OF EFFECTIVE SECTIONS/SPECIFICATIONS

AND

TABLE 2 – TRM BASES RECORD OF REVISIONS

HAVE BEEN REMOVED AND THE INFORMATION HAS BEEN COMBINED INTO

TABLE 1 – MONTICELLO NUCLEAR GENERATING PLANT LIST OF EFFECTIVE SECTIONS FOR THE TRM SPECIFICATIONS AND TRM BASES

AND

TABLE 2 – TRM SPECIFICATIONS AND TRM BASES RECORD OF REVISIONS

(SEE FRONT MATTER SECTION BEFORE THE TRM SPECIFICATION SECTION)

3.0 TECHNICAL LIMITING CONDITION FOR OPERATION (TLCO) APPLICABILITY

BASES

TLCOs

TLCO 3.0.1 through TLCO 3.0.5 establish the general requirements applicable to all TLCOs in Sections 3.1 through 3.10 and apply at all times, unless otherwise stated.

TLCO 3.0.1

TLCO 3.0.1 establishes the Applicability statement within each individual Requirement as the requirement for when the TLCO is required to be met (i.e., when the unit is in the MODES or other specified conditions of the Applicability statement of each Requirement).

TLCO 3.0.2

TLCO 3.0.2 establishes that upon discovery of a failure to meet a TLCO, the associated ACTIONS shall be met. The Completion Time of each Required Action for an ACTIONS Condition is applicable from the point in time that an ACTIONS Condition is entered. The Required Actions establish those remedial measures that must be taken within specified Completion Times when the requirements of a TLCO are not met. This Requirement establishes that:

a. Completion of the Required Actions within the specified Completion Times constitute compliance with a Requirement; and

b. Completion of the Required Actions is not required when a TLCO is met within the specified Completion Time, unless otherwise specified.

There are two basic types of Required Actions. The first type of Required Action specifies a time limit in which the TLCO must be met. This time limit is the Completion Time to restore an inoperable system or component to OPERABLE status or to restore variables to within specified limits. If this type of Required Action is not completed within the specified Completion Time, a shutdown may be required to place the unit in a MODE or condition in which the Requirement is not applicable. (Whether stated as a Required Action or not, correction of the entered Condition is an action that may always be considered upon entering ACTIONS.) The second type of Required Action specifies the remedial measures that permit continued operation of the unit that is not further restricted by the Completion Time. In this case, compliance with the Required Actions provides an acceptable justification for continued operation.

Completing the Required Actions is not required when a TLCO is met or is no longer applicable, unless otherwise stated in the individual Requirement.

BASES

TLCO 3.0.2 (continued)

The nature of some Required Actions of some Conditions necessitates that, once the Condition is entered, the Required Actions must be completed even though the associated Conditions no longer exist. The individual TLCO's ACTIONS specify the Required Actions where this is the case. An example of this is in TLCO 3.4.3, "Snubbers."

The Completion Times of the Required Actions are also applicable when a system or component is removed from service intentionally. The reasons for intentionally relying on the ACTIONS include, but are not limited to, performance of TSRs, preventive maintenance, corrective maintenance, or investigation of operational problems. Entering ACTIONS for these reasons must be done in a manner that does not compromise safety. Individual Requirements may specify a time limit for performing a TSR when equipment is removed from service or bypassed for testing. In this case, the Completion Times of the Required Actions are applicable when this time limit expires, if the equipment remains removed from service or bypassed.

When a change in MODE or other specified condition is required to comply with Required Actions, the unit may enter a MODE or other specified condition in which another Requirement becomes applicable. In this case, the Completion Times of the associated Required Actions would apply from the point in time that the new Requirement becomes applicable and the ACTIONS Condition(s) are entered.

TLCO 3.0.3

TLCO 3.0.3 establishes the actions that must be implemented when a TLCO is not met and:

a. An associated Required Action and Completion Time is not met and no other Condition applies; or

b. The condition of the unit is not specifically addressed by the associated ACTIONS. This means that no combination of Conditions stated in the ACTIONS can be made that exactly corresponds to the actual condition of the unit. Sometimes, possible combinations of Conditions are such that entering TLCO 3.0.3 is warranted; in such cases, the ACTIONS specifically state a Condition corresponding to such combinations and also that TLCO 3.0.3 be entered immediately.

This Requirement delineates the time limits for evaluating impacts on safety function and if the plant is in an unanalyzed condition, as well as time limits for establishing compensatory actions when operation cannot be maintained within the limits for safe operation as defined by the TLCO and its ACTIONS.

BASES

TLCO 3.0.3 (continued)

Upon entering TLCO 3.0.3, 1 hour is allowed to initiate action to implement appropriate compensatory actions, to verify the unit is not in an unanalyzed condition, and to verify that a required safety function is not compromised. Within 12 hours, the Operation Manager's approval of the compensatory actions and the plan for exiting TLCO 3.0.3 must be obtained. The use and interpretation of specific times to complete the actions of TLCO 3.0.3 are consistent with the discussion of Section 1.3, "Completion Times."

When determining if the plant is in an unanalyzed condition and when determining if a required safety function is not compromised by the inoperabilities, Technical Specification requirements need to be considered.

The actions required in accordance with TLCO 3.0.3 may be terminated and TLCO 3.0.3 exited if any of the following occurs:

a. The TLCO is now met;

b. A Condition exists for which the Required Actions have now been performed; or

c. ACTIONS exist that do not have expired Completion Times. These Completion Times are applicable from the point in time that the Condition is initially entered and not from the time TLCO 3.0.3 is exited.

Exceptions to TLCO 3.0.3 are addressed in the individual Requirements.

TLCO 3.0.4

TLCO 3.0.4 establishes limitations on changes in MODES or other specified conditions in the Applicability when a TLCO is not met. It allows placing the unit in a MODE or other specified condition stated in that Applicability (i.e., the Applicability desired to be entered) when unit conditions are such that the requirements of the TLCO would not be met, in accordance with TLCO 3.0.4.a, TLCO 3.0.4.b, or TLCO 3.0.4.c.

TLCO 3.0.4.a allows entry into a MODE or other specified condition in the Applicability with the TLCO not met when the associated ACTIONS to be entered permit continued operation in the MODE or other specified condition in the Applicability for an unlimited period of time. Compliance with Required Actions that permit continued operation of the unit for an unlimited period of time in a MODE or other specified condition provides an acceptable level of safety for continued operation. This is without

BASES

TLCO 3.0.4 (continued)

regard to the status of the unit before or after the MODE change. Therefore, in such cases, entry into a MODE or other specified condition in the Applicability may be made in accordance with the provisions of the Required Actions.

TLCO 3.0.4.b allows entry into a MODE or other specified condition in the Applicability with the TLCO not met after performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering the MODE or other specified condition in the Applicability, and establishment of risk management actions, if appropriate.

The risk assessment may use quantitative, qualitative, or blended approaches, and the risk assessment will be conducted using the plant program, procedures, and criteria in place to implement 10 CFR 50.65(a)(4), which requires that risk impacts of maintenance activities to be assessed and managed. The risk assessment, for the purposes of TLCO 3.0.4.b, must take into account all inoperable Technical Specification equipment regardless of whether the equipment is included in the normal 10 CFR 50.65(a)(4) risk assessment scope. The risk assessments will be conducted using the procedures and guidance endorsed by Regulatory Guide 1.182, "Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants." Regulatory Guide 1.182 endorses the guidance in Section 11 of NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." These documents address general guidance for conduct of the risk assessment, quantitative and qualitative guidelines for establishing risk management actions, and example risk management actions. These include actions to plan and conduct other activities in a manner that controls overall risk, increased risk awareness by shift and management personnel, actions to reduce the duration of the condition, actions to minimize the magnitude of risk increases (establishment of backup success paths or compensatory measures), and determination that the proposed MODE change is acceptable. Consideration should also be given to the probability of completing restoration such that the requirements of the TLCO would be met prior to the expiration of ACTIONS Completion Times that would require exiting the Applicability.

TLCO 3.0.4.b may be used with single, or multiple systems and components unavailable. NUMARC 93-01 provides guidance relative to consideration of simultaneous unavailability of multiple systems and components.

BASES

TLCO 3.0.4 (continued)

The results of the risk assessment shall be considered in determining the acceptability of entering the MODE or other specified condition in the Applicability, and any corresponding risk management actions. The TLCO 3.0.4.b risk assessments do not have to be documented. The TLCOs allow continued operation with equipment unavailable in MODE 1 for the duration of the Completion Time. Since this is allowable, and since in general the risk impact in that particular MODE bounds the risk of transitioning into and through the applicable MODES or other specified conditions in the Applicability of the TLCO, the use of the TLCO 3.0.4.b allowance should be generally acceptable, as long as the risk is assessed and managed as stated above.

TLCO 3.0.4.c allows entry into a MODE or other specified condition in the Applicability with the TLCO not met based on a Note in the Requirement which states TLCO 3.0.4.c is applicable. These specific allowances permit entry into MODES or other specified conditions in the Applicability when the associated ACTIONS to be entered do not provide for continued operation for an unlimited period of time and a risk assessment has not been performed. This allowance may apply to all the ACTIONS or to a specific Required Action of a Requirement. The risk assessments performed to justify the use of TLCO 3.0.4.b usually only consider systems and components. For this reason, TLCO 3.0.4.c is typically applied to Requirements which describe values and parameters.

The provisions of this Requirement should not be interpreted as endorsing the failure to exercise the good practice of restoring systems or components to OPERABLE status before entering an associated MODE or other specified condition in the Applicability.

TLCO 3.0.5

TLCO 3.0.5 establishes the allowance for restoring equipment to service under administrative controls when it has been removed from service or declared inoperable to comply with ACTIONS. The sole purpose of this Requirement is to provide an exception to TLCO 3.0.2 (e.g., to not comply with the applicable Required Action(s)) to allow the performance of required testing to demonstrate:

a. The OPERABILITY of the equipment being returned to service; or

b. The OPERABILITY of other equipment.

The administrative controls ensure the time the equipment is returned to service in conflict with the requirements of the ACTIONS is limited to the time absolutely necessary to perform the required testing to demonstrate OPERABILITY. This Requirement does not provide time to perform any other preventive or corrective maintenance.

B 3.0 TECHNICAL SURVEILLANCE REQUIREMENT (TSR) APPLICABILITY

BASES

TSRs	TSR 3.0.1 through TSR 3.0.4 establish the general requirements applicable to all TSRs in Sections 3.1 through 3.10 and apply at all times, unless otherwise stated.

TSR 3.0.1

TSR 3.0.1 establishes the requirement that TSRs must be met during the MODES or other specified conditions in the Applicability for which the requirements of the TLCOs apply, unless otherwise specified in the individual TSRs. This TSR is to ensure that TSRs are performed to verify the OPERABILITY of systems and components, and that variables are within specified limits. Failure to meet a TSR within the specified Frequency, in accordance with TSR 3.0.2, constitutes a failure to meet a TLCO.

Systems and components are assumed to be OPERABLE when the associated TSRs have been met. Nothing in this TSR, however, is to be construed as implying that systems or components are OPERABLE when:

a. The systems or components are known to be inoperable, although still meeting the TSRs; or

b. The requirements of the TSR(s) are known not to be met between required TSR performances.

TSRs do not have to be performed when the unit is in a MODE or other specified condition for which the requirements of the associated TLCO are not applicable, unless otherwise specified.

Unplanned events may satisfy the requirements (including applicable acceptance criteria) for a given TSR. In this case, the unplanned event may be credited as fulfilling the performance of the TSR.

TSRs, including TSRs invoked by Required Actions, do not have to be performed on inoperable equipment because the ACTIONS define the remedial measures that apply. TSRs have to be met and performed in accordance with TSR 3.0.2, prior to returning equipment to OPERABLE status.

Upon completion of maintenance, appropriate post maintenance testing is required to declare equipment OPERABLE. This includes ensuring applicable TSRs are not failed and their most recent performance is in accordance with TSR 3.0.2. Post maintenance testing may not be possible in the current MODE or other specified conditions in the Applicability due to the necessary unit parameters not having been established. In these situations, the equipment may be considered

BASES

TSR 3.0.1 (continued)

OPERABLE provided testing has been satisfactorily completed to the extent possible and the equipment is not otherwise believed to be incapable of performing its function. This will allow operation to proceed to a MODE or other specified condition where other necessary post maintenance testing can be completed.

TSR 3.0.2

TSR 3.0.2 establishes the requirements for meeting the specified Frequency for TSRs and any Required Action with a Completion Time that requires the periodic performance of the Required Action on a “once per . . .” interval.

TSR 3.0.2 permits a 25% extension of the interval specified in the Frequency. This extension facilitates TSR scheduling and considers plant operating conditions that may not be suitable for conducting the TSR (e.g., transient conditions or other ongoing TSR or maintenance activities).

The 25% extension does not significantly degrade the reliability that results from performing the TSR at its specified Frequency. This is based on the recognition that the most probable result of any particular TSR being performed is the verification of conformance with the TSRs. The exception to TSR 3.0.2 are those TSRs for which the 25% extension of the interval specified in the Frequency does not apply. These exceptions are stated in the individual TSRs. The requirements of regulations take precedence over the TRM. The TRM cannot in and of itself extend a test interval specified in the regulations.

As stated in TSR 3.0.2, the 25% extension also does not apply to the initial portion of a periodic Completion Time that requires performance on a "once per . . ." basis. The 25% extension applies to each performance after the initial performance. The initial performance of the Required Action, whether it is a particular TSR or some other remedial action, is considered a single action with a single Completion Time. One reason for not allowing the 25% extension to this Completion Time is that such an action usually verifies that no loss of function has occurred by checking the status of redundant or diverse components or accomplishes the function of the inoperable equipment in an alternative manner.

The provisions of TSR 3.0.2 are not intended to be used repeatedly merely as an operational convenience to extend TSR intervals (other than those consistent with refueling intervals) or periodic Completion Time intervals beyond those specified.

BASES

TSR 3.0.3

TSR 3.0.3 establishes the flexibility to defer declaring affected equipment inoperable or an affected variable outside the specified limits when a TSR has not been completed within the specified Frequency. A delay period of up to 24 hours or up to the limit of the specified Frequency, whichever is greater, applies from the point in time it is discovered that the TSR has not been performed in accordance with TSR 3.0.2, and not at the time that the specified frequency was not met.

This delay period provides adequate time to complete TSRs that have been missed. This delay period permits the completion of a TSR before complying with Required Actions or other remedial measures that might preclude completion of the TSR.

The basis for this delay period includes consideration of unit conditions, adequate planning, availability of personnel, the time required to perform the TSR, the safety significance of the delay in completing the required TSR, and the recognition that the most probable result of any particular TSR being performed is the verification of conformance with the requirements.

When a TSR with a Frequency based not on time intervals, but upon specified unit conditions or operational situations (e.g., prior to entering MODE 1 after each fueling loading), is discovered not to have been performed when specified, TSR 3.0.3 allows the full delay period of up to the specified frequency to perform the TSR. However, since there is not a time interval specified, the missed TSR should be performed at the first reasonable opportunity.

TSR 3.0.3 provides a time limit for and allowances for, the performance of, TSRs that become applicable as a consequence of MODE changes imposed by Required Actions.

Failure to comply with specified Frequencies for TSRs is expected to be an infrequent occurrence. Use of the delay period established by TSR 3.0.3 is a flexibility which is not intended to be used as an operational convenience to extend TSR intervals. While up to 24 hours or the limit of the specified Frequency is provided to perform the missed TSR, it is expected that the missed TSR will be performed at the first reasonable opportunity. The determination of the first reasonable opportunity should include consideration of the impact on unit risk (from delaying the TSR as well as any unit configuration changes required or shutting the unit down to perform the TSR) and impact on any analysis assumptions, in addition to unit conditions, planning, availability of personnel, and the time required to perform the TSR. This risk impact should be managed through the program in place to implement 10 CFR 50.65(a)(4) and its implementation guidance Regulatory Guide 1.182, "Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants." This Regulatory Guide addresses

BASES

TSR 3.0.3 (continued)

consideration of temporary and aggregate risk impacts, determination of risk management action thresholds, and risk management action up to and including plant shutdown. The missed TSR should be treated as an emergent condition as discussed in the Regulatory Guide. The risk evaluation may use quantitative, qualitative, or blended methods. The degree of depth and rigor of the evaluation should be commensurate with the importance of the component. Missed TSRs for important components should be analyzed quantitatively. If the results of the risk evaluation determine the risk increase is significant this evaluation should be used to determine the safest course of action. All missed TSRs will be placed in the licensee's Corrective Action Program.

If a TSR is not completed within the allowed delay period, then the equipment is considered inoperable or the variable then is considered outside the specified limits and the Completion Times of the Required Actions for the applicable TLCO Conditions begin immediately upon expiration of the delay period. If a TSR is failed within the delay period, then the equipment is inoperable, or the variable is outside the specified limits and the Completion Times of the Required Actions for the applicable TLCO Conditions begin immediately upon the failure of the TSR.

Completion of the TSR within the delay period allowed by this TSR, or within the Completion Time of the ACTIONS, restores compliance with TSR 3.0.1.

TSR 3.0.4

TSR 3.0.4 establishes the requirement that all applicable TSRs must be met before entry into a MODE or other specified condition in the Applicability.

This TSR ensures that system and component OPERABILITY requirements and variable limits are met before entry into MODES or other specified conditions in the Applicability for which these system and components ensure safe operation of the unit. The provisions of this TSR should not be interpreted as endorsing the failure to exercise the good practice of restoring systems or components to OPERABLE status before entering an associated MODE or other specified condition in the Applicability.

A provision is included to allow entry into a MODE or other specified Condition in the Applicability when a TLCO is not met due to a TSR not being met in accordance with TLCO 3.0.4. However, in certain circumstances, failing to meet a TSR will not result in TSR 3.0.4 restricting a MODE change or other specified condition change. When a system, subsystem, division, component, device, or variable is inoperable

BASES

TSR 3.0.4 (continued)

or outside its specified limits, the associated TSR(s) are not required to be performed, per TSR 3.0.1, which states that TSRs do not have to be performed on inoperable equipment. When equipment is inoperable, TSR 3.0.4 does not apply to the associated TSR(s) since the requirement for the TSR(s) to be performed is removed. Therefore, failing to perform the TSRs within the specified Frequency does not result in a TSR 3.0.4 restriction to changing MODES or other specified conditions of the Applicability. However, since the TLCO is not met in this instance, TLCO 3.0.4 will govern any restrictions that may (or may not) apply to MODE or other specified condition changes. TRS 3.0.4 does not restrict changing MODES or other specified conditions of the Applicability when a Surveillance has not been performed within the specified Frequency, provided the requirement to declare the TLCO not met has been delayed in accordance with TRS 3.0.3.

The provisions of TSR 3.0.4 shall not prevent changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS. In addition, the provisions of TSR 3.0.4 shall not prevent changes in MODES or other specified conditions in the Applicability that result from any unit shutdown. In this context, a unit shutdown is defined as a change in MODE or other specified condition in the Applicability associated with transitioning from MODE 1 to MODE 2, MODE 2 to MODE 3, and MODE 3 to MODE 4.

The precise requirements for performance of TSRs are specified such that exceptions to TSR 3.0.4 are not necessary. The specific time frames and conditions necessary for meeting the TSRs are specified in the Frequency, in the TSR, or both. This allows performance of TSRs when the prerequisite condition(s) specified in a TSR procedure require entry into the MODE or other specified condition in the Applicability of the associated TLCO prior to the performance or completion of a TSR. A TSR that could not be performed until after entering the TLCO Applicability would have its Frequency specified such that it is not "due" until the specific conditions needed are met. Alternately, the TSR may be stated in the form of a Note as not required (to be met or performed) until a particular event, condition, or time has been reached. Further discussion of the specific formats of TSRs' annotation is found in Section 1.4, "Frequency."

B 3.3 INSTRUMENTATION

B 3.3.1.1 Turbine Condenser Vacuum – Low Instrumentation

BASES

BACKGROUND

The Turbine Condenser Vacuum – Low Function is provided to shut down the reactor and reduce the energy input to protect the main condenser from over-pressurization in the event of a loss of main condenser vacuum. The Function protects from over-pressurization by stopping reactor steam generation (via the safety related reactor scram). Over-pressurization of the main condenser is also prevented by actuation of the non-safety grade turbine instrumentation initiating closure of the turbine stop valves and turbine bypass valves, shutting off steam flow to the main condenser. This ensures that a postulated main condenser failure from over-pressurization remains a non-limiting event for dose consequences to the public (Ref. 4).

While not directly credited in the safety analyses, the Turbine Condenser Vacuum – Low Function provides a proactive scram signal for the loss of condenser vacuum event. For this event, the reactor scram reduces the amount of energy required to be absorbed by the main condenser by reducing the core energy prior to the fast closure of the turbine stop valves. This Function helps maintain the main condenser as a heat sink during this event.

Turbine condenser vacuum pressure signals are derived from four pressure switches that sense the pressure in the condenser. Four channels of Turbine Condenser Vacuum – 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.

APPLICABLE SAFETY ANALYSES

No specific safety analyses take credit for the Turbine Condenser Vacuum – Low Function scram because the Turbine Trip without bypass (TTNBP) event, equivalent to an instantaneous loss of condenser vacuum, was analyzed as part of the safety analyses. However, this proactive scram Function is included as part of the Reactor Protection System (RPS) and reduces the amount of energy to be absorbed by the main condenser and maintain the condenser as a heat sink during a loss of condenser vacuum event.

TLCO

The TLCO requires four channels of the Turbine Condenser Vacuum – Low instrumentation to be OPERABLE to ensure that no single instrument failure will preclude a scram from this Function on a valid signal. Each channel must have its setpoint set within the specified Allowable Value of TSR 3.3.1.1.2. The Allowable Value was selected to reduce the severity of a loss of main condenser vacuum event by anticipating the transient and scramming the reactor at a higher vacuum

BASES

TLCO (continued)

than the setpoints that close the turbine stop valves. The Turbine Condenser Vacuum – Low instrumentation Function must have the required number of OPERABLE channels per RPS trip system, with the setpoint within the specified Allowable Value, where appropriate. The actual setpoint is calibrated to be consistent with the applicable setpoint methodology assumptions. Nominal trip setpoints are specified in the setpoint calculations. The nominal setpoints are selected to ensure that the actual setpoints do not exceed the Allowable Value between successive CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable. A channel is inoperable if its actual trip is not within its required Allowable Value.

Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (e.g., condenser vacuum), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., trip unit) changes state. The Allowable Value and the nominal trip setpoint (NTSP) is derived, using the General Electric setpoint methodology guidance, as specified in the Monticello setpoint methodology. The Allowable Value is derived from the analytical limit. The difference between the analytical limit and the Allowable Value allows for channel instrument accuracy, calibration accuracy, process measurement accuracy, and primary element accuracy. The margin between the Allowable Value and the NTSP allows for instrument drift that might occur during the established surveillance period. Two separate verifications are performed for the calculated NTSP. The first, a Spurious Trip Avoidance Test, evaluates the impact of the NTSP on plant availability. The second verification, an LER Avoidance Test, calculates the probability of exceeding the Allowable Value due to instrument drift. These two verifications are statistical evaluations to provide additional assurance of the acceptability of the NTSP and may require changes to the NTSP. Use of these methods and verifications provides the assurance that if the setpoint is found conservative to the Allowable Value during surveillance testing, the instrumentation would have provided the required trip function by the time the process reached the analytical limit for the applicable events.

APPLICABILITY

The Turbine Condenser Vacuum – Low Instrumentation is required to be OPERABLE in MODE 1, and MODE 2 with the reactor steam dome pressure greater than or equal to 600 psig, since in these MODEs there is a significant amount of core energy that can be rejected to the main condenser. During MODE 2 (below 600 psig) and Modes 3, 4, and 5, the core energy is significantly lower. This Function is automatically bypassed with the reactor mode switch in any position other than run and reactor steam dome pressure below 600 psig.

BASES

ACTIONS

A Note has been provided to modify the ACTIONS related to Turbine Condenser Vacuum – Low 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. As such, a Note has been provided that allows separate Condition entry for each inoperable Turbine Condenser Vacuum – Low Instrumentation channel.

<u>A.1 and A.2</u>

Because of the diversity of sensors available to provide trip signals and the redundancy of the RPS design, a Completion Time of 12 hours has been shown to be acceptable (Ref. 3) to permit restoration of any inoperable channel to OPERABLE status. However, this Completion Time is only acceptable provided the associated Function's inoperable channel is in one trip system and the Function still maintains RPS trip capability (refer to Required Actions B.1, B.2 and C.1 Bases). If the inoperable channel cannot be restored to OPERABLE status within the Completion Time, the channel or the associated trip system must be placed in the tripped condition per Required Actions A.1 and A.2. Placing the inoperable channel in trip (or the associated trip system in trip) would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. Alternatively, if it is not desired to place the channel (or trip system) in trip (e.g., as in the case where placing the inoperable channel in trip would result in a full scram), Condition D must be entered and its Required Action taken.

<u>B.1 and B.2</u>

Condition B exists when at least one required channel is inoperable in each trip system. In this condition, provided at least one channel per trip system is OPERABLE, the RPS still maintains trip capability for that Function, but cannot accommodate a single failure in either trip system.

Required Actions B.1 and B.2 limit the time the RPS scram logic would not accommodate a single failure in either trip system. The reduced reliability of this logic arrangement was not evaluated in Reference 3 for the 12 hour Completion Time. Within the 6 hour allowance, the Turbine Condenser Vacuum – Low Function will have all required channels OPERABLE or in trip (or any combination) in one trip system.

BASES

ACTIONS (continued)

Completing one of these Required Actions restores RPS to a reliability level equivalent to that evaluated in Reference 3, which justified a 12 hour Completion Time as presented in Condition A. The trip system in the more degraded state should be placed in trip or, alternatively, all the inoperable channels in that trip system should be placed in trip (e.g., a trip system with two inoperable channels could be in a more degraded state than a trip system with four inoperable channels if the two inoperable channels are in the same Function while the four inoperable channels are all in different Functions). The decision of which trip system is in the more degraded state should be based on prudent judgment and take into account current plant conditions (i.e., what MODE the plant is in). If this action would result in a scram, it is permissible to place the other trip system or its inoperable channels in trip.

The 6 hour Completion Time is judged acceptable based on the remaining capability to trip, the diversity of the sensors available to provide the trip signals, the low probability of extensive numbers of inoperabilities affecting all diverse Functions, and the low probability of an event requiring the initiation of a scram.

Alternately, if it is not desired to place the inoperable channels (or one trip system) in trip (e.g., as in the case where placing the inoperable channel or associated trip system in trip would result in a scram, Condition D must be entered and its Required Action taken.

<u>C.1</u>

Required Action C.1 is intended to ensure that appropriate actions are taken if one or more inoperable, untripped channels within the same trip system for the same Function result in the Function not maintaining RPS trip capability. A Function is considered to be maintaining RPS trip capability when sufficient channels are OPERABLE or in trip (or the associated trip system is in trip), such that both trip systems will generate a trip signal from the Function on a valid signal. For the Turbine Condenser Vacuum – Low Instrumentation function with one-out-of-two taken twice logic this would require both trip systems to have one channel OPERABLE or in trip (or the associated trip system in trip).

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

BASES

ACTIONS (continued)

D.1

Condition D corresponds to a level of degradation that results in the required safety function of the Turbine Condenser Vacuum – Low Instrumentation function to be lost. Therefore, no additional time is justified for continued operation. TLCO 3.0.3 must be entered immediately to commence a controlled shutdown.

SURVEILLANCE REQUIREMENTS

The Surveillances are modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided Turbine Condenser Vacuum – Low Instrumentation scram capability is maintained. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the reliability analysis (Ref. 3) assumption that 6 hours is the average time required to perform channel Surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that the Turbine Condenser Vacuum – Low Instrumentation will initiate a scram when necessary.

TSR 3.3.1.1.1

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

The 31 day Frequency is based on engineering judgment, operating experience, and reliability of this instrumentation.

BASES

SURVEILLANCE REQUIREMENTS (continued)

TSR 3.3.1.1.2

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

The Frequency is based upon the assumption of a 31 day calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

REFERENCES

1. USAR, Section 7.6.1.2.9
2. USAR, Section 7.7.3
3. NEDC-30851-P-A, "Technical Specification Improvement Analyses for BWR Reactor Protection System," March 1988.
4. Calculation 06-105, “Instrument Setpoint Calculation, Condenser Low Vacuum Scram,” Revision 2

B 3.3 INSTRUMENTATION

B 3.3.2.1 Control Rod Block Instrumentation

BASES

The control rod block functions are provided to prevent excessive control rod withdrawal so that MCPR remains above the Safety Limit (Technical Specification 2.1.1). The trip logic for this function is 1 out of n; e.g., any trip on one of the four APRM's, eight IRM's, four SRM's, or two scram discharge volume water level channels will result in a rod block. For each Control Rod Block Function, there are two trip systems, with the exception of the scram discharge volume water level trip function, which only feeds one trip system. The scram discharge volume water level instrumentation includes one sensor on each of the two scram discharge volumes. This assures that no control rod is withdrawn unless enough capacity is available in either scram discharge volume to accommodate a scram. The setting is selected to initiate a rod block no later than the scram that is initiated on scram discharge volume high water level.

The minimum instrument channel requirements for the IRM may be reduced by one for a short period of time to allow for maintenance, testing, or calibration. See Section 7.3 FSAR.

The APRM Simulated Thermal Power – High rod block (Refs. 3 and 4) is referenced to flow and prevents operation significantly above the licensing basis power level especially during operation at reduced flow. For operation at low power (i.e., MODE 2), the APRM Neutron Flux – High (Setdown) Function (Ref. 3) is capable of generating a rod block to prevent fuel damage resulting from abnormal operating transients in this power range. The APRMs provides gross core protection; i.e., limits the gross core power increase from withdrawal of control rods in the normal withdrawal sequence. The operator will set the APRM rod block trip settings no greater than that stated in Table 3.3.2.1-1. However, the actual setpoint can be as much as 3% greater than that stated in Table 3.3.2.1-1 for recirculation driving flows less than 50% of design and 2% greater than that shown for recirculation driving flows greater than 50% of design due to the deviations that could be caused by inherent instrument error, operator setting error, drift of the setpoint, etc.

The APRM Backup Stability Protection (BSP) Flow-Bias rod blocks are active when the Automated Backup Stability Protection (ABSP) function is enabled. The BSP Flow-Bias rod blocks provide a rod block for reactivity transients when operating at low recirculation flows with the OPRMs out of service. These rod blocks provide a warning of potential ABSP scrams. The constant flow line and flow breakpoint are in terms of rated (recirculation) drive flow or RDF (see Ref. 5). Addition of these rod block functions was approved by Amendment No. 180 (Ref. 6).

The IRM rod block function provides local as well as gross core protection. The scaling arrangement is such that trip setting is less than a factor of 10 above the indicated level. Analysis of the worst case accident results in rod block action before MCPR approaches the Safety Limit (Technical Specification 2.1.1).

A downscale indication of an IRM is an indication the instrument has failed or the instrument is not sensitive enough. In either case the instrument will not respond to changes in control rod motion and thus control rod motion is prevented. The downscale IRM rod block assures that there will be proper overlap between the neutron monitoring systems and thus, that adequate coverage is provided for all ranges of reactor operation. The downscale IRM rod block is set at 3/125 of full scale.

BASES

Although the operator will set the setpoints within the trip settings specified in Table 3.3.2.1-1, the actual values of the various set points can differ appreciably from the value the operator is attempting to set. The deviations could be caused by inherent instrument error, operator setting error, drift of the set point, etc. Therefore, these deviations have been accounted for in the various transient analyses.

Trip Function	Deviation
IRM Downscale	- 2/125 of Scale
IRM Upscale	+ 2/125 of Scale
APRM Downscale	- 2/125 of Scale
APRM Upscale	+ 3% for recirculation driving flows < 50% of design
	+ 2% for recirculation driving flows > 50% of design
Scram Discharge Volume-High Level	+ 1 gallon

The instrumentation in this section will be functionally tested and calibrated at regularly scheduled intervals. The 184 day CHANNEL FUNCTIONAL TEST and 24 month CHANNEL CALIBRATION surveillance frequencies for the APRM Simulated Thermal Power – High, APRM Downscale, and APRM Neutron Flux – High (Setdown) rod block functions are consistent with the NUMAC PRNMS design assumptions (Refs. 1 and 2). Although this instrumentation is not generally considered to be as important to plant safety as the Reactor Protection System, the same design reliability goals are applied. Where applicable, sensor checks are specified on a once/12 hours basis.

REFERENCES

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

2. NEDC-32410P-A, Supplement 1, "Nuclear Measurement Analysis and Control Power Range Neutron Monitor (NUMAC PRNM) Retrofit Plus Option III Stability Trip Function," November 1997.

3. Amendment No. 159, "Issuance of Amendment Re: Request to Install Power Range Neutron Monitoring System," dated February 3, 2009. (ADAMS Accession No. ML083440681)

4. Calculation 08-052, "Instrument Setpoint Calculation – Average Power Range Monitor (APRM) Flow Biased PRNM Setpoints for EPU," Revision 2.

5. Calculation 12-043 "Average Power Range Monitor NUMAC PRNM Setpoints – MELLLA+ Automatic Backup Stability Protection (ABSP)," Revision 0.

6. Amendment No. 180, "Monticello Nuclear Generating Plant – Issuance of Amendment No. 180 to Renewed Facility Operating License Regarding MELLLA+," dated March 28, 2014. (ADAMS Accession No. ML14035A248)

B 3.3 INSTRUMENTATION

B 3.3.3.1 Post Accident Monitoring (PAM) Instrumentation

BASES

The OPERABILITY of the accident monitoring instrumentation ensures that sufficient information is available on selected plant parameters to monitor and assess these variables during and following an accident. This capability is consistent with the recommendations of NUREG-0578, TMI-2 Learned Task Force Status Report and Short Term Recommendations.

For the Safety/Relief Valve (S/RV) position (pressure switch) channels, the CHANNEL CHECK will consist of verifying the pressure switches are not tripped.

B 3.3 INSTRUMENTATION

B 3.3.4.1 Anticipated Transient Without Scram (ATWS) Alternate Rod Injection Instrumentation

BASES

The ATWS Alternate Rod Injection consists of two independent trip systems, with two channels of Reactor Vessel Steam Dome Pressure - High and two channels of Reactor Vessel Water Level - Low Low in each trip system. Each ATWS Alternate Rod Injection trip system is a two-out-of-two logic for each Function. Thus, either two Reactor Vessel Water Level - Low Low or two Reactor Vessel Steam Dome Pressure - High signals are needed to trip a trip system. The outputs of the channels in a trip system are combined in a logic so that either trip system will cause all control rods to be inserted into the core. Each Reactor Vessel Water Level - Low Low output must remain below the setpoint for approximately 7 seconds for the channel output to provide an actuation signal to the associated trip system. Two solenoid valves are installed in the scram air header upstream of the hydraulic control units. Each of the two trip systems energizes a valve to vent the header and causes rod insertion. This greatly reduces the long term consequences of an ATWS event.

B 3.3 INSTRUMENTATION

B 3.3.5.1 Loss of Auxiliary Power (LOP) Instrumentation

BASES

BACKGROUND

Successful operation of the required safety functions of the Emergency Core Cooling Systems (ECCS) is dependent upon the availability of adequate power sources for energizing the pump motors. The LOP instrumentation monitors the 4.16 kV essential buses and source breakers. The Loss of Auxiliary Power “Pump Bus Power Monitor” instrumentation determines if there is sufficient power available to allow the starting of the ECCS pump motors in sequence.

Each 4.16 kV essential bus has its own independent LOP Pump Bus Power Monitor instrumentation and associated trip logic. The 4.16 kV power availability for each bus is monitored by two different methods, which can be considered as two different LOP Pump Bus Power Monitor power availability monitoring Channels: 4.16kV Essential Bus Loss of Voltage channel and 4.16 kV Essential Bus source breaker position channel.

The 4.16 kV Essential Bus Loss of Voltage Channel is monitored by two (2) undervoltage relays for each emergency bus, whose outputs are arranged in a one-out-of-two logic configuration (i.e., either undervoltage relay must sense 4kV power is available to provide a permissive to allow the Core Spray and RHR pumps to start in sequence). The undervoltage relays are shown in the Core Spray System Schematic Diagrams.

The 4.16 kV Essential Bus source breaker position Channel is monitored by breaker contacts on the three (3) Essential Bus Power Source breakers for each essential bus (from the EDG, 1AR or the Non-Essential Bus respectively) (i.e., one source breaker must indicate the source breaker is closed and therefore 4kV power is available at the essential bus to provide a permissive to allow the Core Spray and RHR pumps to start in sequence). The 4.16kV Essential Bus source breaker contacts for the three (3) Essential Bus Power Source breakers are shown in the RHR System Schematic Diagrams.

Either Bus Power Monitoring Channel will provide the permissive signal to allow both the Core Spray and RHR pumps to start in sequence.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY	The LOP instrumentation is required to ensure the availability of adequate power sources for energizing the ECCS pump motors. The LOP instrumentation monitors the 4.16 kV essential buses and source breakers. The Loss of Auxiliary Power Pump Bus Power Monitor instrumentation determines if there is sufficient power available to allow the starting of the ECCS pump motors in sequence.

ACTIONS

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

A.1

With one channel of a Function inoperable in one required trip system, the channel is not capable of performing the intended function for that trip system. Therefore, only 12 hours is allowed to restore the inoperable channel to OPERABLE status.

If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, Condition B must be entered and its Required Action taken.

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. The 12 hour Completion Time is acceptable because it minimizes risk while allowing time for restoration of channels.

BASES

ACTIONS (continued)

B.1

If any Required Action and associated Completion Time are not met, or if two Loss of Auxiliary Power instrument channels are inoperable in one or both required trip systems, the associated Function is not capable of performing the intended function. Therefore, the associated low pressure ECCS Pumps are declared inoperable immediately. This requires entry into applicable Conditions and Required Actions of LCO 3.5.1 and LCO 3.5.2, which provide appropriate actions for inoperable Core Spray and RHR Pumps.

SURVEILLANCE REQUIREMENTS

The Surveillances are modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the channel in the same trip system is monitoring that parameter. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken.

TSR 3.3.5.1.1

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy.

CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

The Frequency of TSR 3.3.5.1.1 is based upon the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

BASES

REFERENCES

1. USAR, Section 8.4.1.3.
2. USAR, Section 6.2.
3. USAR, Section 14.7.2.
4. AR 01429107

B 3.3 INSTRUMENTATION

B 3.3.7.1 Control Room Air Intake Radiation - High Instrumentation

BASES

The Control Room Air Intake Radiation Monitors measure radiation levels in the intake ducting of the control room envelope. In the event of increased radiation in the outside environment, the radiation monitors will automatically initiate the Control Room Emergency Filtration (CREF) System to provide protection for Control Room operators.

The Control Room Air Intake Radiation Monitor is not credited in any safety analysis. The monitor was removed from Tech Spec 3.3.7.1 by License Amendment 148, which also added four new signals to Tech Spec 3.3.7.1 (Reactor Vessel Water Level - Low Low, Drywell Pressure - High, Reactor Building Ventilation Exhaust Radiation - High, and Refueling Floor Radiation - High). These new signals are credited in the DBA safety analyses for initiation of the CREF System.

The Control Room Air Intake Radiation Monitor is maintained as an additional CREFS initiation signal for defense-in-depth. Inclusion in the Technical Requirements Manual satisfies NRC Commitment M06030A.

The CREF System has two trip systems. One trip system isolates the control room boundary and initiates one CREF subsystem while the other trip system also isolates the control room boundary and initiates the other CREF subsystem. Each trip system receives input from one Control Room Air Intake Radiation - High signal, as well as the signals discussed above. The Control Room Air Intake Radiation - High Function is arranged in a one-out-of-one logic. The channels include electronic equipment (e.g., relays) that compares measured input signals with pre-established setpoints. When the setpoint is exceeded, the channel output relay actuates, which then outputs a CREF System initiation signal to the initiation logic.

The Control Room Air Intake Radiation - High Function consists of two independent monitors. Two channels of Control Room Air Intake Radiation - High are available and are required to be OPERABLE to ensure that no single instrument failure can preclude CREF System initiation by the radiation monitors. Each channel must have its setpoint within the specified Allowable Value of SR 3.3.7.1.3. The Allowable Value for the Control Room Air Intake Radiation - High Function is set just above background to ensure that the control room operators are protected from increased radiation exposure.

The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions. Nominal trip setpoints are specified in plant procedures. The nominal setpoints are selected to ensure that the setpoints do not exceed the Allowable Value between successive CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable. A channel is inoperable if its actual trip setpoint is not within its required Allowable Value.

BASES (continued)

The Surveillances are modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 8 hours, provided the associated Function maintains CREF System initiation capability. Upon completion of the Surveillance, or expiration of the 8 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the time required to perform the channel Surveillance.

Performance of the CHANNEL CHECK once every 12 hours ensures that a gross failure of instrumentation has not occurred. The Frequency is based upon operating experience that demonstrates channel failure is rare.

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the channel will perform the intended function. The Frequency of 31 days is based on the known reliability of the equipment and the two channel redundancy available.

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology. The Frequency is based upon operating experience, which has shown that these components usually pass the Surveillance when performed at the 24 month Frequency.

3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.1 RCS Chemistry

BASES

Materials in the primary system are primarily 304 stainless steel and zircaloy. The reactor water chemistry limits are established to prevent damage to these materials. The limit placed on chloride concentration is to prevent stress corrosion cracking of the stainless steel.

When conductivity is in its proper normal range (approximately 10 μmho/cm during reactor startup and 5 μmho/cm during power operation), pH and chloride and other impurities affecting conductivity must also be within their normal range. When and if conductivity becomes abnormal, then chloride measurements are made to determine whether or not they are also out of their normal operating values. This would not necessarily be the case. Conductivity could be high due to the presence of a neutral salt, e.g., Na_2SO_4, which would not have an effect on pH or chloride. In such a case, high conductivity alone is not a cause for shutdown. In some types of water-cooled reactors, conductivities are in fact high due to purposeful addition of additives. In the case of BWRs, however, no additives are used and where neutral pH is maintained, conductivity provides a very good measure of the quality of the reactor water. Significant changes therein provide the operator with a warning mechanism so he can investigate and remedy the condition causing the change before limiting conditions, with respect to variables affecting the boundaries of the reactor coolant, are exceeded. Methods available to the operator for correcting the off-standard condition include operation of the reactor cleanup system reducing the input of impurities and placing the reactor in the cold shutdown condition. The major benefit of cold shutdown is to reduce the temperature dependent corrosion rates and provide time for the cleanup system to reestablish the purity of the reactor coolant. During startup periods, which are in the category of less than 100,000 pounds per hour, conductivity may exceed 5 μmho/cm because of the initial evolution of gases and the initial addition of dissolved metals. During this period of time when the conductivity exceeds 5 μmho (other than short term spikes), samples will be taken to assure the chloride concentration is less than 0.1 ppm.

The conductivity of the reactor coolant is continuously monitored. The samples of the coolant which are taken every 96 hours will serve as a reference for calibration of these monitors and is considered adequate to assure accurate readings of the monitors. If conductivity is within its normal range, chlorides and other impurities will also be within their normal ranges. The reactor coolant samples will also be used to determine the chlorides. Therefore, the sampling frequency is considered adequate to detect long-term changes in the chloride ion content.

3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.2 Safety/Relief Valve (S/RV) Bellows and Bellows Monitoring System

BASES

Article 9, Section N-911.4(a)(4) of the ASME Pressure Vessel Code Section III Nuclear Vessels (1965 and 1968 editions) requires that safety/relief valve bellows be monitored for failure since this would defeat the self actuated safety function of the safety/relief valve.

Provision has been made to detect failure of the bellows monitoring system. Testing of this system once per 24 months provides assurance of bellows integrity.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.4 Safety/Relief Valves (S/RVs) Out-of-Service

BASES

BACKGROUND

The ASME Boiler and Pressure Vessel Code requires the reactor pressure vessel be protected from overpressure during upset conditions by self-actuated safety valves. As part of the nuclear pressure relief system, the size and number of S/RVs are selected such that peak pressure in the nuclear system will not exceed the ASME Code limits for the reactor coolant pressure boundary (RCPB).

Technical Specification LCO 3.4.3, "Safety/Relief Valves (S/RVs)," provides safety mode requirements for the limiting design basis event of closure of all main steam isolation valves (MSIVs), followed by reactor scram on high neutron flux. This TLCO imposes an additional restriction that all eight S/RVs be OPERABLE to meet reactor vessel overpressure protection limits for operation within the Maximum Extended Load Line Limit Analysis Plus (MELLLA+) operating domain for an Anticipated Transient Without Scram (ATWS) event. Reactor vessel pressure is required to remain within ASME Code Service Level C limits of 1500 psig for the postulated ATWS event in the MELLLA+ operating domain.

APPLICABLE SAFETY ANALYSES

The overpressure protection system must accommodate the most severe pressurization transient. Evaluations have determined that the most severe design basis event is the closure of all main steam isolation valves (MSIVs), followed by reactor scram on high neutron flux (i.e., failure of the direct scram associated with MSIV position) (Ref. 1). For the purpose of the analyses, five S/RVs are assumed to operate in the safety mode. The analysis results demonstrate that the design S/RV capacity is capable of maintaining reactor pressure below the ASME Code limit of 110% of vessel design pressure as described in Technical Specification 3.4.3. However, two additional S/RVs are required to be OPERABLE to provide additional relief capability per Technical Specification 3.4.3.

For the purpose of the ATWS analyses occurring within the MELLLA+ operating domain, eight S/RVs are assumed to operate in the safety mode (Ref. 2). Consequently, the S/RV Out of Service (SRVOOS) flexibility option is not permitted during operation in the MELLLA+ operating domain. Analysis results demonstrate that the design S/RV capacity is capable of maintaining reactor pressure below the ASME Service Level C Code limit of 1500 psig. This TLCO helps to ensure that this acceptance limit of 1500 psig is met if an ATWS were to occur while operating in the MELLLA+ operating domain.

BASES

TLCO	The safety mode of eight S/RVs are required to be OPERABLE to satisfy the assumptions of the MELLLA+ safety analysis (Ref. 2). The requirements of this TLCO are applicable only to the capability of the S/RVs to mechanically open to relieve excess pressure when the lift setpoint is exceeded (valve safety function). The S/RV setpoints are established to ensure that the ASME Code Service Level C limit on peak reactor pressure is satisfied. Operation with fewer than eight valves OPERABLE, or with setpoints outside the ASME limits, could result in a more severe reactor response to an ATWS than predicted, possibly resulting in the ASME Code Service Level C limit on reactor pressure being exceeded for an ATWS event that originates within the MELLLA+ operating domain.
APPLICABILITY	In MODE 1 all eight S/RVs must be OPERABLE in the MELLLA+ operating domain, since considerable energy may be in the reactor core and the limiting ATWS event is assumed to occur in this MODE. The lower end of the MELLLA+ operating domain is approximately 70.2% of Rated Thermal Power (RTP), which is not achievable in the other operating modes. The S/RVs may be required to provide pressure relief to discharge energy from the core until such time that the Residual Heat Removal (RHR) System is capable of dissipating the core heat.
ACTIONS	<u>A.1</u> The TLCO requires eight S/RVs to be OPERABLE to provide overpressure protection for a postulated ATWS event in the MELLLA+ operating domain. With less than the number of S/RVs specified OPERABLE, an overpressure event could result in violation of the ASME Code Service Level C limit on reactor pressure based on the licensing basis overpressure analysis ATWS in the MELLLA+ operating domain. The Required Action and associated Completion Time are consistent with Section 9.3.1.1 and Appendix B, Condition 12.18.d, of Reference 2. For this reason, continued operation with an S/RV inoperable is permitted for a limited time. The 14 day Completion Time to restore inoperable S/RVs to OPERABLE status is based on the low probability of an event requiring S/RV actuation, and a reasonable time to complete the Required Action. This Required Action aligns with the the Required Action and associated Completion Time for Technical Specification 3.4.3 when an S/RV is inoperable.

BASES

ACTIONS (continued)

B.1

If the safety function of the inoperable S/RVs cannot be restored to OPERABLE status within the associated Completion Time of Required Action A.1, the plant must be brought to a condition in which the TLCO does not apply. To achieve this status, the MELLLA+ operating domain must be exited within 12 hours. The allowed Completion Time is reasonable, based on similar plant operating experience, to exit the MELLLA+ operating domain from full power conditions in an orderly manner and without challenging plant systems.

C.1

If the MELLLA+ operating domain cannot be exited within 12 hours, the assumption on the number of S/RVs credited in the safety analyses to provide to an overpressure protection for an ATWS event in the MELLLA+ operating domain is not met and the unit is in a condition outside the accident analyses. Therefore, TLCO 3.0.3 must be entered immediately.

SURVEILLANCE REQUIREMENTS

There are no surveillance requirements associated with this TLCO.

REFERENCES

1. USAR, Section 14.5.1.

2. NEDC-33453P, Revision 1, Maximum Extended Load Limit Analysis Plus (MELLLA+) Safety Analysis Report.

3. Amendment No. 180, “Monticello Nuclear Generating Plant – Issuance of Amendment No. 180 to Renewed Facility Operating License Regarding MELLLA+,” March 28, 2014. (ADAMS Accession No. ML14035A248).

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

B 3.5.1 Automatic Depressurization System (ADS) Inhibit Switch

BASES

No Bases information is provided.

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

B 3.5.2 Core Spray (CS) System Nozzle Differential Pressure Instrumentation

BASES

BACKGROUND

Two independent Core Spray subsystems are provided. Each subsystem consists of a 100 percent-capacity centrifugal pump driven by an electric motor, a spray sparger in the reactor vessel above the core, piping and valves to convey water from the suppression pool to the sparger, and the associated controls and instrumentation.

The two 100-percent capacity core spray lines separately enter the reactor vessel through two core spray nozzles that are 180 degrees apart. Each internal pipe then divides into a semicircular header with a downcomer at each end, which enters through the shroud near the top. A semicircular sparger is attached to each of the four outlets to make two practically complete circles, one above the other. Short elbow nozzles are spaced around the spargers to spray the water radially onto the tops of the fuel assemblies.

A detection system is also provided to continuously confirm the integrity of the core spray piping between the inside of the reactor vessel and the core shroud. A differential pressure switch measures the pressure difference between the bottom of the core and the inside of the core spray sparger pipe just outside the reactor vessel. If the core spray sparger piping is sound, this pressure difference will be the pressure drop across the core. If integrity is lost, this pressure drop will include the core pressure drop and the steam separator pressure drop. An increase in the normal pressure drop (decrease in indicated differential pressure to the setpoint) initiates an alarm in the control room.

It should be noted that the instrument is in alarm during cold moderator conditions due to the instrument leg variations in densities. The alarm should clear during the increase to rated temperature and pressure. During operation at rated temperature and pressure, the alarm should remain clear.

APPLICABLE SAFETY ANALYSIS

The safety function of the Core Spray System is to maintain the fuel cladding temperature to ≤ 2200°F during times the other ECCS systems may be incapable of maintaining vessel water inventory above the top of active fuel (TAF). The method of cooling requires that the water spray directly on top of the fuel assemblies rather than trying to maintain water above TAF. If the Core Spray sparger is broken, this will not be accomplished and the subsystem will not meet its safety design function.

BASES

APPLICABLE SAFETY ANALYSIS (continued)	The Core Spray sparger break detection instrumentation provides continuous monitoring of the integrity of the sparger.
TLCO 3.5.2	The Core Spray sparger break detection alarm, within the allowable value at rated temperature and pressure, provides indication of a potential break in the associated subsystem's sparger. A broken sparger will cause the subsystem to be inoperable.
APPLICABILITY	The OPERABILITY requirement is consistent with Technical Specification requirements for the times when the affected subsystem is required to be OPERABLE and the instrument is indicating meaningful readings.
ACTIONS	<u>A.1</u> When one or both Core Spray System nozzle differential pressure channels are inoperable, it is required that actions be initiated immediately to restore the channel(s) to OPERABLE status.
TECHNICAL SURVEILLANCE REQUIREMENTS	The Technical Surveillances are modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Technical Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours. Upon completion of the Technical Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the reliability analysis (Ref. 2) assumption that 6 hours is the average time required to perform channel surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that the capability for monitoring the integrity of the Core Spray spargers will be available when necessary.

BASES

TECHNICAL SURVEILLANCE REQUIREMENTS (continued)

TSR 3.5.2.1

Performance of the CHANNEL CHECK once every 24 hours ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between instrument channels could be an indication of excessive instrument drift in one of the channels or something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

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

The Frequency is based upon operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the channels required by the TLCO.

TSR 3.5.2.2

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specification tests at least once per refueling interval with applicable extensions.

Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology. The Frequency of 31 days is based on engineering judgment and the reliability of these components.

BASES

TECHNICAL SURVEILLANCE REQUIREMENTS (continued)

TSR 3.5.2.3

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

The Frequency is based upon the assumption of a 92 day calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

REFERENCES

1. MNGP Technical Specifications (version prior to standardized version)

2. GENE-770-06-1-A, "Bases for Changes to Surveillance Test Intervals and Allowed Out-Of-Service Times for Selected Instrumentation Technical Specifications," December 1992.

3.6 CONTAINMENT SYSTEMS

B 3.6.1.3 Primary Containment Isolation Valves (PCIVs)

BASES

TSR 3.6.1.3.1

It is required to test each normally open power operated PCIV, the Main Steam Isolation Valves (MSIVs) in this case, in accordance with the Inservice Test Program. This testing is performed for one MSIV at a time and at a THERMAL POWER level of less than 75% of Rated Thermal Power (RTP). The licensed RTP at the time this surveillance was transferred to the TRM from the TS was 1775 MW_{th} (which correlated to approximately 1330 MW_{th}). Data taken during MSIV testing in April 2005 (Procedure 8025) indicated that sufficient margin existed to the acceptance criteria for high steam flow differential pressure, reactor pressure, reactor power and reactor water level when an MSIV was “fast stroked” closed at power levels of up to 74% of the then current RTP (1775 MW_{th}). Stroking an MSIV closed at too high a power level can result in a plant trip. Stroke testing at 1330 MW_{th} allows testing to be performed at a power level that will preclude a plant trip.

TSR 3.6.1.3.2

The partial stroke test of each Main Steam Isolation Valve (MSIV) is conducted to demonstrate that the valve is functional and will not malfunction due to valve or actuator problems. The exercise is performed by depressing and holding the MSIV test pushbutton until position indication changes or Reactor Protection System (RPS) limit switches de-energize. The exercise does not operate any MSIV solenoid or air control valve that would operate during an auto close of the MSIV or during a manual fast close of the MSIV performed using the MSIV hand switch. The IST Program requires each MSIV to be partially stroked on a quarterly basis. Continuance of the MSIV testing requirements of TSR 3.6.1.3.2 on a quarterly basis will satisfy ASME Operation and Maintenance (OM) Code partial stroke exercise testing requirements.

3.6 CONTAINMENT SYSTEMS

B 3.6.1.7 Suppression Chamber-to-Drywell Vacuum Breakers

BASES

No Bases information is provided.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.3.2 Online Containment Leakage Check

BASES

BACKGROUND

The function of the primary containment is to isolate and contain fission products released from the Reactor Primary System following a design basis loss of coolant accident (LOCA) and to confine the postulated release of radioactive material as described in Technical Specification 3.6.1.1. For plants crediting containment accident pressure (CAP) to maintain net positive suction head (NPSH) margin for emergency core cooling system (ECCS) pump performance, maintenance of containment integrity is required to meet the assumptions of the safety analyses.

The purpose of this TRM specification is to ensure that an undetected containment leakage rate in excess of that required to maintain CAP does not develop between integrated containment leakage tests. Monticello takes credit for CAP to provide adequate NPSH to the Core Spray and Residual Heat Removal (RHR) pumps during certain postulated accident events.

NRC SECY 11-0014 (Ref. 1), Section 6.6.7, “Assurance of no Pre-existing Leak”, requires consideration of a loss of containment isolation that could compromise containment integrity, e.g., containment venting required by procedures or loss of containment isolation from a postulated 10 CFR 50 Appendix R fire. To apply the SECY’s guidance it is required to determine the minimum containment leakage rate sufficient to lose the CAP needed for adequate NPSH margin. Second, a method to determine whether the actual containment leakage rate exceeds this leakage rate is required. For inerted containments, this method could consist of a periodic quantitative measurement of the nitrogen makeup performed at an appropriate frequency to ensure that no unusually large makeup of nitrogen occurs.

This TRM specification specifies performance of an online (MODE 1) containment leakage test to determine the containment leakage rate during power operation (Ref. 2 and 3). Addition of this specification is required as part of the changes necessary to implement the Extended Power Uprate (Ref. 4). This leakage rate test is performed once-per-cycle, after an outage at the beginning of a new operating cycle when the plant is stabilized at full power. This online containment leakage rate test is a benchmark quantitative test which provides a baseline that would identify any significant change in the containment leakage rate at any time during power operation.

The containment leakage rate surveillance is performed at normal operating conditions when containment is at a pressure slightly higher than atmospheric pressure. Consequently, the surveillance leakage rate

BASES

BACKGROUND (Continued)

test acceptance criterion has been correlated to a leakage rate associated with normal operating containment pressure which assumes leakage behavior is orifice-like. This reduced test pressure acceptance criterion correlation is consistent with the method currently used to leak test the MSIVs at reduced pressure per Technical Specification SR 3.6.1.3.12.

There are several control room inputs that are used for normal monitoring and that can indicate an increase in the containment leak rate between performance of this TSR:

- A computer point that continually calculates N_2 mass in containment and provides a computer alarm if the N_2 mass is too low or too high.
- A control room annunciator that alarms on drywell high or low pressure.
- A flow indicator that measures N_2 flow in the supply to the containment air system.

APPLICABLE SAFETY ANALYSES

The safety design basis for the primary containment is that it must withstand the pressures and temperatures of the limiting DBA-LOCA without exceeding the design leakage rate. 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 5 and 6. Sufficient primary containment integrity is also required to maintain ECCS NPSH margin to ensure that the required CAP is available to meet the assumptions used in the safety analyses of References 5 and 6.

A computer analysis using the GOTHIC code was performed to determine the MNGP containment leakage rates sufficient to lose CAP. Conservative input assumptions were applied, with the exception of a temperature dependent K-value for the RHR heat exchanger. Results were determined for various multiples of L_a (the Technical Specification specified leakage rate). 1 L_a is equivalent to a leakage rate of 7.6 scfm at the current licensed thermal power. The results indicate that a containment leakage rate greater than 228 scfm will result in a complete loss of NPSH margin. A leakage rate of $\leq$150 scfm (based on the peak containment accident pressure of 44.1 psig) was chosen as the TRM acceptance criteria to provide margin to the limiting containment leakage rate of 228 scfm.

BASES

APPLICABLE SAFETY ANALYSES (Continued)	Note that the actual leakage rate that could challenge NPSH margin for the ECCS and containment heat removal pumps (RHR) is greater than 228 scfm, which is well above the leakage that can be detected by the testing method.
TLCO	Primary containment OPERABILITY for ECCS pump (and containment heat removal (RHR) pump) performance is maintained by limiting the containment leakage rate to within the acceptance criteria specified in the TSR. Compliance with this TLCO will ensure a primary containment configuration that will limit leakage to the leakage rate assumed with respect to CAP in the safety analyses.
APPLICABILITY	In MODE 1 once-per-cycle, after an outage at the beginning of a new operating cycle when the plant is stabilized at full power. This surveillance also may be performed during a cycle when results of online parameter measurements indicate another measurement is warranted. A Note is provided indicating that this surveillance is performed once at the beginning of a cycle following refueling when containment and reactor conditions are stable.
ACTIONS	<u>A.1</u> In the event primary containment leakage rate surveillance is not met, the assumption of sufficient NPSH to maintain ECCS and containment heat removal (RHR) pump performance as assumed in the safety analyses may not be met. This condition requires immediate entry into the Required Actions of Technical Specification 3.5.1, “ECCS – Operating”, for two or more ECCS injection/spray subsystems inoperable.
SURVEILLANCE REQUIREMENTS	<u>SR 3.6.1.1.1</u> Maintaining the primary containment OPERABLE to provide ECCS pump NPSH margin requires compliance with the allowable containment leakage rate specified.
REFERENCES	1. SECY-11-0014, Enclosure 1, “The Use of Containment Accident Pressure in Reactor Safety Analysis” (ADAMS Accession No. ML102110167)

BASES

REFERENCES (Continued)

2. Letter from NSPM to NRC, “Monticello Extended Power Uprate and Maximum Extended Load Line Limit Analysis Plus License Amendment Requests: Supplement to Address SECY-11-0014, Use Containment Accident Pressure (TAC Nos. MD9990 and ME3145),” (L-MT-12-082) dated September 28, 2012

3. Letter from NSPM to NRC, “Monticello Extended Power Uprate: SECY-11-0014, Use of Containment Accident Pressure – Responses to Requests for Additional Information, (TAC No. MD9990),” (L-MT-13-033) dated March 21, 2013

4. Amendment No. 176, “Monticello Nuclear Generating Plant – Issuance of Amendment No. 176 to Renewed Facility Operating License Regarding Extended Power Uprate,” (ADAMS Accession No. ML13316C459)

5. USAR, Section 5.2

6. USAR, Section 14.7.2

3.8 ELECTRICAL POWER SYSTEMS

B 3.8.1 Northern States Power (NSP) Transmission Lines

BASES

No Bases information is provided.

3.8 ELECTRICAL POWER SYSTEMS

B 3.8.2 24 VDC Battery Systems

BASES

No Bases information is provided.

3.9 REFUELING OPERATIONS

B 3.9.1 Decay Time

BASES

A minimum shutdown period of 24 hours is specified prior to movement of fuel within the reactor since analysis of refueling accidents assume a 24-hour decay time following extended operation at power. Since the reactor must be shut down, depressurized, and the head removed prior to moving fuel, it is not expected that fuel could actually be moved in less than 24 hours.

MONTICELLO NUCLEAR GENERATING PLANT TECHNICAL SPECIFICATION BASES

TABLE 1 (Page 1 of 1)
MONTICELLO NUCLEAR GENERATING PLANT
BASES LIST OF EFFECTIVE SECTIONS/SPECIFICATIONS

Section/Specification	Revision No.	Section/Specification	Revision No.
B 2.1.1	39	B 3.6.1.4	0
B 2.1.2	6	B 3.6.1.5	25
B 3.0	27	B 3.6.1.6	0
B 3.1.1	39	B 3.6.1.7	0
B 3.1.2	0	B 3.6.1.8	29
B 3.1.3	11	B 3.6.2.1	30
B 3.1.4	39	B 3.6.2.2	0
B 3.1.5	0	B 3.6.2.3	0
B 3.1.6	39	B 3.6.3.1	0
B 3.1.7	4	B 3.6.4.1	42
B 3.1.8	4	B 3.6.4.2	42
B 3.2.1	39	B 3.6.4.3	42
B 3.2.2	39	B 3.7.1	40
B 3.2.3	39	B 3.7.2	40
B 3.3.1.1	37	B 3.7.3	17
B 3.3.1.2	0	B 3.7.4	42
B 3.3.2.1	39	B 3.7.5	42
B 3.3.2.2	29	B 3.7.6	4
B 3.3.3.1	3	B 3.7.7	29
B 3.3.3.2	3	B 3.7.8	0
B 3.3.4.1	0	B 3.8.1	43
B 3.3.5.1	38	B 3.8.2	27
B 3.3.5.2	0	B 3.8.3	43
B 3.3.6.1	34	B 3.8.4	7
B 3.3.6.2	42	B 3.8.5	4
B 3.3.6.3	3	B 3.8.6	0
B 3.3.7.1	42	B 3.8.7	0
B 3.3.7.2	4	B 3.8.8	4
B 3.3.8.1	22		
B 3.3.8.2	0	B 3.9.1	0
B 3.4.1	39	B 3.9.2	0
B 3.4.2	0	B 3.9.3	0
B 3.4.3	25	B 3.9.4	0
B 3.4.4	0	B 3.9.5	0
B 3.4.5	0	B 3.9.6	0
B 3.4.6	4	B 3.9.7	21
B 3.4.7	0	B 3.9.8	0
B 3.4.8	0	B 3.10.1	28
B 3.4.9	25	B 3.10.2	0
B 3.4.10	0	B 3.10.3	3
B 3.5.1	41	B 3.10.4	0
B 3.5.2	0	B 3.10.5	0
B 3.5.3	0	B 3.10.6	0
B 3.6.1.1	29	B 3.10.7	39
B 3.6.1.2	29	B 3.10.8	39
B 3.6.1.3	41	TOC	4

TABLE 2 (Page 1 of 7)
TECHNICAL SPECIFICATION BASES RECORD OF REVISIONS

Revision Number	Affected Section/ Specification	Description of Revision
0	All	Amendment 146 – Original ITS Revision
1	B 3.8.3	SR 3.8.3.3, Diesel Fuel Oil Testing Description
2	B 3.5.1	LCO 3.5.1, ACTION D, changed description of LPCI injection pathway.
3	B 3.3.3.1, B 3.3.3.2, B 3.3.6.3, B 3.10.3	Miscellaneous ITS Bases Clarifications/Corrections
4	B 2.1.1, B 2.1.2, B 3.1.6, B 3.1.7, B 3.1.8, B 3.3.6.1, B 3.3.7.1, B 3.3.7.2, B 3.4.6, B 3.6.1.3, B 3.7.4, B 3.7.5, B 3.7.6, B 3.8.2, B 3.8.5, B 3.8.8	Amendment 148 – Bases Changes implementing Full Scope AST.
5	B 3.3.5.1 B 3.8.1[1]	Amendment 151 – Extend Surveillance Interval and AV for the LPCI Loop Select TD Relays.
6	B 2.1.2	Clarify RCS Safety Limit values.
	B 3.3.2.1	Correct that initial MCPR values are specified in the COLR.
7	B.3.8.1, B 3.8.2	Clarify that the 2R and 1AR transformers are considered as a single off-site source when 1AR is supplied from 345 kV Bus 1.

1. Replaces page B 3.8.1-25 in Sharepoint version of the TS. Page inadvertently deleted during implementation of Amendment 148 (CAP 01095053).

TECHNICAL SPECIFICATION BASES RECORD OF REVISIONS

Revision Number	Affected Section/ Specification	Description of Revision
7 (con't)	B.3.8.4	Correct the float voltage for the 125 VDC batteries in SR 3.8.4.1.
	B.3.8.4	Amendment 153 – Specify in SR 3.8.4.2 that the Division 2 battery charger supplies ≥ 110 amps.
8	B.3.5.1	Amendment 155 – Revise SR 3.5.1.3 to correct Alternate Nitrogen System supply pressure to ADS and clarify OPERABILITY during bottle changeout.
	B.3.7.4, B.3.7.5	Amendment 154 – Revise Bases for Specification 3.7.5 to reflect adoption of TSTF-477, which allows both CRV subsystems to be inoperable for 72 hours. Clarify the OPERABILITY requirements of certain CRV fans currently required to support CREF subsystem operation.
9	B 3.5.1	Clarify RHR intertie discussion.
	B 3.5.1	Clarify Action M to indicate that the plant may not be in a condition outside the accident analysis but is in a condition not specifically justified for continued operation.
	B 3.6.1.3	Add Action E to describe actions for when the MSIVs are not within leakage limits and re-label subsequent actions.
10	B 3.5.1	Add HPCI "Keep-fill" discussion.
	B 3.9.7	Clarify Action A.1 for what is meant by inoperable.
11	B 3.1.3, B 3.1.4	Amendment 158 – Change control rod notch testing frequency from every 7 days to only once per 31 days in accordance with TSTF-475, Revision 1.

TECHNICAL SPECIFICATION BASES RECORD OF REVISIONS

Revision Number	Affected Section/ Specification	Description of Revision
12	B 3.3.1.1, B 3.3.2.1, B 3.4.1	Amendment 159 – PRNMS.
	B 3.3.5.1	Amendment 161 – LPCI Recirculation Riser Differential Pressure – High (Break Size) allowable value and channel calibration interval change.
13	B 3.0	Amendment 157 – Add Bases for new LCO 3.0.9 for the unavailability of barriers, reflecting adoption of TSTF-427.
	B 3.4.9	Clarify that the shift in Figure 3.4.9-1 includes both delta RT_{NDT} and margin.
	B 3.5.1	Amendment 162 – Add new Conditions to Specification 3.5.1 for restoration of various low-pressure ECCS subsystem out-of-service combinations.
14	B 3.0	Section B 3.0 reissued in entirety. Page numbers at end of LCO Applicability over-lapped SR Applicability page numbers (CAP 01192534).
15	B 3.7.4	Amendment 160 – Revise Bases for the specification reflecting adoption of a Control Room Envelope Habitability program in accordance with TSTF-448.
16	B 3.3.1.1	Replace IRM – Neutron Flux – High High (1.a) for calibrating IRMs by a heat balance by referring to IRM/APRM overlap and APRM Setdown Scram meeting reactivity requirements.
	B 3.7.7	Correct Turbine Bypass Valve capacity.
17	B 3.7.3	Correct EDG-ESW Background description.

TECHNICAL SPECIFICATION BASES RECORD OF REVISIONS

Revision Number	Affected Section/ Specification	Description of Revision
18	B 3.6.1.3	Clarify PCIV definition.
19	B 3.1.4	Clarify spacing requirements of adjacent slow control rods.
	B 3.8.1, B 3.8.2	Revise Bases to reflect separation of 1ARS Transformer and Bus 1.
20	B 3.5.1	Reissue section, missing text on HPCI keep-fill discussion. (CAP 01328422)
21	B 3.9.7	Correct prior clarification to Action A.1 for what is meant by inoperable. (CAP 01257096)
22	B 3.3.8.1	Amendment 169 – Revise licensing basis to reflect removal of the capability to automatically transfer to the 1AR Transformer as a source of power to the essential buses on degraded voltage and instead directly transfer to the EDGs.
23	B 3.3.5.1	Amendment 170 – Revised to reflect ancillary change related to ADS 20-minute Bypass Timer.
24	B 3.3.1.1	Amendment 171 – Revised to provide restoration period before declaring the APRMs inoperable when SR 3.3.1.1.2 is not met.
25	B 3.4.3, B 3.5.1, B 3.6.1.5	Amendment 168 – Revised surveillance requirements within these specifications to allow crediting overlapping testing rather than requiring a lift-test during plant startup.
	B 3.4.9	Amendment 172 – Revised specification to adopt PTLR.
26	B 3.1.6, B 3.3.2.1	Amendment 173 – Revised to reflect incorporation of TSTF-476 for improved BPWS.

TECHNICAL SPECIFICATION BASES RECORD OF REVISIONS

Revision Number	Affected Section/ Specification	Description of Revision
27	B 3.0	Clarify application of SR 3.0.2 and SR 3.0.3 to IST tests to clarify compliance to Enforcement Guidance Memorandum (EGM) 12-001 (CAP 01389604).
	B 3.8.2	Correct referenced SR number from SR 3.8.1.8 to SR 3.8.1.6.
28	B 3.10.1	Amendment 174 – Revised specification to incorporate TSTF-484, to allow scram time testing in conjunction with hydrostatic testing.
29	B 3.1.6, B 3.2.1, B 3.3.1.1, B 3.3.2.2, B 3.3.5.1, B 3.4.1, B 3.5.1, B 3.6.1.1, B 3.6.1.2, B 3.6.1.3, B 3.6.1.8, B 3.7.1, B 3.7.7	Amendment 176 – Implement Extended Power Uprate.
30	B 3.6.2.1	Revised TS Bases to indicate local Suppression Pool temperature limits were eliminated with Amendment 126.
	B 3.8.3	Amendment 178 – Revised specification to relocate stored fuel and lube oil volumes to TS bases and replace with duration requirements in accordance with TSTF-501.
31	B 3.6.4.3, B 3.7.4	Amendment 181 – Revised specifications to reflect reduced runtime for SBGT and CREF from 10 hours to 15 minutes in accordance with TSTF-522.

TECHNICAL SPECIFICATION BASES RECORD OF REVISIONS

Revision Number	Affected Section/ Specification	Description of Revision
32	B 3.3.1.1, B 3.4.1	Amendment 180 – Implement Maximum Extended Load Line Limit Analysis, Plus (MELLLA+)
33	B 3.8.1, B 3.8.3	Add EDG Fuel Oil Transfer System train description for each EDG.
34	B 2.1.1, B 3.3.6.1	Amendment 185 – Reduce the Reactor Steam Dome Pressure specified in the Reactor Core Safety Limits, resolved GE Part 21 condition for a potential to violate the safety limit during a Pressure Regulator Failure Downscale event.
	B 3.5.1	Amendment 184 – Removes former Condition F which allowed both Core Spray subsystems to be inoperable for 72 hours.
35	B 3.8.1, B 3.8.3	Revised to reflect EDG Fuel Oil Transfer System separation modifications.
36	B 3.8.1, B 3.8.3	Revised to reflect completion of EDG Fuel Oil Transfer System modifications and differentiate between 6-day and 7-day EDG fuel oil storage tank level requirements for each division.
37	B 3.3.1.1	Revised to clarify Automated BSP Scram Region implementation to protect MCPR safety limit during thermal-hydraulic power oscillations when the OPRM Upscale function is inoperable.
38	B 3.3.5.1	Revised ADS Bypass Timer value from 20 to 18 minutes in two locations missed under EPU amendment implementation (Am. 176).
39	B 2.1.1, B 3.1.1, B 3.1.4, B 3.1.6, B 3.2.1, B 3.2.2,	Amendment 188 – AREVA Fuel Transition, Part 1

TECHNICAL SPECIFICATION BASES RECORD OF REVISIONS

Revision Number	Affected Section/ Specification	Description of Revision
39 (con't)	B 3.2.3, B 3.3.2.1, B 3.4.1, B 3.10.7, B 3.10.8	Amendment 188 – AREVA Fuel Transition, Part 1
40	B 3.7.1, B 3.7.2	Clarified that although the RHRSW System, ESW System, and UHS LCOs are not applicable in MODES 4 and 5, their capability to perform support functions may be required for OPERABILITY of the supported systems. Also, clarified that opening RHRSW cross tie valve renders the operating system inoperable. Additionally, clarified cooling requirements for core spray pump motors.
41	B 3.5.1	Amendment 190 – Alternate Nitrogen System revise SR 3.1.5.3.b required supply pressure.
	B 3.6.1.3	Removes incorrect statements about purge and vent valve alignment.
42	B 3.3.6.2, B 3.3.7.1, B 3.6.4.1, B 3.6.4.2, B 3.6.4.3, B 3.7.4, B 3.7.5	Clarifies secondary containment systems and control room ventilation systems that DBA LOCAs, and FHAs involving recently irradiated fuel are the accidents of concern.
43	B 3.8.1	Clarifies 2R and 1R bus lockout of the auxiliary and essential 4.16 kV buses, and corrects the number of 345 kV transmission lines.
	B 3.8.3	Revised required 12 EDG fuel oil volumes in the diesel fuel oil storage tank.

B 2.0 SAFETY LIMITS (SLs)

B 2.1.1 Reactor Core SLs

BASES

BACKGROUND

USAR Section 1.2.2 (Ref. 1) requires the reactor core and associated systems to be designed to accommodate plant operational transients or maneuvers that might be expected without compromising safety and without fuel damage. Therefore, SLs ensure that specified acceptable fuel design limits are not exceeded during steady state operation, normal operational transients, and anticipated operational occurrences (AOOs).

The fuel cladding integrity SL is set such that no significant fuel damage is calculated to occur if the limit is not violated. Because fuel damage is not directly observable, a stepback approach is used to establish an SL, such that the MCPR is not less than the limit specified in Specification 2.1.1.2. MCPR greater than the specified limit represents a conservative margin relative to the conditions required to maintain fuel cladding integrity.

The fuel cladding is one of the physical barriers that separate the radioactive materials from the environs. The integrity of this cladding barrier is related to its relative freedom from perforations or cracking. Although some corrosion or use related cracking may occur during the life of the cladding, fission product migration from this source is incrementally cumulative and continuously measurable. Fuel cladding perforations, however, can result from thermal stresses, which occur from reactor operation significantly above design conditions.

While fission product migration from cladding perforation is just as measurable as that from use related cracking, the thermally caused cladding perforations signal a threshold beyond which still greater thermal stresses may cause gross, rather than incremental, cladding deterioration. Therefore, the fuel cladding SL is defined with a margin to the conditions that would produce onset of transition boiling (i.e., MCPR = 1.00). These conditions represent a significant departure from the condition intended by design for planned operation. The MCPR fuel cladding integrity SL ensures that during normal operation and during AOOs, at least 99.9% of the fuel rods in the core do not experience transition boiling.

Operation above the boundary of the nucleate boiling regime could result in excessive cladding temperature because of the onset of transition boiling and the resultant sharp reduction in heat transfer coefficient. Inside the steam film, high cladding temperatures are reached, and a cladding water (zirconium water) reaction may take place. This chemical

BASES

BACKGROUND (continued)

reaction results in oxidation of the fuel cladding to a structurally weaker form. This weaker form may lose its integrity, resulting in an uncontrolled release of activity to the reactor coolant.

The reactor vessel water level SL ensures that adequate core cooling capability is maintained during all MODES of reactor operation. Establishment of Emergency Core Cooling System initiation setpoints higher than this SL provides margin such that the SL will not be reached or exceeded.

APPLICABLE SAFETY ANALYSES

NOTE: Certain AREVA safety analysis methods have been approved for use (Amendment 188); however, those methods may not be invoked in the analysis-of-record until AREVA fuel is loaded in the core. Until that time, General Electric – Hitachi (GEH) safety analysis methods will continue to support core operation and the description of the GEH methods in the TS Bases shall prevail. To the extent that approved AREVA methods may be described and referenced without conflicting with the GEH analysis-of-record, the TS Bases reflect both GEH and AREVA methods. Refer to Section 1.0 of the CORE OPERATING LIMIT REPORT (COLR) to determine whether GEH or AREVA methods were used for the current operating cycle.

The fuel cladding must not sustain damage as a result of normal operation and AOOs. The reactor core SLs are established to preclude violation of the fuel design criterion that a MCPR limit is to be established, such that at least 99.9% of the fuel rods in the core would not be expected to experience the onset of transition boiling.

The Reactor Protection System setpoints (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation"), in combination with the other LCOs, are designed to prevent any anticipated combination of transient conditions for Reactor Coolant System water level, pressure, and THERMAL POWER level that would result in reaching the MCPR Safety Limit.

Specifications 2.1.1.1 and 2.1.1.2 are each written to describe a Safety Limit that is appropriate for the respective safety analysis method being used to operate the reactor. This TS construction was approved to provide flexibility during the MNGP transition from operating under the GEH safety analysis methods to the AREVA safety analysis methods. Separate SLs were required because no single value of steam dome pressure would accurately cover the applicability range of GEH methodology as well as the applicability range of AREVA methodology during fuel transition operations. To accommodate this transition, TS 2.1.1.1 and 2.1.1.2 are structured to require the use of the GEH safety

BASES

APPLICABLE SAFETY ANALYSES (continued)

limit when operating under GEH safety analysis methods and use of the AREVA safety limit when operating under the AREVA safety analysis methods. The method used for safety analysis (whether GEH or AREVA) is established during the core reload safety analysis process that precedes any particular fuel cycle. In that same process, the appropriate operating limits for that analysis methodology are provided in the COLR.

The approved pressure range (700 to 1400 psia) of the GEXL 14 critical power correlation is applied to resolve a 10 CFR Part 21 condition concerning a potential to violate Reactor Core Safety Limit 2.1.1.1 during a Pressure Regulator Failure Maximum Demand (Open) transient (Reference 5). Application of this correlation, which applies to the GE14 fuel in the core, allows reduction of the reactor steam dome pressure from 785 to 686 psig, precluding violation of the safety limit for this event. This change in reactor steam dome pressure was approved in Amendment 185 (Reference 7).

The AREVA critical power correlations (ACE and SPCB) are applicable at reactor steam dome pressures ≥ 586 psig. A Pressure Regulator Failure Maximum Demand (Open) transient applying AREVA safety analysis methods would not violate Reactor Core Safety Limit 2.1.1.1.

2.1.1.1 Fuel Cladding Integrity

AREVA critical power correlations (ACE and SPCB) are applicable at pressures ≥ 586 psig and core flows ≥ 10% of rated flow. AREVA correlations (approved in Am. 188, Ref. 12) are used for cores analyzed with AREVA safety analysis methods, with the ACE correlation used for AREVA fuel and the SPCB correlation used for co-resident fuel.

The GEXL14 critical power correlation is applicable for all critical power calculations at pressures ≥ 686 psig and core flows ≥ 10% of rated flow (Reference 6). For operation at low pressures or low flows, another basis is used, as follows:

> Since the pressure drop in the bypass region is essentially all elevation head, the core pressure drop at low power and flows will always be > 4.56 psi. Analyses (Ref. 2) show that with a bundle flow of 28 x 10^3 lb/hr, bundle pressure drop is nearly independent of bundle power and has a value of 3.5 psi. Thus, the bundle flow with a 4.56 psi driving head will be > 28 x 10^3 lb/hr. Full scale ATLAS test data taken at pressures from 0 psig to 785 psig indicate that the fuel assembly critical power at this flow is approximately 3.35 MWt. With the design peaking factors, this corresponds to a THERMAL POWER > 50 % RTP. Thus, a THERMAL POWER limit of 25% RTP for reactor pressure < 686 psig or < 10% core flow is conservative.

BASES

APPLICABLE SAFETY ANALYSES (continued)

2.1.1.2 MCPR

The fuel cladding integrity SL is set such that no significant fuel damage is calculated to occur if the limit is not violated. Since the parameters that result in fuel damage are not directly observable during reactor operation, the thermal and hydraulic conditions that result in the onset of transition boiling have been used to mark the beginning of the region in which fuel damage could occur. Although it is recognized that the onset of transition boiling would not result in damage to BWR fuel rods, the critical power at which boiling transition is calculated to occur has been adopted as a convenient limit. However, the uncertainties in monitoring the core operating state and in the procedures used to calculate the critical power result in an uncertainty in the value of the critical power. Therefore, the fuel cladding integrity SL is defined as the critical power ratio in the limiting fuel assembly for which more than 99.9% of the fuel rods in the core are expected to avoid boiling transition, considering the power distribution within the core and all uncertainties.

The MCPR SL is determined using a statistical model that combines all the uncertainties in operating parameters and the procedures used to calculate critical power.

For operating cycles using AREVA safety analysis methods, the probability of the occurrence of boiling transition is determined using the approved AREVA correlations. For such operating cycles, References 8, 9, 10, and 11 describe the uncertainties and methodologies used in determining the MCPR SL.

For operating cycles using GEH safety analysis methods, the probability of the occurrence of boiling transition is determined using the approved General Electric Critical Power correlations. Details of the fuel cladding integrity SL calculation are given in Reference 2. Reference 3 includes a tabulation of the uncertainties used in the determination of the MCPR SL and of the nominal values of the parameters used in the MCPR SL statistical analysis.

2.1.1.3 Reactor Vessel Water Level

During MODES 1 and 2 the reactor vessel water level is required to be above the top of the active irradiated fuel to provide core cooling capability. With fuel in the reactor vessel during periods when the reactor is shut down, consideration must be given to water level requirements due to the effect of decay heat. If the water level should drop below the top of the active irradiated fuel during this period, the ability to remove decay heat is reduced. This reduction in cooling capability could lead to elevated cladding temperatures and clad perforation in the event that the

BASES

APPLICABLE SAFETY ANALYSES (continued)

water level becomes < 2/3 of the core height. The reactor vessel water level SL has been established at the top of the active irradiated fuel to provide a point that can be monitored and to also provide adequate margin for effective action.

SAFETY LIMITS

The reactor core SLs are established to protect the integrity of the fuel clad barrier to prevent the release of radioactive materials to the environs. SL 2.1.1.1 and SL 2.1.1.2 ensure that the core operates within the fuel design criteria. SL 2.1.1.3 ensures that the reactor vessel water level is greater than the top of the active irradiated fuel in order to prevent elevated clad temperatures and resultant clad perforations.

APPLICABILITY

SLs 2.1.1.1, 2.1.1.2, and 2.1.1.3 are applicable in all MODES.

SAFETY LIMIT VIOLATIONS

Exceeding an SL may cause fuel damage and create a potential for radioactive releases in excess of 10 CFR 50.67, “Accident source term,” limits (Ref. 4). Therefore, it is required to insert all insertable control rods and restore compliance with the SLs within 2 hours. The 2 hour Completion Time ensures that the operators take prompt remedial action and also ensures that the probability of an accident occurring during this period is minimal.

REFERENCES

1. USAR, Section 1.2.2.
2. NEDE-24011-P-A, "General Electric Standard Application for Reactor Fuel" (revision specified in Specification 5.6.3).
3. NEDE-31152P, "General Electric Fuel Bundle Designs," Revision 8, April 2001.
4. 10 CFR 50.67.
5. GE Part 21 Notification SC05-03, “Potential to Exceed Low Pressure Technical Specification Safety Limit,” dated March 29, 2005.
6. NRC Letter to A. Lingenfelter (GNF), ‘Final Safety Evaluation for Global Nuclear Fuel (GNF) Topical Report (TR) NEDC-32851P, Revision 2, "GEXL14 Correlation for GE14 Fuel," (TAC No. MD5486)’ dated August 3, 2007.

BASES

REFERENCES (continued)

7. Amendment No. 185, "Issuance of Amendment to Reduce the Reactor Steam Dome Pressure Specified in the Reactor Core Safety Limits," dated November 25, 2014. (ADAMS Accession No. ML14281A318)

8. EMF-2209(P)(A) Revision 3, "SPCB Critical Power Correlation", AREVA NP, September 2009.

9. EMF-2245(P)(A) Revision 0, "Application of Siemens Power Corporation's Critical Power Correlations to Co-Resident Fuel," Siemens Power Corporation, August 2000.

10. ANP-10298P-A Revision 1, "ACE/ATRIUM 10XM Critical Power Correlation," AREVA, March 2014.

11. ANP-10307PA, Revision 0, "AREVA MCPR Safety Limit Methodology for Boiling Water Reactors," AREVA NP, June 2011.

12. Amendment No. 188, "Issuance of Amendment to Transition to AREVA ATRIUM 10XM Fuel and AREVA Safety Analysis Methods," dated June 5, 2015. (ADAMS Accession Nos. ML15072A141, ML15154A477, and ML15072A135)

B 2.0 SAFETY LIMITS (SLs)

B 2.1.2 Reactor Coolant System (RCS) Pressure SL

BASES

BACKGROUND	The SL on reactor steam dome pressure protects the RCS against overpressurization. In the event of fuel cladding failure, fission products are released into the reactor coolant. The RCS then serves as the primary barrier in preventing the release of fission products into the atmosphere. Establishing an upper limit on reactor steam dome pressure ensures continued RCS integrity. According to USAR Section 4.2.1 (Ref. 1), the reactor vessel design pressure of 1250 psig was determined by an analysis of margins required to provide a reasonable range for maneuvering during operation, with additional allowances to accommodate transients above the operating pressure without causing operation of the safety/relief valves. In addition, the reactor vessel was also designed for the transients that could occur during the design life. During normal operation and anticipated operational occurrences (AOOs), RCS pressure is limited from exceeding the design pressure by more than 10%, in accordance with Section III of the ASME Code (Ref. 2) for the pressure vessel. To ensure system integrity, all RCS components are hydrostatically tested at 125% of design pressure, in accordance with ASME Code requirements, prior to initial operation when there is no fuel in the core. Any further hydrostatic testing with fuel in the core may be done under LCO 3.10.1, "Inservice Leak and Hydrostatic Testing Operation." Following inception of unit operation, RCS components shall be pressure tested in accordance with the requirements of ASME Code, Section XI (Ref. 3). Overpressurization of the RCS could result in a breach of the reactor coolant pressure boundary (RCPB), reducing the number of protective barriers designed to prevent radioactive releases from exceeding the limits specified in 10 CFR 50.67, "Accident source term" (Ref. 4). If this occurred in conjunction with a fuel cladding failure, fission products could enter the containment atmosphere.
APPLICABLE SAFETY ANALYSES	The RCS safety/relief valves and the Reactor Protection System Reactor Vessel Steam Dome Pressure - High Function have settings established to ensure that the RCS pressure SL will not be exceeded. The RCS pressure SL has been selected such that it is at a pressure below which it can be shown that the integrity of the system is not endangered. The reactor pressure vessel is designed to Section III of the ASME, Boiler and Pressure Vessel Code, 1965 Edition, including Addenda through the summer of 1966 (Ref. 5), which permits a maximum pressure transient of 110%, 1375 psig, of design pressure 1250 psig.

BASES

APPLICABLE SAFETY ANALYSES (continued)

Piping attached to the reactor vessel steam space is limited to a pressure of 1.2 x 1110 psig = 1332 psig. A reactor vessel steam dome pressure limit of 1332 psig protects the vessel (SL = 1375 psig), the steam piping (SL = 1332 psig) and lower level water piping (SL = 1363.2 psig) (Ref. 7). The RCS is designed to the USAS Nuclear Power Piping Code, Section B31.1, 1977 Edition, including Addenda through summer of 1978 (Ref. 6), for the piping, which permits a maximum pressure transient of 120% of design pressures of 1110 psig for piping communicating with the vessel steam space and 1136 psig for piping communicating with the bottom of the vessel. The RCS pressure SL is selected to be the lowest transient overpressure allowed by the applicable codes.

SAFETY LIMITS

The maximum transient pressure allowable in the RCS pressure vessel under the ASME Code, Section III, is 110% of design pressure. The maximum transient pressure allowable in the RCS piping, valves, and fittings is 120% of design pressures of 1110 psig for piping communicating with the vessel steam space and 1136 psig for piping communicating with the bottom of the vessel. The most limiting of these allowances is the 120% of the piping communicating with the vessel steam space design pressure; therefore, the SL on maximum allowable RCS pressure is established at 1332 psig as measured at the reactor steam dome.

APPLICABILITY

SL 2.1.2 applies in all MODES.

SAFETY LIMIT VIOLATIONS

Exceeding the RCS pressure SL may cause immediate RCS failure and create a potential for radioactive releases in excess of 10 CFR 50.67, "Accident source term," limits (Ref. 4). Therefore, it is required to insert all insertable control rods and restore compliance with the SL within 2 hours. The 2 hour Completion Time ensures that the operators take prompt remedial action and also assures that the probability of an accident occurring during this period is minimal.

REFERENCES

1. USAR, Section 4.2.1.
2. ASME, Boiler and Pressure Vessel Code, Section III, Article NB-7000.
3. ASME, Boiler and Pressure Vessel Code, Section XI, Article IW-5000.
4. 10 CFR 50.67.
5. ASME, Boiler and Pressure Vessel Code, Section III, 1965 Edition, Addenda summer of 1966.

BASES

REFERENCES (continued)

6. ASME, USAS, Nuclear Power Piping Code, Section B31.1, 1977 Edition, Addenda summer 1978.

7. Amendment No. 128.

B 3.0 LIMITING CONDITION FOR OPERATION (LCO) Applicability

BASES

LCOs	LCO 3.0.1 through LCO 3.0.9 establish the general requirements applicable to all Specifications in Sections 3.1 through 3.10 and apply at all times, unless otherwise stated.
LCO 3.0.1	LCO 3.0.1 establishes the Applicability statement within each individual Specification as the requirement for when the LCO is required to be met (i.e., when the unit is in the MODES or other specified conditions of the Applicability statement of each Specification).

LCO 3.0.2

LCO 3.0.2 establishes that upon discovery of a failure to meet an LCO, the associated ACTIONS shall be met. The Completion Time of each Required Action for an ACTIONS Condition is applicable from the point in time that an ACTIONS Condition is entered. The Required Actions establish those remedial measures that must be taken within specified Completion Times when the requirements of an LCO are not met. This Specification establishes that:

a. Completion of the Required Actions within the specified Completion Times constitutes compliance with a Specification; and

b. Completion of the Required Actions is not required when an LCO is met within the specified Completion Time, unless otherwise specified.

There are two basic types of Required Actions. The first type of Required Action specifies a time limit in which the LCO must be met. This time limit is the Completion Time to restore an inoperable system or component to OPERABLE status or to restore variables to within specified limits. If this type of Required Action is not completed within the specified Completion Time, a shutdown may be required to place the unit in a MODE or condition in which the Specification is not applicable. (Whether stated as a Required Action or not, correction of the entered Condition is an action that may always be considered upon entering ACTIONS.) The second type of Required Action specifies the remedial measures that permit continued operation of the unit that is not further restricted by the Completion Time. In this case, compliance with the Required Actions provides an acceptable level of safety for continued operation.

Completing the Required Actions is not required when an LCO is met or is no longer applicable, unless otherwise stated in the individual Specifications.

The nature of some Required Actions of some Conditions necessitates that, once the Condition is entered, the Required Actions must be completed even though the associated Conditions no longer exist. The

BASES

LCO 3.0.2 (continued)

individual LCO's ACTIONS specify the Required Actions where this is the case. An example of this is in LCO 3.4.9, "RCS Pressure and Temperature (P/T) Limits."

The Completion Times of the Required Actions are also applicable when a system or component is removed from service intentionally. The reasons for intentionally relying on the ACTIONS include, but are not limited to, performance of Surveillances, preventive maintenance, corrective maintenance, or investigation of operational problems. Entering ACTIONS for these reasons must be done in a manner that does not compromise safety. Intentional entry into ACTIONS should not be made for operational convenience. Additionally, if intentional entry into ACTIONS would result in redundant equipment being inoperable, alternatives should be used instead. Doing so limits the time both subsystems/divisions of a safety function are inoperable and limits the time conditions exist which may result in LCO 3.0.3 being entered. Individual Specifications may specify a time limit for performing an SR when equipment is removed from service or bypassed for testing. In this case, the Completion Times of the Required Actions are applicable when this time limit expires, if the equipment remains removed from service or bypassed.

When a change in MODE or other specified condition is required to comply with Required Actions, the unit may enter a MODE or other specified condition in which another Specification becomes applicable. In this case, the Completion Times of the associated Required Actions would apply from the point in time that the new Specification becomes applicable, and the ACTIONS Condition(s) are entered.

LCO 3.0.3

LCO 3.0.3 establishes the actions that must be implemented when an LCO is not met and:

a. An associated Required Action and Completion Time is not met and no other Condition applies; or

b. The condition of the unit is not specifically addressed by the associated ACTIONS. This means that no combination of Conditions stated in the ACTIONS can be made that exactly corresponds to the actual condition of the unit. Sometimes, possible combinations of Conditions are such that entering LCO 3.0.3 is warranted; in such cases, the ACTIONS specifically state a Condition corresponding to such combinations and also that LCO 3.0.3 be entered immediately.

This Specification delineates the time limits for placing the unit in a safe MODE or other specified condition when operation cannot be maintained within the limits for safe operation as defined by the LCO and its

BASES

LCO 3.0.3 (continued)

ACTIONS. It is not intended to be used as an operational convenience that permits routine voluntary removal of redundant systems or components from service in lieu of other alternatives that would not result in redundant systems or components being inoperable.

Upon entering LCO 3.0.3, 1 hour is allowed to prepare for an orderly shutdown before initiating a change in unit operation. This includes time to permit the operator to coordinate the reduction in electrical generation with the load dispatcher to ensure the stability and availability of the electrical grid. The time limits specified to reach lower MODES of operation permit the shutdown to proceed in a controlled and orderly manner that is well within the specified maximum cooldown rate and within the capabilities of the unit, assuming that only the minimum required equipment is OPERABLE. This reduces thermal stresses on components of the Reactor Coolant System and the potential for a plant upset that could challenge safety systems under conditions to which this Specification applies. The use and interpretation of specified times to complete the actions of LCO 3.0.3 are consistent with the discussion of Section 1.3, "Completion Times."

A unit shutdown required in accordance with LCO 3.0.3 may be terminated and LCO 3.0.3 exited if any of the following occurs:

a. The LCO is now met;

b. A Condition exists for which the Required Actions have now been performed; or

c. ACTIONS exist that do not have expired Completion Times. These Completion Times are applicable from the point in time that the Condition is initially entered and not from the time LCO 3.0.3 is exited.

The time limits of LCO 3.0.3 allow 37 hours for the unit to be in MODE 4 when a shutdown is required during MODE 1 operation. If the unit is in a lower MODE of operation when a shutdown is required, the time limit for reaching the next lower MODE applies. If a lower MODE is reached in less time than allowed, however, the total allowable time to reach MODE 4, or other applicable MODE, is not reduced. For example, if MODE 2 is reached in 2 hours, then the time allowed for reaching MODE 3 is the next 11 hours, because the total time for reaching MODE 3 is not reduced from the allowable limit of 13 hours. Therefore, if remedial measures are completed that would permit a return to MODE 1, a penalty is not incurred by having to reach a lower MODE of operation in less than the total time allowed.

BASES

LCO 3.0.3 (continued)

In MODES 1, 2, and 3, LCO 3.0.3 provides actions for Conditions not covered in other Specifications. The requirements of LCO 3.0.3 do not apply in MODES 4 and 5 because the unit is already in the most restrictive condition required by LCO 3.0.3. The requirements of LCO 3.0.3 do not apply in other specified conditions of the Applicability (unless in MODE 1, 2, or 3) because the ACTIONS of individual Specifications sufficiently define the remedial measures to be taken.

Exceptions to LCO 3.0.3 are provided in instances where requiring a unit shutdown, in accordance with LCO 3.0.3, would not provide appropriate remedial measures for the associated condition of the unit. An example of this is in LCO 3.7.8, "Spent Fuel Storage Pool Water Level." LCO 3.7.8 has an Applicability of "During movement of irradiated fuel assemblies in the spent fuel storage pool." Therefore, this LCO can be applicable in any or all MODES. If the LCO and the Required Actions of LCO 3.7.8 are not met while in MODE 1, 2, or 3, there is no safety benefit to be gained by placing the unit in a shutdown condition. The Required Action of LCO 3.7.8 to "Suspend movement of irradiated fuel assemblies in the spent fuel storage pool" is the appropriate Required Action to complete in lieu of the actions of LCO 3.0.3. These exceptions are addressed in the individual Specifications.

LCO 3.0.4

LCO 3.0.4 establishes limitations on changes in MODES or other specified conditions in the Applicability when an LCO is not met. It allows placing the unit in a MODE or other specified condition stated in that Applicability (i.e., the Applicability desired to be entered) when unit conditions are such that the requirements of the LCO would not be met, in accordance with LCO 3.0.4.a, LCO 3.0.4.b, or LCO 3.0.4.c.

LCO 3.0.4.a allows entry into a MODE or other specified condition in the Applicability with the LCO not met when the associated ACTIONS to be entered permit continued operation in the MODE or other specified condition in the Applicability for an unlimited period of time. Compliance with Required Actions that permit continued operation of the unit for an unlimited period of time in a MODE or other specified condition provides an acceptable level of safety for continued operation. This is without regard to the status of the unit before or after the MODE change. Therefore, in such cases, entry into a MODE or other specified condition in the Applicability may be made in accordance with the provisions of the Required Actions.

LCO 3.0.4.b allows entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, consideration of the

BASES

LCO 3.0.4 (continued)

results, determination of the acceptability of entering the MODE or other specified condition in the Applicability, and establishment of risk management actions, if appropriate.

The risk assessment may use quantitative, qualitative, or blended approaches, and the risk assessment will be conducted using the plant program, procedures, and criteria in place to implement 10 CFR 50.65(a)(4), which requires that risk impacts of maintenance activities to be assessed and managed. The risk assessment, for the purposes of LCO 3.0.4.b, must take into account all inoperable Technical Specification equipment regardless of whether the equipment is included in the normal 10 CFR 50.65(a)(4) risk assessment scope. The risk assessments will be conducted using the procedures and guidance endorsed by Regulatory Guide 1.182, "Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants" (Ref. 1). Regulatory Guide 1.182 endorses the guidance in Section 11 of NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants" (Ref. 2). These documents address general guidance for conduct of the risk assessment, quantitative and qualitative guidelines for establishing risk management actions, and example risk management actions. These include actions to plan and conduct other activities in a manner that controls overall risk, increased risk awareness by shift and management personnel, actions to reduce the duration of the condition, actions to minimize the magnitude of risk increases (establishment of backup success paths or compensatory measures), and determination that the proposed MODE change is acceptable. Consideration should also be given to the probability of completing restoration such that the requirements of the LCO would be met prior to the expiration of ACTIONS Completion Times that would require exiting the Applicability.

LCO 3.0.4.b may be used with single, or multiple systems and components unavailable. NUMARC 93-01 provides guidance relative to consideration of simultaneous unavailability of multiple systems and components.

The results of the risk assessment shall be considered in determining the acceptability of entering the MODE or other specified condition in the Applicability, and any corresponding risk management actions. The LCO 3.0.4.b risk assessments do not have to be documented.

The Technical Specifications allow continued operation with equipment unavailable in MODE 1 for the duration of the Completion Time. Since this is allowable, and since in general the risk impact in that particular MODE bounds the risk of transitioning into and through the applicable MODES or other specified conditions in the Applicability of the LCO, the

BASES

LCO 3.0.4 (continued)

use of the LCO 3.0.4.b allowance should be generally acceptable, as long as the risk is assessed and managed as stated above. However, there is a small subset of systems and components that have been determined to be more important to risk and use of the LCO 3.0.4.b allowance is prohibited. The LCOs governing these systems and components contain Notes prohibiting the use of LCO 3.0.4.b by stating that LCO 3.0.4.b is not applicable.

LCO 3.0.4.c allows entry into a MODE or other specified condition in the Applicability with the LCO not met based on a Note in the Specification which states LCO 3.0.4.c is applicable. These specific allowances permit entry into MODES or other specified conditions in the Applicability when the associated ACTIONS to be entered do not provide for continued operation for an unlimited period of time and a risk assessment has not been performed. This allowance may apply to all the ACTIONS or to a specific Required Action of a Specification. The risk assessments performed to justify the use of LCO 3.0.4.b usually only consider systems and components. For this reason, LCO 3.0.4.c is typically applied to Specifications which describe values and parameters (e.g., Primary Containment Air Temperature and MCPR), and may be applied to other Specifications based on NRC plant specific approval.

The provisions of this Specification should not be interpreted as endorsing the failure to exercise the good practice of restoring systems or components to OPERABLE status before entering an associated MODE or other specified condition in the Applicability.

The provisions of LCO 3.0.4 shall not prevent changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS. In addition, the provisions of LCO 3.0.4 shall not prevent changes in MODES or other specified conditions in the Applicability that result from any unit shutdown. In this context, a unit shutdown is defined as a change in MODE or other specified condition in the Applicability associated with transitioning from MODE 1 to MODE 2, MODE 2 to MODE 3, and MODE 3 to MODE 4.

Upon entry into a MODE or other specified condition in the Applicability with the LCO not met, LCO 3.0.1 and LCO 3.0.2 require entry into the applicable Conditions and Required Actions until the Condition is resolved, until the LCO is met, or until the unit is not within the Applicability of the Technical Specifications.

Surveillances do not have to be performed on the associated inoperable equipment (or on variables outside the specified limits), as permitted by SR 3.0.1. Therefore, utilizing LCO 3.0.4 is not a violation of SR 3.0.1 or

BASES

LCO 3.0.4 (continued)

SR 3.0.4 for Surveillances that have not been performed on inoperable equipment. However, SRs must be met to ensure OPERABILITY prior to declaring the associated equipment OPERABLE (or variable within limits) and restoring compliance with the affected LCO.

LCO 3.0.5

LCO 3.0.5 establishes the allowance for restoring equipment to service under administrative controls when it has been removed from service or declared inoperable to comply with ACTIONS. The sole purpose of this Specification is to provide an exception to LCO 3.0.2 (e.g., to not comply with the applicable Required Action(s)) to allow the performance of required testing to demonstrate:

a. The OPERABILITY of the equipment being returned to service; or

b. The OPERABILITY of other equipment.

The administrative controls ensure the time the equipment is returned to service in conflict with the requirements of the ACTIONS is limited to the time absolutely necessary to perform the required testing to demonstrate OPERABILITY. This Specification does not provide time to perform any other preventive or corrective maintenance.

An example of demonstrating the OPERABILITY of the equipment being returned to service is reopening a primary containment isolation valve that has been closed to comply with Required Actions and must be reopened to perform the required testing.

An example of demonstrating the OPERABILITY of other equipment is taking an inoperable channel or trip system out of the tripped condition to prevent the trip function from occurring during the performance of required testing on another channel in the other trip system. A similar example of demonstrating the OPERABILITY of other equipment is taking an inoperable channel or trip system out of the tripped condition to permit the logic to function and indicate the appropriate response during the performance of required testing on another channel in the same trip system.

LCO 3.0.6

LCO 3.0.6 establishes an exception to LCO 3.0.2 for supported systems that have a support system LCO specified in the Technical Specifications (TS). This exception is provided because LCO 3.0.2 would require that the Conditions and Required Actions of the associated inoperable supported system LCO be entered solely due to the inoperability of the support system. This exception is justified because the actions that are required to ensure the plant is maintained in a safe condition are specified

BASES

LCO 3.0.6 (continued)

in the support system LCO's Required Actions. These Required Actions may include entering the supported systems' Conditions and Required Actions or may specify other Required Actions.

When a support system is inoperable and there is an LCO specified for it in the TS, the supported system(s) are required to be declared inoperable if determined to be inoperable as a result of the support system inoperability. However, it is not necessary to enter into the supported systems' Conditions and Required Actions unless directed to do so by the support system's Required Actions. The potential confusion and inconsistency of requirements related to the entry into multiple support and supported systems' LCO's Conditions and Required Actions are eliminated by providing all the actions that are necessary to ensure the plant is maintained in a safe condition in the support system's Required Actions.

However, there are instances where a support system's Required Action may either direct a supported system to be declared inoperable or direct entry into Conditions and Required Actions for the supported system. This may occur immediately or after some specified delay to perform some other Required Action. Regardless of whether it is immediate or after some delay, when a support system's Required Action directs a supported system to be declared inoperable or directs entry into Conditions and Required Actions for a supported system, the applicable Conditions and Required Actions shall be entered in accordance with LCO 3.0.2.

Specification 5.5.10, "Safety Function Determination Program (SFDP)," ensures loss of safety function is detected and appropriate actions are taken. Upon entry into LCO 3.0.6, an evaluation shall be made to determine if loss of safety function exists. Additionally, other limitations, remedial actions, or compensatory actions may be identified as a result of the support system inoperability and corresponding exception to entering supported system Conditions and Required Actions. The SFDP implements the requirements of LCO 3.0.6.

Cross division checks to identify a loss of safety function for those support systems that support safety systems are required. The cross division check verifies that the supported systems of the redundant OPERABLE support system are OPERABLE, thereby ensuring safety function is retained. A loss of safety function may exist when a support system is inoperable, and:

a. A required system redundant to system(s) supported by the inoperable support system is also inoperable (EXAMPLE B 3.0.6-1);

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LCO 3.0.6 (continued)

b. A required system redundant to system(s) in turn supported by the inoperable supported system is also inoperable (EXAMPLE B 3.0.6-2); or

c. A required system redundant to support system(s) for the supported systems (a) and (b) above is also inoperable (EXAMPLE B 3.0.6-3).

<u>EXAMPLE B 3.0.6-1</u>

If System 2 of Division A is inoperable and System 5 of Division B is inoperable, a loss of safety function exists in supported System 5.

<u>EXAMPLE B 3.0.6-2</u>

If System 2 of Division A is inoperable, and System 11 of Division B is inoperable, a loss of safety function exists in System 11 which is in turn supported by System 5.

<u>EXAMPLE B 3.0.6-3</u>

If System 2 of Division A is inoperable, and System 1 of Division B is inoperable, a loss of safety function exists in Systems 2, 4, 5, 8, 9, 10, and 11.

If this evaluation determines that a loss of safety function exists, the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists are required to be entered.

This loss of safety function does not require the assumption of additional single failures or loss of offsite power. Since operations are being restricted in accordance with the ACTIONS of the support system, any resulting temporary loss of redundancy or single failure protection is taken into account. Similarly, the ACTIONS for inoperable offsite circuit(s) and inoperable diesel generator(s) provide the necessary restriction for cross train inoperabilities. This explicit cross train verification for inoperable AC electrical power sources also acknowledges that supported system(s) are not declared inoperable solely as a result of inoperability of a normal or emergency electrical power source (refer to the definition of OPERABILITY).

When loss of safety function is determined to exist, and the SFDP requires entry into the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists, consideration must be given to the specific type of function affected. Where a loss of function is solely due to a single Technical Specification support system (e.g., loss of automatic start due to inoperable instrumentation, or loss of pump suction

BASES

LCO 3.0.6 (continued)

source due to low tank level) the appropriate LCO is the LCO for the support system. The ACTIONS for a support system LCO adequately address the inoperabilities of that system without reliance on entering its supported system LCO. When the loss of function is the result of multiple support systems, the appropriate LCO is the LCO for the supported system.

LCO 3.0.7

There are certain special tests and operations required to be performed at various times over the life of the unit. These special tests and operations are necessary to demonstrate select unit performance characteristics, to perform special maintenance activities, and to perform special evolutions. Special Operations LCOs in Section 3.10 allow specified TS requirements to be changed to permit performances of these special tests and operations, which otherwise could not be performed if required to comply with the requirements of these TS. Unless otherwise specified, all the other TS requirements remain unchanged. This will ensure all appropriate requirements of the MODE or other specified condition not directly associated with or required to be changed to perform the special test or operation will remain in effect.

The Applicability of a Special Operations LCO represents a condition not necessarily in compliance with the normal requirements of the TS. Compliance with Special Operations LCOs is optional. A special operation may be performed either under the provisions of the appropriate Special Operations LCO or under the other applicable TS requirements. If it is desired to perform the special operation under the provisions of the Special Operations LCO, the requirements of the Special Operations LCO shall be followed. When a Special Operations LCO requires another LCO to be met, only the requirements of the LCO statement are required to be met regardless of that LCO's Applicability (i.e., should the requirements of this other LCO not be met, the ACTIONS of the Special Operations LCO apply, not the ACTIONS of the other LCO). However, there are instances where the Special Operations LCO ACTIONS may direct the other LCO's ACTIONS be met. The Surveillances of the other LCO are not required to be met, unless specified in the Special Operations LCO. If conditions exist such that the Applicability of any other LCO is met, all the other LCO's requirements (ACTIONS and SRs) are required to be met concurrent with the requirements of the Special Operations LCO.

LCO 3.0.8

LCO 3.0.8 establishes conditions under which systems are considered to remain capable of performing their intended safety function when associated snubbers are not capable of providing their associated support function(s). This LCO states that the supported system is not considered to be inoperable solely due to one or more snubbers not capable of performing their associated support function(s). This is appropriate

BASES

LCO 3.0.8 (continued)

because a limited length of time is allowed for maintenance, testing, or repair of one or more snubbers not capable of performing their associated support function(s) and appropriate compensatory measures are specified in the snubber requirements, which are located outside of the Technical Specifications (TS) under licensee control. The snubber requirements do not meet the criteria in 10 CFR 50.36(c)(2)(ii), and, as such, are appropriate for control by the licensee.

If the allowed time expires and the snubber(s) are unable to perform their associated support function(s), the affected supported system's LCO(s) must be declared not met and the Conditions and Required Actions entered in accordance with LCO 3.0.2.

LCO 3.0.8.a applies when one or more snubbers are not capable of providing their associated support function(s) to a single subsystem of a multiple subsystem supported system or to a single subsystem supported system. LCO 3.0.8.a allows 72 hours to restore the snubber(s) before declaring the supported system inoperable. The 72 hour Completion Time is reasonable based on the low probability of a seismic event concurrent with an event that would require operation of the supported system occurring while the snubber(s) are not capable of performing their associated support function and due to the availability of the redundant train of the supported system.

LCO 3.0.8.b applies when one or more snubbers are not capable of providing their associated support function(s) to more than one subsystem of a multiple subsystem supported system. LCO 3.0.8.b allows 12 hours to restore the snubber(s) before declaring the supported system inoperable. The 12 hour Completion Time is reasonable based on the low probability of a seismic event concurrent with an event that would require operation of the supported system occurring while the snubber(s) are not capable of performing their associated support function.

LCO 3.0.8 requires that risk be assessed and managed. Industry and NRC guidance on the implementation of 10 CFR 50.65(a)(4) (the Maintenance Rule) does not address seismic risk. However, use of LCO 3.0.8 should be considered with respect to other plant maintenance activities, and integrated into the existing Maintenance Rule process to the extent possible so that maintenance on any unaffected subsystem is properly controlled, and emergent issues are properly addressed. The risk assessment need not be quantified, but may be a qualitative awareness of the vulnerability of systems and components when one or more snubbers are not able to perform their associated support function.

BASES

LCO 3.0.9

LCO 3.0.9, issued under Amendment 157 (Ref. 4), establishes conditions under which systems described in the Technical Specifications are considered to remain OPERABLE when required barriers are not capable of providing their related support function(s).

Barriers are doors, walls, floor plugs, curbs, hatches, installed structures or components, or other devices, not explicitly described in Technical Specifications, that support the performance of the safety function of systems described in the Technical Specifications. This LCO states that the supported system is not considered to be inoperable solely due to required barriers not capable of performing their related support function(s) under the described conditions. LCO 3.0.9 allows 30 days before declaring the supported system(s) inoperable and the LCO(s) associated with the supported system(s) not met. A maximum time is placed on each use of this allowance to ensure that as required barriers are found or are otherwise made unavailable, they are restored. However, the allowable duration may be less than the specified maximum time based on the risk assessment.

If the allowed time expires and the barriers are unable to perform their related support function(s), the supported system's LCO(s) must be declared not met and the Conditions and Required Actions entered in accordance with LCO 3.0.2.

This provision does not apply to barriers which support ventilation systems or to fire barriers. The Technical Specifications for ventilation systems provide specific Conditions for inoperable barriers. Fire barriers are addressed by other regulatory requirements and associated plant programs. This provision does not apply to barriers which are not required to support system OPERABILITY (see NRC Regulatory Issue Summary 2001-09, "Control of Hazard Barriers" (Ref. 3)).

The provisions of LCO 3.0.9 are justified because of the low risk associated with required barriers not being capable of performing their related support function. This provision is based on consideration of the following initiating event categories:

- Loss of coolant accidents;
- High energy line breaks;
- Feedwater line breaks;
- Internal flooding;
- External flooding;
- Turbine missile ejection; and
- Tornado or high wind.

The risk impact of the barriers which cannot perform their related support function(s) must be addressed pursuant to the risk assessment and management provision of the Maintenance Rule, 10 CFR 50.65 (a)(4),

BASES

LCO 3.0.9 (continued)

and the associated implementation guidance, Regulatory Guide 1.182 (Ref. 1). Regulatory Guide 1.182 endorses the guidance in Section 11 of NUMARC 93-01 (Ref. 2). This guidance provides for the consideration of dynamic plant configuration issues, emergent conditions, and other aspects pertinent to plant operation with the barriers unable to perform their related support function(s). These considerations may result in risk management and other compensatory actions being required during the period that barriers are unable to perform their related support function(s).

LCO 3.0.9 may be applied to one or more divisions or subsystems of a system supported by barriers that cannot provide their related support function(s), provided that risk is assessed and managed (including consideration of the effects on Large Early Release and from external events). If applied concurrently to more than one division or subsystem of a multiple division or subsystem supported system, the barriers supporting each of these divisions or subsystems must provide their related support function(s) for different categories of initiating events. For example, LCO 3.0.9 may be applied for up to 30 days for more than one division of a multiple division supported system if the affected barrier for one division protects against internal flooding and the affected barrier for the other division protects against tornado missiles. In this example, the affected barrier may be the same physical barrier but serve different protection functions for each division.

The High Pressure Coolant Injection (HPCI) and Reactor Core Isolation Cooling (RCIC) systems are single train systems for injecting makeup water into the reactor during an accident or transient event. The RCIC system is not a safety system, nor required to operate during a transient, therefore, it does not have to meet the single failure criterion. The HPCI system provides backup in case of a RCIC system failure. The Automatic Depressurization System (ADS) and low pressure Emergency Core Cooling System (ECCS) coolant injection provide the core cooling function in the event of failure of the HPCI system during an accident. Thus, for the purposes of LCO 3.0.9, the HPCI system, the RCIC system, and the ADS are considered independent subsystems of a single system and LCO 3.0.9 can be used on these single division systems in a manner similar to multiple division or subsystem systems.

BASES

LCO 3.0.9 (continued)

If during the time that LCO 3.0.9 is being used, the required OPERABLE division or subsystem becomes inoperable, it must be restored to OPERABLE status within 24 hours. Otherwise, the division(s) or subsystem(s) supported by barriers that cannot perform their related support function(s) must be declared inoperable and the associated LCOs declared not met. This 24 hour period provides time to respond to emergent conditions that would otherwise likely lead to entry into LCO 3.0.3 and a rapid plant shutdown, which is not justified given the low probability of an initiating event which would require the barrier(s) not capable of performing their related support function(s). During this 24 hour period, the plant risk associated with the existing conditions is assessed and managed in accordance with 10 CFR 50.65(a)(4).

REFERENCES

1. Regulatory Guide 1.182, “Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants,” May 2000.

2. NUMARC 93-01, Revision 2, “Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants.”

3. Regulatory Issue Summary 2001-09, “Control of Hazard Barriers,” April 2, 2001.

4. Amendment No. 157, “Issuance of Amendment to Add New Limiting Condition for Operation 3.0.9 Regarding Unavailability of Barriers,” dated October 22, 2008. (ADAMS Accession No. ML082550139)

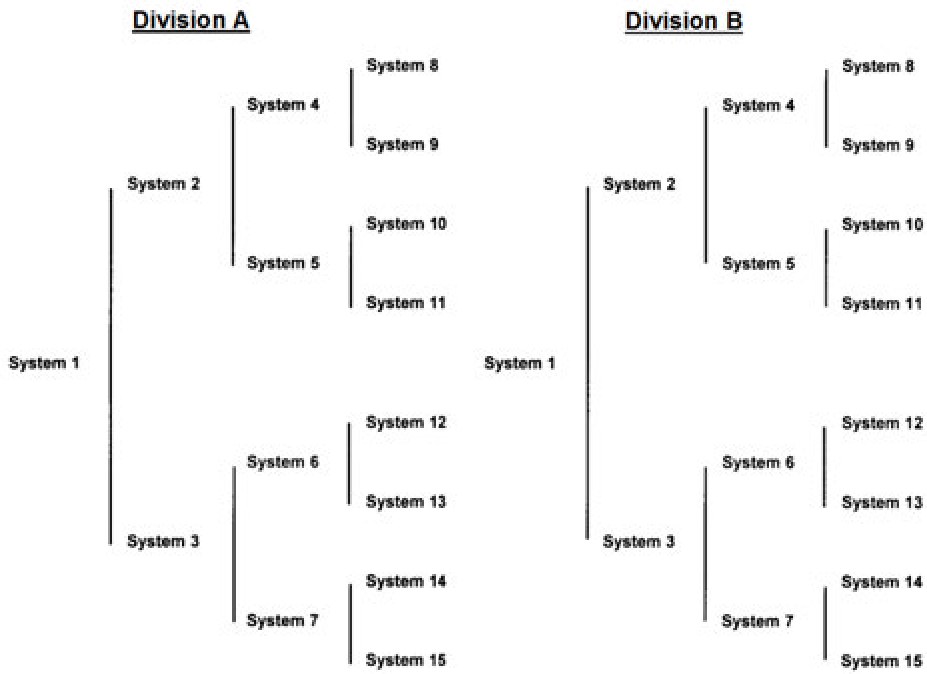

Figure B 3.0-1
Configuration of Divisions and Systems

B 3.0 SURVEILLANCE REQUIREMENT (SR) Applicability

BASES

SRs	SR 3.0.1 through SR 3.0.4 establish the general requirements applicable to all Specifications in Sections 3.1 through 3.10 and apply at all times, unless otherwise stated.

SR 3.0.1

SR 3.0.1 establishes the requirement that SRs must be met during the MODES or other specified conditions in the Applicability for which the requirements of the LCO apply, unless otherwise specified in the individual SRs. This Specification is to ensure that Surveillances are performed to verify the OPERABILITY of systems and components, and that variables are within specified limits. Failure to meet a Surveillance within the specified Frequency, in accordance with SR 3.0.2, constitutes a failure to meet an LCO. Surveillances may be performed by means of any series of sequential, overlapping, or total steps provided the entire Surveillance is performed within the specified Frequency. Additionally, the definitions related to instrument testing (e.g., CHANNEL CALIBRATION) specify that these tests are performed by means of any series of sequential, overlapping, or total steps.

Systems and components are assumed to be OPERABLE when the associated SRs have been met. Nothing in this Specification, however, is to be construed as implying that systems or components are OPERABLE when:

a. The systems or components are known to be inoperable, although still meeting the SRs; or

b. The requirements of the Surveillance(s) are known to be not met between required Surveillance performances.

Surveillances do not have to be performed when the unit is in a MODE or other specified condition for which the requirements of the associated LCO are not applicable, unless otherwise specified. The SRs associated with a Special Operations LCO are only applicable when the Special Operations LCO is used as an allowable exception to the requirements of a Specification.

Unplanned events may satisfy the requirements (including applicable acceptance criteria) for a given SR. In this case, the unplanned event may be credited as fulfilling the performance of the SR.

Surveillances, including Surveillances invoked by Required Actions, do not have to be performed on inoperable equipment because the ACTIONS define the remedial measures that apply. Surveillances have to be met and performed in accordance with SR 3.0.2, prior to returning equipment to OPERABLE status.

BASES

SR 3.0.1 (continued)

Upon completion of maintenance, appropriate post maintenance testing is required to declare equipment OPERABLE. This includes ensuring applicable Surveillances are not failed and their most recent performance is in accordance with SR 3.0.2. Post maintenance testing may not be possible in the current MODE or other specified conditions in the Applicability due to the necessary unit parameters not having been established. In these situations, the equipment may be considered OPERABLE provided testing has been satisfactorily completed to the extent possible and the equipment is not otherwise believed to be incapable of performing its function. This will allow operation to proceed to a MODE or other specified condition where other necessary post maintenance tests can be completed.

Some examples of this process are:

a. Control Rod Drive maintenance during refueling that requires scram testing at > 800 psig. However, if other appropriate testing is satisfactorily completed and the scram time testing of SR 3.1.4.3 is satisfied, the control rod can be considered OPERABLE. This allows startup to proceed to reach 800 psig to perform other necessary testing.

b. High pressure coolant injection (HPCI) maintenance during shutdown that requires system functional tests at a specified pressure. Provided other appropriate testing is satisfactorily completed, startup can proceed with HPCI considered OPERABLE. This allows operation to reach the specified pressure to complete the necessary post maintenance testing.

SR 3.0.2

SR 3.0.2 establishes the requirements for meeting the specified Frequency for Surveillances and any Required Action with a Completion Time that requires the periodic performance of the Required Action on a "once per..." interval.

SR 3.0.2 permits a 25% extension of the interval specified in the Frequency. This extension facilitates Surveillance scheduling and considers plant operating conditions that may not be suitable for conducting the Surveillance (e.g., transient conditions or other ongoing Surveillance or maintenance activities). As noted in NRC Enforcement Guidance Memorandum (EGM) 12-001 (Reference 1), the 25% interval extension allowed by SR 3.0.2 applies to TS Section 5.5 Programs which invoke SR 3.0.2.

The 25% extension does not significantly degrade the reliability that results from performing the Surveillance at its specified Frequency. This is based on the recognition that the most probable result of any particular

BASES

SR 3.0.2 (continued)

Surveillance being performed is the verification of conformance with the SRs. The exceptions to SR 3.0.2 are those Surveillances for which the 25% extension of the interval specified in the Frequency does not apply. These exceptions are stated in the individual Specifications. The requirements of regulations take precedence over the TS. An example of where SR 3.0.2 does not apply is in the Primary Containment Leakage Rate Testing Program. This program establishes testing requirements and Frequencies in accordance with the requirements of regulations. The TS cannot in and of themselves extend a test interval specified in the regulations.

As stated in SR 3.0.2, the 25% extension also does not apply to the initial portion of a periodic Completion Time that requires performance on a "once per ..." basis. The 25% extension applies to each performance after the initial performance. The initial performance of the Required Action, whether it is a particular Surveillance or some other remedial action, is considered a single action with a single Completion Time. One reason for not allowing the 25% extension to this Completion Time is that such an action usually verifies that no loss of function has occurred by checking the status of redundant or diverse components or accomplishes the function of the inoperable equipment in an alternative manner.

The provisions of SR 3.0.2 are not intended to be used repeatedly merely as an operational convenience to extend Surveillance intervals (other than those consistent with refueling intervals) or periodic Completion Time intervals beyond those specified.

SR 3.0.3

SR 3.0.3 establishes the flexibility to defer declaring affected equipment inoperable or an affected variable outside the specified limits when a Surveillance has not been completed within the specified Frequency. A delay period of up to 24 hours or up to the limit of the specified Frequency, whichever is greater, applies from the point in time that it is discovered that the Surveillance has not been performed in accordance with SR 3.0.2, and not at the time that the specified Frequency was not met. SR 3.0.3 does not apply to TS 5.5.5, “Inservice Testing Program”, tests unless the tests are required by TS Chapter 3 SRs since SR 3.0.3 does not apply to 10 CFR 50.55a(f) tests (References 1 through 3). Missed TS 5.5.5 tests not required by a TS Chapter 3 SR should be addressed in the Corrective Action Program (CAP) as a nonconformance to ASME OM Code requirements.

This delay period provides adequate time to complete Surveillances that have been missed. This delay period permits the completion of a Surveillance before complying with Required Actions or other remedial measures that might preclude completion of the Surveillance.

BASES

SR 3.0.3 (continued)

The basis for this delay period includes consideration of unit conditions, adequate planning, availability of personnel, the time required to perform the Surveillance, the safety significance of the delay in completing the required Surveillance, and the recognition that the most probable result of any particular Surveillance being performed is the verification of conformance with the requirements.

When a Surveillance with a Frequency based not on time intervals, but upon specified unit conditions, operating situations, or requirements of regulations (e.g., prior to entering MODE 1 after each fuel loading, or in accordance with 10 CFR 50, Appendix J, as modified by approved exemptions, etc.) is discovered to not have been performed when specified, SR 3.0.3 allows for the full delay period of up to the specified Frequency to perform the Surveillance. However, since there is not a time interval specified, the missed Surveillance should be performed at the first reasonable opportunity.

SR 3.0.3 provides a time limit for, and allowances for the performance of, Surveillances that become applicable as a consequence of MODE changes imposed by Required Actions.

Failure to comply with specified Frequencies for SRs is expected to be an infrequent occurrence. Use of the delay period established by SR 3.0.3 is a flexibility which is not intended to be used as an operational convenience to extend Surveillance intervals. While up to 24 hours or the limit of the specified Frequency is provided to perform the missed Surveillance, it is expected that the missed Surveillance will be performed at the first reasonable opportunity. The determination of the first reasonable opportunity should include consideration of the impact on plant risk (from delaying the Surveillance as well as any plant configuration changes required or shutting the plant down to perform the Surveillance) and impact on any analysis assumptions, in addition to unit conditions, planning, availability of personnel, and the time required to perform the Surveillance. This risk impact should be managed through the program in place to implement 10 CFR 50.65(a)(4) and its implementation guidance, Regulatory Guide 1.182, "Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants." This Regulatory Guide addresses consideration of temporary and aggregate risk impacts, determination of risk management action thresholds, and risk management action up to and including plant shutdown. The missed Surveillance should be treated as an emergent condition as discussed in the Regulatory Guide. The risk evaluation may use quantitative, qualitative, or blended methods. The degree of depth and rigor of the evaluation should be commensurate with the importance of the component. Missed Surveillances for important components should be analyzed quantitatively. If the results of the risk evaluation

BASES

SR 3.0.3 (continued)

determine the risk increase is significant, this evaluation should be used to determine the safest course of action. All missed Surveillances will be placed in the licensee's Corrective Action Program.

If a Surveillance is not completed within the allowed delay period, then the equipment is considered inoperable or the variable is considered outside the specified limits and the Completion Times of the Required Actions for the applicable LCO Conditions begin immediately upon expiration of the delay period. If a Surveillance is failed within the delay period, then the equipment is inoperable, or the variable is outside the specified limits and the Completion Times of the Required Actions for the applicable LCO Conditions begin immediately upon the failure of the Surveillance.

Completion of the Surveillance within the delay period allowed by this Specification, or within the Completion Time of the ACTIONS, restores compliance with SR 3.0.1.

SR 3.0.4

SR 3.0.4 establishes the requirement that all applicable SRs must be met before entry into a MODE or other specified condition in the Applicability.

This Specification ensures that system and component OPERABILITY requirements and variable limits are met before entry into MODES or other specified conditions in the Applicability for which these systems and components ensure safe operation of the unit. The provisions of this Specification should not be interpreted as endorsing the failure to exercise the good practice of restoring systems or components to OPERABLE status before entering an associated MODE or other specified condition in the Applicability.

A provision is included to allow entry into a MODE or other specified condition in the Applicability when an LCO is not met due to a Surveillance not being met in accordance with LCO 3.0.4.

However, in certain circumstances, failing to meet an SR will not result in SR 3.0.4 restricting a MODE change or other specified condition change. When a system, subsystem, division, component, device, or variable is inoperable or outside its specified limits, the associated SR(s) are not required to be performed, per SR 3.0.1, which states that Surveillances do not have to be performed on inoperable equipment. When equipment is inoperable, SR 3.0.4 does not apply to the associated SR(s) since the requirement for the SR(s) to be performed is removed. Therefore, failing to perform the Surveillance(s) within the specified Frequency does not result in an SR 3.0.4 restriction to changing MODES or other specified conditions of the Applicability. However, since the LCO is not met in this instance, LCO 3.0.4 will govern any restrictions that may (or may not)

BASES

SR 3.0.4 (continued)

apply to MODE or other specified condition changes. SR 3.0.4 does not restrict changing MODES or other specified conditions of the Applicability when a Surveillance has not been performed within the specified Frequency, provided the requirement to declare the LCO not met has been delayed in accordance with SR 3.0.3.

The provisions of SR 3.0.4 shall not prevent entry into MODES or other specified conditions in the Applicability that are required to comply with ACTIONS. In addition, the provisions of SR 3.0.4 shall not prevent changes in MODES or other specified conditions in the Applicability that result from any unit shutdown. In this context, a unit shutdown is defined as a change in MODE or other specified condition in the Applicability associated with transitioning from MODE 1 to MODE 2, MODE 2 to MODE 3, and MODE 3 to MODE 4.

The precise requirements for performance of SRs are specified such that exceptions to SR 3.0.4 are not necessary. The specific time frames and conditions necessary for meeting the SRs are specified in the Frequency, in the Surveillance, or both. This allows performance of Surveillances when the prerequisite condition(s) specified in a Surveillance procedure require entry into the MODE or other specified condition in the Applicability of the associated LCO prior to the performance or completion of a Surveillance. A Surveillance that could not be performed until after entering the LCO’s Applicability, would have its Frequency specified such that it is not "due" until the specific conditions needed are met. Alternately, the Surveillance may be stated in the form of a Note, as not required (to be met or performed) until a particular event, condition, or time has been reached. Further discussion of the specific formats of SRs' annotation is found in Section 1.4, "Frequency."

REFERENCES

1. NRC Enforcement Guidance Memorandum (EGM) 12-001, “Dispositioning Noncompliance with Administrative Controls Technical Specifications Programmatic Requirements That Extend Test Frequencies and Allow Performance of Missed Tests.”

2. NRC Regulatory Issue Summary 2012-10, “NRC Staff Position on Applying Surveillance Requirements 3.0.2 and 3.0.3 to Administrative Control Program Tests”.

3. NRC Reply to Industry Questions on EGM 12-001, dated July 6, 2012 (ADAMS Accession Number ML12143A051).

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.1 SHUTDOWN MARGIN (SDM)

BASES

BACKGROUND

SDM requirements are specified to ensure:

a. The reactor core is designed so that control rod action, with the maximum worth control rod fully withdrawn and unavailable for use, is capable of bringing the reactor core subcritical and maintaining it so from any power level in the operating cycle; and

b. The reactor core and associated systems are designed to accommodate unit operational transients or maneuvers which might be expected without compromising safety and without fuel damage.

These requirements are satisfied by the control rods, as described in USAR, Section 3.3.3.3 (Ref. 1), which can compensate for the reactivity effects of the fuel and water temperature changes experienced during all operating conditions.

APPLICABLE SAFETY ANALYSES

NOTE: Certain AREVA safety analysis methods have been approved for use (Amendment 188); however, those methods may not be invoked in the analysis-of-record until AREVA fuel is loaded in the core. Until that time, General Electric – Hitachi (GEH) safety analysis methods will continue to support core operation and the description of the GEH methods in the TS Bases shall prevail. To the extent that approved AREVA methods may be described and referenced without conflicting with the GEH analysis-of-record, the TS Bases reflect both GEH and AREVA methods. Refer to CORE OPERATING LIMIT REPORT (COLR) Section 1.0 to determine whether GEH or AREVA methods were used for the current operating cycle.

Having sufficient SDM assures that the reactor will become and remain subcritical after all design basis accidents and transients. The control rod drop accident (CRDA) analysis (Refs. 2, 3, 6 and 7) assumes the core is subcritical with the highest worth control rod withdrawn. The control rod removal error during refueling and fuel assembly insertion error during refueling events rely on adequate SDM and proper operation of the refueling interlocks when the reactor is in the refueling mode of operation. These interlocks prevent the withdrawal of more than one control rod from the core during refueling. (Special consideration and requirements for multiple control rod withdrawal during refueling are covered in Special Operations LCO 3.10.6, "Multiple Control Rod Withdrawal - Refueling.") This condition is acceptable since the core will be shut down with the highest worth control rod withdrawn, if adequate SDM has been demonstrated.

BASES

APPLICABLE SAFETY ANALYSES (continued)	Prevention or mitigation of positive reactivity insertion events is necessary to limit energy deposition in the fuel, thereby preventing significant fuel damage, which could result in undue release of radioactivity. Adequate SDM ensures inadvertent criticalities and potential CRDAs involving high worth control rods will not cause significant fuel damage. SDM satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).
LCO	The specified SDM limit accounts for the uncertainty in the demonstration of SDM by testing. Separate SDM limits are provided for testing where the highest worth control rod is determined analytically or by measurement. This is due to the reduced uncertainty in the SDM test when the highest worth control rod is determined by measurement. When SDM is demonstrated by calculations not associated with a test (e.g., to confirm SDM during the fuel loading sequence), additional margin is included to account for uncertainties in the calculation. To ensure adequate SDM, a design margin is included to account for uncertainties in the design calculations (Ref. 4).
APPLICABILITY	In MODES 1 and 2, SDM must be provided because subcriticality with the highest worth control rod withdrawn is assumed in the CRDA analysis (Ref. 2) and other design basis accidents and transients. In MODES 3 and 4, SDM is required to ensure the reactor will be held subcritical with margin for a single withdrawn control rod. SDM is required in MODE 5 to prevent an open vessel, inadvertent criticality during the withdrawal of a single control rod from a core cell containing one or more fuel assemblies or a fuel assembly insertion error.
ACTIONS	<u>A.1</u> With SDM not within the limits of the LCO in MODE 1 or 2, SDM must be restored within 6 hours. Failure to meet the specified SDM may be caused by a control rod that cannot be inserted. The allowed Completion Time of 6 hours is acceptable, considering that the reactor can still be shut down, assuming no failures of additional control rods to insert, and the low probability of an event occurring during this interval. <u>B.1</u> If the SDM cannot be restored, the plant must be brought to MODE 3 in 12 hours, to prevent the potential for further reductions in available SDM (e.g., additional stuck control rods). The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

ACTIONS (continued)

C.1

With SDM not within limits in MODE 3, the operator must immediately initiate action to fully insert all insertable control rods. Action must continue until all insertable control rods are fully inserted. This action results in the least reactive condition for the core.

D.1, D.2, D.3, and D.4

With SDM not within limits in MODE 4, the operator must immediately initiate action to fully insert all insertable control rods. Action must continue until all insertable control rods are fully inserted. This action results in the least reactive condition for the core. Action must also be initiated within 1 hour to provide means for control of potential radioactive releases. This includes ensuring secondary containment is OPERABLE; at least one Standby Gas Treatment (SGT) subsystem is OPERABLE; and secondary containment isolation capability is available in each associated penetration flow path not isolated that is assumed to be isolated to mitigate radioactivity releases (i.e., at least one secondary containment isolation valve and associated instrumentation are OPERABLE, or other acceptable administrative controls to assure isolation capability). These administrative controls consist of stationing a dedicated operator, who is in continuous communication with the control room, at the controls of the isolation device. In this way, the penetration can be rapidly isolated when a need for secondary containment isolation is indicated. This (ensuring components are OPERABLE) may be performed as an administrative check, by examining logs or other information, to determine if the components are out of service for maintenance or other reasons. It is not necessary to perform the surveillances needed to demonstrate the OPERABILITY of the components. If, however, any required component is inoperable, then it must be restored to OPERABLE status. In this case, SRs may need to be performed to restore the component to OPERABLE status. Actions must continue until all required components are OPERABLE.

E.1, E.2, E.3, E.4, and E.5

With SDM not within limits in MODE 5, the operator must immediately suspend CORE ALTERATIONS that could reduce SDM (e.g., insertion of fuel in the core or the withdrawal of control rods). Suspension of these activities shall not preclude completion of movement of a component to a safe condition. Inserting control rods or removing fuel from the core will reduce the total reactivity and are therefore excluded from the suspended actions.

BASES

ACTIONS (continued)

Action must also be immediately initiated to fully insert all insertable control rods in core cells containing one or more fuel assemblies. Action must continue until all insertable control rods in core cells containing one or more fuel assemblies have been fully inserted. Control rods in core cells containing no fuel assemblies do not affect the reactivity of the core and therefore do not have to be inserted.

Action must also be initiated within 1 hour to provide means for control of potential radioactive releases. This includes ensuring secondary containment is OPERABLE; at least one SGT subsystem is OPERABLE; and secondary containment isolation capability is available in each associated penetration flow path not isolated that is assumed to be isolated to mitigate radioactivity releases (i.e., at least one secondary containment isolation valve and associated instrumentation are OPERABLE, or other acceptable administrative controls to assure isolation capability). These administrative controls consist of stationing a dedicated operator, who is in continuous communication with the control room, at the controls of the isolation device. In this way, the penetration can be rapidly isolated when a need for secondary containment isolation is indicated. This (ensuring components are OPERABLE) may be performed as an administrative check, by examining logs or other information, to determine if the components are out of service for maintenance or other reasons. It is not necessary to perform the Surveillances as needed to demonstrate the OPERABILITY of the components. If, however, any required component is inoperable, then it must be restored to OPERABLE status. In this case, SRs may need to be performed to restore the component to OPERABLE status. Action must continue until all required components are OPERABLE.

SURVEILLANCE REQUIREMENTS

SR 3.1.1.1

Adequate SDM must be verified to ensure that the reactor can be made subcritical from any initial operating condition. This can be accomplished by a test, an evaluation, or a combination of the two. Adequate SDM is demonstrated by testing before or during the first startup after fuel movement, shuffling within the reactor pressure vessel, or control rod replacement. Control rod replacement refers to the decoupling and removal of a control rod from a core location, and subsequent replacement with a new control rod or a control rod from another core location. Since core reactivity will vary during the cycle as a function of fuel depletion and poison burnup, the beginning of cycle (BOC) test must also account for changes in core reactivity during the cycle. Therefore, to obtain the SDM, the initial measured value of core reactivity must be increased by an adder, "R", which is the difference between the calculated value of maximum core reactivity during the operating cycle

BASES

SURVEILLANCE REQUIREMENTS (continued)

and the calculated BOC core reactivity. If the value of R is negative (that is, BOC is the most reactive point in the cycle), no correction to the BOC measured value is required (Ref. 5). For the SDM demonstrations that rely solely on calculation of the highest worth control rod, additional margin (0.10% $\Delta k/k$) must be added to the SDM limit of 0.28% $\Delta k/k$ to account for uncertainties in the calculation.

The SDM may be demonstrated during an in-sequence control rod withdrawal, in which the highest worth control rod is analytically determined, or during local control rod tests, where the highest worth control rod is determined by testing.

Local control rod tests require the withdrawal of out of sequence control rods. This testing could therefore require bypassing of the rod worth minimizer to allow the out of sequence withdrawal, and therefore additional requirements must be met (see LCO 3.10.7, "Control Rod Testing - Operating").

The Frequency of 4 hours after reaching criticality is allowed to provide a reasonable amount of time to perform the required calculations and have appropriate verification.

During MODES 3 and 4, analytical calculation of SDM may be used to assure the requirements of SR 3.1.1.1 are met. During MODE 5, adequate SDM is required to ensure that the reactor does not reach criticality during control rod withdrawals. An evaluation of each in-vessel fuel movement during fuel loading (including shuffling fuel within the core) is required to ensure adequate SDM is maintained during refueling. This evaluation ensures that the intermediate loading patterns are bounded by the safety analyses for the final core loading pattern. For example, bounding analyses that demonstrate adequate SDM for the most reactive configurations during the refueling may be performed to demonstrate acceptability of the entire fuel movement sequence. These bounding analyses include additional margins to the associated uncertainties. Spiral offload/reload sequences inherently satisfy the SR, provided the fuel assemblies are reloaded in the same configuration analyzed for the new cycle. Removing fuel from the core will always result in an increase in SDM.

REFERENCES

1. USAR, Section 3.3.3.3.

2. USAR, Section 14.7.1.

BASES

REFERENCES (continued)

3. NEDE-24011-P-A, "General Electric Standard Application for Reactor Fuel," Supplement for United States, Section S.2.2.3.1 (revision specified in Specification 5.6.3).

4. USAR, Section 14A.3.1.

5. NEDE-24011-P-A, "General Electric Standard Application for Reactor Fuel," Section 3.2.4.1 (revision specified in Specification 5.6.3).

6. XN-NF-80-19(P)(A) Volume 1 and Supplements 1 and 2, “Exxon Nuclear Methodology for Boiling Water Reactors – Neutronic Methods for Design and Analysis”, Exxon Nuclear Company, March 1983.

7. EMF-2158(P)(A) Revision 0, “Siemens Power Corporation Methodology for Boiling Water Reactors: Evaluation and Validation for CASMO-4/MICROBURN-B2”, Siemens Power Corporation, October 1999.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.2 Reactivity Anomalies

BASES

BACKGROUND

In accordance with USAR, Section 1.2.2 (Ref. 1), the reactor core is designed so that control rod action, with the maximum worth control rod fully withdrawn and unavailable for use, is capable of bringing the reactor core subcritical and maintaining it so from any power level in the operating cycle. In addition, the reactor core and associated systems are designed to accommodate unit operational transients or maneuvers that might be expected without compromising safety and without fuel damage. Therefore, Reactivity Anomalies is used as a measure of the predicted versus measured core reactivity during power operation. The continual confirmation of core reactivity is necessary to ensure that the Design Basis Accident (DBA) and transient safety analyses remain valid. A large reactivity anomaly could be the result of unanticipated changes in fuel reactivity or control rod worth or operation at conditions not consistent with those assumed in the predictions of core reactivity, and could potentially result in a loss of SDM or violation of acceptable fuel design limits. Comparing predicted versus measured core reactivity validates the nuclear methods used in the safety analysis and supports the SDM demonstrations (LCO 3.1.1, "SHUTDOWN MARGIN (SDM)") in assuring the reactor can be brought safely to cold, subcritical conditions.

When the reactor core is critical, a reactivity balance exists and the net reactivity is zero. A comparison of predicted and measured reactivity is convenient under such a balance, since parameters are being maintained relatively stable under steady state power conditions. The positive reactivity inherent in the core design is balanced by the negative reactivity of the control components, thermal feedback, neutron leakage, and materials in the core that absorb neutrons, such as burnable absorbers, producing zero net reactivity.

In order to achieve the required fuel cycle energy output, the uranium enrichment in the new fuel loading and the fuel loaded in the previous cycles provide excess positive reactivity beyond that required to sustain steady state operation at the beginning of cycle (BOC). When the reactor is critical at RTP and operating moderator temperature, the excess positive reactivity is compensated by burnable absorbers (e.g., gadolinia), control rods, and whatever neutron poisons (mainly xenon and samarium) are present in the fuel. The predicted core reactivity, as represented by control rod inventory, is calculated by a 3D core simulator code as a function of cycle exposure. This calculation is performed for projected operating states and conditions throughout the cycle. The core reactivity is determined from control rod inventory for actual plant conditions and is then compared to the predicted value for the cycle exposure.

BASES

APPLICABLE SAFETY ANALYSES	Accurate prediction of core reactivity is an implicit assumption in the accident analysis evaluations (Ref. 2). In particular, SDM and reactivity transients, such as control rod withdrawal accidents or rod drop accidents, are very sensitive to accurate prediction of core reactivity. These accident analysis evaluations rely on computer codes that have been qualified against available test data, operating plant data, and analytical benchmarks. Monitoring reactivity anomaly provides additional assurance that the nuclear methods provide an accurate representation of the core reactivity. The comparison between measured and predicted initial core reactivity provides a normalization for the calculational models used to predict core reactivity. If the measured and predicted control rod inventory for identical core conditions at BOC do not reasonably agree, then the assumptions used in the reload cycle design analysis or the calculation models used to predict control rod inventory may not be accurate. If reasonable agreement between measured and predicted core reactivity exists at BOC, then the prediction may be normalized to the measured value. Thereafter, any significant deviations in the measured control rod inventory from the predicted control rod inventory that develop during fuel depletion may be an indication that the assumptions of the DBA and transient analyses are no longer valid, or that an unexpected change in core conditions has occurred. Reactivity Anomalies satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).
LCO	The reactivity anomaly limit is established to ensure plant operation is maintained within the assumptions of the safety analyses. Large differences between monitored and predicted core reactivity may indicate that the assumptions of the DBA and transient analyses are no longer valid, or that the uncertainties in the "Nuclear Design Methodology" are larger than expected. A limit on the difference between the monitored and the predicted control rod inventory of ± 1% $\Delta k/k$ has been established based on engineering judgment. A > 1% deviation in reactivity from that predicted is larger than expected for normal operation and should therefore be evaluated.
APPLICABILITY	In MODE 1, most of the control rods are withdrawn and steady state operation is typically achieved. Under these conditions, the comparison between predicted and monitored core reactivity provides an effective measure of the reactivity anomaly. In MODE 2, control rods are typically being withdrawn during a startup. In MODES 3 and 4, all control rods are fully inserted and therefore the reactor is in the least reactive state, where monitoring core reactivity is not necessary. In MODE 5, fuel loading results in a continually changing core reactivity. SDM requirements (LCO 3.1.1) ensure that fuel movements are performed within the bounds of the safety analysis, and an SDM demonstration is required before or

BASES

APPLICABILITY (continued)

during the first startup following operations that could have altered core reactivity (e.g., fuel movement, control rod replacement, shuffling). The SDM test, required by LCO 3.1.1, provides a direct comparison of the predicted and monitored core reactivity at cold conditions; therefore, Reactivity Anomalies is not required during these conditions.

ACTIONS

A.1

Should an anomaly develop between measured and predicted core reactivity, the core reactivity difference must be restored to within the limit to ensure continued operation is within the core design assumptions. Restoration to within the limit could be performed by an evaluation of the core design and safety analysis to determine the reason for the anomaly. This evaluation normally reviews the core conditions to determine their consistency with input to design calculations. Measured core and process parameters are also normally evaluated to determine that they are within the bounds of the safety analysis, and safety analysis calculational models may be reviewed to verify that they are adequate for representation of the core conditions. The required Completion Time of 72 hours is based on the low probability of a DBA occurring during this period, and allows sufficient time to assess the physical condition of the reactor and complete the evaluation of the core design and safety analysis.

B.1

If the core reactivity cannot be restored to within the 1% $\Delta k/k$ limit, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.2.1

Verifying the reactivity difference between the monitored and predicted control rod inventory is within the limits of the LCO provides added assurance that plant operation is maintained within the assumptions of the DBA and transient analyses. The process computer calculates the control rod inventory for the reactor conditions obtained from plant instrumentation. A comparison of the monitored control rod inventory to the predicted control rod inventory at the same cycle exposure is used to calculate the reactivity difference. The comparison is required when the core reactivity has potentially changed by a significant amount. This may

BASES

SURVEILLANCE REQUIREMENTS (continued)

occur following a refueling in which new fuel assemblies are loaded, fuel assemblies are shuffled within the core, or control rods are replaced or shuffled. Control rod replacement refers to the decoupling and removal of a control rod from a core location, and subsequent replacement with a new control rod or a control rod from another core location. Also, core reactivity changes during the cycle. The 24 hour interval after reaching equilibrium conditions following a startup is based on the need for equilibrium xenon concentrations in the core, such that an accurate comparison between the monitored and predicted control rod inventory can be made. For the purposes of this SR, the reactor is assumed to be at equilibrium conditions when steady state operations (no control rod movement or core flow changes) at ≥ 75% RTP have been obtained. At a specific steady state base condition the actual control rod inventory will be periodically compared to a normalized computed prediction of the inventory. The comparisons will be used as base data for reactivity monitoring during subsequent power operation throughout the fuel cycle. The 1000 MWD/T (where T is a short ton) Frequency was developed, considering the relatively slow change in core reactivity with exposure and operating experience related to variations in core reactivity. This comparison requires the core to be operating at power levels which minimize the uncertainties and measurement errors, in order to obtain meaningful results. Therefore, the comparison is only done when in MODE 1.

REFERENCES

1. USAR, Section 1.2.2.
2. USAR, Chapter 14.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.3 Control Rod OPERABILITY

BASES

BACKGROUND	Control rods are components of the Control Rod Drive (CRD) System, which is the primary reactivity control system for the reactor. In conjunction with the Reactor Protection System, the CRD System provides the means for the reliable control of reactivity changes to ensure under conditions of normal operation, including anticipated operational occurrences, that specified acceptable fuel design limits are not exceeded. In addition, the control rods provide the capability to hold the reactor core subcritical under all conditions and to limit the potential amount and rate of reactivity increase caused by a malfunction in the CRD System. The CRD System is designed to satisfy the requirements as described in USAR, Section 1.2.2 (Ref. 1). The CRD System consists of 121 locking piston control rod drive mechanisms (CRDMs) and a hydraulic control unit for each drive mechanism. The locking piston type CRDM is a double acting hydraulic piston, which uses condensate water as the operating fluid. Accumulators provide additional energy for scram. An index tube and piston, coupled to the control rod, are locked at fixed increments by a collet mechanism. The collet fingers engage notches in the index tube to prevent unintentional withdrawal of the control rod, but without restricting insertion. This Specification, along with LCO 3.1.4, "Control Rod Scram Times," LCO 3.1.5, "Control Rod Scram Accumulators," and LCO 3.1.6, "Rod Pattern Control," ensure that the performance of the control rods in the event of a Design Basis Accident (DBA) or transient meets the assumptions used in the safety analyses of References 2, 3, and 4.
APPLICABLE SAFETY ANALYSES	The analytical methods and assumptions used in the evaluations involving control rods are presented in References 2, 3, and 4. The control rods provide the primary means for rapid reactivity control (reactor scram), for maintaining the reactor subcritical and for limiting the potential effects of reactivity insertion events caused by malfunctions in the CRD System. The capability to insert the control rods provides assurance that the assumptions for scram reactivity in the DBA and transient analyses are not violated. Since the SDM ensures the reactor will be subcritical with the highest worth control rod withdrawn (assumed single failure), the

BASES

APPLICABLE SAFETY ANALYSES (continued)

additional failure of a second control rod to insert, if required, could invalidate the demonstrated SDM and potentially limit the ability of the CRD System to hold the reactor subcritical. If the control rod is stuck at an inserted position and becomes decoupled from the CRD, a control rod drop accident (CRDA) can possibly occur. Therefore, the requirement that all control rods be OPERABLE ensures the CRD System can perform its intended function.

The control rods also protect the fuel from damage which could result in release of radioactivity. The limits protected are the MCPR Safety Limit (SL) (see Bases for SL 2.1.1, "Reactor Core SLs," and LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)"), the 1% cladding plastic strain fuel design limit (see Bases for LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)," and LCO 3.2.3, "LINEAR HEAT GENERATION RATE (LHGR)"), and the fuel design limit (see Bases for LCO 3.1.6) during reactivity insertion events.

The negative reactivity insertion (scram) provided by the CRD System provides the analytical basis for determination of plant thermal limits and provides protection against violating fuel design limits during a CRDA. The Bases for LCO 3.1.4, LCO 3.1.5, and LCO 3.1.6 discuss in more detail how the SLs are protected by the CRD System.

Control rod OPERABILITY satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The OPERABILITY of an individual control rod is based on a combination of factors, primarily, the scram insertion times, the control rod coupling integrity, and the ability to determine the control rod position. Accumulator OPERABILITY is addressed by LCO 3.1.5. The associated scram accumulator status for a control rod only affects the scram insertion times; therefore, an inoperable accumulator does not immediately require declaring a control rod inoperable. Although not all control rods are required to be OPERABLE to satisfy the intended reactivity control requirements, strict control over the number and distribution of inoperable control rods is required to satisfy the assumptions of the DBA and transient analyses.

OPERABILITY requirements for control rods also include correct assembly of the CRD housing supports.

BASES

APPLICABILITY

In MODES 1 and 2, the control rods are assumed to function during a DBA or transient and are therefore required to be OPERABLE in these MODES. In MODES 3 and 4, control rods are not able to be withdrawn since the reactor mode switch is in shutdown and a control rod block is applied. This provides adequate requirements for control rod OPERABILITY during these conditions. Control rod requirements in MODE 5 are located in LCO 3.9.5, "Control Rod OPERABILITY - Refueling."

ACTIONS

The ACTIONS Table is modified by a Note indicating that a separate Condition entry is allowed for each control rod. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable control rod. Complying with the Required Actions may allow for continued operation, and subsequent inoperable control rods are governed by subsequent Condition entry and application of associated Required Actions.

A.1, A.2, A.3, and A.4

A control rod is considered stuck if it will not insert by either CRD drive water or scram pressure. With a fully inserted control rod stuck, no actions are required as long as the control rod remains fully inserted. The Required Actions are modified by a Note, which allows the rod worth minimizer (RWM) to be bypassed if required to allow continued operation. LCO 3.3.2.1, "Control Rod Block Instrumentation," provides additional requirements when the RWM is bypassed to ensure compliance with the CRDA analysis. With one withdrawn control rod stuck, the local scram reactivity rate assumptions may not be met if the stuck control rod separation criteria are not met. Therefore, a verification that the stuck control rod separation criteria are met must be performed immediately. The stuck control rod separation criteria are not met if: a) the stuck control rod occupies a location adjacent (face or diagonal) to two "slow" control rods, b) the stuck control rod occupies a location adjacent to one "slow" control rod, and the one "slow" control rod is also adjacent to another "slow" control rod, or c) if the stuck control rod occupies a location adjacent to one "slow" control rod when there is another pair of "slow" control rods elsewhere in the core adjacent to one another. The description of "slow" control rods is provided in LCO 3.1.4, "Control Rod Scram Times." In addition, the associated control rod drive must be disarmed in 2 hours. The allowed Completion Time of 2 hours is acceptable, considering the reactor can still be shut down, assuming no additional control rods fail to insert, and provides a reasonable time to perform the Required Action in an orderly manner. The control rod must be isolated from both scram and normal insert and withdraw pressure. Isolating the control rod from scram and normal insert and withdraw pressure prevents damage to the CRDM. The control rod isolation method should also ensure cooling water to the CRD is maintained.

BASES

ACTIONS (continued)

Monitoring of the insertion capability of each withdrawn control rod must also be performed within 24 hours from discovery of Condition A concurrent with THERMAL POWER greater than the low power setpoint (LPSP) of the RWM. SR 3.1.3.2 performs periodic tests of the control rod insertion capability of withdrawn control rods. Testing each withdrawn control rod ensures that a generic problem does not exist. This Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." The Required Action A.3 Completion Time only begins upon discovery of Condition A concurrent with THERMAL POWER greater than the actual LPSP of the RWM since the notch insertions may not be compatible with the requirements of rod pattern control (LCO 3.1.6) and the RWM (LCO 3.3.2.1). The allowed Completion Time of 24 hours from discovery of Condition A, concurrent with THERMAL POWER greater than the LPSP of the RWM, provides a reasonable time to test the control rods, considering the potential for a need to reduce power to perform the tests.

To allow continued operation with a withdrawn control rod stuck, an evaluation of adequate SDM is also required within 72 hours. Should a DBA or transient require a shutdown, to preserve the single failure criterion, an additional control rod would have to be assumed to fail to insert when required. Therefore, the original SDM demonstration may not be valid. The SDM must therefore be evaluated (by measurement or analysis) with the stuck control rod at its stuck position and the highest worth OPERABLE control rod assumed to be fully withdrawn.

The allowed Completion Time of 72 hours to verify SDM is adequate, considering that with a single control rod stuck in a withdrawn position, the remaining OPERABLE control rods are capable of providing the required scram and shutdown reactivity. Failure to reach MODE 4 is only likely if an additional control rod adjacent to the stuck control rod also fails to insert during a required scram. Even with the postulated additional single failure of an adjacent control rod to insert, sufficient reactivity control remains to reach MODE 3 conditions.

<u>B.1</u>

With two or more withdrawn control rods stuck, the plant must be brought to MODE 3 within 12 hours. The occurrence of more than one control rod stuck at a withdrawn position increases the probability that the reactor cannot be shut down if required. Insertion of all insertable control rods eliminates the possibility of an additional failure of a control rod to insert. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

BASES

ACTIONS (continued)

C.1 and C.2

With one or more control rods inoperable for reasons other than being stuck in a withdrawn position, operation may continue, provided the control rods are fully inserted within 3 hours and disarmed (electrically or hydraulically) within 4 hours. Inserting a control rod ensures the shutdown and scram capabilities are not adversely affected. The control rod is disarmed to prevent inadvertent withdrawal during subsequent operations. The control rods can be hydraulically disarmed by closing the drive water and exhaust water isolation valves. The control rods can be electrically disarmed by disconnecting power from all four directional control valve solenoids. Required Action C.1 is modified by a Note, which allows the RWM to be bypassed if required to allow insertion of the inoperable control rods and continued operation. LCO 3.3.2.1 provides additional requirements when the RWM is bypassed to ensure compliance with the CRDA analysis.

The allowed Completion Times are reasonable, considering the small number of allowed inoperable control rods, and provide time to insert and disarm the control rods in an orderly manner and without challenging plant systems.

D.1 and D.2

Out of sequence control rods may increase the potential reactivity worth of a dropped control rod during a CRDA. At ≤ 10% RTP, the generic banked position withdrawal sequence (BPWS) analysis (Ref. 5) requires inserted control rods not in compliance with BPWS to be separated by at least two OPERABLE control rods in all directions, including the diagonal (i.e., all other control rods in a five-by-five array centered on the inoperable control rod are OPERABLE). Therefore, if two or more inoperable control rods are not in compliance with BPWS and not separated by at least two OPERABLE control rods in all directions, action must be taken to restore compliance with BPWS or restore the control rods to OPERABLE status. Condition D is modified by a Note indicating that the Condition is not applicable when > 10% RTP, since the BPWS is not required to be followed under these conditions, as described in the Bases for LCO 3.1.6. The allowed Completion Time of 4 hours is acceptable, considering the low probability of a CRDA occurring.

BASES

ACTIONS (continued)

E.1

If any Required Action and associated Completion Time of Condition A, C, or D are not met, or there are nine or more inoperable control rods, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 12 hours. This ensures all insertable control rods are inserted and places the reactor in a condition that does not require the active function (i.e., scram) of the control rods. The number of control rods permitted to be inoperable when operating above 10% RTP (e.g., no CRDA considerations) could be more than the value specified, but the occurrence of a large number of inoperable control rods could be indicative of a generic problem, and investigation and resolution of the potential problem should be undertaken. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.3.1

The position of each control rod must be determined to ensure adequate information on control rod position is available to the operator for determining control rod OPERABILITY and controlling rod patterns. Control rod position may be determined by the use of OPERABLE position indicators, by moving control rods to a position with an OPERABLE indicator, or by the use of other appropriate methods. The 24 hour Frequency of this SR is based on operating experience related to expected changes in control rod position and the availability of control rod position indications in the control room.

SR 3.1.3.2

Control rod insertion capability is demonstrated by inserting each partially or fully withdrawn control rod at least one notch and observing that the control rod moves. The control rod may then be returned to its original position. This ensures the control rod is not stuck and is free to insert on a scram signal. These Surveillances are not required when THERMAL POWER is less than or equal to the actual LPSP of the RWM, since the notch insertions may not be compatible with the requirements of the Banked Position Withdrawal Sequence (BPWS) (LCO 3.1.6) and the RWM (LCO 3.3.2.1). Partially and fully withdrawn control rods are tested at a 31 day Frequency, based on the potential power reduction required to allow the control rod movement (Ref. 6). Furthermore, the 31 day Frequency takes into account operating experience related to changes in

BASES

SURVEILLANCE REQUIREMENTS (continued)

CRD performance. At any time, if a control rod is immovable, a determination of that control rod's trippability (OPERABILITY) must be made and appropriate action taken.

The SR is modified by a Note that allows 31 days after withdrawal of the control rod and increasing power to above the LPSP, to perform the Surveillance. This acknowledges that the control rod must be first withdrawn and THERMAL POWER must be increased to above the LPSP before performance of the Surveillance, and therefore, the Note avoids potential conflicts with SR 3.0.1 and SR 3.0.4.

SR 3.1.3.3

Verifying that the scram time for each control rod to notch position 06 is ≤ 7 seconds provides reasonable assurance that the control rod will insert when required during a DBA or transient, thereby completing its shutdown function. This SR is performed in conjunction with the control rod scram time testing of SR 3.1.4.1, SR 3.1.4.2, SR 3.1.4.3, and SR 3.1.4.4. The LOGIC SYSTEM FUNCTIONAL TEST in LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation," and the functional testing of SDV vent and drain valves in LCO 3.1.8, "Scram Discharge Volume (SDV) Vent and Drain Valves," overlap this Surveillance to provide complete testing of the assumed safety function. The associated Frequencies are acceptable, considering the more frequent testing performed to demonstrate other aspects of control rod OPERABILITY and operating experience, which shows scram times do not significantly change over an operating cycle.

SR 3.1.3.4

Coupling verification is performed to ensure the control rod is connected to the CRDM and will perform its intended function when necessary. The Surveillance requires verifying that a control rod does not go to the withdrawn overtravel position when it is fully withdrawn. The overtravel position feature provides a positive check on the coupling integrity since only an uncoupled CRD can reach the overtravel position. The verification is required to be performed any time a control rod is withdrawn to the "full out" position (notch position 48) or prior to declaring the control rod OPERABLE after work on the control rod or CRD System that could affect coupling. This includes control rods inserted one notch and then returned to the "full out" position during the performance of SR 3.1.3.2. This Frequency is acceptable, considering the low probability that a control rod will become uncoupled when it is not being moved and operating experience related to uncoupling events.

BASES

REFERENCES

1. USAR, Section 1.2.2.

2. USAR, Chapter 14.

3. USAR, Chapter 14A.

4. USAR, Chapter 3.

5. NEDO-21231, "Banked Position Withdrawal Sequence," Section 7.2, January 1977.

6. Amendment No. 158, “Monticello Nuclear Generating Plant – Issuance of Amendment Regarding Control Rod Notch Surveillance Test Frequency and Clarification of a Frequency Example,“ November 19, 2008 (TSTF-475, Revision 1).

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.4 Control Rod Scram Times

BASES

BACKGROUND

The scram function of the Control Rod Drive (CRD) System is designed to accommodate plant operational transients or maneuvers which might be expected without compromising safety and without fuel damage (Ref. 1). The control rods are scrammed by positive means using hydraulic pressure exerted on the CRD piston.

When a scram signal is initiated, control air is vented from the scram valves, allowing them to open by spring action. Opening the exhaust valve reduces the pressure above the main drive piston to atmospheric pressure, and opening the inlet valve applies the accumulator or reactor pressure to the bottom of the piston. Since the notches in the index tube are tapered on the lower edge, the collet fingers are forced open by cam action, allowing the index tube to move upward without restriction because of the high differential pressure across the piston. As the drive moves upward and the accumulator pressure reduces below the reactor pressure, a ball check valve opens, letting the reactor pressure complete the scram action. If the reactor pressure is low, such as during startup, the accumulator will fully insert the control rod in the required time without assistance from reactor pressure.

APPLICABLE SAFETY ANALYSES

NOTE: Certain AREVA safety analysis methods have been approved for use (Amendment 188); however, those methods may not be invoked in the analysis-of-record until AREVA fuel is loaded in the core. Until that time, General Electric – Hitachi (GEH) safety analysis methods will continue to support core operation and the description of the GEH methods in the TS Bases shall prevail. To the extent that approved AREVA methods may be described and referenced without conflicting with the GEH analysis-of-record, the TS Bases reflect both GEH and AREVA methods. Refer to CORE OPERATING LIMIT REPORT (COLR) Section 1.0 to determine whether GEH or AREVA methods were used for the current operating cycle.

The analytical methods and assumptions used in evaluating the control rod scram function are presented in References 2, 3, 4, 8, and 9. The Design Basis Accident (DBA) and transient analyses assume that all of the control rods scram at a specified insertion rate. The resulting negative scram reactivity forms the basis for the determination of plant thermal limits (e.g., the MCPR). Other distributions of scram times (e.g., several control rods scramming slower than the average time with several control rods scramming faster than the average time) can also provide sufficient scram reactivity. Surveillance of each individual control rod's

BASES

APPLICABLE SAFETY ANALYSES (continued)

scram time ensures the scram reactivity assumed in the DBA and transient analyses can be met.

The scram function of the CRD System protects the MCPR Safety Limit (SL) (see Bases for SL 2.1.1, "Reactor Core SLs," and LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)") and the 1% cladding plastic strain fuel design limit (see Bases for LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)," and LCO 3.2.3, "LINEAR HEAT GENERATION RATE (LHGR)"), which ensure that no fuel damage will occur if these limits are not exceeded. At ≥ 800 psig, the scram function is designed to insert negative reactivity at a rate fast enough to prevent the actual MCPR from becoming less than the MCPR SL, during the analyzed limiting power transient. Below 800 psig, the scram function is assumed to perform during the control rod drop accident (Ref. 5) and, therefore, also provides protection against violating fuel design limits during reactivity insertion accidents (see Bases for LCO 3.1.6, "Rod Pattern Control"). For the reactor vessel overpressure protection analysis, the scram function, along with the safety/relief valves, ensure that the peak vessel pressure is maintained within the applicable ASME Code limits.

Control rod scram times satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The scram times specified in Table 3.1.4-1 are required to ensure that the scram reactivity assumed in the DBA and transient analysis is met (Ref. 6). To account for single failures and "slow" scramming control rods, the scram times specified in Table 3.1.4-1 are faster than those assumed in the design basis analysis. The scram times have a margin that allows up to approximately 7% of the control rods (e.g., 121 x 7% ≈ 8) to have scram times exceeding the specified limits (i.e., "slow" control rods) assuming a single stuck control rod (as allowed by LCO 3.1.3, "Control Rod OPERABILITY") and an additional control rod failing to scram per the single failure criterion. The scram times are specified as a function of reactor steam dome pressure to account for the pressure dependence of the scram times. The scram times are specified relative to measurements based on reed switch positions, which provide the control rod position indication. The reed switch closes ("pickup") when the index tube passes a specific location and then opens ("dropout") as the index tube travels upward. Verification of the specified scram times in Table 3.1.4-1 is accomplished through measurement of the "dropout" times. To ensure that local scram reactivity rates are maintained within acceptable limits, no more than two of the allowed "slow" control rods may occupy adjacent locations (face or diagonal) (i.e., all “slow” control rods must be separated by at least one cell in all directions, except for one pair).

BASES

LCO (continued)

Table 3.1.4-1 is modified by two Notes which state that control rods with scram times not within the limits of the Table are considered "slow" and that control rods with scram times > 7 seconds are considered inoperable as required by SR 3.1.3.3.

This LCO applies only to OPERABLE control rods since inoperable control rods will be inserted and disarmed (LCO 3.1.3). Slow scramming control rods may be conservatively declared inoperable and not accounted for as "slow" control rods.

APPLICABILITY

In MODES 1 and 2, a scram is assumed to function during transients and accidents analyzed for these plant conditions. These events are assumed to occur during startup and power operation; therefore, the scram function of the control rods is required during these MODES. In MODES 3 and 4, the control rods are not able to be withdrawn since the reactor mode switch is in shutdown and a control rod block is applied. This provides adequate requirements for control rod scram capability during these conditions. Scram requirements in MODE 5 are contained in LCO 3.9.5, "Control Rod OPERABILITY - Refueling."

ACTIONS

A.1

When the requirements of this LCO are not met, the rate of negative reactivity insertion during a scram may not be within the assumptions of the safety analyses. Therefore, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 12 hours. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

The four SRs of this LCO are modified by a Note stating that during a single control rod scram time surveillance, the CRD pumps shall be isolated from the associated scram accumulator. With the CRD pump isolated, (i.e., charging valve closed) the influence of the CRD pump head does not affect the single control rod scram times. During a full core scram, the CRD pump head would be seen by all control rods and would have a negligible effect on the scram insertion times.

SR 3.1.4.1

The scram reactivity used in DBA and transient analyses is based on an assumed control rod scram time. Measurement of the scram times with reactor steam dome pressure ≥ 800 psig demonstrates acceptable scram times for the transients analyzed in References 2 and 3.

BASES

SURVEILLANCE REQUIREMENTS (continued)

Maximum scram insertion times occur at a reactor steam dome pressure of approximately 800 psig because of the competing effects of reactor steam dome pressure and stored accumulator energy. Therefore, demonstration of adequate scram times at reactor steam dome pressure ≥ 800 psig ensures that the measured scram times will be within the specified limits at higher pressures. Limits are specified as a function of reactor pressure to account for the sensitivity of the scram insertion times with pressure and to allow a range of pressures over which scram time testing can be performed. To ensure that scram time testing is performed within a reasonable time following a shutdown ≥ 120 days or longer, control rods are required to be tested before exceeding 40% RTP following the shutdown. This Frequency is acceptable considering the additional Surveillances performed for control rod OPERABILITY, the frequent verification of adequate accumulator pressure, and the required testing of control rods affected by fuel movement within the associated core cell and by work on control rods or the CRD System.

SR 3.1.4.2

Additional testing of a sample of control rods is required to verify the continued performance of the scram function during the cycle. A representative sample contains at least 10% of the control rods. The sample remains representative if no more than 7.5% of the control rods in the sample tested are determined to be "slow." With more than 7.5% of the sample declared to be "slow" per the criteria in Table 3.1.4-1, additional control rods are tested until this 7.5% criterion (e.g., 7.5% of the entire sample size) is satisfied, or until the total number of "slow" control rods (throughout the core, from all Surveillances) exceeds the LCO limit. For planned testing, the control rods selected for the sample should be different for each test. Data from inadvertent scrams should be used whenever possible to avoid unnecessary testing at power, even if the control rods with data may have been previously tested in a sample. The 200 day Frequency is based on operating experience that has shown control rod scram times do not significantly change over an operating cycle. This Frequency is also reasonable based on the additional Surveillances done on the CRDs at more frequent intervals in accordance with LCO 3.1.3 and LCO 3.1.5, "Control Rod Scram Accumulators."

SR 3.1.4.3

When work that could affect the scram insertion time is performed on a control rod or the CRD System, testing must be done to demonstrate that each affected control rod retains adequate scram performance over the range of applicable reactor pressures. The scram testing must be

BASES

SURVEILLANCE REQUIREMENTS (continued)

performed once before declaring the control rod OPERABLE. The required scram time testing must demonstrate the affected control rod is still within acceptable limits. The scram time limits for reactor pressures < 800 psig are found in the Technical Requirements Manual (Ref. 7) andare established based on a high probability of meeting the acceptance criteria at reactor pressures ≥ 800 psig. Limits for ≥ 800 psig are found in Table 3.1.4-1. If testing demonstrates the affected control rod does not meet these limits, but is within the 7-second limit of Table 3.1.4-1, Note 2, the control rod can be declared OPERABLE and "slow."

Specific examples of work that could affect the scram times are (but are not limited to) the following: removal of any CRD for maintenance or modification; replacement of a control rod; and maintenance or modification of a scram solenoid pilot valve, scram valve, accumulator, isolation valve or check valve in the piping required for scram.

The Frequency of once prior to declaring the affected control rod OPERABLE is acceptable because of the capability to test the control rod over a range of operating conditions and the more frequent surveillances on other aspects of control rod OPERABILITY.

SR 3.1.4.4

When work that could affect the scram insertion time is performed on a control rod or CRD System, or when fuel movement within the reactor pressure vessel occurs, testing must be done to demonstrate each affected control rod is still within the limits of Table 3.1.4-1 with the reactor steam dome pressure ≥ 800 psig. Where work has been performed at high reactor pressure, the requirements of SR 3.1.4.3 and SR 3.1.4.4 can be satisfied with one test. For a control rod affected by work performed while shut down, however, a zero pressure and high pressure test may be required. This testing ensures that, prior to withdrawing the control rod for continued operation, the control rod scram performance is acceptable for operating reactor pressure conditions. Alternatively, a control rod scram test during hydrostatic pressure testing could also satisfy both criteria. When fuel movement within the reactor pressure vessel occurs, only those control rods associated with the core cells affected by the fuel movement are required to be scram time tested. During a routine refueling outage, it is expected that all control rods will be affected.

The Frequency of once prior to exceeding 40% RTP is acceptable because of the capability to test the control rod over a range of operating conditions and the more frequent surveillances on other aspects of control rod OPERABILITY.

BASES

REFERENCES

1. USAR, Section 1.2.2.
2. USAR, Chapter 14.
3. USAR, Chapter 14A.
4. USAR, Chapter 3.
5. NEDE-24011-P-A, "General Electric Standard Application for Reactor Fuel" (revision as specified in Specification 5.6.3).
6. Letter from R.F. Janecek (BWROG) to R.W. Starostecki (NRC), "BWR Owners Group Revised Reactivity Control System Technical Specifications," BWROG-8754, September 17, 1987.
7. Technical Requirements Manual.
8. XN-NF-80-19(P)(A) Volume 1 and Supplements 1 and 2, “Exxon Nuclear Methodology for Boiling Water Reactors – Neutronic Methods for Design and Analysis”, Exxon Nuclear Company, March 1983.
9. EMF-2158(P)(A) Revision 0, “Siemens Power Corporation Methodology for Boiling Water Reactors: Evaluation and Validation for CASMO-4/MICROBURN-B2”, Siemens Power Corporation, October 1999.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.5 Control Rod Scram Accumulators

BASES

BACKGROUND	The control rod scram accumulators are part of the Control Rod Drive (CRD) System and are provided to ensure that the control rods scram under varying reactor conditions. The control rod scram accumulators store sufficient energy to fully insert a control rod at any reactor vessel pressure. The accumulator is a hydraulic cylinder with a free floating piston. The piston separates the water used to scram the control rods from the nitrogen, which provides the required energy. The scram accumulators are necessary to scram the control rods within the required insertion times of LCO 3.1.4, "Control Rod Scram Times."
APPLICABLE SAFETY ANALYSES	The analytical methods and assumptions used in evaluating the control rod scram function are presented in References 1, 2, and 3. The Design Basis Accident (DBA) and transient analyses assume that all of the control rods scram at a specified insertion rate. OPERABILITY of each individual control rod scram accumulator, along with LCO 3.1.3, "Control Rod OPERABILITY," and LCO 3.1.4, ensures that the scram reactivity assumed in the DBA and transient analyses can be met. The existence of an inoperable accumulator may invalidate prior scram time measurements for the associated control rod. The scram function of the CRD System, and therefore the OPERABILITY of the accumulators, protects the MCPR Safety Limit (see Bases for SL 2.1.1, "Reactor Core SLs," and LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)") and 1% cladding plastic strain fuel design limit (see Bases for LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)," and LCO 3.2.3, "LINEAR HEAT GENERATION RATE (LHGR)"), which ensure that no fuel damage will occur if these limits are not exceeded (see Bases for LCO 3.1.4). In addition, the scram function at low reactor vessel pressure (i.e., startup conditions) provides protection against violating fuel design limits during reactivity insertion accidents (see Bases for LCO 3.1.6, "Rod Pattern Control"). Control rod scram accumulators satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	The OPERABILITY of the control rod scram accumulators is required to ensure that adequate scram insertion capability exists when needed over the entire range of reactor pressures. The OPERABILITY of the scram accumulators is based on maintaining adequate accumulator pressure.

BASES

APPLICABILITY

In MODES 1 and 2, the scram function is required for mitigation of DBAs and transients, and therefore the scram accumulators must be OPERABLE to support the scram function. In MODES 3 and 4, control rods are not able to be withdrawn since the reactor mode switch is in shutdown and a control rod block is applied. This provides adequate requirements for control rod scram accumulator OPERABILITY during these conditions. Requirements for scram accumulators in MODE 5 are contained in LCO 3.9.5, "Control Rod OPERABILITY - Refueling."

ACTIONS

The ACTIONS Table is modified by a Note indicating that a separate Condition entry is allowed for each control rod scram accumulator. This is acceptable since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable accumulator. Complying with the Required Actions may allow for continued operation and subsequent inoperable accumulators governed by subsequent Condition entry and application of associated Required Actions.

<u>A.1 and A.2</u>

With one control rod scram accumulator inoperable and the reactor steam dome pressure ≥ 900 psig, the control rod may be declared "slow," since the control rod will still scram at the reactor operating pressure but may not satisfy the required scram times in Table 3.1.4-1. Required Action A.1 is modified by a Note indicating that declaring the control rod "slow" only applies if the associated control rod scram time was within the limits of Table 3.1.4-1 during the last scram time Surveillance. Otherwise, the control rod may already be considered "slow" and the further degradation of scram performance with an inoperable accumulator could result in excessive scram times. In this event, the associated control rod is declared inoperable (Required Action A.2) and LCO 3.1.3 is entered. This would result in requiring the affected control rod to be fully inserted and disarmed, thereby satisfying its intended function, in accordance with ACTIONS of LCO 3.1.3.

The allowed Completion Time of 8 hours is reasonable, based on the large number of control rods available to provide the scram function and the ability of the affected control rod to scram only with reactor pressure at high reactor pressures.

BASES

ACTIONS (continued)

B.1, B.2.1, and B.2.2

With two or more control rod scram accumulators inoperable and reactor steam dome pressure ≥ 900 psig, adequate pressure must be supplied to the charging water header. With inadequate charging water pressure, all of the accumulators could become inoperable, resulting in a potentially severe degradation of the scram performance. Therefore, within 20 minutes from discovery of charging water header pressure < 940 psig concurrent with Condition B, adequate charging water header pressure must be restored. The allowed Completion Time of 20 minutes is reasonable, to place a CRD pump into service to restore the charging header pressure, if required. This Completion Time is based on the ability of the reactor pressure alone to fully insert all control rods.

The control rod may be declared "slow," since the control rod will still scram using only reactor pressure, but may not satisfy the times in Table 3.1.4-1. Required Action B.2.1 is modified by a Note indicating that declaring the control rod "slow" only applies if the associated control rod scram time is within the limits of Table 3.1.4-1 during the last scram time Surveillance. Otherwise, the control rod may already be considered "slow" and the further degradation of scram performance with an inoperable accumulator could result in excessive scram times. In this event, the associated control rod is declared inoperable (Required Action B.2.2) and the ACTIONS of LCO 3.1.3 entered. This would result in requiring the affected control rod to be fully inserted and disarmed, thereby satisfying its intended function in accordance with ACTIONS of LCO 3.1.3.

The allowed Completion Time of 1 hour is reasonable, based on the ability of only the reactor pressure to scram the control rods and the low probability of a DBA or transient occurring while the affected accumulators are inoperable.

C.1 and C.2

With one or more control rod scram accumulators inoperable and the reactor steam dome pressure < 900 psig, the pressure supplied to the charging water header must be adequate to ensure that accumulators remain charged. With the reactor steam dome pressure < 900 psig, the function of the accumulators in providing the scram force becomes much more important since the scram function could become severely

BASES

ACTIONS (continued)

degraded during a depressurization event or at low reactor pressures. Therefore, immediately upon discovery of charging water header pressure < 940 psig, concurrent with Condition C, all control rods associated with inoperable accumulators must be verified to be fully inserted. Withdrawn control rods with inoperable accumulators may fail to scram under these low pressure conditions. The associated control rods must also be declared inoperable within 1 hour. The allowed Completion Time of 1 hour is reasonable for Required Action C.2, considering the low probability of a DBA or transient occurring during the time that the accumulator is inoperable.

D.1

The reactor mode switch must be immediately placed in the shutdown position if either Required Action and associated Completion Time associated with loss of the CRD pump (Required Actions B.1 and C.1) cannot be met. This ensures that all insertable control rods are inserted and that the reactor is in a condition that does not require the active function (i.e., scram) of the control rods. This Required Action is modified by a Note stating that the action is not applicable if all control rods associated with the inoperable scram accumulators are fully inserted, since the function of the control rods has been performed.

SURVEILLANCE REQUIREMENTS

SR 3.1.5.1

SR 3.1.5.1 requires that the accumulator pressure be checked every 7 days to ensure adequate accumulator pressure exists to provide sufficient scram force. The primary indicator of accumulator OPERABILITY is the accumulator pressure. A minimum accumulator pressure is specified, below which the capability of the accumulator to perform its intended function becomes degraded and the accumulator is considered inoperable. The minimum accumulator pressure of 940 psig is well below the expected pressure of 1100 psig. Declaring the accumulator inoperable when the minimum pressure is not maintained ensures that significant degradation in scram times does not occur. The 7 day Frequency has been shown to be acceptable through operating experience and takes into account indications available in the control room.

REFERENCES

1. USAR, Chapter 3.

2. USAR, Chapter 14.

3. USAR, Chapter 14A.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.6 Rod Pattern Control

BASES

BACKGROUND

Control rod patterns during startup conditions are controlled by the operator and the rod worth minimizer (RWM) (LCO 3.3.2.1, "Control Rod Block Instrumentation"), so that only specified control rod sequences and relative positions are allowed over the operating range of all control rods inserted to 10% RTP. The sequences limit the potential amount of reactivity addition that could occur in the event of a Control Rod Drop Accident (CRDA).

This Specification assures that the control rod patterns are consistent with the assumptions of the CRDA analyses of References 1, 2, and 3.

APPLICABLE SAFETY ANALYSES

NOTE: Certain AREVA safety analysis methods have been approved for use (Amendment 188); however, those methods may not be invoked in the analysis-of-record until AREVA fuel is loaded in the core. Until that time, General Electric – Hitachi (GEH) safety analysis methods will continue to support core operation and the description of the GEH methods in the TS Bases shall prevail. To the extent that approved AREVA methods may be described and referenced without conflicting with the GEH analysis-of-record, the TS Bases reflect both GEH and AREVA methods. Refer to CORE OPERATING LIMIT REPORT (COLR) Section 1.0 to determine whether GEH or AREVA methods were used for the current operating cycle.

The analytical methods and assumptions used in evaluating the CRDA are summarized in References 1, 2, and 3. CRDA analyses assume that the reactor operator follows prescribed withdrawal sequences. These sequences define the potential initial conditions for the CRDA analysis. The RWM (LCO 3.3.2.1) provides backup to operator control of the withdrawal sequences to ensure that the initial conditions of the CRDA analysis are not violated.

Prevention or mitigation of positive reactivity insertion events is necessary to limit the energy deposition in the fuel, thereby preventing significant fuel damage which could result in the undue release of radioactivity. Since the failure consequences for UO_2 have been shown to be insignificant below fuel energy depositions of 300 cal/gm (Ref. 4), the fuel design limit of 280 cal/gm provides a margin of safety from significant core damage which would result in release of radioactivity (Ref. 5). Generic evaluations (Refs. 6 and 7) of a design basis CRDA, which were evaluated for the effects of increased power at Extended Power Uprate conditions (Ref. 12), have shown that if the peak fuel enthalpy remains below 280 cal/gm, then the maximum reactor pressure will be less than the required ASME Code limits (Ref. 8) and the calculated offsite doses will be well within the required limits (Ref. 9).

APPLICABLE SAFETY ANALYSES (continued)

Control rod patterns analyzed in References 1, 13, and 14 follow the banked position withdrawal sequence (BPWS). The BPWS is applicable from the condition of all control rods fully inserted to 10% RTP (Ref. 2). For the BPWS, the control rods are required to be moved in groups, with all control rods assigned to a specific group required to be within specified banked positions (e.g., between notches 08 and 12). The banked positions are established to minimize the maximum incremental control rod worth without being overly restrictive during normal plant operation.

Analyses are performed using the Reference 13 methodology to demonstrate that the 280 cal/gm fuel design limit will not be violated during a CRDA while following the BPWS mode of operation. The generic BPWS analysis (Ref. 10) also evaluates the effect of fully inserted, inoperable control rods not in compliance with the sequence, to allow a limited number (i.e., eight) and distribution of fully inserted, inoperable control rods.

When performing a shutdown of the plant, an optional BPWS control rod sequence (Ref. 11) may be used. Before reducing power to the low power setpoint (LPSP), control rod coupling integrity shall be confirmed for all rods that are fully withdrawn. Control rods that have not been confirmed coupled and which are in intermediate positions must be fully inserted prior to power reduction to the LPSP. No action is required for fully-inserted control rods. If a shutdown is required and all rods which are not confirmed coupled cannot be fully inserted prior to the power dropping below the LPSP, then the original BPWS must be adhered to. The rods may be fully inserted without the need to stop at intermediate positions since the possibility of a CRDA is eliminated by the confirmation that withdrawn control rods are coupled (Ref. 11). It is recommended that control rods be inserted in the same order as specified for the original BPWS as much as reasonably possible. When in the process of shutting down following optional BPWS with the power below the LPSP, no control rod shall be withdrawn unless the control rod pattern is in compliance with original BPWS requirements.

When using the Reference 11 control rod sequence for shutdown, the rod worth minimizer may be bypassed in accordance with the allowance provided in the Applicability Note for the Rod Worth Minimizer in Table 3.3.2.1-1.

In order to use the Reference 11 BPWS shutdown process, an extra check is required in order to consider a control rod *to* be "confirmed" to be coupled. This extra check ensures that no Single Operator Error can result in an incorrect coupling check. For purposes of this shutdown process, the method for confirming that control rods are coupled varies depending on the position of the control rod in the core. Details on this coupling confirmation requirement are provided in Reference 11. If the requirements for use of the BPWS control rod insertion process contained

APPLICABLE SAFETY ANALYSES (continued)

in Reference 11 are followed, the plant is considered to be in compliance with BPWS requirements, as required by LCO 3.1.6.

Rod pattern control satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Compliance with the prescribed control rod sequences minimizes the potential consequences of a CRDA by limiting the initial conditions to those consistent with the BPWS analysis. Compliance with the optional BPWS control rod insertion process prevents a CRDA from occurring. This LCO only applies to OPERABLE control rods. For inoperable control rods required to be inserted, separate requirements are specified in LCO 3.1.3, "Control Rod OPERABILITY," consistent with the allowances for inoperable control rods in the BPWS.

APPLICABILITY

In MODES 1 and 2, when THERMAL POWER is ≤ 10% RTP, the CRDA is a Design Basis Accident and, therefore, compliance with the assumptions of the safety analysis is required. When THERMAL POWER is > 10% RTP, there is no credible control rod configuration that results in a control rod worth that could exceed the 280 cal/gm fuel design limit during a CRDA (Ref. 2). In MODES 3 and 4, the reactor is shut down and the control rods are not able to be withdrawn since the reactor mode switch is in the shutdown position and a control rod block is applied, therefore a CRDA is not postulated to occur. In MODE 5, since the reactor is shut down and only a single control rod can be withdrawn from a core cell containing fuel assemblies, adequate SDM ensures that the consequences of a CRDA are acceptable, since the reactor will remain subcritical with a single control rod withdrawn.

ACTIONS

<u>A.1 and A.2</u>

With one or more OPERABLE control rods not in compliance with the prescribed control rod sequence, actions may be taken to either correct the control rod pattern or declare the associated control rods inoperable within 8 hours. Noncompliance with the prescribed sequence may be the result of "double notching," drifting from a control rod drive cooling water transient, leaking scram valves, or a power reduction to ≤ 10% RTP before establishing the correct control rod pattern. The number of OPERABLE control rods not in compliance with the prescribed sequence is limited to eight, to prevent the operator from attempting to correct a control rod pattern that significantly deviates from the prescribed sequence.

ACTIONS (continued)

Required Action A.1 is modified by a Note which allows the RWM to be bypassed to allow the affected control rods to be returned to their correct position. LCO 3.3.2.1 requires verification of control rod movement by a second licensed operator (Operator or Senior Operator) or by a qualified member of the technical staff (e.g., engineer). This helps to ensure that the control rods will be moved to the correct position. A control rod not in compliance with the prescribed sequence is not considered inoperable except as required by Required Action A.2. The allowed Completion Time of 8 hours is reasonable, considering the restrictions on the number of allowed out of sequence control rods and the low probability of a CRDA occurring during the time the control rods are out of sequence.

B.1 and B.2

If nine or more OPERABLE control rods are out of sequence, the control rod pattern significantly deviates from the prescribed sequence. Control rod withdrawal should be suspended immediately to prevent the potential for further deviation from the prescribed sequence. Control rod insertion to correct control rods withdrawn beyond their allowed position is allowed since, in general, insertion of control rods has less impact on control rod worth than withdrawals have. Required Action B.1 is modified by a Note which allows the RWM to be bypassed to allow the affected control rods to be returned to their correct position. LCO 3.3.2.1 requires verification of control rod movement by a second licensed operator (Operator or Senior Operator) or by a qualified member of the technical staff (e.g., engineer).

When nine or more OPERABLE control rods are not in compliance with BPWS, the reactor mode switch must be placed in the shutdown position within 1 hour. With the mode switch in shutdown, the reactor is shut down, and as such, does not meet the applicability requirements of this LCO. The allowed Completion Time of 1 hour is reasonable to allow insertion of control rods to restore compliance, and is appropriate relative to the low probability of a CRDA occurring with the control rods out of sequence.

SURVEILLANCE REQUIREMENTS

SR 3.1.6.1

The control rod pattern is verified to be in compliance with the BPWS at a 24 hour Frequency to ensure the assumptions of the CRDA analyses are met. The 24 hour Frequency was developed considering that the primary check on compliance with the BPWS is performed by the RWM (LCO 3.3.2.1), which provides control rod blocks to enforce the required sequence and is required to be OPERABLE when operating at ≤ 10% RTP.

REFERENCES

1. NEDE-24011-P-A, "General Electric Standard Application for Reactor Fuel" (revision specified in Specification 5.6.3).

2. Letter from T.A. Pickens (BWROG) to G.C. Lainas (NRC), "Amendment 17 to General Electric Licensing Topical Report NEDE-24011-P-A," BWROG-8644, August 15, 1986.

3. USAR, Section 14.7.1.

4. NUREG-0979, Section 4.2.1.3.2, April 1983.

5. NUREG-0800, Section 15.4.9, Revision 2, July 1981.

6. NEDO-21778-A, "Transient Pressure Rises Affected Fracture Toughness Requirements for Boiling Water Reactors," December 1978.

7. NEDO-10527, "Rod Drop Accident Analysis for Large BWRs," (including Supplements 1 and 2), March 1972.

8. ASME, Boiler and Pressure Vessel Code.

9. 10 CFR 50.67.

10. NEDO-21231, "Banked Position Withdrawal Sequence," January 1977.

11. NEDO-33091-A, Revision 2, "Improved BPWS Control Rod Insertion Process," July 2004.

12. Amendment No. 176, “Monticello Nuclear Generating Plant – Issuance of Amendment No. 176 to Renewed Facility Operating License Regarding Extended Power Uprate,” (ADAMS Accession No. ML13316C459)

13. XN-NF-80-19(P)(A) Volume 1 and Supplements 1 and 2, “Exxon Nuclear Methodology for Boiling Water Reactors – Neutronic Methods for Design and Analysis”, Exxon Nuclear Company, March 1983.

14. EMF-2158(P)(A) Revision 0, “Siemens Power Corporation Methodology for Boiling Water Reactors: Evaluation and Validation for CASMO-4/MICROBURN-B2”, Siemens Power Corporation, October 1999.

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.7 Standby Liquid Control (SLC) System

BASES

BACKGROUND

The SLC System is designed to provide the capability of bringing the reactor, at any time in a fuel cycle, from full power and minimum control rod inventory (which is at the peak of the xenon transient) to a subcritical condition with the reactor in the most reactive, xenon free state without taking credit for control rod movement. The SLC System satisfies the requirements of 10 CFR 50.62 (Ref. 1) on anticipated transient without scram (ATWS).

The SLC System is also used to maintain suppression pool pH > 7 following a loss of coolant accident (LOCA) involving significant fission product release. Maintaining suppression pool pH > 7 following an accident ensures that iodine will be retained in the suppression pool water (Ref. 2).

The SLC System consists of a boron solution storage tank, two positive displacement pumps, two explosive valves that are provided in parallel for redundancy, and associated piping and valves used to transfer borated water from the storage tank to the reactor pressure vessel (RPV). The borated solution is discharged near the bottom of the core shroud, where it then mixes with the cooling water rising through the core. A smaller tank containing demineralized water is provided for testing purposes.

APPLICABLE SAFETY ANALYSES

The SLC System is manually initiated from the main control room, as directed by the emergency operating procedures, if the operator determines the reactor cannot be shut down, or kept shut down, with the control rods. The SLC System is used in the event that enough control rods cannot be inserted to accomplish shutdown and cooldown in the normal manner. The SLC System injects borated water into the reactor core to add negative reactivity to compensate for all of the various reactivity effects that could occur during plant operations. To meet this objective, it is necessary to inject a quantity of boron that produces a concentration of 660 ppm of natural boron in the reactor coolant at 68°F. To allow for potential leakage and imperfect mixing in the reactor system, an amount of boron equal to 25% of the amount cited above is added (Ref. 3). The volume versus concentration limits in Figure 3.1.7-1 and the temperature versus concentration limits in Figure 3.1.7-2 are calculated such that the required concentration is achieved accounting for dilution in the RPV with normal water level and including the water volume in the residual heat removal shutdown cooling piping and in the recirculation loop piping and with B-10 enrichment of ≥ 55.0 atom percent. This quantity of borated solution is the amount that is above the pump suction nozzle and accounts for wide range instrument accuracy. No credit is taken for the portion of the tank volume that cannot be injected.

BASES

APPLICABLE SAFETY ANALYSES

In addition, following a LOCA involving significant fission product release, offsite and Control Room doses from the accident will remain within 10 CFR 50.67 (Ref. 4) limits provided sufficient iodine activity is retained in the suppression pool. Credit for iodine retention in the suppression pool is allowed as long as suppression pool pH is maintained > 7. The Alternative Source Term analyses credit the manual initiation of the SLC System for maintaining the pH of the suppression pool > 7 (Ref. 5) following a LOCA with significant core damage. The initiation of SLC is a manual operator action assumed to occur within the first hour of the accident. Assuming a conservative system flow rate, the contents of the SLC tank can be injected into the reactor vessel and reach the suppression pool within two hours, which is in accordance with the timing and concentration assumptions of the analysis.

The SLC System satisfies Criteria 3 and 4 of 10 CFR 50.36(c)(2)(ii).

LCO

The OPERABILITY of the SLC System provides backup capability for reactivity control independent of normal reactivity control provisions provided by the control rods and suppression pool pH control following a LOCA. The OPERABILITY of the SLC System is based on the conditions of the borated solution in the storage tank and the availability of a flow path to the RPV, including the OPERABILITY of the pumps and valves. Two SLC subsystems are required to be OPERABLE; each contains an OPERABLE pump, an explosive valve, and associated piping, valves, and instruments and controls to ensure an OPERABLE flow path.

APPLICABILITY

The SLC System must be OPERABLE in MODES 1, 2, and 3 to ensure that offsite doses remain within 10 CFR 50.67 limits following a LOCA involving significant fission product release. The SLC System is designed to maintain suppression pool pH >7 following a LOCA to ensure that iodine will be retained in the suppression pool water. In MODES 4 and 5, no LOCA event involving significant fission product releases is postulated.

Furthermore, in MODES 1 and 2, shutdown capability is required. In MODES 3 and 4, control rods are not able to be withdrawn since the reactor mode switch is in shutdown and a control rod block is applied. This provides adequate controls to ensure that the reactor remains subcritical. In MODE 5, only a single control rod can be withdrawn from a core cell containing fuel assemblies. Demonstration of adequate SDM (LCO 3.1.1, "SHUTDOWN MARGIN (SDM)") ensures that the reactor will not become critical. Therefore, the SLC System is not required to be OPERABLE when only a single control rod can be withdrawn.

ACTIONS

A.1

If the concentration of sodium pentaborate in solution is not within limits of Figure 3.1.7-1 and Table 3.1.7-1 Equation 2 (ATWS design basis) but

ACTIONS (continued)

available volume of sodium pentaborate solution is within limits of Table 3.1.7-1 Equation 1 (original design basis), the concentration must be restored to within limits in 7 days. It is not necessary under these conditions to enter Condition C for both SLC subsystems inoperable since they are capable of performing their original design basis function, as well as providing suppression pool pH control following a LOCA. Because of the low probability of an event and the fact that the SLC System capability still exists for vessel injection under these conditions, the allowed Completion Time of 7 days is acceptable and provides adequate time to restore concentration to within limits.

B.1

If one SLC subsystem is inoperable for reasons other than Condition A, the inoperable subsystem must be restored to OPERABLE status within 7 days. In this condition, the remaining OPERABLE subsystem is adequate to perform the ATWS design basis function, as well as providing suppression pool pH control following a LOCA. However, the overall reliability is reduced because a single failure in the remaining OPERABLE subsystem could result in reduced SLC System shutdown capability. The 7 day Completion Time is based on the availability of an OPERABLE subsystem capable of performing the intended SLC System function and the low probability of a Design Basis Accident (DBA) or severe transient occurring concurrent with the failure of the Control Rod Drive (CRD) System to shut down the plant.

C.1

If both SLC subsystems are inoperable for reasons other than Condition A, at least one subsystem must be restored to OPERABLE status within 8 hours. The allowed Completion Time of 8 hours is considered acceptable given the low probability of a DBA or transient occurring concurrent with the failure of the control rods to shut down the reactor.

D.1

If any Required Action and associated Completion Time is not met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 12 hours and 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 3.1.7.1 and SR 3.1.7.2

SR 3.1.7.1 and SR 3.1.7.2 are 24 hour Surveillances verifying certain characteristics of the SLC System (e.g., the volume and temperature of the borated solution in the storage tank), thereby ensuring SLC System OPERABILITY without disturbing normal plant operation. These Surveillances ensure that the proper borated solution volume and temperature are maintained. Maintaining a minimum specified borated solution temperature is important in ensuring that the boron remains in solution and does not precipitate out in the storage tank. The temperature versus concentration curve of Figure 3.1.7-2 ensures that a 5°F margin will be maintained above the saturation temperature. The volume of sodium pentaborate solution requirements in Figure 3.1.7-1 and Table 3.1.7-1 Equation 1 will ensure both the original design basis and the ATWS design basis are met. Figure 3.1.7-1 can only be used if the B-10 enrichment in the storage tank is ≥ 55.0 atom percent. If the volume requirement of Table 3.1.7-1 Equation 1 is utilized for verification of volume requirements the concentration requirements for the original design basis can also be considered to be met. However, to verify the ATWS design basis requirements are met, Table 3.1.7-1 Equation 2 must be used to verify the concentration of sodium pentaborate solution requirements are met. The AST design basis for suppression pool pH control is preserved if the requirements of Figure 3.1.7-1 are met. The 24 hour Frequency is based on operating experience and has shown there are relatively slow variations in the measured parameters of volume and temperature.

SR 3.1.7.3

SR 3.1.7.3 is a 24 hour Surveillance that requires the verification that the room temperature in the vicinity of the SLC pumps is within the solution temperature limits of Figure 3.1.7-2 or that the SLC pump suction lines heat tracing is OPERABLE. This Surveillance will help ensure that the proper borated solution temperature of the pump suction piping is maintained. Maintaining a minimum specified room temperature is important in ensuring that the boron remains in solution and does not precipitate out in the pump suction piping. The temperature versus concentration curve of Figure 3.1.7-2 ensures that a 5°F margin will be maintained above the saturation temperature. An acceptable alternate requirement is to verify the pump suction lines heat tracing is OPERABLE. The heat tracing is sized to maintain the pump suction above 70°F when the room temperature is 45°F. OPERABILITY of the heat tracing is confirmed by verifying the light associated with each controller is on, or by depressing the toggle switch and ensuring the light is on. The 24 hour Frequency is based on operating experience and has shown there are relatively slow variations in the measured room temperature.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.1.7.4 and SR 3.1.7.6

SR 3.1.7.4 verifies the continuity of the explosive charges in the injection valves to ensure that proper operation will occur if required. Other administrative controls, such as those that limit the shelf life of the explosive charges, must be followed. The 31 day Frequency is based on operating experience and has demonstrated the reliability of the explosive charge continuity.

SR 3.1.7.6 verifies that each valve in the system is in its correct position, but does not apply to the squib (i.e., explosive) valves. Verifying the correct alignment for manual valves in the SLC System flow path provides assurance that the proper flow paths will exist for system operation. A valve is also allowed to be in the nonaccident position provided it can be aligned to the accident position from the control room, or locally by a dedicated operator at the valve control. This is acceptable since the SLC System is a manually initiated system. This Surveillance also does not apply to valves that are locked, sealed, or otherwise secured in position since they are verified to be in the correct position prior to locking, sealing, or securing. This verification of valve alignment does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves. The 31 day Frequency is based on engineering judgment and is consistent with the procedural controls governing valve operation that ensures correct valve positions.

SR 3.1.7.5

This Surveillance requires an examination of the sodium pentaborate solution by using chemical analysis to ensure that the proper concentration of sodium pentaborate exists in the storage tank. The concentration of sodium pentaborate in solution required in Figure 3.1.7-1 will ensure the original design basis, the AST design basis for suppression pool pH control and the ATWS design basis are met. Figure 3.1.7-1 can only be used if the B-10 enrichment in the storage tank is $\geq$ 55.0 atom percent and as long as the flow rate requirements of SR 3.1.7.7 are met. Equation 2 of Table 3.1.7-1 ensures both the original design basis and ATWS design basis are satisfied. If the volume requirement of Equation 1 of Table 3.1.7-1 is utilized for verification of volume requirements the concentration requirements for the original design basis can also be considered to be met. However, to verify the ATWS requirements are met, Equation 2 of Table 3.1.7-1 must be used to verify the concentration of sodium pentaborate solution requirements are

SURVEILLANCE REQUIREMENTS (continued)

met. SR 3.1.7.5 must be performed any time sodium pentaborate or water is added to the storage tank solution to determine that the sodium pentaborate solution concentration is within the specified limits. SR 3.1.7.5 must also be performed anytime the temperature is restored to within the limits of Figure 3.1.7-2, to ensure that no significant boron

precipitation occurred. The 31 day Frequency of this Surveillance is appropriate because of the relatively slow variation of sodium pentaborate concentration between Surveillances.

SR 3.1.7.7

Demonstrating that each SLC System pump develops a flow rate ≥ 24 gpm at a discharge pressure ≥ 1275 psig ensures that pump performance has not degraded during the fuel cycle. This minimum pump flow rate requirement ensures that, when combined with the sodium pentaborate solution concentration requirements, the rate of negative reactivity insertion from the SLC System will adequately compensate for the positive reactivity effects encountered during power reduction, cooldown of the moderator, and xenon decay. This test confirms one point on the pump design curve and is indicative of overall performance. Such inservice tests confirm component OPERABILITY, trend performance, and detect incipient failures by indicating abnormal performance. The Frequency of this Surveillance is in accordance with the Inservice Testing Program.

SR 3.1.7.8 and SR 3.1.7.9

These Surveillances ensure that there is a functioning flow path from the boron solution storage tank to the RPV, including the firing of an explosive valve. The replacement charge for the explosive valve shall be from the same manufactured batch as the one fired or from another batch that has been certified by having one of that batch successfully fired. The pump and explosive valve tested should be alternated such that both complete flow paths are tested every 48 months at alternating 24 month intervals. The Surveillance may be performed in separate steps to prevent injecting boron into the RPV. An acceptable method for verifying flow from the pump to the RPV is to pump demineralized water from a test tank through one manually initiated SLC subsystem and into the RPV. 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.

BASES

SURVEILLANCE REQUIREMENTS (continued)

Demonstrating that all heat traced piping between the boron solution storage tank and the suction inlet to the injection pumps is unblocked ensures that there is a functioning flow path for injecting the sodium pentaborate solution. An acceptable method for verifying that the suction piping is unblocked is to pump from the storage tank to the test tank.

The 24 month Frequency is acceptable since there is a low probability that the subject piping will be blocked due to precipitation of the boron from solution in the heat traced piping. This is especially true in light of the temperature verification of this piping required by SR 3.1.7.3. However, if, in performing SR 3.1.7.3, it is determined that the temperature of this piping has fallen below the specified minimum and the SLC pump suction lines heat tracing is inoperable, SR 3.1.7.9 must be performed once within 24 hours after the room temperature in the vicinity of the SLC pumps is restored to within the solution temperature limits of Figure 3.1.7-2.

SR 3.1.7.10

Enriched sodium pentaborate solution is made by mixing granular, enriched sodium pentaborate with water. Isotopic tests (laboratory analyses) on the granular sodium pentaborate to verify the actual B-10 enrichment must be performed prior to addition to the SLC tank in order to ensure that the proper B-10 atom percentage is being used.

REFERENCES

1. 10 CFR 50.62
2. NUREG-1465, “Accident Source Term for Light-Water Nuclear Power Plants, Final Report,” February 1995.
3. USAR, Section 6.6.1.1.
4. 10 CFR 50.67 “Accident Source Term”
5. USAR Section 14.7.2.4

B 3.1 REACTIVITY CONTROL SYSTEMS

B 3.1.8 Scram Discharge Volume (SDV) Vent and Drain Valves

BASES

BACKGROUND

The SDV vent and drain valves are normally open and discharge any accumulated water in the SDV to ensure that sufficient volume is available at all times to allow a complete scram. During a scram, the SDV vent and drain valves close to contain reactor water. The SDV is a volume of header piping that connects to each hydraulic control unit (HCU) and drains into an instrument volume. There are two SDVs (headers) and two instrument volumes, each receiving approximately one half of the control rod drive (CRD) discharges. Each instrument volume is connected to a drain line with two valves in series for a total of four drain valves. Each header is connected to a vent line with two valves in series for a total of four vent valves. The header piping is sized to receive and contain all the water discharged by the CRDs during a scram. The design and functions of the SDV are described in Reference 1.

APPLICABLE SAFETY ANALYSES

The Design Basis Accident and transient analyses assume all of the control rods are capable of scramming. The acceptance criteria for the SDV vent and drain valves are that they operate automatically to:

a. Close during scram to limit the amount of reactor coolant discharged so that adequate core cooling is maintained and offsite doses remain within the limits of 10 CFR 50.67 (Ref. 2) and

b. Open on scram reset to maintain the SDV vent and drain path open so that there is sufficient volume to accept the reactor coolant discharged during a scram.

Isolation of the SDV can also be accomplished by manual closure of the SDV valves. Additionally, the discharge of reactor coolant to the SDV can be terminated by scram reset or closure of the HCU manual isolation valves. For a bounding leakage case, the offsite doses are well within the limits of 10 CFR 50.67 (Ref. 2), and adequate core cooling is maintained (Ref. 3). The SDV vent and drain valves allow continuous drainage of the SDV during normal plant operation to ensure that the SDV has sufficient capacity to contain the reactor coolant discharge during a full core scram. To automatically ensure this capacity, a reactor scram (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation") is initiated if the SDV water level in the instrument volume exceeds a specified setpoint. The setpoint is chosen so that all control rods are inserted before the SDV has insufficient volume to accept a full scram.

SDV vent and drain valves satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO	The OPERABILITY of all SDV vent and drain valves ensures that the SDV vent and drain valves will close during a scram to contain reactor water discharged to the SDV piping. Since the vent and drain lines are provided with two valves in series, the single failure of one valve in the open position will not impair the isolation function of the system. Additionally, the valves are required to open on scram reset to ensure that a path is available for the SDV piping to drain freely at other times.
APPLICABILITY	In MODES 1 and 2, a scram may be required; therefore, the SDV vent and drain valves must be OPERABLE. In MODES 3 and 4, control rods are not able to be withdrawn since the reactor mode switch is in shutdown and a control rod block is applied. Also, during MODE 5, only a single control rod can be withdrawn from a core cell containing fuel assemblies. Therefore, the SDV vent and drain valves are not required to be OPERABLE in these MODES since the reactor is subcritical and only one rod may be withdrawn and subject to scram.

ACTIONS

The ACTIONS Table is modified by Note 1 indicating that a separate Condition entry is allowed for each SDV vent and drain line. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable SDV line. Complying with the Required Actions may allow for continued operation, and subsequent inoperable SDV lines are governed by subsequent Condition entry and application of associated Required Actions.

The ACTIONS Table is modified by a second Note stating that an isolated line may be unisolated under administrative control to allow draining and venting of the SDV. When a line is isolated, the potential for an inadvertent scram due to high SDV level is increased. During these periods, the line may be unisolated under administrative control. This allows any accumulated water in the line to be drained, to preclude a reactor scram on SDV high level. This is acceptable since the administrative controls ensure the valve can be closed quickly, by a dedicated operator, if a scram occurs with the valve open.

A.1

When one SDV vent or drain valve is inoperable in one or more lines, the associated line must be isolated to contain the reactor coolant during a scram. The 7 day Completion Time is reasonable, given the level of redundancy in the line and the low probability of a scram occurring while the valve is inoperable and the line is not isolated. The SDV is still isolable since the redundant valve in the affected line is OPERABLE. During these periods, the single failure criterion may not be preserved, and a higher risk exists to allow reactor water out of the primary system during a scram.

BASES

ACTIONS (continued)

B.1

If both valves in a line are inoperable, the line must be isolated to contain the reactor coolant during a scram. The 8 hour Completion Time to isolate the line is based on the low probability of a scram occurring while the line is not isolated and unlikelihood of significant CRD seal leakage.

C.1

If any Required Action and associated Completion Time is not met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 12 hours. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.1.8.1

During normal operation, the SDV vent and drain valves should be in the open position (except when performing SR 3.1.8.2) to allow for drainage of the SDV piping. Verifying that each valve is in the open position ensures that the SDV vent and drain valves will perform their intended functions during normal operation. This SR does not require any testing or valve manipulation; rather, it involves verification that the valves are in the correct position.

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

SR 3.1.8.2

During a scram, the SDV vent and drain valves should close to contain the reactor water discharged to the SDV piping. Cycling each valve through its complete range of motion (closed and open) ensures that the valve will function properly during a scram. The 92 day Frequency is based on operating experience and takes into account the level of redundancy in the system design.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.1.8.3

SR 3.1.8.3 is an integrated test of the SDV vent and drain valves to verify total system performance. After receipt of a simulated or actual scram signal, the closure of the SDV vent and drain valves is verified. The closure time of 30 seconds after receipt of a scram signal is based on the bounding leakage case evaluated in the accident analysis (Ref. 3). Similarly, after receipt of a simulated or actual scram reset signal, the opening of the SDV vent and drain valves is verified. The LOGIC SYSTEM FUNCTIONAL TEST in LCO 3.3.1.1 and the scram time testing of control rods in LCO 3.1.3, "Control Rod OPERABILITY," 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 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. USAR, Section 3.5.3.3.3.5.
2. 10 CFR 50.67, Accident Source Term.
3. NUREG-0803, "Generic Safety Evaluation Report Regarding Integrity of BWR Scram System Piping," August 1981.

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.1 AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)

BASES

BACKGROUND

The APLHGR is a measure of the average LHGR of all the fuel rods in a fuel assembly at any axial node location. Limits on the APLHGR are specified to ensure that the fuel design limits identified in Reference 1 are not exceeded during anticipated operational occurrences (AOOs) and that the peak cladding temperature (PCT) during the postulated design basis loss of coolant accident (LOCA) does not exceed the limits specified in 10 CFR 50.46.

APPLICABLE SAFETY ANALYSES

NOTE: Certain AREVA safety analysis methods have been approved for use (Amendment 188); however, those methods may not be invoked in the analysis-of-record until AREVA fuel is loaded in the core. Until that time, General Electric – Hitachi (GEH) safety analysis methods will continue to support core operation and the description of the GEH methods in the TS Bases shall prevail. To the extent that approved AREVA methods may be described and referenced without conflicting with the GEH analysis-of-record, the TS Bases reflect both GEH and AREVA methods. Refer to CORE OPERATING LIMIT REPORT (COLR) Section 1.0 to determine whether GEH or AREVA methods were used for the current operating cycle.

The analytical methods and assumptions used in evaluating the fuel design limits are presented in References 1 and 2. The analytical methods and assumptions used in evaluating Design Basis Accidents (DBAs), anticipated operational transients, and normal operation that determine the APLHGR limits are presented in References 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, and 15).

Fuel design evaluations are performed to demonstrate that the 1% limit on the fuel cladding plastic strain and other fuel design limits described in Reference 1 are not exceeded during AOOs for operation with LHGRs up to the operating limit LHGR. APLHGR limits are developed as a function of exposure and the various operating core flow and power states to ensure adherence to fuel design limits during the limiting AOOs (Refs. 7, 8, 9, and 10). Flow dependent APLHGR limits are determined using the three dimensional BWR simulator code (Ref. 11) to analyze slow flow runout transients. The flow dependent multiplier, $MAPFAC_f$, is dependent on the maximum core flow runout capability. The maximum runout flow is dependent on the existing setting of the core flow limiter in the Recirculation Flow Control System.

BASES

APPLICABLE SAFETY ANALYSES (continued)

Based on analyses of limiting plant transients (other than core flow increases) over a range of power and flow conditions, power dependent multipliers, $MAPFAC_p$, are also generated. Due to the sensitivity of the transient response to initial core flow levels at power levels below those at which turbine stop valve closure and turbine control valve fast closure scram trips are bypassed, both high and low core flow $MAPFAC_p$ limits are provided for operation at power levels between 25% RTP and the previously mentioned bypass power level. The exposure dependent APLHGR limits are reduced by $MAPFAC_p$ and $MAPFAC_f$ at various operating conditions to ensure that all fuel design criteria are met for normal operation and AOOs. A complete discussion of the analysis code is provided in Reference 12.

LOCA analyses are then performed to ensure that the above determined APLHGR limits are adequate to meet the PCT and maximum oxidation limits of 10 CFR 50.46. The analysis is performed using calculational models that are consistent with the requirements of 10 CFR 50, Appendix K. A complete discussion of the analysis code is provided in Reference 13. The PCT following a postulated LOCA is a function of the average heat generation rate of all the rods of a fuel assembly at any axial location and is not strongly influenced by the rod to rod power distribution within an assembly. A conservative multiplier is applied to the LHGR assumed in the LOCA analysis to account for the uncertainty associated with the measurement of the APLHGR.

For single recirculation loop operation, the MAPFAC multiplier is limited to a maximum value determined by the particular fuel type (Ref. 14). This maximum limit is due to the conservative analysis assumption of an earlier departure from nucleate boiling with one recirculation loop available, resulting in a more severe cladding heatup during a LOCA.

The APLHGR satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The APLHGR limits specified in the COLR for each type of fuel as a function of average planar exposure are the result of the fuel design, DBA, and transient analyses. For two recirculation loops operating, the limit is determined by multiplying the smaller of the $MAPFAC_p$ and $MAPFAC_f$ factors times the exposure dependent APLHGR limits. With only one recirculation loop in operation, in conformance with the requirements of LCO 3.4.1, "Recirculation Loops Operating," the limit is determined by multiplying the exposure dependent APLHGR limit by the smaller of either $MAPFAC_p$, $MAPFAC_f$, or the fuel-specific single loop multiplier, which has been determined by a specific single recirculation loop analysis (Refs. 5 and 14).

BASES

APPLICABILITY

The APLHGR limits are primarily derived from fuel design evaluations and LOCA and transient analyses that are assumed to occur at high power levels. Design calculations (Ref. 10) and operating experience have shown that as power is reduced, the margin to the required APLHGR limits increases. This trend continues down to the power range of 5% to 15% RTP when entry into MODE 2 occurs. When in MODE 2, the intermediate range monitor scram function provides prompt scram initiation during any significant transient, thereby effectively removing any APLHGR limit compliance concern in MODE 2. Therefore, at THERMAL POWER levels ≤ 25% RTP, the reactor is operating with substantial margin to the APLHGR limits; thus, this LCO is not required.

ACTIONS

A.1

If any APLHGR exceeds the required limits, an assumption regarding an initial condition of the DBA and transient analyses may not be met. Therefore, prompt action should be taken to restore the APLHGR(s) to within the required limits such that the plant operates within analyzed conditions and within design limits of the fuel rods. The 2 hour Completion Time is sufficient to restore the APLHGR(s) to within its limits and is acceptable based on the low probability of a transient or DBA occurring simultaneously with the APLHGR out of specification.

B.1

If the APLHGR cannot be restored to within its required limits within the associated Completion Time, the plant must be brought to a MODE or other specified condition in which the LCO does not apply. To achieve this status, THERMAL POWER must be reduced to < 25% RTP within 4 hours. The allowed Completion Time is reasonable, based on operating experience, to reduce THERMAL POWER to < 25% RTP in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.2.1.1

APLHGRs are required to be initially calculated within 12 hours after THERMAL POWER is ≥ 25% RTP and then every 24 hours thereafter. They are compared to the specified limits in the COLR to ensure that the reactor is operating within the assumptions of the safety analysis. The 24 hour Frequency is based on both engineering judgment and recognition of the slowness of changes in power distribution during normal operation. The 12 hour allowance after THERMAL POWER ≥ 25% RTP is achieved is acceptable given the large inherent margin to operating limits at low power levels.

BASES

REFERENCES

1. NEDE-24011-P-A, "General Electric Standard Application for Reactor Fuel" (revision specified in Specification 5.6.3).
2. USAR, Chapter 3.
3. USAR, Section 6.2.6.
4. USAR, Section 14.7.2.
5. USAR, Section 14.3.
6. USAR, Chapter 14A.
7. NEDE-23785-P (A), Revision 1, "The GESTR-LOCA and SAFER Models for Evaluation of the Loss-of-Coolant Accident (Volume III), SAFER/GESTR Application Methodology," October 1984.
8. NEDC-30515, "GE BWR Extended Load Line Limit Analysis for Monticello Nuclear Generating Plant, Cycle 11," March 1984.
9. NEDC-31849P, including Supplement 1, "Maximum Extended Load Line Limit Analysis for Monticello Nuclear Generating Plant Cycle 15," June 1992.
10. NEDC-30492-P, "Average Power Range Monitor, Rod Block Monitor and Technical Specification Improvement (ARTS) Program for Monticello Nuclear Generating Plant," April 1984.
11. NEDO-30130-A, "Steady State Nuclear Methods," May 1985.
12. NEDO-24154, "Qualification of the One-Dimensional Core Transient Model for Boiling Water Reactors," October 1978.
13. GE-NE-187-02-0392, "Monticello Nuclear Generating Plant SAFER/GESTR-LOCA Analysis Basis Documentation," July 1993.
14. Supplemental Reload Licensing Report for Monticello Nuclear Generation Plant (version specified in the COLR).
15. Amendment No. 176 – Extended Power Uprate

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.2 MINIMUM CRITICAL POWER RATIO (MCPR)

BASES

BACKGROUND

MCPR is a ratio of the fuel assembly power that would result in the onset of transition boiling to the actual fuel assembly power. The MCPR Safety Limit (SL) is set such that 99.9% of the fuel rods avoid transition boiling if the limit is not violated (refer to the Bases for SL 2.1.1). The operating limit MCPR is established to ensure that no fuel damage results during anticipated operational occurrences (AOOs). Although fuel damage does not necessarily occur if a fuel rod actually experienced transition boiling (Ref. 1), the critical power at which transition boiling is calculated to occur has been adopted as a fuel design criterion.

The onset of transition boiling is a phenomenon that is readily detected during the testing of various fuel bundle designs. Based on these experimental data, correlations have been developed to predict critical bundle power (i.e., the bundle power level at the onset of transition boiling) for a given set of plant parameters (e.g., reactor vessel pressure, flow, and subcooling). Because plant operating conditions and bundle power levels are monitored and determined relatively easily, monitoring the MCPR is a convenient way of ensuring that fuel failures due to inadequate cooling do not occur.

APPLICABLE SAFETY ANALYSES

NOTE: Certain AREVA safety analysis methods have been approved for use (Amendment 188); however, those methods may not be invoked in the analysis-of-record until AREVA fuel is loaded in the core. Until that time, General Electric – Hitachi (GEH) safety analysis methods will continue to support core operation and the description of the GEH methods in the TS Bases shall prevail. To the extent that approved AREVA methods may be described and referenced without conflicting with the GEH analysis-of-record, the TS Bases reflect both GEH and AREVA methods. Refer to CORE OPERATING LIMIT REPORT (COLR) Section 1.0 to determine whether GEH or AREVA methods were used for the current operating cycle.

The analytical methods and assumptions used in evaluating the AOOs to establish the operating limit MCPR are presented in References 2, 3, 4, 5, 6, 7, 8, and 9. To ensure that the MCPR SL is not exceeded during any transient event that occurs with moderate frequency, limiting transients have been analyzed to determine the largest reduction in critical power ratio (CPR). The types of transients evaluated are loss of flow, increase in pressure and power, positive reactivity insertion, and coolant temperature decrease. The limiting transient yields the largest change in CPR (ΔCPR). When the largest ΔCPR is added to the MCPR SL, the required operating limit MCPR is obtained.

BASES

APPLICABLE SAFETY ANALYSES (continued)

The MCPR operating limits derived from the transient analysis are dependent on the operating core flow and power state ($MCPR_f$ and $MCPR_p$, respectively) to ensure adherence to fuel design limits during the worst transient that occurs with moderate frequency (Refs. 7, 8, 9, and 10). Flow dependent MCPR limits are determined by steady state thermal hydraulic methods with key physics response inputs benchmarked using the three dimensional BWR simulator code (Ref. 11) to analyze slow flow runout transients. The operating limit is dependent on the maximum core flow limiter setting in the Recirculation Flow Control System.

Power dependent MCPR limits ($MCPR_p$) are determined mainly by the one dimensional transient code (Ref. 12). Due to the sensitivity of the transient response to initial core flow levels at power levels below those at which the turbine stop valve closure and turbine control valve fast closure scrams are bypassed, high and low flow $MCPR_p$ operating limits are provided for operating between 25% RTP and the previously mentioned bypass power level.

The MCPR satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The MCPR operating limits specified in the COLR are the result of the Design Basis Accident (DBA) and transient analysis. The operating limit MCPR is determined by the larger of the $MCPR_f$ and $MCPR_p$ limits.

APPLICABILITY

The MCPR operating limits are primarily derived from transient analyses that are assumed to occur at high power levels. Below 25% RTP, the reactor is operating at a low recirculation pump speed and the moderator void ratio is small. Surveillance of thermal limits below 25% RTP is unnecessary due to the large inherent margin that ensures that the MCPR SL is not exceeded even if a limiting transient occurs. Statistical analyses indicate that the nominal value of the initial MCPR expected at 25% RTP is > 3.5. Studies of the variation of limiting transient behavior have been performed over the range of power and flow conditions. These studies encompass the range of key actual plant parameter values important to typically limiting transients. The results of these studies demonstrate that a margin is expected between performance and the MCPR requirements, and that margins increase as power is reduced to 25% RTP. This trend is expected to continue to the 5% to 15% power range when entry into MODE 2 occurs. When in MODE 2, the intermediate range monitors provide rapid scram initiation for any significant power increase transient, which effectively eliminates any MCPR compliance concern. Therefore, at THERMAL POWER levels < 25% RTP, the reactor is operating with substantial margin to the MCPR limits and this LCO is not required.

BASES

ACTIONS

A.1

If any MCPR is outside the required limits, an assumption regarding an initial condition of the design basis transient analyses may not be met. Therefore, prompt action should be taken to restore the MCPR(s) to within the required limits such that the plant remains operating within analyzed conditions. The 2 hour Completion Time is normally sufficient to restore the MCPR(s) to within its limits and is acceptable based on the low probability of a transient or DBA occurring simultaneously with the MCPR out of specification.

B.1

If the MCPR cannot be restored to within its required limits within the associated Completion Time, the plant must be brought to a MODE or other specified condition in which the LCO does not apply. To achieve this status, THERMAL POWER must be reduced to < 25% RTP within 4 hours. The allowed Completion Time is reasonable, based on operating experience, to reduce THERMAL POWER to < 25% RTP in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.2.2.1

The MCPR is required to be initially calculated within 12 hours after THERMAL POWER is ≥ 25% RTP and then every 24 hours thereafter. It is compared to the specified limits in the COLR to ensure that the reactor is operating within the assumptions of the safety analysis. The 24 hour Frequency is based on both engineering judgment and recognition of the slowness of changes in power distribution during normal operation. The 12 hour allowance after THERMAL POWER ≥ 25% RTP is achieved is acceptable given the large inherent margin to operating limits at low power levels.

SR 3.2.2.2

Because the transient analysis takes credit for conservatism in the scram speed performance, it must be demonstrated that the specific scram speed distribution is consistent with that used in the transient analysis. SR 3.2.2.2 determines the value of τ, which is a measure of the actual scram speed distribution compared with the assumed distribution. The MCPR operating limit is then determined based on an interpolation between the applicable limits for Option A (scram times of LCO 3.1.4, "Control Rod Scram Times") and Option B (realistic scram times) analyses. The parameter τ must be determined once within 72 hours

BASES

SURVEILLANCE REQUIREMENTS (continued)	after each set of scram time tests required by SR 3.1.4.1, SR 3.1.4.2, and SR 3.1.4.4 because the effective scram speed distribution may change during the cycle or after maintenance that could affect scram times. The 72 hour Completion Time is acceptable due to the relatively minor changes in τ expected during the fuel cycle.

REFERENCES

1. NUREG-0562, June 1979.
2. NEDE-24011-P-A, "General Electric Standard Application for Reactor Fuel" (revision specified in Specification 5.6.3).
3. USAR, Section 3.2.4.
4. USAR, Section 6.2.6.
5. USAR, Chapter 14.
6. USAR, Chapter 14A.
7. NEDE-23785-P (A), Revision 1, "The GESTR-LOCA and SAFER Models for Evaluation of the Loss-of-Coolant Accident (Volume III), SAFER/GESTR Application Methodology," October 1984.
8. NEDC-30515, "GE BWR Extended Load Line Limit Analysis for Monticello Nuclear Generating Plant, Cycle 11," March 1984.
9. NEDC-31849P, including Supplement 1, "Maximum Extended Load Line Limit Analysis for Monticello Nuclear Generating Plant Cycle 15," June 1992.
10. NEDC-30492-P, "Average Power Range Monitor, Rod Block Monitor and Technical Specification Improvement (ARTS) Program for Monticello Nuclear Generating Plant," April 1984.
11. NEDO-30130-A, "Steady State Nuclear Methods," May 1985.
12. NEDO-24154, "Qualification of the One-Dimensional Core Transient Model for Boiling Water Reactors," October 1978.

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.3 LINEAR HEAT GENERATION RATE (LHGR)

BASES

BACKGROUND	The LHGR is a measure of the heat generation rate of a fuel rod in a fuel assembly at any axial node location. Limits on LHGR are specified to ensure that fuel design limits are not exceeded anywhere in the core during normal operation, including anticipated operational occurrences (AOOs). Exceeding the LHGR limit could potentially result in fuel damage and subsequent release of radioactive materials. Fuel design limits are specified to ensure that fuel system damage, fuel rod failure, or inability to cool the fuel does not occur during the normal operations and anticipated operating conditions identified in Reference 1.

APPLICABLE SAFETY ANALYSES

NOTE: Certain AREVA safety analysis methods have been approved for use (Amendment 188); however, those methods may not be invoked in the analysis-of-record until AREVA fuel is loaded in the core. Until that time, General Electric – Hitachi (GEH) safety analysis methods will continue to support core operation and the description of the GEH methods in the TS Bases shall prevail. To the extent that approved AREVA methods may be described and referenced without conflicting with the GEH analysis-of-record, the TS Bases reflect both GEH and AREVA methods. Refer to CORE OPERATING LIMIT REPORT (COLR) Section 1.0 to determine whether GEH or AREVA methods were used for the current operating cycle.

The analytical methods and assumptions used in evaluating the fuel system design are presented in References 1 and 2. The fuel assembly is designed to ensure (in conjunction with the core nuclear and thermal hydraulic design, plant equipment, instrumentation, and protection system) that fuel damage will not result in the release of radioactive materials in excess of the guidelines of 10 CFR, Parts 20, 50, and 100. The mechanisms that could cause fuel damage during operational transients and that are considered in fuel evaluations are:

a. Rupture of the fuel rod cladding caused by strain from the relative expansion of the UO_2 pellet; and

b. Severe overheating of the fuel rod cladding caused by inadequate cooling.

A value of 1% plastic strain of the fuel cladding has been defined as the limit below which fuel damage caused by overstraining of the fuel cladding is not expected to occur (Ref. 3).

Fuel design evaluations have been performed and demonstrate that the 1% fuel cladding plastic strain design limit is not exceeded during

BASES

APPLICABLE SAFETY ANALYSES (continued)

continuous operation with LHGRs up to the operating limit specified in the COLR. The analysis also includes allowances for short term transient operation above the operating limit to account for AOOs, plus an allowance for densification power spiking.

The LHGR satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The LHGR is a basic assumption in the fuel design analysis. The fuel has been designed to operate at rated core power with sufficient design margin to the LHGR calculated to cause a 1% fuel cladding plastic strain. The operating limit to accomplish this objective is specified in the COLR.

APPLICABILITY

The LHGR limits are derived from fuel design analysis that is limiting at high power level conditions. At core thermal power levels < 25% RTP, the reactor is operating with a substantial margin to the LHGR limits and, therefore, the Specification is only required when the reactor is operating at ≥ 25% RTP.

ACTIONS

A.1

If any LHGR exceeds its required limit, an assumption regarding an initial condition of the fuel design analysis is not met. Therefore, prompt action should be taken to restore the LHGR(s) to within its required limits such that the plant is operating within analyzed conditions. The 2 hour Completion Time is normally sufficient to restore the LHGR(s) to within its limits and is acceptable based on the low probability of a transient or Design Basis Accident occurring simultaneously with the LHGR out of specification.

B.1

If the LHGR cannot be restored to within its required limits within the associated Completion Time, the plant must be brought to a MODE or other specified condition in which the LCO does not apply. To achieve this status, THERMAL POWER is reduced to < 25% RTP within 4 hours. The allowed Completion Time is reasonable, based on operating experience, to reduce THERMAL POWER TO < 25% RTP in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.2.3.1

The LHGRs are required to be initially calculated within 12 hours after THERMAL POWER is ≥ 25% RTP and then every 24 hours thereafter. They are compared to the specified limits in the COLR to ensure that the reactor is operating within the assumptions of the safety analysis. The 24 hour Frequency is based on both engineering judgment and recognition of the slow changes in power distribution during normal operation. The 12 hour allowance after THERMAL POWER ≥ 25% RTP is achieved is acceptable given the large inherent margin to operating limits at lower power levels.

REFERENCES

1. USAR, Chapter 14.
2. USAR, Chapter 3.
3. NUREG-0800, Section II.A.2(g), Revision 2, July 1981.

B 3.3 INSTRUMENTATION

B 3.3.1.1 Reactor Protection System (RPS) Instrumentation

BASES

BACKGROUND

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

The protection and monitoring functions of the RPS have been designed to ensure safe operation of the reactor. This is achieved by specifying limiting safety system settings (LSSS) in terms of parameters directly monitored by the RPS, as well as LCOs on other reactor system parameters and equipment performance. Technical Specifications are required by 10 CFR 50.36 to contain LSSS defined by the regulation as "...settings for automatic protective devices...so chosen that automatic protective actions will correct the abnormal situation before a Safety Limit (SL) is exceeded." The Analytic Limit is the limit of the process variable at which a safety action is initiated, as established by the safety analysis, to ensure that a SL is not exceeded. Any automatic protection action that occurs on reaching the Analytic Limit therefore ensures that the SL is not exceeded. However, in practice, the actual settings for automatic protective devices must be chosen to be more conservative than the Analytic Limit to account for instrument loop uncertainties related to the setting at which the automatic protective action would actually occur.

The trip setpoint is a predetermined setting for a protective device chosen to ensure automatic actuation prior to the process variable reaching the Analytic Limit and thus ensuring that the SL would not be exceeded. As such, the trip setpoint accounts for uncertainties in setting the device (e.g., calibration), uncertainties in how the device might actually perform (e.g., repeatability), changes in the point of action of the device over time (e.g., drift during surveillance intervals), and any other factors which may influence its actual performance (e.g., harsh accident environments). In this manner, the trip setpoint plays an important role in ensuring that SLs are not exceeded. As such, the trip setpoint meets the definition of an LSSS (Ref. 1) and could be used to meet the requirement that they be contained in the Technical Specifications.

Technical Specifications contain values related to the OPERABILITY of equipment required for safe operation of the facility. OPERABLE is defined in Technical Specifications as "...being capable of performing its safety function(s)." For automatic protective devices, the required safety function is to ensure that a SL is not exceeded and therefore the LSSS as

BASES

BACKGROUND (continued)

defined by 10 CFR 50.36 is the same as the OPERABILITY limit for these devices. However, use of the trip setpoint to define OPERABILITY in Technical Specifications and its corresponding designation as the LSSS required by 10 CFR 50.36 would be an overly restrictive requirement if it were applied as an OPERABILITY limit for the "as found" value of a protective device setting during a Surveillance. This would result in Technical Specification compliance problems, as well as reports and corrective actions required by the rule which are not necessary to ensure safety. For example, an automatic protective device with a setting that has been found to be different from the trip setpoint due to some drift of the setting may still be OPERABLE since drift is to be expected. This expected drift would have been specifically accounted for in the setpoint methodology for calculating the trip setpoint and thus the automatic protective action would still have ensured that the SL would not be exceeded with the "as found" setting of the protective device. Therefore, the device would still be OPERABLE since it would have performed its safety function and the only corrective action required would be to reset the device to the trip setpoint to account for further drift during the next surveillance interval.

Use of the trip setpoint to define "as found" OPERABILITY and its designation as the LSSS under the expected circumstances described above would result in actions required by both the rule and Technical Specifications that are clearly not warranted. However, there is also some point beyond which the device would have not been able to perform its function due, for example, to greater than expected drift. This value needs to be specified in the Technical Specifications in order to define OPERABILITY of the devices and is designated as the Allowable Value which, as stated above, is the same as the LSSS.

The Allowable Valuable specified in Table 3.3.1-1 serves as the LSSS such that a channel is OPERABLE if the trip setpoint is found not to exceed the Allowable Value. As such, the Allowable Value differs from the trip setpoint by an amount primarily equal to the expected instrument loop uncertainties, such as drift, during the surveillance interval. In this manner, the actual setting of the device will still meet the LSSS definition and ensure that a SL is not exceeded at any given point of time as long as the device has not drifted beyond that expected during the surveillance interval. If the actual setting of the device is found to have exceeded the Allowable Value the device would be considered inoperable from a Technical Specification perspective. This requires corrective action including those actions required by 10 CFR 50.36 when automatic protective devices do not function as required. Note that, although the

BASES

BACKGROUND (continued)

channel is "OPERABLE" under these circumstances, the trip setpoint should be left adjusted to a value within the established trip setpoint calibration tolerance band, in accordance with uncertainty assumptions stated in the referenced setpoint methodology (as-left criteria), and confirmed to be operating within the statistical allowances of the uncertainty terms assigned.

The RPS, as described in USAR, Section 7.6.1.2.1 (Ref. 2), includes sensors, relays, bypass circuits, and switches that are necessary to cause initiation of a reactor scram. Functional diversity is provided by monitoring a wide range of dependent and independent parameters. The input parameters to the scram logic are from instrumentation that monitors reactor vessel water level, reactor vessel pressure, neutron flux, main steam line isolation valve position, turbine control valve (TCV) acceleration relay oil pressure, turbine stop valve (TSV) position, drywell pressure, and scram discharge volume (SDV) water level, as well as reactor mode switch in shutdown position and manual scram signals. There are at least four redundant sensor input signals from each of these parameters (with the exception of the reactor mode switch in shutdown and manual scram signals). Some channels include electronic equipment (e.g., trip units) that compares measured input signals with pre-established setpoints. When the setpoint is exceeded, the channel output relay actuates, which then outputs an RPS trip signal to the trip logic.

The RPS is comprised of two independent trip systems (A and B) with three logic channels in each trip system (logic channels A1, A2, and A3, B1, B2, and B3) as described in Reference 3. The automatic trip logics of trip system A are logic channels A1 and A2; the manual trip logic of trip system A is logic channel A3. Similarly, the trip logics for trip system B are logic channels B1, B2, and B3. The outputs of the automatic logic channels in a trip system are combined in a one-out-of-two logic so that either channel can trip the associated trip system. The tripping of both trip systems will produce a reactor scram. This logic arrangement is referred to as a one-out-of-two taken twice logic. The outputs of the manual logic channels in a trip system are combined in a one-out-of-one logic. The tripping of both manual logic channels will produce a scram. Each trip system can be reset by use of a reset switch. If a full scram occurs (both trip systems trip), a relay prevents reset of the trip systems for a short time delay after the full scram signal is received. The short time delay on reset ensures that the scram function will be completed.

BASES

BACKGROUND (continued)

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

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

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The actions of the RPS are assumed in the safety analyses of References 4 and 5. The RPS initiates a reactor scram when monitored parameter values exceed the Allowable Values, specified by the setpoint methodology and listed in Table 3.3.1.1-1 to preserve the integrity of the fuel cladding, the reactor coolant pressure boundary (RCPB), and the containment by minimizing the energy that must be absorbed following a LOCA.

RPS instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii). Functions not specifically credited in the accident analysis are retained for the overall redundancy and diversity of the RPS as required by the NRC approved licensing basis.

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

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Allowable Values are specified for most of the RPS Functions specified in the Table. Nominal trip setpoints are specified in the setpoint calculations. The nominal setpoints are selected to ensure that the actual setpoints do not exceed the Allowable Value between successive CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable. A channel is inoperable if its actual trip setpoint is not within its required Allowable Value.

Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (e.g., reactor vessel water level), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., trip unit) changes state. The analytic limits are derived from the limiting values of the process parameters obtained from the safety analysis. The Allowable Values and nominal trip setpoints (NTSP) are derived, using the General Electric setpoint methodology guidance, as specified in the Monticello setpoint methodology. The Allowable Values are derived from the analytic limits. The difference between the analytic limit and the Allowable Value allows for channel instrument accuracy, calibration accuracy, process measurement accuracy, and primary element accuracy. The margin between the Allowable Value and the NTSP allows for instrument drift that might occur during the established surveillance period. Two separate verifications are performed for the calculated NTSP. The first, a Spurious Trip Avoidance Test, evaluates the impact of the NTSP on plant availability. The second verification, an LER Avoidance Test, calculates the probability of avoiding a Licensee Event Report (or exceeding the Allowable Value) due to instrument drift. These two verifications are statistical evaluations to provide additional assurance of the acceptability of the NTSP and may require changes to the NTSP. Use of these methods and verifications provides the assurance that if the setpoint is found conservative to the Allowable Value during surveillance testing, the instrumentation would have provided the required trip function by the time the process reached the analytic limit for the applicable events.

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

The individual Functions are required to be OPERABLE in the MODES or other specified conditions indicated in Table 3.3.1.1-1, which may require an RPS trip to mitigate the consequences of a design basis accident or transient. To ensure a reliable scram function, a combination of Functions are required in each MODE to provide primary and diverse initiation signals.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

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

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

<u>Intermediate Range Monitor (IRM)</u>

<u>1.a. Intermediate Range Monitor Neutron Flux – High High</u>

The IRMs monitor neutron flux levels from the upper range of the source range monitor (SRM) to the lower range of the average power range monitors (APRMs). The IRMs are capable of generating trip signals that can be used to prevent fuel damage resulting from abnormal operating transients in the intermediate power range. In this power range, the most significant source of reactivity change is due to control rod withdrawal. The IRM provides diverse protection for the rod worth minimizer (RWM), which monitors and controls the movement of control rods at low power. The RWM prevents the withdrawal of an out of sequence control rod during startup that could result in an unacceptable neutron flux excursion (Ref. 6). The IRM provides mitigation of the neutron flux excursion. To demonstrate the capability of the IRM System to mitigate control rod withdrawal events, generic analyses have been performed (Ref. 7) to evaluate the consequences of control rod withdrawal events during startup that are mitigated only by the IRM. This analysis, which assumes that one IRM channel in each trip system is bypassed, demonstrates that the IRMs provide protection against local control rod withdrawal errors and results in peak fuel energy depositions below the 170 cal/gm fuel failure threshold criterion. The IRMs are capable of limiting other reactivity excursions during startup, such as cold water injection events, although no credit is specifically assumed. This Function was not specifically credited in the accident analysis but it is retained for the overall redundancy and diversity of the RPS as required by the NRC approved licensing basis.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The IRM System is divided into two groups of IRM channels, with four IRM channels inputting to each trip system. The analysis of Reference 7 assumes that one channel in each trip system is bypassed. Therefore, six channels with three channels in each trip system are required for IRM OPERABILITY to ensure that no single instrument failure will preclude a scram from this Function on a valid signal. For an IRM to be considered OPERABLE it must be fully inserted. This trip is active in each of the 9 ranges of the IRM (center IRMs 13, 16 and 17 highest range is Range 10), which must be selected by the operator to maintain the neutron flux within the monitored level of an IRM range.

The calculation in Reference 26 has adequate conservatism to permit an IRM Allowable Value of 121.5 divisions of a 125 division scale. The Intermediate Range Monitor Neutron Flux – High High SCRAM at the top of scale (125 divisions) provides effective protection against reactivity insertion transients in the startup mode (MODE 2). During startup, the operator changes IRM ranges to keep the IRM onscale and, by procedure, assures the IRM is ≥ 10 and ≤ 75 divisions of scale on any range for reliable monitoring. Thus, any local power transient occurring during startup (on any range but the highest) cannot cause power to increase beyond a factor of 10 before reaching the IRM Neutron Flux – High High SCRAM setpoint. In the startup range, this provides effective safety protection. There is enough overlap with the APRM on the highest IRM range so the Average Power Range Monitor Neutron Flux – High (Setdown) SCRAM, which is OPERABLE in MODE 2, will provide protection if required. The APRM Neutron Flux – High (Setdown) setpoint assures the SCRAM will occur before power exceeds 25% RTP in MODE 2 and, per procedure, that the plant changes from MODE 2 to RUN (MODE 1) before power reaches 25% RTP. This also assures that MODE 1 thermal limits monitoring is performed as required for power > 25% RTP.

The Intermediate Range Monitor Neutron Flux – High High Function must be OPERABLE during MODE 2 when control rods may be withdrawn and the potential for criticality exists. In MODE 5, when a cell with fuel has its control rod withdrawn, the IRMs provide monitoring for and protection against unexpected reactivity excursions. In MODE 1, the APRM System and the RWM provide protection against control rod withdrawal error events and the IRMs are not required.

<u>1.b. Intermediate Range Monitor – Inop</u>

This trip signal provides assurance that a minimum number of IRMs are OPERABLE. Anytime an IRM mode switch is moved to any position other than "Operate," the detector voltage drops below a preset level, or when a module is not plugged in, an inoperative trip signal will be

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

received by the RPS unless the IRM is bypassed. Since only one IRM in each trip system may be bypassed, only one IRM in each RPS trip system may be inoperable without resulting in an RPS trip signal.

This Function was not specifically credited in the accident analysis but it is retained for the overall redundancy and diversity of the RPS as required by the NRC approved licensing basis.

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

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

This Function is required to be OPERABLE when the Intermediate Range Monitor Neutron Flux – High High Function is required.

Average Power Range Monitor

The APRM channels provide the primary indication of neutron flux within the core and respond almost instantaneously to neutron flux increases. The APRM channels receive input signals from the local power range monitors (LPRMs) within the reactor core to provide an indication of the power distribution and local power changes. The APRM channels average these LPRM signals to provide a continuous indication of average reactor power from a few percent to greater than RTP. Each APRM channel also includes an Oscillation Power Range Monitor (OPRM) Upscale Function which monitors small groups of LPRM signals to detect thermal-hydraulic instabilities.

The APRM System is divided into four APRM channels and four 2-out-of-4 voter channels. Each APRM channel provides inputs to each of the four voter channels. The four voter channels are divided into two groups of two each; with each group of two providing inputs to one RPS trip system. The system is designed to allow one APRM channel, but no voter channels, to be bypassed. A trip from any one un-bypassed APRM will result in a "half-trip" in all four of the voter channels, but no trip inputs to either RPS trip system. Because APRM trip Functions 2.a, 2.b, 2.c and 2.f are implemented in the same hardware, these trip Functions are combined with APRM Inop trip Function 2.d. Any Function 2.a, 2.b, 2.c or 2.d trip from any two un-bypassed APRM channels will result in a full trip in each of the four voter channels, which in turn results in two trip inputs into each RPS trip system logic channel (A1, A2, B1 and B2). Similarly, any Function 2.d or 2.f trip from any two un-bypassed APRM channels

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

will result in a full trip from each of the four voter channels.

Three of the four APRM channels and all four of the voter channels are required to be OPERABLE to ensure that no single failure will preclude a scram on a valid signal. In addition, to provide adequate coverage of the entire core, consistent with the design bases for the APRM Functions 2.a, 2.b and 2.c, at least 14 LPRM inputs, with at least two LPRM inputs from each of the four axial levels at which the LPRMs are located, must be operable for each APRM channel.

For the OPRM Upscale Function (Function 2.f), LPRMs are assigned to “cells". A minimum of 8 responsive cells, each with a minimum of 2 LPRMs, must be OPERABLE for the OPRM Upscale Function to be OPERABLE (Ref. 25).

2.a. Average Power Range Monitor Neutron Flux – High (Setdown)

For operation at low power (i.e., Mode 2), the Average Power Range Monitor Neutron Flux – High (Setdown) Function is capable of generating a trip signal to prevent fuel damage resulting from abnormal operating transients in this power range. During most operation at low power levels, the Average Power Range Monitor Neutron Flux – High (Setdown) Function will provide a secondary scram to the Intermediate Range Monitor (IRM) Neutron Flux – High Function because of the relative setpoints. When the IRMs are on Range 9 or 10, it is possible that the Average Power Range Monitor Neutron Flux – High (Setdown) Function will provide the primary trip signal for a core wide increase in power.

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

The Allowable Value is based on preventing significant increases in power when THERMAL POWER is ≤ 25% RTP.

The Average Power Range Monitor Neutron Flux – High (Setdown) Function must be OPERABLE during MODE 2 when control rods may be withdrawn because the potential for criticality exists.

In MODE 1, the Average Power Range Monitor Neutron Flux – High Function provides protection against reactivity transients and the RWM and rod block monitor protect against control rod withdrawal error events.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

In accordance with the NRC Safety Evaluation for Amendment 159 (Ref. 24), the Average Power Range Monitor Neutron Flux – High (Setdown) Function is not LSSS SL-related.

2.b. Average Power Range Monitor Simulated Thermal Power – High

The Average Power Range Monitor Simulated Thermal Power – High Function monitors neutron flux to approximate the THERMAL POWER being transferred to the reactor coolant. The APRM neutron flux is electronically filtered with a time constant, representative of the fuel heat transfer dynamics to generate a signal proportional to the THERMAL POWER in the reactor. The trip level is varied as a function of recirculation drive flow (i.e., at lower core flows, the setpoint is reduced proportional to the reduction in power experienced as core flow is reduced with a fixed control rod pattern) but is clamped at an upper limit that is always lower than the Average Power Range Monitor Neutron Flux – High Function Allowable Value.

A note is included, applicable when the plant is in single recirculation loop operation per LCO 3.4.1, which requires reducing by Delta W the flow value used in the Allowable Value equation. The value of Delta W is defined in the COLR. The value of Delta W is established to conservatively bound the inaccuracy created in the core flow/drive flow correlation due to back flow in the jet pumps associated with the inactive recirculation loop. This adjusted Allowable Value thus maintains thermal margins essentially unchanged from those for two-loop operation.

No specific safety analyses take credit for the Average Power Range Monitor Simulated Thermal Power – High Function, however it provides protection against transients where THERMAL POWER increases slowly (such as the loss of feedwater heating event) and therefore mitigates over-power and delta CPR for such events. During these events, the THERMAL POWER increase does not significantly lag the neutron flux response and, because of a lower trip setpoint, will initiate a scram before the high neutron flux scram. For rapid neutron flux increase events, the THERMAL POWER lags the neutron flux and the Average Power Range Monitor Neutron Flux – High Function will provide a scram signal before the Average Power Range Monitor Simulated Thermal Power – High Function setpoint is exceeded.

Each APRM channel uses one total drive flow signal representative of total core flow. The total drive flow signal is generated by the flow processing logic, part of the APRM channel, by summing up the flow calculated from two flow transmitter signal inputs, one from each of the two recirculation loop flows. The flow processing logic OPERABILITY is part of the APRM channel OPERABILITY requirements for this Function.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Although no specific safety analyses take credit for the clamped Allowable Value at Monticello, it is based on analyses that do take credit for the Average Power Range Monitor Simulated Thermal Power – High Function for the mitigation of the loss of feedwater heating event. The THERMAL POWER time constant of < 7 seconds is based on the fuel heat transfer dynamics and provides a signal proportional to the THERMAL POWER.

The Average Power Range Monitor Simulated Thermal Power – High Function is required to be OPERABLE in MODE 1 when there is the possibility of generating excessive THERMAL POWER.

In accordance with the NRC Safety Evaluation for Amendment 159 (Ref. 24), the Average Power Range Monitor Simulated Thermal Power – High Function is not LSSS SL-related.

Automated Backup Stability Protection (BSP)

When Oscillation Power Range Monitor (OPRM) Upscale (Function 2.f) trip capability is not maintained, alternate backup stability protection is required in accordance with Action I.2. An Automated BSP Scram Region (see Section 7.4 of Reference 18) is implemented to prevent entry into the region of the power and flow-operating map susceptible to reactor instability. Modified Average Power Range Monitor Simulated Thermal Power – High scram setpoints initiate a reactor trip for flow reduction events that would terminate in the Manual BSP Region I. The Automated BSP Scram Region ensures an early scram to provide protection from exceeding the fuel MCPR safety limit (SL) due to anticipated thermal-hydraulic power oscillations.

2.c. Average Power Range Monitor Neutron Flux – High

The Average Power Range Monitor Neutron Flux – High Function is capable of generating a trip signal to prevent fuel damage or excessive RCS pressure. For the overpressurization protection analysis of Reference 9, high neutron flux is assumed to terminate the main steam isolation valve (MSIV) closure event and, along with the safety/relief valves (SRVs), limits the peak reactor pressure vessel (RPV) pressure to less than the ASME Code limits. The control rod drop accident (CRDA) analysis (Ref. 10) takes credit for high neutron flux to terminate the CRDA.

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

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The Average Power Range Monitor Neutron Flux – High Function is required to be OPERABLE in MODE 1 where the potential consequences of the analyzed transients could result in the SLs (e.g., MCPR and RCS pressure) being exceeded. Although the Average Power Range Monitor Neutron Flux – High Function is functional in MODE 2, the Average

Power Range Monitor Neutron Flux – High (Setdown) Function conservatively bounds the assumed trip and, together with the assumed IRM trips, provides adequate protection. Therefore, the Average Power Range Monitor Neutron Flux – High Function is not required in MODE 2.

In accordance with the guidance of Regulatory Issue Summary 2006-17 (Ref. 23) and the NRC Safety Evaluation for Amendment 159 (Ref. 24), the Average Power Range Monitor Neutron Flux – High Function is LSSS SL-related.

2.d. Average Power Range Monitor – Inop

Three of the four APRM channels are required to be OPERABLE for each of the APRM Functions. This Function (Inop) provides assurance that the minimum numbers of APRM channels are OPERABLE.

For any APRM channel, any time its mode switch is in any position other than “Operate,” an APRM module is unplugged, or the automatic self-test system detects a critical fault with the APRM channel, an Inop trip is sent to all four voter channels. Inop trips from two or more unbypassed APRM channels result in a trip output from all four voter channels to their associated trip system.

This Function was not specifically credited in the accident analysis, but it is retained for the overall redundancy and diversity of the RPS as required by the NRC approved licensing basis.

There is no Allowable Value for this Function.

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

2.e. 2-Out-Of-4 Voter

The 2-Out-Of-4 Voter Function provides the interface between the APRM Functions, including the OPRM Upscale Function, and the final RPS trip system logic. As such, it is required to be OPERABLE in the MODES where the APRM Functions are required and is necessary to support the safety analysis applicable to each of those Functions. Therefore, the 2-Out-Of-4 Voter Function needs to be OPERABLE in MODES 1 and 2.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

All four voter channels are required to be OPERABLE. Each voter channel includes self-diagnostic functions. If any voter channel detects a critical fault in its own processing, a trip is issued from that voter channel to the associated trip system.

The 2-Out-Of-4 Voter Function votes APRM Functions 2.a, 2.b and 2.c independently of Function 2.f. This voting is accomplished by the 2-Out-Of-4 Voter hardware in the Two-Out-Of-Four Logic Module. The voter also includes separate outputs to RPS for the two independently voted sets of Functions, each of which is redundant (four total outputs). The voter Function 2.e must be declared inoperable if any of its functionality is inoperable. However, due to the independent voting of APRM trips, and the redundancy of outputs, there may be conditions where the voter Function 2.e is inoperable, but trip capability for one or more of the other APRM Functions through that voter is still maintained. This may be considered when determining the condition of other APRM Functions resulting from partial inoperability of the 2-Out-Of-4 Voter Function 2.e.

There is no Allowable Value for this Function.

<u>2.f. Oscillation Power Range Monitor (OPRM Upscale)</u>

The OPRM Upscale Function provides compliance with GDC 10 and GDC 12, thereby providing protection from exceeding the fuel MCPR safety limit (SL) due to anticipated thermal-hydraulic power oscillations.

Reference 18 describes the Detect and Suppress – Confirmation Density (DSS-CD) long-term stability solution and the licensing basis Confirmation Density Algorithm (CDA). Use of DSS-CD was approved by Amendment 180 (Ref. 31). There are three additional algorithms for detecting thermal-hydraulic instability related neutron flux oscillations: the period based detection algorithm (PBDA), the amplitude based algorithm (ABA), and the growth rate algorithm (GRA) are implemented in the OPRM Upscale Function, but the safety analysis takes credit only for the CDA. The remaining three algorithms provide defense in depth and additional protection against unanticipated oscillations. OPRM Upscale Function OPERABILITY for Technical Specification purposes is based only on the CDA.

The OPRM Upscale Function receives input signals from the local power range monitors (LPRMs) within the reactor core, which are combined into “cells” for evaluation by the OPRM algorithms.

DSS-CD operability requires at least 8 responsive OPRM cells per channel.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The OPRM Upscale Function is required to be OPERABLE when the plant is ≥ 20% RTP, which is established as a power level that is greater than or equal to 5% below the lower boundary of the Armed Region. This requirement is designed to encompass the region of power-flow operation where anticipated events could lead to thermal-hydraulic instability and related neutron flux oscillations. The OPRM Upscale Function is automatically trip-enabled when THERMAL POWER, as indicated by the APRM Simulated Thermal Power, is ≥ 25% RTP corresponding to the plant specific MCPR monitoring threshold and reactor recirculation drive flow, is less than 75% of rated flow. This region is the OPRM Armed Region. Note e allows for entry into the DSS-CD Armed Region without automatic arming of DSS-CD prior to completely passing though the DSS-CD Armed Region during both a single startup and a single shutdown following DSS-CD implementation. Note e reflects the need for plant data collection in order to test the DSS-CD equipment. Testing the DSS-CD equipment ensures its proper operation and prevents spurious reactor trips. Entry into the DSS-CD Armed Region without automatic arming of DSS-CD during this initial testing phase also allows for changes in plant operations to address maintenance or other operational needs. However, during this initial testing period, the OPRM upscale function is OPERABLE and DSS-CD operability and capability to automatically arm shall be maintained at recirculation drive flow rates above the DSS-CD Armed Region flow boundary.

An OPRM Upscale trip is issued from an OPRM channel when the confirmation density algorithm in that channel detects oscillatory changes in the neutron flux, indicated by period confirmations and amplitude exceeding specified setpoints for a specified number of OPRM cells in the channel. An OPRM Upscale trip is also issued from the channel if any of the defense-in-depth algorithms (PBDA, ABA, GRA) exceed its trip condition for one or more cells in that channel.

Three of the four channels are required to be operable. Each channel is capable of detecting thermal-hydraulic instabilities, by detecting the related neutron flux oscillations, and issuing a trip signal before the MCPR SL is exceeded. There is no allowable value for this function.

The OPRM Upscale settings are not traditional instrumentation setpoints determined under an instrument setpoint methodology. In accordance with the NRC Safety Evaluation for Amendment 159 (Ref. 24), the OPRM Upscale Function is not LSSS SL-related and Reference 26 confirms that the OPRM Upscale Function settings based on DSS-CD also do not have traditional instrumentation setpoints determined under an instrument's setpoint methodology.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

3. Reactor Vessel Steam Dome Pressure – High

An increase in the RPV pressure during reactor operation compresses the steam voids and results in a positive reactivity insertion. This causes the neutron flux and THERMAL POWER transferred to the reactor coolant to increase, which could challenge the integrity of the fuel cladding and the RCPB. No specific safety analysis takes direct credit for this Function. However, the Reactor Vessel Steam Dome Pressure – High Function initiates a scram for transients that results in a pressure increase, counteracting the pressure increase by rapidly reducing core power. For the overpressurization protection analysis of Reference 9, reactor scram (the analyses conservatively assume scram on the Average Power Range Monitor Neutron Flux – High signal, not the Reactor Vessel Steam Dome Pressure – High signal), along with the S/RVs, limits the peak RPV pressure to less than the ASME Section III Code limits.

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

Four channels of Reactor Vessel Steam Dome Pressure – High Function, with two channels in each trip system arranged in a one-out-of-two logic, are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from this Function on a valid signal. The Function is required to be OPERABLE in MODES 1 and 2 when the RCS is pressurized and the potential for pressure increase exists.

4. Reactor Vessel Water Level – Low

Low RPV water level indicates the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. Therefore, a reactor scram is initiated at this level to substantially reduce the heat generated in the fuel from fission. The Reactor Vessel Water Level – Low Function is not assumed in the analysis of the recirculation line break (Ref. 11) since the scram occurs in the beginning of the event due to the loss of offsite power. However, analyses have been performed that indicate that the difference between a scram initiated at the beginning of the event and a scram initiated by Reactor Vessel Water Level – Low is negligible. The reactor scram reduces the amount of energy required to be absorbed and, along with the actions of the Emergency Core Cooling Systems (ECCS), ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Reactor Vessel Water Level – Low signals are initiated from four level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel.

Four channels of Reactor Vessel Water Level – Low Function, with two channels in each trip system arranged in a one-out-of-two logic, are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from this Function on a valid signal.

The Reactor Vessel Water Level – Low Allowable Value is selected to ensure that for transients involving loss of all normal feedwater flow, initiation of the low pressure ECCS subsystems at Reactor Vessel Water Level – Low Low will not be required.

The Function is required in MODES 1 and 2 where considerable energy exists in the RCS resulting in the limiting transients and accidents. ECCS initiations at Reactor Vessel Water Level – Low Low provide sufficient protection for level transients in all other MODES.

5. Main Steam Isolation Valve – Closure

MSIV closure results in loss of the main turbine and the condenser as a heat sink for the nuclear steam supply system and indicates a need to shut down the reactor to reduce heat generation. Therefore, a reactor scram is initiated on a Main Steam Isolation Valve – Closure signal before the MSIVs are completely closed in anticipation of the complete loss of the normal heat sink and subsequent overpressurization transient. However, for the overpressurization protection analysis of Reference 9, the Average Power Range Monitor Neutron Flux – High Function, along with the S/RVs, limits the peak RPV pressure to less than the ASME Code limits. That is, the direct scram on position switches for MSIV closure events is not assumed in the overpressurization analysis. Additionally, MSIV closure is assumed in the main steam line break accident analyzed in Reference 12. The reactor scram reduces the amount of energy required to be absorbed and, along with the actions of the ECCS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

MSIV closure signals are initiated from position switches located on each of the eight MSIVs. Each MSIV has two position switches; one inputs to RPS trip system A while the other inputs to RPS trip system B. Thus, each RPS trip system receives an input from eight Main Steam Isolation Valve – Closure channels, each consisting of one position switch. The logic for the Main Steam Isolation Valve – Closure Function is arranged

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

such that either the inboard or outboard valve on three or more of the main steam lines must close in order for a scram to occur.

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

Sixteen channels of the Main Steam Isolation Valve – Closure Function, with eight channels in each trip system, are required to be OPERABLE to ensure that no single instrument failure will preclude the scram from this Function on a valid signal. This Function is only required in MODE 1 and MODE 2 with reactor pressure $\geq$ 600 psig since, with the MSIVs open and the heat generation rate high, a pressurization transient can occur if the MSIVs close. In MODE 2 with reactor pressure < 600 psig, the heat generation rate is low enough so that the other diverse RPS functions provide sufficient protection. This Function is automatically bypassed when the reactor mode switch is in a position other than run and the reactor pressure is < 600 psig.

6. Drywell Pressure – High

High pressure in the drywell could indicate a break in the RCPB. A reactor scram is initiated to minimize the possibility of fuel damage and to reduce the amount of energy being added to the coolant and the drywell. The Drywell Pressure – High Function is a secondary scram signal to Reactor Vessel Water Level – Low for LOCA events inside the drywell. However, no credit is taken for a scram initiated from this Function for any of the DBAs analyzed in the USAR. This Function was not specifically credited in the accident analysis, but it is retained for the overall redundancy and diversity of the RPS as required by the NRC approved licensing basis.

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

Four channels of Drywell Pressure – High Function, with two channels in each trip system arranged in a one-out-of-two logic, are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from this Function on a valid signal. The Function is required in MODES 1 and 2 where considerable energy exists in the RCS, resulting in the limiting transients and accidents.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

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

The SDV receives the water displaced by the motion of the CRD pistons during a reactor scram. Should this volume fill to a point where there is insufficient volume to accept the displaced water, control rod insertion would be hindered. Therefore, a reactor scram is initiated while the remaining free volume is still sufficient to accommodate the water from a full core scram. The two types of Scram Discharge Volume Water Level – High Functions are an input to the RPS logic. No credit is taken for a scram initiated from these Functions for any of the design basis accidents or transients analyzed in the USAR. However, they are retained to ensure the RPS remains OPERABLE.

SDV water level is measured by two diverse methods. The level in each of the two SDVs is measured by two float type level switches and two thermal probes for a total of eight level signals. The outputs of these devices are arranged so that there is a signal from a level switch and a thermal probe to each RPS logic channel. The level measurement instrumentation satisfies the recommendations of Reference 13.

The Allowable Value is chosen low enough to ensure that there is sufficient volume in the SDV to accommodate the water from a full scram.

The Allowable Value refers to the volume of water in the discharge volume receiver tank and does not include the volume in the lines to the level switches.

Four channels of each type of Scram Discharge Volume Water Level – High Function, with two channels of each type in each trip system, are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from these Functions on a valid signal. These Functions are required in MODES 1 and 2, and in MODE 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies, since these are the MODES and other specified conditions when control rods are withdrawn. At all other times, this Function may be bypassed.

8. Turbine Stop Valve – Closure

Closure of the TSVs results in the loss of a heat sink that produces reactor pressure, neutron flux, and heat flux transients that must be limited. Therefore, a reactor scram is initiated at the start of TSV closure in anticipation of the transients that would result from the closure of these valves. The Turbine Stop Valve – Closure Function is the primary scram signal for the turbine trip event analyzed in Reference 14. For this event,

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

the reactor scram reduces the amount of energy required to be absorbed and ensures that the MCPR SL is not exceeded.

Turbine Stop Valve – Closure signals are initiated from position switches located on each of the four TSVs. One position switch and two independent contacts are associated with each stop valve. One of the two contacts provides input to RPS trip system A; the other, to RPS trip system B. Thus, each RPS trip system receives an input from four Turbine Stop Valve – Closure channels, each consisting of one position switch. The logic for the Turbine Stop Valve – Closure Function is such that three or more TSVs must be closed to produce a scram. This Function must be enabled at THERMAL POWER > 40% RTP (Refs. 29 and 30). This is normally accomplished automatically by pressure switches sensing turbine first stage pressure. The pressure switches are normally adjusted lower (26.6% RTP – Refs. 29 and 30) to account for the turbine bypass valves being opened, such that approximately 11.5% of rated steam flow (Refs. 27 and 30) is being passed directly to the condenser.

The Turbine Stop Valve – Closure Allowable Value is selected to be high enough to detect imminent TSV closure, thereby reducing the severity of the subsequent pressure transient.

Eight channels of Turbine Stop Valve – Closure Function, with four channels in each trip system, are required to be OPERABLE to ensure that no single instrument failure will preclude a scram from this Function even if one TSV should fail to close. This Function is required, consistent with analysis assumptions, whenever THERMAL POWER is > 40% RTP. This Function is not required when THERMAL POWER is ≤ 40% RTP since the Reactor Vessel Steam Dome Pressure – High and the Average Power Range Monitor Neutron Flux – High Functions are adequate to maintain the necessary safety margins.

9. Turbine Control Valve Fast Closure, Acceleration Relay Oil Pressure – Low

Fast closure of the TCVs results in the loss of a heat sink that produces reactor pressure, neutron flux, and heat flux transients that must be limited. Therefore, a reactor scram is initiated on TCV fast closure in anticipation of the transients that would result from the closure of these valves. The Turbine Control Valve Fast Closure, Acceleration Relay Oil Pressure – Low Function is the primary scram signal for the generator load rejection event analyzed in Reference 15. For this event, the reactor scram reduces the amount of energy required to be absorbed and ensures that the MCPR SL is not exceeded.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Turbine Control Valve Fast Closure, Acceleration Relay Oil Pressure – Low signals are initiated by loss of oil pressure at the acceleration relay. Two pressure switches are mounted on one pressure tap while two other pressure switches are mounted at a distance on another pressure tap. The pressure switches associated with one pressure tap are assigned to different RPS trip systems. This Function must be enabled at THERMAL POWER > 40% RTP (Refs. 29 and 30). This is normally accomplished automatically by pressure switches sensing turbine first stage pressure. The pressure switches are normally adjusted lower (26.6% RTP – Refs. 29 and 30) to account for the turbine bypass valves being opened, such that approximately 11.5% of rated steam flow (Refs. 27 and 30) is being passed directly to the condenser.

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

Four channels of Turbine Control Valve Fast Closure, Acceleration Relay 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 > 40% RTP. This Function is not required when THERMAL POWER is ≤ 40% RTP, since the Reactor Vessel Steam Dome Pressure – High and the Average Power Range Monitor Neutron Flux – High Functions are adequate to maintain the necessary safety margins.

10. Reactor Mode Switch – Shutdown Position

The Reactor Mode Switch – Shutdown Position Function provides signals, via the two manual scram logic channels (A3 and B3), which are redundant to the automatic protective instrumentation channels and provide manual reactor trip capability. This Function was not specifically credited in the accident analysis, but it is retained for the overall redundancy and diversity of the RPS as required by the NRC approved licensing basis.

The reactor mode switch is a single switch with two channels, each of which provides input into one of the two manual scram logic channels.

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

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Two channels of Reactor Mode Switch – Shutdown Position Function, with one channel in each trip system, are available and required to be OPERABLE. The Reactor Mode Switch – Shutdown Position Function is required to be OPERABLE in MODES 1 and 2, and MODE 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies, since these are the MODES and other specified conditions when control rods are withdrawn.

11. Manual Scram

The Manual Scram push button channels provide signals, via the two manual scram logic channels (A3 and B3), which are redundant to the automatic protective instrumentation channels and provide manual reactor trip capability. This Function was not specifically credited in the accident analysis but it is retained for the overall redundancy and diversity of the RPS as required by the NRC approved licensing basis.

There is one Manual Scram push button channel for each of the two manual scram logic channels. In order to cause a scram it is necessary that both channels be actuated.

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

Two channels of Manual Scram with one channel in each trip system are available and required to be OPERABLE in MODES 1 and 2, and in MODE 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies, since these are the MODES and other specified conditions when control rods are withdrawn.

ACTIONS

Note 1 has been provided to modify the ACTIONS related to RPS instrumentation channels. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition, discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable RPS instrumentation channels provide appropriate compensatory measures for separate inoperable channels. As such, Note 1 has been provided that allows separate Condition entry for each inoperable RPS instrumentation channel.

BASES

ACTIONS (continued)

Note 2 has been provided to modify the ACTIONS for the RPS instrumentation functions of APRM Flow Biased Simulated Thermal Power – Upscale (Function 2.b) and APRM Fixed Neutron Flux – High (Function 2.c) such that an APRM that is not within the limit of SR 3.3.1.1.2 has a specified restoration period before declaring the associated APRM inoperable (Ref. 28). Therefore, Note 2 allows delaying the entry into associated Conditions and Required Actions to be delayed up to 2 hours if the APRM is indicating a lower power value than the calculated power (non-conservative), and for up to 12 hours if the APRM is indicating a higher power value than the calculated power (conservative).

Prior to expiration of the time allotted by the note, the absolute difference between the channel and calculated power is required to be restored to within the limit of SR 3.3.1.1.2 (≤ 2% RTP) or the applicable Condition entered and Required Actions taken. This note is based on the time required to perform APRM adjustments on multiple channels and the impact on safety; additional time is allowed when the APRM is indicating a higher power value than the calculated power, i.e., out of limits but conservative.

A.1 and A.2

Because of the diversity of sensors available to provide trip signals and the redundancy of the RPS design, an allowable out of service time of 12 hours has been shown to be acceptable (Ref. 16) to permit restoration of any inoperable channel to OPERABLE status. However, this out of service time is only acceptable provided the associated Function's inoperable channel is in one trip system and the Function still maintains RPS trip capability (refer to Required Actions B.1, B.2 and C.1 Bases). If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel or the associated trip system must be placed in the tripped condition per Required Actions A.1 and A.2. Placing the inoperable channel in trip (or the associated trip system in trip) would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. Alternatively, if it is not desired to place the channel (or trip system) in trip (e.g., as in the case where placing the inoperable channel in trip would result in a full scram), Condition D must be entered and its Required Action taken. The 12 hour allowance is not allowed for Reactor Mode Switch – Shutdown Position Function and Manual Scram Function channels since with one channel inoperable RPS trip capability is not maintained. In this case, Condition C must be entered and its Required Actions taken.

BASES

ACTIONS (continued)

As noted, Action A.2 is not applicable for APRM Functions 2.a, 2.b, 2.c, 2.d or 2.f. Inoperability of one required APRM channel affects both trip systems. For that condition, Required Action A.1 must be satisfied, and is the only action (other than restoring operability) that will restore capability to accommodate a single failure. Inoperability of more than one required APRM channel of the same trip function results in loss of trip capability and entry into Condition C, as well as entry into Condition A for each channel.

B.1 and B.2

Condition B exists when, for any one or more Functions, at least one required channel is inoperable in each trip system. In this condition, provided at least one channel per trip system is OPERABLE, the RPS still maintains trip capability for that Function, but cannot accommodate a single failure in either trip system.

Required Actions B.1 and B.2 limit the time the RPS scram logic, for any Function, would not accommodate single failure in either trip system (e.g., one-out-of-one and one-out-of-one arrangement for a typical four channel Function). The reduced reliability of this logic arrangement was not evaluated in Reference 16 for the 12 hour Completion Time. Within the 6 hour allowance, the associated Function will have all required channels OPERABLE or in trip (or any combination) in one trip system.

Completing one of these Required Actions restores RPS to a reliability level equivalent to that evaluated in Reference 16, which justified a 12 hour allowable out of service time as presented in Condition A. The trip system in the more degraded state should be placed in trip or, alternatively, all the inoperable channels in that trip system should be placed in trip (e.g., a trip system with two inoperable channels could be in a more degraded state than a trip system with four inoperable channels if the two inoperable channels are in the same Function while the four inoperable channels are all in different Functions). The decision of which trip system is in the more degraded state should be based on prudent judgment and take into account current plant conditions (i.e., what MODE the plant is in). If this action would result in a scram, it is permissible to place the other trip system or its inoperable channels in trip.

The 6 hour Completion Time is judged acceptable based on the remaining capability to trip, the diversity of the sensors available to provide the trip signals, the low probability of extensive numbers of inoperabilities affecting all diverse Functions, and the low probability of an event requiring the initiation of a scram.

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ACTIONS (continued)

Alternately, if it is not desired to place the inoperable channels (or one trip system) in trip (e.g., as in the case where placing the inoperable channel or associated trip system in trip would result in a scram, Condition D must be entered and its Required Action taken. The 6 hour allowance is not allowed for Reactor Mode Switch – Shutdown Position Function and Manual Scram Function channels since with two channels inoperable RPS trip capability is not maintained. In this case, Condition C must be entered and its Required Action taken.

As noted, Condition B is not applicable for APRM Functions 2.a, 2.b, 2.c, 2.d or 2.f. Inoperability of an APRM channel affects both trip systems and is not associated with a specific trip system as are the APRM 2-out-of-4 voter and other non-APRM channels for which Condition B applies. For an inoperable APRM channel, Required Action A.1 must be satisfied, and is the only action (other than restoring OPERABILITY) that will restore capability to accommodate a single failure. Inoperability of a Function in more than one required APRM channel results in loss of trip capability for that Function and entry into Condition C, as well as entry into Condition A for each channel. Because Conditions A and C provide Required Actions that are appropriate for the inoperability of APRM Functions 2.a, 2.b, 2.c, 2.d or 2.f, and these functions are not associated with specific trip systems as are the APRM 2-out-of-4 voter and other non-APRM channels, Condition B does not apply.

<u>C.1</u>

Required Action C.1 is intended to ensure that appropriate actions are taken if one or more inoperable, untripped channels within the same trip system for the same Function result in the Function not maintaining RPS trip capability. A Function is considered to be maintaining RPS trip capability when sufficient channels are OPERABLE or in trip (or the associated trip system is in trip), such that both trip systems will generate a trip signal from the given Function on a valid signal. For the typical Function with one-out-of-two taken twice logic and the IRM Functions, this would require both trip systems to have one channel OPERABLE or in trip (or the associated trip system in trip). For Function 5 (Main Steam Isolation Valve – Closure), this would require both trip systems to have each channel associated with the MSIVs in three main steam lines (not necessarily the same main steam lines for both trip systems) OPERABLE or in trip (or the associated trip system in trip). For Function 8 (Turbine Stop Valve – Closure), this would require both trip systems to have three channels, each OPERABLE or in trip (or the associated trip system in trip). For Function 10 (Reactor Mode Switch – Shutdown Position) and Function 11 (Manual Scram), since each trip system only has one

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ACTIONS (continued)

channel for each Function, with a channel inoperable, RPS trip capability is not maintained.

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

D.1

Required Action D.1 directs entry into the appropriate Condition referenced in Table 3.3.1.1-1. The applicable Condition specified in the Table is Function and MODE or other specified condition dependent and may change as the Required Action of a previous Condition is completed. Each time an inoperable channel has not met any Required Action of Condition A, B, or C and the associated Completion Time has expired, Condition D will be entered for that channel and provides for transfer to the appropriate subsequent Condition.

E.1, F.1, G.1 and J.1

If the channel(s) is not restored to OPERABLE status or placed in trip (or the associated trip system placed in trip) within the allowed Completion Time, the plant must be placed in a MODE or other specified condition in which the LCO does not apply. The allowed Completion Times are reasonable, based on operating experience, to reach the specified condition from full power conditions in an orderly manner and without challenging plant systems. In addition, the Completion Time of Required Actions E.1 and J.1 are consistent with the Completion Time provided in LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)."

H.1

If the channel(s) is not restored to OPERABLE status or placed in trip (or the associated trip system placed in trip) within the allowed Completion Time, the plant must be placed in a MODE or other specified condition in which the LCO does not apply. This is done by immediately initiating action to fully insert all insertable control rods in core cells containing one or more fuel assemblies. Control rods in core cells containing no fuel assemblies do not affect the reactivity of the core and are, therefore, not required to be inserted. Action must continue until all insertable control rods in core cells containing one or more fuel assemblies are fully inserted.

BASES

ACTIONS (continued)

I.1

If OPRM Upscale trip capability is not maintained, Condition I exists and Backup Stability Protection (BSP) is required. The Manual BSP Regions are described in Reference 18. The Manual BSP Regions are procedurally established consistent with the guidelines identified in Reference 18 and require specified manual operator actions if certain predefined operational conditions occur. The Completion Time of immediate is based on the importance of limiting the period of time during which no automatic or alternate detect and suppress trip capability is in place. Use of BSP was approved by Amendment 180 (Ref. 31).

I.2 and I.3

Actions I.2 and I.3 are both required to be taken in conjunction with Action I.1 if OPRM Upscale trip capability is not maintained. As described in Section 7.4 of Reference 18, the Automated BSP Scram Region is designed to avoid reactor instability by automatically preventing entry into the region of the power and flow-operating map that is susceptible to reactor instability. The reactor trip would be initiated by the modified APRM STP scram setpoints for flow reduction events that would have terminated in the Manual BSP Region I. The Automated BSP Scram Region ensures an early scram and SLMCPR protection.

The Completion Time of 12 hours to complete the specified actions is reasonable, based on operational experience, and based on the importance of restoring an automatic reactor trip for thermal hydraulic instability events.

Backup Stability Protection is intended as a temporary means to protect against thermal-hydraulic instability events. The reporting requirements of Specification 5.6.6 document the corrective actions and schedule to restore the required channels to an OPERABLE status. The Completion Time of immediately directs that action be taken in accordance with Specification 5.6.6 to evaluate the cause of the inoperability and to determine the appropriate corrective actions and schedule to restore the required channels to OPERABLE status.

BASES

ACTIONS (continued)

J.1

If the Required Actions I are not completed within the associated Completion Times, then Action J is required. The Bases for the Manual BSP Regions and associated Completion Time are addressed in the Bases for I.1. The Manual BSP Regions are required in conjunction with the BSP Boundary.

J.2

The BSP Boundary, as described in Section 7.3 of Reference 18, defines an operating domain where potential instability events can be effectively addressed by the specified BSP manual operator actions. The BSP Boundary is constructed such that the immediate final statepoint for a flow reduction event initiated from this boundary and terminated at the core natural circulation line (NCL) would not exceed the Manual BSP Region I stability criterion. Potential instabilities would develop slowly as a result of the feedwater temperature transient (Reference 18).

The Completion Time of 12 hours to complete the specified actions is reasonable, based on operational experience, to reach the specific condition from full power conditions in an orderly manner and without challenging plant system.

J.3

Backup Stability Protection (BSP) is a temporary means for protection against thermal-hydraulic instability events. An extended period of inoperability without automatic trip capability is not justified. Consequently, the required channels are required to be restored to OPERABLE status within 120 days.

Based on engineering judgment, the likelihood of an instability event that could not be adequately handled by the use of the BSP Regions (see Action J.1) and the BSP Boundary (see J.2) during a 120-day period is negligibly small. The 120-day period is intended to allow for the case where limited design changes or extensive analysis might be required to understand or correct some unanticipated characteristic of the instability detection algorithms or equipment. This action is not intended and was not evaluated as a routine alternative to returning failed or inoperable equipment to OPERABLE status. Correction of routine equipment failure or inoperability is expected to normally be accomplished within the completion times allowed for Actions for Conditions A and B.

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ACTIONS (continued)

A Note is provided to indicate that LCO 3.0.4 is not applicable. The intent of the note is to allow plant startup while operating within the 120-day Completion Time for Required Action J.3. The primary purpose of this exclusion is to allow an orderly completion of design and verification activities, in the event of a required design change, without undue impact on plant operation.

K.1

If the required channels are not restored to OPERABLE status and the Required Actions of J are not met within the associated Completion Times, then the plant must be placed in an operating condition in which the LCO does not apply. To achieve this status, the THERMAL POWER must be reduced to less than 20% RTP within 4 hours. The allowed Completion Time is reasonable, based on operating experience, to reach the specified operating power level from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

As noted at the beginning of the SRs, the SRs for each RPS instrumentation Function are located in the SRs column of Table 3.3.1.1-1.

The Surveillances are modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours, provided the associated Function maintains RPS trip capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the reliability analysis (Ref. 16) assumption of the average time required to perform channel Surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that the RPS will trip when necessary.

SR 3.3.1.1.1

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

BASES

SURVEILLANCE REQUIREMENTS (continued)

channels could be an indication of excessive instrument drift in one of the channels or something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

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

The Frequency is based upon operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the channels required by the LCO.

SR 3.3.1.1.2

To ensure that the APRMs are accurately indicating the true core average power, the APRMs are calibrated to the reactor power calculated from a heat balance. The Frequency of once per 7 days is based on minor changes in LPRM sensitivity, which could affect the APRM reading between performances of SR 3.3.1.1.6.

A restriction to satisfying this SR when < 25% RTP is provided that requires the SR to be met only at ≥ 25% RTP because it is difficult to accurately maintain APRM indication of core THERMAL POWER consistent with a heat balance when < 25% RTP. At low power levels, a high degree of accuracy is unnecessary because of the large, inherent margin to thermal limits (MCPR and APLHGR). At ≥ 25% RTP, the Surveillance is required to have been satisfactorily performed within the last 7 days, in accordance with SR 3.0.2. A Note is provided which allows an increase in THERMAL POWER above 25% if the 7 day Frequency is not met per SR 3.0.2. In this event, the SR must be performed within 12 hours after reaching or exceeding 25% RTP. Twelve hours is based on operating experience and in consideration of providing a reasonable time in which to complete the SR.

SR 3.3.1.1.3

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL

BASES

SURVEILLANCE REQUIREMENTS (continued)

TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specification tests at least once per refueling interval with applicable extensions.

Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

As noted, SR 3.3.1.1.3 is not required to be performed when entering MODE 2 from MODE 1, since testing of the MODE 2 required IRM Functions cannot be performed in MODE 1 without utilizing jumpers, lifted leads, or movable links. This allows entry into MODE 2 if the 7 day Frequency is not met per SR 3.0.2. In this event, the SR must be performed within 12 hours after entering MODE 2 from MODE 1. Twelve hours is based on operating experience and in consideration of providing a reasonable time in which to complete the SR.

A Frequency of 7 days provides an acceptable level of system average unavailability over the Frequency interval and is based on reliability analysis (Ref. 16).

SR 3.3.1.1.4

A functional test of each automatic scram contactor is performed to ensure that each automatic RPS logic channel will perform the intended function. There are four RPS channel test switches, one associated with each of the four automatic trip channels (A1, A2, B1 and B2). These test switches allow the operator to test the OPERABILITY of the individual trip logic channel automatic scram contactors as an alternative to using an automatic scram function trip. This is accomplished by placing the RPS channel test switch in the test position, which will input a trip signal into the associated RPS logic channel. The RPS channel test switches are not credited in the accident analysis, they just provide a method to test the automatic scram contactors. The Manual Scram Functions are not configured the same as the generic model used in Reference 16. However, Reference 16 concluded that the Surveillance Frequency extensions for RPS Functions were not affected by the difference in configuration since each automatic RPS logic channel has a test switch that is functionally the same as the manual scram switches in the generic model. As such, a functional test of each RPS automatic scram contactor using either its associated test switch or by test of any of the associated automatic RPS Functions is required to be performed once every 7 days. The Frequency of 7 days is based on the reliability analysis of Reference 16.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.1.5

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification and non-Technical Specification tests at least once per refueling interval with applicable extensions. The 31 day Frequency is based on engineering judgment, operating experience, and reliability of this instrumentation.

SR 3.3.1.1.6

LPRM gain settings are determined from the local flux profiles measured by the Traversing Incore Probe (TIP) System. This establishes the relative local flux profile for appropriate representative input to the APRM System. The 1000 MWD/T Frequency (Ref. 30) is based on operating experience with LPRM sensitivity changes.

SR 3.3.1.1.7 and SR 3.3.1.1.10

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specification and non-Technical Specification tests at least once per refueling interval with applicable extensions. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology. The CHANNEL FUNCTIONAL TEST (SR 3.3.1.1.10) for the Reactor Mode Switch – Shutdown Position channels will be performed by placing the reactor mode switch in the shutdown position.

The 92 day Frequency of SR 3.3.1.1.7 is based on the reliability analysis of Reference 16. The 24 month Frequency of SR 3.3.1.1.10 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.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.1.8

Calibration of trip units provides a check of the actual trip setpoints. The channel must be declared inoperable if the trip setting is discovered to be less conservative than the Allowable Value specified in Table 3.3.1.1-1. If the trip setting is discovered to be less conservative than accounted for in the appropriate setpoint methodology, but is not beyond the Allowable Value, the channel performance is still within the requirements of the plant safety analysis. Under these conditions, the setpoint must be readjusted to be equal to or more conservative than accounted for in the appropriate setpoint methodology.

The Frequency of 92 days is based on the reliability analysis of Reference 16.

SR 3.3.1.1.9 and SR 3.3.1.1.11

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. For the APRM Simulated Thermal Power - High Function, this SR also includes calibrating the associated recirculation loop flow channel.

Note 1 to SR 3.3.1.1.11 state that neutron detectors are excluded from CHANNEL CALIBRATION because they are passive devices, with minimal drift, and because of the difficulty of simulating a meaningful signal. Changes in APRM neutron detector sensitivity are compensated for by performing the 7 day calorimetric calibration (SR 3.3.1.1.2) and the 1000 MWD/T LPRM calibration (Ref. 30) against the TIPs (SR 3.3.1.1.6). Note 2 to SR 3.3.1.1.11 requires the IRM SRs to be performed within 12 hours of entering MODE 2 from MODE 1. This Note allows entry into MODE 2 from MODE 1 if the associated Frequency is not met per SR 3.0.2. Twelve hours is based on operating experience and in consideration of providing a reasonable time in which to complete the SR. Note 3 is added to SR 3.3.1.1.11 to clarify that the recirculation flow transmitters that feed the APRMs are included in the CHANNEL CALIBRATION.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The Frequency of SR 3.3.1.1.9 is based upon the assumption of a 92 day calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis. The Frequency of SR 3.3.1.1.11 is based upon the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis. The Frequency of SR 3.3.1.1.11 for the APRM / OPRM functions is based upon a 24 month calibration interval (Refs. 17 and 21).

SR 3.3.1.1.11 for Function 2.c, APRM Neutron Flux - High, is modified by two Notes. This function was determined by the NRC Safety Evaluation for Amendment 159 (Ref. 24) to be a LSSS for the protection of the reactor core SLs.

Note (f) requires evaluation of channel performance for the condition where the as-found setting for the channel setpoint is not the NTSP but is conservative with respect to the Allowable Value. Evaluation of instrument performance will verify that the instrument will continue to perform in accordance with design basis assumptions. The purpose of the assessment is to ensure confidence in the instrument performance prior to returning the instrument to service. This nonconformance will be entered into the Corrective Action Program. Entry into the Corrective Action Program will ensure required review and documentation of the condition for continued OPERABILITY.

Note (g) requires that the as-left setting for the instrument be returned to the NTSP. If the as-left instrument setting cannot be returned to the NTSP, then the instrument channel shall be declared inoperable. The NTSP and the methodology used to determine the NTSP for the APRM Neutron Flux - High Function, (Function 2.c) in Table 3.3.1.1-1 are specified in Appendix C to the Technical Requirements Manual, a document controlled under 10 CFR 50.59.

SR 3.3.1.1.12

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

The LOGIC SYSTEM FUNCTIONAL TEST for APRM Function 2.e simulates APRM and OPRM trip conditions at the 2-out-of-4 voter channel inputs to check all combinations of two tripped inputs to the 2-out-of-4 logic in the voter channels and APRM related redundant RPS relays.

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SURVEILLANCE REQUIREMENTS (continued)

The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency. The Frequency of SR 3.3.1.1.12 for the APRM 2-Out-Of-4 Voter Function is based upon a 24 month calibration interval (Refs. 17 and 21).

SR 3.3.1.1.13

This SR ensures that scrams initiated from the Turbine Stop Valve - Closure and Turbine Control Valve Fast Closure, Acceleration Relay Oil Pressure - Low Functions will not be inadvertently bypassed when THERMAL POWER is > 40% RTP (Refs. 29 and 30). This involves calibration of the bypass channels. Adequate margins for the instrument setpoint methodologies are incorporated into the actual setpoint. Because main turbine bypass flow can affect this setpoint nonconservatively (THERMAL POWER is derived from turbine first stage pressure), the main turbine bypass valves must remain closed during in-service calibration at THERMAL POWER > 40% RTP (Refs. 29 and 30), if performing the calibration using actual turbine first stage pressure, to ensure that the calibration is valid. The pressure switches are normally adjusted lower (26.6% RTP – Refs. 29 and 30) to account for the turbine bypass valves being opened, such that approximately 11.5% of rated steam flow (Refs. 27 and 30) is being passed directly to the condenser.

If any bypass channel's setpoint is nonconservative (i.e., the Functions are bypassed at > 40% RTP, either due to open main turbine bypass valve(s) or other reasons), then the affected Turbine Stop Valve - Closure and Turbine Control Valve Fast Closure, Acceleration Relay 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.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.1.14

This SR ensures that the individual channel response times are less than or equal to the maximum values assumed in the accident analysis. RPS RESPONSE TIME may be verified by actual response time measurements in any series of sequential, overlapping, or total channel measurements.

The RPS RESPONSE TIME acceptance criterion is 50 milliseconds.

RPS RESPONSE TIME for the APRM 2-Out-Of-4 Voter Function (Function 2.e), includes the output relays of the voter and the associated RPS relays and contactors. (The digital portion of the APRM and 2-out-of-4 voter channels are excluded from RPS RESPONSE TIME testing because self-testing and calibration checks the time base of the digital electronics. Confirmation of the time base is adequate to assure required response times are met. Neutron detectors are excluded from RPS RESPONSE TIME testing because the principles of detector operation virtually ensure an instantaneous response time.)

RPS RESPONSE TIME tests are conducted on a 24 month STAGGERED TEST BASIS. Note 2 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.

APRM and OPRM RESPONSE TIME tests are conducted on a 24 month STAGGERED TEST BASIS. Note 1 requires the STAGGERED TEST BASIS to be determined based on 4 channels of APRM outputs and 4 channels of OPRM outputs, (total n = 8) being tested on an alternating basis.

This allows the STAGGERED TEST BASIS Frequency for Function 2.e to be determined based on 8 channels rather than the 4 actual 2-Out-Of-4 Voter channels. The redundant outputs from the 2-Out-Of-4 Voter channel (2 for APRM trips and 2 for OPRM trips) are considered part of the same channel, but the OPRM and APRM outputs are considered to be separate channels for application of SR 3.3.1.1.14, so n = 8. The note further requires that testing of OPRM and APRM outputs from a 2-Out-Of-4 Voter be alternated. In addition to these commitments, References 17 and 21 require that the testing of inputs to each RPS Trip System alternate.

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SURVEILLANCE REQUIREMENTS (continued)

Combining these frequency requirements, an acceptable test sequence is one that:

a) Tests each RPS Trip System interface every other cycle,

b) Alternates the testing of APRM and OPRM outputs from any specific 2-Out-Of-4 Voter channel, and

c) Alternates between divisions at least every other test cycle.

After 8 cycles, the sequence repeats.

Each test of an OPRM or APRM output tests each of the redundant outputs from the 2-Out-Of-4 Voter channel for that Function and each of the corresponding relays in the RPS. Consequently, each of the RPS relays is tested every fourth cycle. This RPS relay testing frequency is twice the frequency justified by References 17 and 21.

This Frequency is based on the logic interrelationships of the various channels required to produce an RPS scram signal. The 24 month Frequency is consistent with the typical industry refueling cycle and is based upon plant operating experience, which shows that random failures of instrumentation components causing serious response time degradation, but not channel failure, are infrequent occurrences.

SR 3.3.1.1.15

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function. For the APRM Functions, this test supplements the automatic self-test functions that operate continuously in the APRM and voter channels. The APRM CHANNEL FUNCTIONAL TEST covers the APRM channels (including recirculation flow processing -- applicable to Function 2.b and 2.f only), the 2-out-of-4 voter channels, and the interface connections into the RPS trip systems from the voter channels. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology. The 184 day Frequency of SR 3.3.1.1.15 is based on the reliability analysis of References 17 and 21. (NOTE: The actual voting logic of the 2-Out-Of-4 Voter Function is tested as part of SR 3.3.1.1.12.)

Note 1 is provided for Function 2.a to clarify that this SR is required to be performed within 12 hours of entering MODE 2 from MODE 1. Testing of the MODE 2 APRM Function cannot be performed in MODE 1 without

BASES

SURVEILLANCE REQUIREMENTS (continued)

utilizing jumpers or lifted leads. Note 1 allows entry into MODE 2 from MODE 1 if the associated Frequency is not met per SR 3.0.2.

Note 2 is added to clarify that the CHANNEL FUNCTIONAL TEST is limited to the recirculation flow input processing and does not include the flow transmitters.

REFERENCES

1. Regulatory Guide 1.105, Revision 3, "Setpoints for Safety-Related Instrumentation."
2. USAR, Section 7.6.1.2.1.
3. USAR, Section 7.6.1.2.5.
4. USAR, Chapter 14.
5. USAR, Chapter 14A.
6. USAR, Section 7.8.2.1.
7. USAR, Section 7.3.4.3.
8. Not Used.
9. USAR, Section 14.5.1.
10. USAR, Section 14.7.1.
11. USAR, Section 14.7.2.
12. USAR, Section 14.7.3.
13. P. Check (NRC) letter to G. Lainas (NRC), "BWR Scram Discharge System Safety Evaluation," December 1, 1980.
14. USAR, Section 14.4.5.
15. USAR, Section 14.4.1.
16. NEDC-30851-P-A, "Technical Specification Improvement Analyses for BWR Reactor Protection System," March 1988.

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REFERENCES (continued)

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

18. NEDC-33075P-A, Revision 6, "General Electric Boiling Water Reactor Detect and Suppress Solution – Confirmation Density," January 2008

19. Not Used.

20. Not Used.

21. NEDC-32410P-A, Supplement 1, "Nuclear Measurement Analysis and Control Power Range Neutron Monitor (NUMAC PRNM) Retrofit Plus Option Ill Stability Trip Function", November 1997.

22. Letter from GEH to NRC, NEDC-33075P-A, Detect and Suppress Solution – Confirmation Density (DSS-CD) Analytical Limit (TAC No. MD0277)," dated October 29, 2008.

23. U.S. NRC Regulatory Issue Summary 2006-17, "NRC Staff Position on the Requirements of 10 CFR 50.36, "Technical Specifications," Regarding Limiting Safety System Settings During Periodic Testing and Calibration of Instrument Channels," dated August 24, 2006.

24. Amendment No. 159, "Issuance of Amendment Re: Request to Install Power Range Neutron Monitoring System," dated February 3, 2009. (ADAMS Accession No. ML083440681)

25. GHNE-0000-0073-4167-R2, "Reactor Long-Term Stability Solution Option III: Licensing Basis Hot Channel Oscillation Magnitude for Monticello Nuclear Generating Plant," December 2007.

26. CA-10-135, "Instrument Setpoint Calculation – Intermediate Range Monitor (IRM) High Flux SCRAM and CR Block" (including Attachment 5, GEH document 0000-0121-5727, IRM Calibration Design Bases).

27. Calculation 09-239, "Turbine Bypass Valve Capacity for EPU"

28. Amendment No. 171, "Issuance of Amendment Regarding the Restoration Period Before Declaring Average Power Range Monitors Inoperable," dated January 25, 2013. (ADAMS Accession No. ML12339A035)

BASES

REFERENCES (continued)

29. MNGP EPU Task Report T0506, Revision 4, “Technical Specification Setpoints”

30. Amendment No. 176, “Monticello Nuclear Generating Plant – Issuance of Amendment 176 to Renewed Facility Operating License Regarding Extended Power Uprate,” December 9, 2013. (ADAMS Accession No. ML12339A035)

31. Amendment No. 180, “Monticello Nuclear Generating Plant – Issuance of Amendment 180 to Renewed Facility Operating License Regarding Maximum Extended Operating Domain (MELLLA+),” March 28, 2014. (ADAMS Accession No. ML14035A248)

B 3.3 INSTRUMENTATION

B 3.3.1.2 Source Range Monitor (SRM) Instrumentation

BASES

BACKGROUND

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

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

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

APPLICABLE SAFETY ANALYSES

Prevention and mitigation of prompt reactivity excursions during refueling and low power operation is provided by LCO 3.9.1, "Refueling Equipment Interlocks," LCO 3.1.1, "SHUTDOWN MARGIN (SDM)," LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation," the IRM Neutron Flux - High High Function, and LCO 3.3.2.1, "Control Rod Block Instrumentation."

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

BASES

LCO

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

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

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

In nonspiral routine operations, two SRMs are required to be OPERABLE to provide redundant monitoring of reactivity changes occurring in the reactor core. Because of the local nature of reactivity changes during refueling, adequate coverage is provided by requiring one SRM to be OPERABLE in the quadrant of the reactor core where CORE ALTERATIONS are being performed, and the other SRM to be OPERABLE in an adjacent quadrant containing fuel. These requirements ensure that the reactivity of the core will be continuously monitored during CORE ALTERATIONS.

Special movable detectors, according to footnote (c) of Table 3.3.1.2-1, may be used in MODE 5 in place of the normal SRM nuclear detectors. These special detectors must be connected to the normal SRM circuits in the NMS, such that the applicable neutron flux indication can be generated. These special detectors provide more flexibility in monitoring reactivity changes during fuel loading, since they can be positioned anywhere within the core during refueling. They must still meet the location requirements of SR 3.3.1.2.2 and all other required SRs for SRMs.

For an SRM channel to be considered OPERABLE, it must be providing neutron flux monitoring indication and must be inserted to the normal operating level.

BASES

APPLICABILITY

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

ACTIONS

A.1 and B.1

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

Provided at least one SRM remains OPERABLE, Required Action A.1 allows 4 hours to restore the required SRMs to OPERABLE status. This time is reasonable because there is adequate capability remaining to monitor the core, there is limited risk of an event during this time, and there is sufficient time to take corrective actions to restore the required SRMs to OPERABLE status or to establish alternate IRM monitoring capability. During this time, control rod withdrawal and power increase is not precluded by this Required Action. Having the ability to monitor the core with at least one SRM, proceeding to IRM Range 3 or greater, and thereby exiting the Applicability of this LCO, is acceptable for ensuring adequate core monitoring and allowing continued operation.

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

C.1

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

BASES

ACTIONS (continued)

D.1 and D.2

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

E.1 and E.2

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

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

SURVEILLANCE REQUIREMENTS

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

SR 3.3.1.2.1 and SR 3.3.1.2.3

Performance of the CHANNEL CHECK ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on another channel. It is based on the assumption that instrument channels monitoring the same parameter should read

BASES

SURVEILLANCE REQUIREMENTS (continued)

approximately the same value. Significant deviations between the instrument channels could be an indication of excessive instrument drift in one of the channels or something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

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

The Frequency of once every 12 hours for SR 3.3.1.2.1 is based on operating experience that demonstrates channel failure is rare. While in MODES 3 and 4, reactivity changes are not expected; therefore, the 12 hour Frequency is relaxed to 24 hours for SR 3.3.1.2.3. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the channels required by the LCO.

SR 3.3.1.2.2

To provide adequate coverage of potential reactivity changes in the core, one SRM is required to be OPERABLE in the quadrant where CORE ALTERATIONS are being performed, and the other OPERABLE SRM must be in an adjacent quadrant containing fuel. Note 1 states that the SR is required to be met only during CORE ALTERATIONS. It is not required to be met at other times in MODE 5 since core reactivity changes are not occurring. This Surveillance consists of a review of plant logs to ensure that SRMs required to be OPERABLE for given CORE ALTERATIONS are, in fact, OPERABLE. In the event that only one SRM is required to be OPERABLE, per Table 3.3.1.2-1, footnote (b), only the a. portion of this SR is required. Note 2 clarifies that more than one of the three requirements can be met by the same OPERABLE SRM. The 12 hour Frequency is based upon operating experience and supplements operational controls over refueling activities that include steps to ensure that the SRMs required by the LCO are in the proper quadrant.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.2.4

This Surveillance consists of a verification of the SRM instrument readout to ensure that the SRM reading is greater than a specified minimum count rate with the detector full in, which ensures that the detectors are indicating count rates indicative of neutron flux levels within the core. With few fuel assemblies loaded, the SRMs will not have a high enough count rate to satisfy the SR. Therefore, allowances are made for loading sufficient "source" material, in the form of irradiated fuel assemblies, to establish the minimum count rate.

To accomplish this, the SR is modified by a Note that states that the count rate is not required to be met on an SRM that has less than or equal to two fuel assemblies adjacent to the SRM and no other fuel assemblies are in the associated core quadrant. With two or less fuel assemblies loaded around each SRM and no other fuel assemblies in the associated core quadrant, even with a control rod withdrawn, the configuration will not be critical.

The Frequency is based upon channel redundancy and other information available in the control room, and ensures that the required channels are frequently monitored while core reactivity changes are occurring. When no reactivity changes are in progress, the Frequency is relaxed from 12 hours to 24 hours.

SR 3.3.1.2.5 and SR 3.3.1.2.6

Performance of a CHANNEL FUNCTIONAL TEST demonstrates the associated channel will function properly. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. SR 3.3.1.2.5 is required in MODE 5, and the 7 day Frequency ensures that the channels are OPERABLE while core reactivity changes could be in progress. This Frequency is reasonable, based on operating experience and on other Surveillances (such as a CHANNEL CHECK), that ensure proper functioning between CHANNEL FUNCTIONAL TESTS.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.2.6 is required in MODE 2 with IRMs on Range 2 or below, and in MODES 3 and 4. Since core reactivity changes do not normally take place, the Frequency is extended from 7 days to 31 days. The 31 day Frequency is based on operating experience and on other Surveillances (such as CHANNEL CHECK) that ensure proper functioning between CHANNEL FUNCTIONAL TESTS.

Verification of the signal to noise ratio also ensures that the detectors are inserted to an acceptable operating level. In a fully withdrawn condition, the detectors are sufficiently removed from the fueled region of the core to essentially eliminate neutrons from reaching the detector. Any count rate obtained while the detectors are fully withdrawn is assumed to be "noise" only.

With few fuel assemblies loaded, the SRMs will not have a high enough count rate to determine the signal to noise ratio. Therefore, allowances are made for loading sufficient source material, in the form of irradiated fuel assemblies, to establish the conditions necessary to determine signal to noise ratio. To accomplish this, SR 3.3.1.2.5 is modified by a Note that states that the determination of signal to noise ratio is not required to be met on an SRM that has less than or equal to two fuel assemblies adjacent to the SRM and no other fuel assemblies are in the associated core quadrant. With two or less fuel assemblies loaded around each SRM and no other fuel assemblies in the associated quadrant, even with the control rod withdrawn the configuration will not be critical. The Note to SR 3.3.1.2.6 allows the Surveillance to be delayed until entry into the specified condition of the Applicability (THERMAL POWER decreased to IRM Range 2 or below). The SR must be performed within 12 hours after IRMs are on Range 2 or below. The allowance to enter the Applicability with the 31 day Frequency not met is reasonable, based on the limited time of 12 hours allowed after entering the Applicability and the inability to perform the Surveillance while at higher power levels. Although the Surveillance could be performed while on IRM Range 3, the plant would not be expected to maintain steady state operation at this power level. In this event, the 12 hour Frequency is reasonable, based on the SRMs being otherwise verified to be OPERABLE (i.e., satisfactorily performing the CHANNEL CHECK) and the time required to perform the Surveillances.

<u>SR 3.3.1.2.7</u>

Performance of a CHANNEL CALIBRATION at a Frequency of 24 months verifies the performance of the SRM circuitry. The Frequency considers the plant conditions required to perform the test, the ease of performing

BASES

SURVEILLANCE REQUIREMENTS (continued)

the test, and the likelihood of a change in the system or component status.

This SR is modified by two Notes. Note 1 excludes the neutron detectors from the CHANNEL CALIBRATION because they cannot readily be adjusted. The detectors are fission chambers that are designed to have a relatively constant sensitivity over the range and with an accuracy specified for a fixed useful life. Note 2 to the Surveillance allows the Surveillance to be delayed until entry into the specified condition of the Applicability. The SR must be performed in MODE 2 within 12 hours of entering MODE 2 with IRMs on Range 2 or below. The allowance to enter the Applicability with the 24 month Frequency not met is reasonable, based on the limited time of 12 hours allowed after entering the Applicability and the inability to perform the Surveillance while at higher power levels. Although the Surveillance could be performed while on IRM Range 3, the plant would not be expected to maintain steady state operation at this power level. In this event, the 12 hour Frequency is reasonable, based on the SRMs being otherwise verified to be OPERABLE (i.e., satisfactorily performing the CHANNEL CHECK) and the time required to perform the Surveillances.

REFERENCES None.

B 3.3 INSTRUMENTATION

B 3.3.2.1 Control Rod Block Instrumentation

BASES

BACKGROUND

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

The purpose of the RBM is to limit control rod withdrawal if localized neutron flux exceeds a predetermined setpoint during control rod manipulations. It is assumed to function to block further control rod withdrawal to preclude a MCPR Safety Limit (SL) violation. The RBM supplies a trip signal to the Reactor Manual Control System (RMCS) to appropriately inhibit control rod withdrawal during power operation above the low power range setpoint. The RBM has two channels, either of which can initiate a control rod block when the channel output exceeds the control rod block setpoint. One RBM channel inputs into one RMCS rod block circuit and the other RBM channel inputs into the second RMCS rod block circuit. The RBM channel signal is generated by averaging a set of local power range monitor (LPRM) signals at various core heights surrounding the control rod being withdrawn. A signal from one of the four redundant average power range monitor (APRM) channels supplies a reference signal for one of the RBM channels and a signal from another of the APRM channel supplies the reference signal to the second RBM channel. This reference signal is used to determine which RBM range setpoint (low, intermediate, or high) is enabled. If the APRM is indicating less than the low power range setpoint, the RBM is automatically bypassed. The RBM is also automatically bypassed if a peripheral control rod is selected (Ref. 1). Furthermore, the Bypass Time Delay, which bypasses the RBM upscale trips for a short period of time, is not utilized (it is permanently disabled). Thus, if it is not disabled, the associated RBM channel is inoperable. In addition, to preclude rod movement with an inoperable RBM, an inoperable trip is provided. A RBM channel is considered inoperable if less than half the total number of inputs are available.

BASES

BACKGROUND (continued)

The purpose of the RWM is to control rod patterns during startup, 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. Prescribed control rod sequences are stored in the RWM, which will initiate control rod withdrawal and insert blocks when the actual sequence deviates beyond allowances from the stored sequence. The RWM determines the actual sequence based position indication for each control rod. The RWM also uses steam flow signals to determine when the reactor power is above the preset power level at which the RWM is automatically bypassed (Ref. 2). The RWM is a single channel system that provides input into both RMCS rod block circuits.

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

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

NOTE: Certain AREVA safety analysis methods have been approved for use (Amendment 188); however, those methods may not be invoked in the analysis-of-record until AREVA fuel is loaded in the core. Until that time, General Electric – Hitachi (GEH) safety analysis methods will continue to support core operation and the description of the GEH methods in the TS Bases shall prevail. To the extent that approved AREVA methods may be described and referenced without conflicting with the GEH analysis-of-record, the TS Bases reflect both GEH and AREVA methods. Refer to CORE OPERATING LIMIT REPORT (COLR) Section 1.0 to determine whether GEH or AREVA methods were used for the current operating cycle.

Allowable Values are specified for each applicable Rod Block Function listed in Table 3.3.2.1-1. The nominal trip setpoints (NTSPs) (actual trip setpoints) are selected to ensure that the setpoints are conservative with respect to the Allowable Value. A channel is inoperable if its actual trip setpoint selected is non-conservative with respect to its required Allowable Value.

NTSPs are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (e.g., reactor power), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g.,

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

trip unit) changes state. The Analytical Limits are derived from the limiting values of the process parameters obtained from the safety analysis. The Allowable Values are derived from the Analytical Limits, corrected for calibration, process, and some of the instrument errors. The NTSPs are then determined, accounting for the remaining channel uncertainties. The trip setpoints derived in this manner provide adequate protection because instrumentation uncertainties, process effects, calibration tolerances, and drift are accounted for. The Limiting Trip Setpoint is the value of the setpoint within its specified as-found tolerance which most closely approaches the Allowed Value. For the Rod Block Monitor, which is a digital system with a zero as-found tolerance, the Limiting Trip Setpoint is the NTSP.

The Rod Block Monitor Low, Intermediate and High Power Range – Upscale functions (Functions 1a, 1b and 1c, respectively) are Limiting Safety System Setting (LSSS), SL-related, as determined in the NRC Safety Evaluation for Amendment 159 (Ref. 12).

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

1. Rod Block Monitor

The RBM is designed to prevent violation of the MCPR SL and the cladding 1% plastic strain fuel design limit that may result from a single control rod withdrawal error (RWE) event. The analytical methods and assumptions used in evaluating the RWE event are summarized in Reference 3. A statistical analysis of RWE events was performed to determine the RBM response for both channels for each event. From these responses, the fuel thermal performance as a function of RBM Allowable Value was determined. The NTSP and Allowable Values are chosen as a function of power level. NTSP operating limits are established based on the specified Allowable Values.

The RBM Function satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

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

NTSPs are specified in the setpoint calculations. The nominal setpoints are selected to ensure that the setpoints do not exceed the Allowable Values between successive CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the NTSP, but within its Allowable

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Value, is acceptable. NTSPs are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter, the calculated RBM flux (RBM channel signal). When the normalized RBM flux value exceeds the applicable trip setpoint, the RBM provides a trip output. The analytic limits are derived from the limiting values of the process parameters obtained from the safety analysis. The Allowable Values and NTSPs are derived, using the General Electric setpoint methodology guidance, as specified in the Monticello setpoint methodology. The Allowable Values are derived from the analytic limits. The difference between the analytic limit and the Allowable Value allows for channel instrument accuracy, calibration accuracy, process measurement accuracy, and primary element accuracy. Use of this method and verification provides the assurance that if the setpoint is found conservative to the Allowable Value during surveillance testing, the instrumentation would have provided the required trip function by the time the process reached the analytic limit for the applicable events, thereby protecting the SL.

For the digital RBM, there is a normalization process initiated upon rod selection, so that only RBM input signal drift over the interval from the rod selection to rod movement needs to be considered in determining the nominal trip setpoints. The RBM has no drift characteristic with no as-left or as-found tolerances since it only performs digital calculations on the digitized input signals provided by the APRMs.

The NTSP (or Limiting Trip Setpoint) is the LSSS since the RBM has no drift characteristic. The RBM Allowable Value demonstrates that the analytic limit would not be exceeded, thereby protecting the safety limit. The trip setpoints and Allowable Values determined in this manner provide adequate protection because instrumentation uncertainties, process effects, calibration tolerances, instrument drift, and environment errors are accounted for and appropriately applied for the RBM. There are no margins applied to the RBM nominal trip setpoint calculations which could mask RBM degradation.

The RBM is assumed to mitigate the consequences of an RWE event when operating ≥ 30% RTP. Below this power level, the consequences of an RWE event will not exceed the MCPR SL and, therefore, the RBM is not required to be OPERABLE (Ref. 3). When operating < 90% RTP, analyses have shown that with an initial MCPR ≥ the cycle and power specific limit specified in the current COLR, no RWE event will result in exceeding the MCPR SL. Also, the analyses demonstrate that when operating at ≥ 90% RTP with MCPR ≥ the cycle and power specific limit specified in the current COLR, no RWE event will result in exceeding the MCPR SL. Therefore, under these conditions, the RBM is also not required to be OPERABLE.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

2. Rod Worth Minimizer

The RWM enforces the banked position withdrawal sequence (BPWS) to ensure that the initial conditions of the CRDA analysis are not violated. The analytical methods and assumptions used in evaluating the CRDA are summarized in References 4, 5, 6, 7 and 14. The standard BPWS requires that control rods be moved in groups, with all control rods assigned to a specific group required to be within specified banked positions. Requirements that the control rod sequence is in compliance with the BPWS are specified in LCO 3.1.6, "Rod Pattern Control."

When performing a shutdown of the plant, an optional BPWS control rod sequence (Ref. 14) may be used if the coupling of each withdrawn control rod has been confirmed. The rods may be inserted without the need to stop at intermediate positions. When using the Reference 14 control rod insertion sequence for shutdown, the rod worth minimizer may be bypassed if it is not programmed to reflect the optional BPWS shutdown sequence, as permitted by the Applicability Note for the RWM in Table 3.3.2.1-1.

The RWM Function satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

Since the RWM is a system designed to act as a backup to operator control of the rod sequences, only one channel of the RWM is available and required to be OPERABLE (Ref. 7). Special circumstances provided for in the Required Action of LCO 3.1.3, "Control Rod OPERABILITY," and LCO 3.1.6 may necessitate bypassing the RWM to allow continued operation with inoperable control rods, or to allow correction of a control rod pattern not in compliance with the BPWS. The RWM may be bypassed as required by these conditions, but then it must be considered inoperable and the Required Actions of this LCO followed.

Compliance with the BPWS, and therefore OPERABILITY of the RWM, is required in MODES 1 and 2 when THERMAL POWER is ≤ 10% RTP. When THERMAL POWER is > 10% RTP, there is no possible control rod configuration that results in a control rod worth that could exceed the 280 cal/gm fuel damage limit during a CRDA (Refs. 5 and 7). In MODES 3 and 4, all control rods are required to be inserted into the core; therefore, a CRDA cannot occur. In MODE 5, since only a single control rod can be withdrawn from a core cell containing fuel assemblies, adequate SDM ensures that the consequences of a CRDA are acceptable, since the reactor will be subcritical.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

3. Reactor Mode Switch - Shutdown Position

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

The Reactor Mode Switch - Shutdown Position Function satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

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

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

ACTIONS

A.1

With one RBM channel inoperable, the remaining OPERABLE channel is adequate to perform the control rod block function; however, overall reliability is reduced because a single failure in the remaining OPERABLE channel can result in no control rod block capability for the RBM. For this reason, Required Action A.1 requires restoration of the inoperable channel to OPERABLE status. The Completion Time of 24 hours is based on the low probability of an event occurring coincident with a failure in the remaining OPERABLE channel.

B.1

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

BASES

ACTIONS (continued)

trip. This initiates a control rod withdrawal block, thereby ensuring that the RBM function is met.

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

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

With the RWM inoperable during a reactor startup, the operator is still capable of enforcing the prescribed control rod sequence. However, the overall reliability is reduced because a single operator error can result in violating the control rod sequence. Therefore, control rod movement must be immediately suspended except by scram. Alternatively, startup may continue if at least 12 control rods have already been withdrawn, or a reactor startup with an inoperable RWM was not performed in the last 12 months. Required Actions C.2.1.1 and C.2.1.2 require verification of these conditions by review of plant logs and control room indications. Once Required Action C.2.1.1 or C.2.1.2 is satisfactorily completed, control rod withdrawal may proceed in accordance with the restrictions imposed by Required Action C.2.2. Required Action C.2.2 allows for the RWM Function to be performed manually and requires a double check of compliance with the prescribed rod sequence by a second licensed operator (Operator or Senior Operator) or other qualified member of the technical staff (engineer).

The RWM may be bypassed under these conditions to allow continued operations. In addition, Required Actions of LCO 3.1.3 and LCO 3.1.6 may require bypassing the RWM, during which time the RWM must be considered inoperable with Condition C entered and its Required Actions taken.

D.1

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

BASES

ACTIONS (continued)

E.1 and E.2

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

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

SURVEILLANCE REQUIREMENTS

As noted at the beginning of the SRs, the SRs for each Control Rod Block instrumentation Function are found in the SRs column of Table 3.3.2.1-1.

The Surveillances are modified by a second Note to indicate that when an RBM channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains control rod block capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the reliability analysis (Ref. 9) assumption of the average time required to perform channel Surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that a control rod block will be initiated when necessary.

SR 3.3.2.1.1

A CHANNEL FUNCTIONAL TEST is performed for each RBM channel to ensure that the entire channel will perform the intended function. It includes the Reactor Manual Control System input. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay.

BASES

SURVEILLANCE REQUIREMENTS (continued)

This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions.

Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology. The Frequency of 184 days is based on reliability analyses (Ref. 10).

SR 3.3.2.1.2 and SR 3.3.2.1.3

A CHANNEL FUNCTIONAL TEST is performed for the RWM to ensure that the entire system will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. The CHANNEL FUNCTIONAL TEST for the RWM is performed by: a) attempting to withdraw a control rod not in compliance with the prescribed sequence and verifying a control rod block occurs; b) verifying proper annunciation of the selection error of at least one out-of-sequence control rod in each fully inserted group; and c) performing a RWM computer on-line diagnostic test. As noted in the SRs, SR 3.3.2.1.2 is not required to be performed until 1 hour after any control rod is withdrawn at ≤ 10% RTP in MODE 2, and SR 3.3.2.1.3 is not required to be performed until 1 hour after THERMAL POWER is ≤ 10% RTP in MODE 1. This allows entry into MODE 2 for SR 3.3.2.1.2, and entry into MODE 1 when THERMAL POWER is ≤ 10% RTP for SR 3.3.2.1.3, to perform the required Surveillance if the 92 day Frequency is not met per SR 3.0.2. The 1 hour allowance is based on operating experience and in consideration of providing a reasonable time in which to complete the SRs. The Frequencies are based on reliability analysis (Ref. 8).

SR 3.3.2.1.4

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

BASES

SURVEILLANCE REQUIREMENTS (continued)

As noted, neutron detectors are excluded from the CHANNEL CALIBRATION because they are passive devices, with minimal drift, and because of the difficulty of simulating a meaningful signal. Neutron detectors are adequately tested in SR 3.3.1.1.2 and SR 3.3.1.1.6.

The Frequency is based upon the assumption of a 24 month calibration interval (Refs. 10 and 11).

SR 3.3.2.1.4 for the following RBM functions is modified by two Notes as identified in Table 3.3.2.1-1. These functions, in accordance with the guidance of Regulatory Issue Summary 2006-17 (Ref. 13) and as determined in the NRC Safety Evaluation for Amendment 159 (Ref. 12), are LSSS SL-related.

Function No.	RBM Function
1.a	Low Power Range – Upscale
1.b	Intermediate Power Range – Upscale
1.c	High Power Range – Upscale

Note (h) requires evaluation of channel performance for the condition where the as-found setting for the channel setpoint is not the NTSP but is conservative with respect to the Allowable Value. For digital channel components, no as-found tolerance or as-left tolerance can be specified. Evaluation of instrument performance will verify that the instrument will continue to behave in accordance with design basis assumptions. The purpose of the assessment is to ensure confidence in the instrument performance prior to returning the instrument to service. This nonconformance will be entered into the Corrective Action Program. Entry into the Corrective Action Program will ensure required review and documentation of the condition for continued OPERABILITY.

Note (i) requires that the as-left setting for the instrument be returned to the NTSP. If the as-left instrument setting cannot be returned to the NTSP, then the instrument channel shall be declared inoperable. The NTSPs and Allowable Values for Rod Block Monitor Functions 1.a, 1.b and 1.c are specified in the COLR. The methodology used to determine the NTSPs are specified in Appendix C to the Technical Requirements Manual, a document controlled under 10 CFR 50.59.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.1.5

The RBM setpoints are automatically varied as a function of power. The three control rod block Allowable Values required in Table 3.3.2.1-1, each within a specific power range, are specified in the COLR. The power at which the control rod block Allowable Values automatically change are based on the APRM signal's input to each RBM channel. Below the minimum power setpoint, the RBM is automatically bypassed. These control rod block bypass setpoints must be verified periodically to be less than or equal to the specified values. If any power range setpoint is nonconservative, then the affected RBM channel is considered inoperable. Alternatively, the power range channel can be placed in the conservative condition (i.e., enabling the proper RBM setpoint). If placed in this condition, the SR is met and the RBM channel is not considered inoperable. As noted, neutron detectors are excluded from the Surveillance because they are passive devices, with minimal drift, and because of the difficulty of simulating a meaningful signal. Neutron detectors are adequately tested in SR 3.3.1.1.2 and SR 3.3.1.1.6. The 24 month Frequency is based on the actual trip setpoint methodology utilized for these channels.

SR 3.3.2.1.6

The RWM is automatically bypassed when power is above a specified value. The power level is determined from steam flow signals. The automatic bypass setpoint must be verified periodically to be > 10% RTP. If the RWM low power setpoint is nonconservative, then the RWM is considered inoperable. Alternately, the low power setpoint channel can be placed in the conservative condition (nonbypass). If placed in the nonbypassed condition, the SR is met and the RWM is not considered inoperable. The 24 month Frequency is based on engineering judgment considering the reliability of the components, and that indication of whether or not the RWM is bypassed is provided in the control room.

SR 3.3.2.1.7

A CHANNEL FUNCTIONAL TEST is performed for the Reactor Mode Switch - Shutdown Position Function to ensure that the entire channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least

BASES

SURVEILLANCE REQUIREMENTS (continued)

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

As noted in the SR, the Surveillance is not required to be performed until 1 hour after the reactor mode switch is in the shutdown position, since testing of this interlock with the reactor mode switch in any other position cannot be performed without using jumpers, lifted leads, or movable links.

This allows entry into MODES 3 and 4 if the 24 month Frequency is not met per SR 3.0.2. The 1 hour allowance is based on operating experience and in consideration of providing a reasonable time in which to complete the SRs.

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

SR 3.3.2.1.8

The RWM will only enforce the proper control rod sequence if the rod sequence is properly input into the RWM computer. This SR ensures that the proper sequence is loaded into the RWM so that it can perform its intended function. The Surveillance is performed once prior to declaring RWM OPERABLE following loading of sequence into RWM, since this is when rod sequence input errors are possible.

REFERENCES

1. USAR, Section 7.3.5.3.

2. USAR, Section 7.8.2.

3. NEDC-30492-P, "Average Power Range Monitor, Rod Block Monitor, and Technical Specification Improvements (ARTS) Program for Monticello Nuclear Generating Plant," April 1984.

4. NEDE-24011-P-A, "General Electrical Standard Application for Reload Fuel" (revision specified in Specification 5.6.3).

BASES

REFERENCES (continued)

5. Letter from T.A. Pickens (BWROG) to G.C. Lainas (NRC), "Amendment 17 to General Electric Licensing Topical Report NEDE-24011-P-A," BWROG-8644, August 15, 1986.

6. NEDO-21231, "Banked Position Withdrawal Sequence," January 1977.

7. NRC SER, "Acceptance of Referencing of Licensing Topical Report NEDE-24011-P-A," "General Electric Standard Application for Reactor Fuel, Revision 8, Amendment 17," December 27, 1987.

8. NEDC-30851-P-A, "Technical Specification Improvement Analysis for BWR Control Rod Block Instrumentation," October 1988.

9. GENE-770-06-1-A, "Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications," December 1992.

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

11. NEDC-32410P-A, Supplement 1, "Nuclear Measurement Analysis and Control Power Range Neutron Monitor (NUMAC PRNM) Retrofit Plus Option III Stability Trip Function," November 1987.

12. Amendment No. 159, “Issuance of Amendment Re: Request to Install Power Range Neutron Monitoring System, dated February 3, 2009. (ADAMS Accession No. ML083440681)

13. U.S. NRC Regulatory Issue Summary 2006 17, "NRC Staff Position on the Requirements of 10 CFR 50.36, "Technical Specifications," Regarding Limiting Safety System Settings During Periodic Testing and Calibration of Instrument Channels," dated August 24, 2006.

14. NEDC-33091-A, Revision 2, “Improved BPWS Control Rod Insertion Process,” July 2004.

B 3.3 INSTRUMENTATION

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

BASES

BACKGROUND

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

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

Reactor Vessel Water Level - High signals are provided by level sensors that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level in the reactor vessel (variable leg). Four channels of Reactor Vessel Water Level - High instrumentation are provided as input to a one-out-of-two-taken-twice initiation logic that trips the two feedwater pumps and the main turbine. The channels include electronic equipment (e.g., trip units) that compares measured input signals with pre- established setpoints. When the setpoint is exceeded, the channel output relay actuates, which then outputs a feedwater pump and main turbine trip signal to the trip logic.

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

APPLICABLE SAFETY ANALYSES

The Feedwater Pump and Main Turbine High Water Level Trip Instrumentation is assumed to be capable of providing a turbine trip in the design basis transient analysis for a feedwater controller failure, maximum demand event (Ref. 1). The high level trip indirectly initiates a reactor scram from the main turbine trip (above 40% RTP – Ref. 3) and trips the feedwater pumps, thereby terminating the event. The reactor scram mitigates the reduction in MCPR.

Feedwater Pump and Main Turbine High Water Level Trip Instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The LCO requires four channels of the Reactor Vessel Water Level - High instrumentation to be OPERABLE to ensure that no single instrument failure will prevent the feedwater pumps and main turbine trip on a valid high level signal. Each channel must have its setpoint set within the specified Allowable Value of SR 3.3.2.2.4. The Allowable Value is set to ensure that the thermal limits are not exceeded during the event. The

BASES

LCO (continued)

actual setpoint is calibrated to be consistent with the applicable setpoint methodology assumptions. Nominal trip setpoints are specified in the setpoint calculations. The nominal setpoints are selected to ensure that the setpoints do not exceed the Allowable Value between successive CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable.

Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (e.g., reactor vessel water level), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., trip unit) changes state. The analytic limits are derived from the limiting values of the process parameters obtained from the safety analysis. The Allowable Values and nominal trip setpoints (NTSP) are derived, using the General Electric setpoint methodology guidance, as specified in the Monticello setpoint methodology. The Allowable Values are derived from the analytic limits. The difference between the analytic limit and the Allowable Value allows for channel instrument accuracy, calibration accuracy, process measurement accuracy, and primary element accuracy. The margin between the Allowable Value and the NTSP allows for instrument drift that might occur during the established surveillance period. Two separate verifications are performed for the calculated NTSP. The first, a Spurious Trip Avoidance Test, evaluates the impact of the NTSP on plant availability. The second verification, an LER Avoidance Test, calculates the probability of avoiding a Licensee Event Report (or exceeding the Allowable Value) due to instrument drift. These two verifications are statistical evaluations to provide additional assurance of the acceptability of the NTSP and may require changes to the NTSP. Use of these methods and verifications provides the assurance that if the setpoint is found conservative to the Allowable Value during surveillance testing, the instrumentation would have provided the required trip function by the time the process reached the analytic limit for the applicable events.

APPLICABILITY

The Feedwater Pump and Main Turbine High Water Level Trip Instrumentation is required to be OPERABLE at ≥ 25% RTP to ensure that the fuel cladding integrity Safety Limit and the cladding 1% plastic strain limit are not violated during the feedwater controller failure, maximum demand event. As discussed in the Bases for LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)," LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)," and LCO 3.2.3, "LINEAR HEAT GENERATION RATE (LHGR)," sufficient margin to these limits exists below 25% RTP; therefore, these requirements are only necessary when operating at or above this power level.

BASES

ACTIONS

A Note has been provided to modify the ACTIONS related to Feedwater Pump and Main Turbine High Water Level Trip Instrumentation channels. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition, discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable feedwater and main turbine high water level trip instrumentation channels provide appropriate compensatory measures for separate inoperable channels. As such, a Note has been provided that allows separate Condition entry for each inoperable Feedwater Pump and Main Turbine High Water Level Trip Instrumentation channel.

A.1

With one or more channels inoperable and trip capability maintained, the remaining OPERABLE channels can provide the required trip signal. However, overall instrumentation reliability is reduced because a single failure in one of the remaining channels concurrent with feedwater controller failure, maximum demand event, may result in the instrumentation not being able to perform its intended function. Therefore, continued operation is only allowed for a limited time. If the inoperable channel(s) cannot be restored to OPERABLE status within the Completion Time, the channel(s) must be placed in the tripped condition per Required Action A.1. Placing the inoperable channel(s) in trip would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue with no further restrictions. Alternately, if it is not desired to place the channel(s) in trip (e.g., as in the case where placing the inoperable channel(s) in trip would result in a feedwater pump or main turbine trip), Condition C must be entered and its Required Action taken.

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

B.1

With the feedwater pump and main turbine high water level trip capability not maintained, the Feedwater Pump and Main Turbine High Water Level Trip Instrumentation cannot perform its design function. Therefore, continued operation is only permitted for a 2 hour period, during which feedwater pump and main turbine high water level trip capability must be restored. The trip capability is considered maintained when sufficient

BASES

ACTIONS (continued)

channels are OPERABLE or in trip such that the feedwater pump and main turbine high water level trip logic will generate a trip signal on a valid signal. Trip capability is lost if two parallel contacts (channels) in the same trip system are inoperable and not tripped. If the required channels cannot be restored to OPERABLE status or placed in trip, Condition C must be entered and its Required Action taken.

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

C.1 and C.2

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

Required Action C.1 is modified by a Note which states that the Required Action is only applicable if the inoperable channel is the result of an inoperable feedwater pump breaker or main turbine stop valve. The Note clarifies the situations under which the associated Required Action would be the appropriate Required Action.

SURVEILLANCE REQUIREMENTS

The Surveillances are modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains feedwater pump and main turbine high water level trip capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the

BASES

SURVEILLANCE REQUIREMENTS (continued)

channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the reliability analysis (Ref. 2) assumption that 6 hours is the average time required to perform channel Surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that the feedwater pumps and main turbine will trip when necessary.

SR 3.3.2.2.1

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

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

The Frequency is based on operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channel status during normal operational use of the displays associated with the channels required by the LCO.

SR 3.3.2.2.2

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The Frequency of 184 days is based on engineering judgment and the reliability of these components.

SR 3.3.2.2.3

Calibration of trip units provides a check of the actual trip setpoints. The channel must be declared inoperable if the trip setting is discovered to be less conservative than the Allowable Value specified in SR 3.3.2.2.4. If the trip setting is discovered to be less conservative than the setting accounted for in the appropriate setpoint methodology, but is not beyond the Allowable Value, the channel is still within the requirements of the plant safety analysis. Under these conditions, the setpoint must be readjusted to be equal to or more conservative than accounted for in the appropriate setpoint methodology.

The Frequency of 184 days is based on engineering judgment and the reliability of these components.

SR 3.3.2.2.4

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

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

SR 3.3.2.2.5

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required trip logic for a specific channel. The system functional test of the feedwater pump breakers and main turbine stop valves is included as part of this Surveillance and overlaps the LOGIC SYSTEM FUNCTIONAL TEST to provide complete testing of the assumed safety function. Therefore, if a valve is incapable of operating, the associated instrumentation would also be inoperable. The 24 month Frequency is based on the need to perform this Surveillance under the

BASES

SURVEILLANCE REQUIREMENTS (continued)

conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency.

REFERENCES

1. USAR, Section 14.4.4.

2. GENE-770-06-1-A, "Bases for Changes to Surveillance Test Intervals and Allowed Out-Of-Service Times for Selected Instrumentation Technical Specifications," December 1992.

3. Amendment No. 176, “Monticello Nuclear Generating Plant – Issuance of Amendment No. 176 to Renewed Facility Operating License Regarding Extended Power Uprate,” (ADAMS Accession No. ML13316C459)

B 3.3 INSTRUMENTATION

B 3.3.3.1 Post Accident Monitoring (PAM) Instrumentation

BASES

BACKGROUND

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

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

APPLICABLE SAFETY ANALYSES

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

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

The PAM instrumentation LCO also ensures OPERABILITY of Category 1, non-Type A, variables so that the control room operating staff can:

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

BASES

APPLICABLE SAFETY ANALYSES (continued)

The plant specific Regulatory Guide 1.97 Analysis conformance requirements (Ref. 2) documents the process that identified Type A and Category 1, non-Type A, variables.

Accident monitoring instrumentation that satisfies the definition of Type A in Regulatory Guide 1.97 meets Criterion 3 of 10 CFR 50.36(c)(2)(ii). Category 1, non-Type A, instrumentation is retained in Technical Specifications (TS) because they are intended to assist operators in minimizing the consequences of accidents. Therefore, these Category 1 variables are important for reducing public risk.

LCO

LCO 3.3.3.1 requires two OPERABLE channels for all but one Function to ensure that no single failure prevents the operators from being presented with the information necessary to determine the status of the plant and to bring the plant to, and maintain it in, a safe condition following an accident.

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

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

The following list is a discussion of the specified instrument Functions listed in Table 3.3.3.1-1 in the accompanying LCO.

1. Reactor Vessel Pressure

Reactor vessel pressure is a Category 1 variable provided to support monitoring of Reactor Coolant System (RCS) integrity and to verify operation of the Emergency Core Cooling Systems (ECCS). Two independent pressure transmitters with a range of 0 psig to 1500 psig monitor pressure. Wide range indicators are the primary indication used by the operator during an accident. Therefore, the PAM Specification deals specifically with this portion of the instrument channel.

BASES

LCO (continued)

2. Reactor Vessel Water Level

Reactor vessel water level is a Type A and Category 1 variable provided to support monitoring of core cooling and to verify operation of the ECCS. The reactor vessel fuel zone wide range water level channels provide the PAM Reactor Vessel Water Level Function. The reactor vessel fuel zone wide range water level channels provide indication, based on instrument zero, from -335 inches to +65 inches, which includes the reactor vessel fuel zone and normal operating range. Reactor vessel fuel zone wide range water level is measured by two independent differential pressure transmitters. One reactor vessel fuel zone wide range channel consists of a transmitter and a control room indicator. The other reactor vessel fuel zone wide range channel consists of a transmitter, a control room indicator, and a control room recorder. The output from these channels is the primary indication used by the operator during an accident. Therefore, the PAM Specification deals specifically with this portion of the instrument channel.

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

3. Suppression Pool Water Level

Suppression pool water level is a Category 1 variable provided to detect a breach in the reactor coolant pressure boundary (RCPB). This variable is also used to verify and provide long term surveillance of ECCS function. The wide range suppression pool water level measurement provides the operator with sufficient information to assess the status of both the RCPB and the water supply to the ECCS. The wide range water level recorders monitor the suppression pool water level from -8 ft to +15 ft, with 0 inches corresponding to the 910 ft elevation. Two wide range suppression pool water level signals are transmitted from separate differential pressure transmitters and are continuously recorded on two recorders in the control room. These recorders are the primary indication used by the operator during an accident. Therefore, the PAM Specification deals specifically with this portion of the instrument channel.

BASES

LCO (continued)

4. Drywell Pressure

Drywell pressure is a Category 1 variable provided to detect breach of the RCPB and to verify ECCS functions that operate to maintain RCS integrity. Two wide range drywell pressure signals are transmitted from separate pressure transmitters and are continuously recorded and displayed on two control room recorders. These recorders are the primary indication used by the operator during an accident. Therefore, the PAM Specification deals specifically with this portion of the instrument channel.

5. Primary Containment Area Radiation

Primary containment area radiation (high range) is provided to monitor the potential of significant radiation releases and to provide release assessment for use by operators in determining the need to invoke site emergency plans. Primary containment area radiation (high range) PAM instrumentation consists of two physically separated and redundant radiation detectors with a range of 1 R/hr to 10 E8 R/hr located inside the drywell. The detectors provide a signal to separate radiation monitor recorders located in the control room. These detectors and associated recorders in the control room provide the primary indication used by the operator during an accident. Therefore, the PAM Specification deals specifically with these portions of the instrument channel.

6. Penetration Flow Path Primary Containment Isolation Valve (PCIV) Position

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

BASES

LCO (continued)

penetration flow path is considered a separate Function. Therefore, separate Condition entry is allowed for each inoperable penetration flow path.

The Penetration Flow Path PCIV Position PAM instrumentation consists of position switches mounted on the valves for the positions to be indicated, associated wiring, and control room indicating lamps for active PCIVs (check valves and manual valves are not required to have position indication). These position switches and associated indicators in the control room provide the primary indication used by the operator during an accident. Therefore, the PAM Specification deals specifically with these portions of the instrument channel.

7. Suppression Pool Water Temperature

Suppression pool water temperature is a Type A and Category 1 variable provided to detect a condition that could potentially lead to containment breach and to verify the effectiveness of ECCS actions taken to prevent containment breach. The suppression pool water temperature instrumentation allows operators to detect trends in suppression pool water temperature. The suppression pool water temperature is monitored by two redundant channels. Each channel consists of eight resistance temperature detectors (RTDs) that monitor temperature over a range of 30°F to 230°F. The RTDs are mounted in thermowells spaced at equal intervals around the periphery of the suppression pool. The eight RTD signals are averaged and the resulting bulk temperature is sent to redundant indicating recorders in the control room.

These recorders are the primary indication used by the operator during an accident. Therefore, the PAM Specification deals specifically with this portion of the instrument channels.

APPLICABILITY

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

BASES

ACTIONS

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

A.1

When one or more Functions have one required channel that is inoperable, the required inoperable channel must be restored to OPERABLE status within 30 days. The 30 day Completion Time is based on operating experience and takes into account the remaining OPERABLE channels (or, in the case of a Function that has only one required channel, other non-Regulatory Guide 1.97 instrument channels to monitor the Function), the passive nature of the instrument (no critical automatic action is assumed to occur from these instruments), and the low probability of an event requiring PAM instrumentation during this interval.

B.1

If a channel has not been restored to OPERABLE status in 30 days, this Required Action specifies initiation of action in accordance with Specification 5.6.4, which requires a written report to be submitted to the NRC. This report discusses the results of the root cause evaluation of the inoperability and identifies proposed restorative actions. This action is appropriate in lieu of a shutdown requirement, since alternative actions are identified before loss of functional capability, and given the likelihood of plant conditions that would require information provided by this instrumentation.

C.1

When one or more Functions have two required channels that are inoperable (i.e., two channels inoperable in the same Function), one channel in the Function should be restored to OPERABLE status within 7 days. The Completion Time of 7 days is based on the relatively low

BASES

ACTIONS (continued)

C.1

probability of an event requiring PAM instrument operation and the availability of alternate means to obtain the required information. Continuous operation with two required channels inoperable in a Function is not acceptable because the alternate indications may not fully meet all performance qualification requirements applied to the PAM instrumentation. Therefore, requiring restoration of one inoperable channel of the Function limits the risk that the PAM Function will be in a degraded condition should an accident occur.

D.1

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

E.1

For the majority of Functions in Table 3.3.3.1-1, if the Required Action and associated Completion Time of Condition C is not met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

F.1

Since alternate means of monitoring primary containment area radiation and suppression pool water temperature have been developed and tested, the Required Action is not to shut down the plant, but rather to follow the directions of Specification 5.6.4. These alternate means may be temporarily installed if the normal PAM channel cannot be restored to OPERABLE status within the allotted time. The report provided to the NRC should discuss the alternate means used, describe the degree to which the alternate means are equivalent to the installed PAM channels, justify the areas in which they are not equivalent, and provide a schedule for restoring the normal PAM channels.

BASES

SURVEILLANCE REQUIREMENTS

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

The Surveillances are modified by a second Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. The 6 hour testing allowance is acceptable since it does not significantly reduce the probability of properly monitoring post accident parameters when necessary.

SR 3.3.3.1.1

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

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

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

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.3.1.2

A CHANNEL CALIBRATION is required to be performed every 24 months. CHANNEL CALIBRATION is a complete check of the instrument loop, including the sensor. The test verifies the channel responds to measured parameter with the necessary range and accuracy.

The Frequency is based on operating experience and consistency with the typical industry refueling cycles.

REFERENCES

1. Regulatory Guide 1.97, "Instrumentation for Light Water Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident," Revision 2, December 1980.

2. USAR, Section 7.9.3.

B 3.3 INSTRUMENTATION

B 3.3.3.2 Alternate Shutdown System

BASES

BACKGROUND

The Alternate Shutdown System provides the control room operator with sufficient instrumentation and controls to place and maintain the plant in a safe shutdown condition from a location other than the control room. This capability is necessary to protect against the possibility of the control room becoming inaccessible. A safe shutdown condition is defined as MODE 3. With the plant in MODE 3, the Core Spray (CS) System, the safety/relief valves (S/RVs), and the Residual Heat Removal (RHR) System operating in the suppression pool cooling mode can be used to remove core decay heat and meet all safety requirements. A minimum of two S/RVs will be manually controlled at the Alternate Shutdown System panel to reduce Reactor Coolant System pressure. After depressurization, the CS System will provide reactor inventory makeup. The CS System will be used to establish a cooling path by allowing the reactor vessel water level to rise until water flows through the S/RV lines into the suppression pool. Decay heat removal is provided by manual operation of the RHR System in the suppression pool cooling mode. The long term supply of water for the CS System and the ability to operate the RHR System in the suppression pool cooling mode from outside the control room allow extended operation in MODE 3.

In the event that the control room becomes inaccessible, the operators can establish control at the Alternate Shutdown System panel and place and maintain the plant in MODE 3. The design of the Alternate Shutdown System panel includes a master transfer switch which, when activated, enables Alternate Shutdown System operation, initiates an annunciator in the control room, and initiates an indication light and activates other transfer switches at the Alternate Shutdown System panel. It also includes a main steam isolation valve (MSIV) isolation switch and four system transfer switches which, when activated, will ensure closure of MSIVs and enable the manual control and operation of the four S/RVs, CS System, RHR System, and other auxiliary systems from the Alternate Shutdown System panel. The plant automatically reaches MODE 3 following a plant shutdown and can be maintained safely in MODE 3 for an extended period of time.

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

BASES

APPLICABLE SAFETY ANALYSES	The Alternate Shutdown System is required to provide equipment at appropriate locations outside the control room with a design capability to promptly shut down the reactor to MODE 3, including the necessary instrumentation and controls, to maintain the plant in a safe condition in MODE 3. The criteria governing the design and the specific system requirements of the Alternate Shutdown System are located in USAR, Section 7.11.1 (Ref. 1). The Alternate Shutdown System satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).
LCO	The Alternate Shutdown System LCO provides the requirements for the OPERABILITY of the instrumentation and controls necessary to place and maintain the plant in MODE 3 from a location other than the control room. The instrumentation and controls required are from Division 2 and are listed in Table B 3.3.3.2-1. The Alternate Shutdown System panel transfer switch is also required to be OPERABLE. The controls, instrumentation, and transfer switches are those required for: • Reactor pressure vessel (RPV) pressure control; • Decay heat removal; • RPV inventory control; and • Safety support systems for the above functions, including the RHR Service Water System and ECCS room coolers. The Alternate Shutdown System is OPERABLE if all instrument and control channels needed to support the Alternate Shutdown System Functions are OPERABLE. The Alternate Shutdown System instruments and control circuits covered by this LCO do not need to be energized to be considered OPERABLE. In addition, the Alternate Shutdown System master transfer switch is required to be locked in the normal position when the panel is not in use. This LCO is intended to ensure that the instruments and control circuits will be OPERABLE if plant conditions require that the Alternate Shutdown System be placed in operation.
APPLICABILITY	The Alternate Shutdown System LCO is applicable in MODES 1 and 2. This is required so that the plant can be placed and maintained in MODE 3 for an extended period of time from a location other than the control room.

BASES

APPLICABILITY (continued)

This LCO is not applicable in MODES 3, 4, and 5. In these MODES, the plant is already subcritical and in a condition of reduced Reactor Coolant System energy. Under these conditions, considerable time is available to restore necessary instrument control Functions if control room instruments or control becomes unavailable. Consequently, the TS do not require OPERABILITY in MODES 3, 4, and 5.

ACTIONS

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

A.1

Condition A addresses the situation where one or more required Functions of the Alternate Shutdown System is inoperable. This includes the control and transfer switches for any required Function.

The Required Action is to restore the Function to OPERABLE status within 30 days. The Completion Time is based on operating experience and the low probability of an event that would require evacuation of the control room.

B.1

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

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.3.2.1

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

Agreement criteria are determined by the plant staff based on a combination of the channel instrument uncertainties, including indication and readability. If a channel is outside the criteria, it may be an indication that the sensor or the signal processing equipment has drifted outside its limit. As specified in the Surveillance, a CHANNEL CHECK is only required for those channels that are normally energized.

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

SR 3.3.3.2.2

SR 3.3.3.2.2 verifies each required Alternate Shutdown System transfer switch and control circuit performs the intended function. This verification is performed from the Alternate Shutdown System panel and locally, as appropriate. In addition, for the master transfer switch, this SR ensures the alarm in the control room functions when the switch is in the transfer position. Operation of the equipment from the Alternate Shutdown System panel is not necessary. The Surveillance can be satisfied by performance of a continuity check. This will ensure that if the control room becomes inaccessible, the plant can be placed and maintained in MODE 3 from the Alternate Shutdown System panel and the local control stations. Operating experience demonstrates that Alternate Shutdown System control channels usually pass the Surveillance when performed at the 24 month Frequency.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.3.2.3

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

The 24 month Frequency is based upon operating experience and consistency with the typical industry refueling cycle.

REFERENCES

1. USAR, Section 7.11.1.

Table B 3.3.3.2-1 (page 1 of 1)
Alternate Shutdown System Instrumentation

FUNCTION (INSTRUMENT OR CONTROL PARAMETER)	REQUIRED CHANNELS
1. Reactor Pressure Vessel Pressure	
a. Reactor Pressure	1
b. Safety/Relief Valve Transfer Switch	1
c. Safety/Relief Valve Controls	2
2. Decay Heat Removal	
a. RHR System Transfer Switch	1
b. RHR Suppression Pool Cooling Flow	1
c. RHR Suppression Pool Cooling Controls (includes RHR Service Water controls)	1
d. RHR Service Water Flow	1
e. Suppression Pool Water Level	1
f. Suppression Pool Water Temperature (Average and Local)	1
g. ECCS Room Cooler Controls	1
3. Reactor Pressure Vessel Inventory Control	
a. Reactor Vessel Water Level (Flooding Range)	1
b. Reactor Vessel Water Level (Wide Range)	1
c. Core Spray System Transfer Switch	1
d. Core Spray Flow	1
e. Core Spray Controls	1
f. Main Steam Isolation Valve Isolation Switch	1

B 3.3 INSTRUMENTATION

B 3.3.4.1 Anticipated Transient Without Scram Recirculation Pump Trip (ATWS-RPT) Instrumentation

BASES

BACKGROUND	The ATWS-RPT System initiates an RPT, adding negative reactivity, following events in which a scram does not (but should) occur, to lessen the effects of an ATWS event. Tripping the recirculation pumps adds negative reactivity from the increase in steam voiding in the core area as core flow decreases. When Reactor Vessel Water Level - Low Low or Reactor Vessel Steam Dome Pressure - High setpoint is reached, the recirculation pump motor generator (MG) set drive motor field breakers trip. The ATWS-RPT System (Ref. 1) includes sensors, relays, bypass capability circuit breakers, and switches that are necessary to cause initiation of an RPT. The channels include electronic equipment (e.g., trip units) that compares measured input signals with pre-established setpoints. When the setpoint is exceeded, the channel output relay actuates, which then outputs an ATWS-RPT signal to the trip logic. The ATWS-RPT consists of two independent trip systems, with two channels of Reactor Vessel Steam Dome Pressure - High and two channels of Reactor Vessel Water Level - Low Low in each trip system. Each ATWS-RPT trip system is a two-out-of-two logic for each Function. Thus, either two Reactor Vessel Water Level - Low Low or two Reactor Vessel Steam Dome Pressure - High signals are needed to trip a trip system. The outputs of the channels in a trip system are combined in a logic so that either trip system will trip both recirculation pumps (by tripping the respective MG set drive motor field breakers). Each Reactor Vessel Water Level - Low Low output must remain below the setpoint for approximately 7 seconds for the channel output to provide an actuation signal to the associated trip system. There is one MG set drive motor field breaker provided for each of the two recirculation pumps for a total of two breakers. The output of each trip system is provided to both recirculation pump MG set drive motor field breakers.
APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY	The ATWS-RPT is not assumed to mitigate any accident or transient in the original design or licensing basis in the safety analysis. The ATWS-RPT initiates an RPT to aid in preserving the integrity of the fuel cladding following events in which a scram does not, but should, occur. ATWS-RPT instrumentation satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The OPERABILITY of the ATWS-RPT is dependent on the OPERABILITY of the individual instrumentation channel Functions. Each Function must have a required number of OPERABLE channels in each trip system, with their setpoints within the specified Allowable Value of SR 3.3.4.1.4 or SR 3.3.4.1.5, as applicable. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions. Channel OPERABILITY also includes the associated recirculation pump MG set drive motor field breakers.

Allowable Values are specified for each ATWS-RPT Function specified in the LCO. Nominal trip setpoints are specified in the setpoint calculations. The nominal setpoints are selected to ensure that the setpoints do not exceed the Allowable Value between CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable. A channel is inoperable if its actual trip setpoint is not within its required Allowable Value. Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (e.g., reactor vessel water level), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., trip unit) changes state. The analytic limits are derived from the limiting values of the process parameters obtained from the ATWS analysis (Ref. 2). The Allowable Values and nominal trip setpoints (NTSP) are derived, using the General Electric setpoint methodology guidance, as specified in the Monticello setpoint methodology. The Allowable Values are derived from the analytic limits. The difference between the analytic limit and the Allowable Value allows for channel instrument accuracy, calibration accuracy, process measurement accuracy, and primary element accuracy. The margin between the Allowable Value and the NTSP allows for instrument drift that might occur during the established surveillance period. Two separate verifications are performed for the calculated NTSP. The first, a Spurious Trip Avoidance Test, evaluates the impact of the NTSP on plant availability. The second verification, an LER Avoidance Test, calculates the probability of avoiding a Licensee Event Report (or exceeding the Allowable Value) due to instrument drift. These two verifications are statistical evaluations to provide additional assurance of the acceptability of the NTSP and may require changes to the NTSP. Use of these methods and verifications provides the assurance that if the setpoint is found conservative to the Allowable Value during surveillance testing, the instrumentation would have provided the required trip function by the time the process reached the analytic limit for the applicable events.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

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

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

a. <u>Reactor Vessel Water Level - Low Low</u>

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

Reactor vessel water level signals are initiated from four level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel.

Four channels of Reactor Vessel Water Level - Low Low, with two channels in each trip system, are available and required to be OPERABLE to ensure that no single instrument failure can preclude an ATWS-RPT from this Function on a valid signal. Each channel includes a time delay relay that delays the Reactor Vessel Water Level - Low Low Function channel output signal from providing input to the associated trip system. The Reactor Vessel Water Level - Low Low Allowable Value is chosen so that the system will not be initiated after a reactor vessel water level scram with feedwater still available,

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

and for convenience with the Emergency Core Cooling System and Reactor Core Isolation Cooling System initiation. The Reactor Vessel Water Level - Low Low Function trip is delayed since there is an insignificant effect on the ATWS consequences and it is desirable to avoid making the consequences of a loss of coolant accident more severe.

b. Reactor Vessel Steam Dome Pressure - High

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

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

ACTIONS

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

BASES

ACTIONS (continued)

A.1 and A.2

With one or more channels inoperable, but with ATWS-RPT trip capability for each Function maintained (refer to Required Actions B.1 and C.1 Bases), the ATWS-RPT System is capable of performing the intended function. However, the reliability and redundancy of the ATWS-RPT instrumentation is reduced, such that a single failure in the remaining trip system could result in the inability of the ATWS-RPT System to perform the intended function. Therefore, only a limited time is allowed to restore the inoperable channels to OPERABLE status. Because of the diversity of sensors available to provide trip signals, the low probability of extensive numbers of inoperabilities affecting all diverse Functions, and the low probability of an event requiring the initiation of ATWS-RPT, 14 days is provided to restore the inoperable channel (Required Action A.1). Alternately, the inoperable channel may be placed in trip (Required Action A.2), since this would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. As noted, placing the channel in trip with no further restrictions is not allowed if the inoperable channel is the result of an inoperable breaker, since this may not adequately compensate for the inoperable breaker (e.g., the breaker may be inoperable such that it will not open). If it is not desired to place the channel in trip (e.g., as in the case where placing the inoperable channel in trip would result in an RPT), or if the inoperable channel is the result of an inoperable breaker, Condition D must be entered and its Required Actions taken.

B.1

Required Action B.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same Function result in the Function not maintaining ATWS-RPT trip capability. A Function is considered to be maintaining ATWS-RPT trip capability when sufficient channels are OPERABLE or in trip such that the ATWS-RPT System will generate a trip signal from the given Function on a valid signal, and both recirculation pumps can be tripped. This requires two channels of the Function in the same trip system to each be OPERABLE or in trip, and the recirculation pump MG set drive motor field breakers to be OPERABLE or in trip.

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

BASES

ACTIONS (continued)

C.1

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

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

D.1 and D.2

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

Required Action D.1 is modified by a Note which states that the Required Action is only applicable if the inoperable channel is the result of an inoperable breaker. The Note clarifies the situations under which the associated Required Action would be the appropriate Required Action.

SURVEILLANCE REQUIREMENTS

The Surveillances are modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into the associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains ATWS-RPT trip capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the reliability analysis (Ref. 3) assumption of the average time required to perform channel Surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that the recirculation pumps will trip when necessary.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.4.1.1

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

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

The Frequency is based upon operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the required channels of this LCO. A Note has been added to SR 3.3.4.1.1 that states the CHANNEL CHECK is not required for the time delay portion of the Reactor Vessel Water Level - Low Low Function.

SR 3.3.4.1.2

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions.

Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

The Frequency of 92 days is based on the reliability analysis of Reference 3.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.4.1.3

Calibration of trip units provides a check of the actual trip setpoints. The channel must be declared inoperable if the trip setting is discovered to be less conservative than the Allowable Value specified in SR 3.3.4.1.5. If the trip setting is discovered to be less conservative than the setting accounted for in the appropriate setpoint methodology, but is not beyond the Allowable Value, the channel performance is still within the requirements of the plant safety analysis. Under these conditions, the setpoint must be readjusted to be equal to or more conservative than accounted for in the appropriate setpoint methodology.

The Frequency of 92 days is based on the reliability analysis of Reference 3.

SR 3.3.4.1.4 and SR 3.3.4.1.5

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

The Frequency of SR 3.3.4.1.4 is based upon the assumption of a 184 day calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis. The Frequency of SR 3.3.4.1.5 is based upon the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.4.1.6

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required trip logic for a specific channel. The system functional test of the pump breakers is included as part of this Surveillance and overlaps the LOGIC SYSTEM FUNCTIONAL TEST to provide complete testing of the assumed safety function. Therefore, if a breaker 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

BASES

SURVEILLANCE REQUIREMENTS (continued)

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

REFERENCES

1. USAR, Section 7.6.2.2.

2. USAR, Section 14.8.

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

B 3.3 INSTRUMENTATION

B 3.3.5.1 Emergency Core Cooling System (ECCS) Instrumentation

BASES

BACKGROUND

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

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

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

Core Spray System

The CS System may be initiated by either automatic or manual means, although manual initiation requires manipulation of individual pump and valve control switches. Automatic initiation occurs for conditions of Reactor Vessel Water Level - Low Low or Drywell Pressure - High. The Reactor Vessel Water Level - Low Low initiation signal is generated coincident with Reactor Steam Dome Pressure - Low (Pump Permissive) or if the Reactor Vessel Water Level - Low Low signal is sustained for 18 minutes (Refs. 7 and 8). The Reactor Vessel Water Level - Low Low variable is monitored by four redundant transmitters, connected to four trip units. The outputs of the four trip units are connected to relays whose contacts are directed to two trip systems and the logic in each trip system is arranged in a one-out-of-two taken twice logic. The Drywell Pressure - High variable is monitored by four redundant pressure switches. The outputs of the switches are connected to relays whose contacts are directed to two trip systems and the logic in each trip system is arranged in a one-out-of-two taken twice logic. The Reactor Steam Dome Pressure - Low (Pump Permissive) variable is monitored by two redundant switches. The outputs of the switches are connected to relays whose contacts are directed to two trip systems and the logic in each trip system is arranged in a one-out-of-two logic. Each trip system will delay CS pump start and valve logic on low low reactor vessel water level until reactor steam dome pressure has fallen to a value below the CS System's maximum design pressure. The Reactor Steam Dome Pressure Permissive - Bypass Timer (Pump Permissive) variable is developed by two redundant time delay relays. A time delay relay is

BACKGROUND (continued)

located in each trip system and a contact associated with this relay (one-out-of-one logic for each trip system) will bypass the Reactor Steam Dome Pressure - Low (Pump Permissive) after the timer has timed out. The CS pumps start and valve logic will receive the high drywell pressure signals without delay. The Reactor Steam Dome Pressure - Low (Injection Permissive) variable is monitored by two redundant pressure switches. The outputs of the switches are connected to relays whose contacts input into two trip systems. Each trip system is arranged in a one-out-of-two logic. Each trip system will delay CS injection valve actuation logic until reactor steam dome pressure has fallen to a value below the CS System's maximum design pressure regardless of the initiation signal. Each trip system will open the associated CS subsystem valves.

Upon receipt of an initiation signal, the CS pumps are started in approximately 15 seconds after AC power is available. The Core Spray Pump Start - Time Delay Relay Function for each CS pump is developed by one time delay relay. The time delay relay starts when there is a LOCA signal present and power is available on the associated 4.16 kV essential bus. After the time delay relay times out, the associated CS pump starts.

The CS test line isolation valve, which is also a primary containment isolation valve (PCIV), is closed on a CS initiation signal to allow full system flow assumed in the accident analyses and maintain primary containment isolated in the event CS is not operating.

Low Pressure Coolant Injection System

The LPCI is an operating mode of the Residual Heat Removal (RHR) System, with two LPCI subsystems. The LPCI subsystems may be initiated by automatic or manual means, although manual initiation requires manipulation of individual pump and valve control switches. Automatic initiation occurs for conditions of Reactor Vessel Water Level - Low Low, Drywell Pressure - High, or both. The Reactor Vessel Water Level - Low Low initiation signal is generated coincident with Reactor Steam Dome Pressure - Low (Pump Permissive) or if the Reactor Vessel Water Level - Low Low signal is sustained for 18 minutes (Refs. 7 and 8). The Reactor Vessel Water Level - Low Low variable is monitored by four redundant transmitters, connected to four trip units. The outputs of the four trip units are connected to relays whose contacts are directed to two trip systems and the logic in each trip system is arranged in a one-out-of-two taken twice logic. The Drywell Pressure - High variable is monitored by four redundant pressure switches. The outputs of the switches are connected to relays whose contacts are directed to two trip systems and the logic in each trip system is arranged in a one-out-of-two taken twice

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BACKGROUND (continued)

logic. The Reactor Steam Dome Pressure - Low (Pump Permissive) variable is monitored by two redundant switches. The outputs of the switches are connected to relays whose contacts are directed to two trip systems and the logic in each trip system is arranged in a one-out-of-two logic. Each trip system will delay LPCI pump start and valve logic on low low reactor vessel water level until reactor steam dome pressure has fallen to a value below the LPCI System's maximum design pressure. The Reactor Steam Dome Pressure Permissive - Bypass Timer (Pump Permissive) variable is developed by two redundant time delay relays. A time delay relay is located in each trip system and a contact associated with this relay (one-out-of-one logic for each trip system) will bypass the Reactor Steam Dome Pressure - Low (Pump Permissive) after the timer has timed out. The LPCI pumps start and valve logic will receive the high drywell pressure signals without delay. The Reactor Steam Dome Pressure - Low (Injection Permissive) variable is monitored by two redundant pressure switches. The outputs of the switches are connected to relays whose contacts input into two trip systems. Each trip system is arranged in a one-out-of-two logic. Each trip system will delay LPCI injection valve actuation logic until reactor steam dome pressure has fallen to a value below the LPCI System's maximum design pressure regardless of the initiation signal. Each trip system will open the associated LPCI subsystem valves.

Upon receipt of an initiation signal, the LPCI pumps are automatically started (pumps A and B approximately 5 seconds after AC power is available and pumps C and D approximately 10 seconds after AC power is available). The Low Pressure Coolant Injection Pump Start - Time Delay Relay Function for each LPCI pump is developed by four time delay relays. Each time delay relay will start when there is a LOCA signal present and power is available on the associated 4.16 kV essential bus. After a time delay relay times out, a signal is sent to start the associated LPCI pump. The outputs of the time delay relays are arranged in a one-out-of-two taken twice logic for each LPCI pump.

Each LPCI subsystem's discharge flow is monitored by a flow switch. When a pump is running and discharge flow is low enough so that pump overheating may occur, the respective minimum flow return line valve is opened after an approximate 10 second time delay. If flow is above the minimum flow setpoint, the valve is automatically closed to allow the full system flow assumed in the analyses.

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

BASES

BACKGROUND (continued)

The LPCI System initiation logic also contains LPCI Loop Select Logic whose purpose is to identify and direct LPCI flow to the unbroken recirculation loop if a Design Basis Accident (DBA) occurs. The LPCI Loop Select Logic is initiated upon the receipt of either a Reactor Vessel Water Level - Low Low signal or a Drywell Pressure - High signal, as discussed previously. When initiated, the LPCI Loop Select Logic first determines recirculation pump operation by sensing the differential pressure (dp) between the suction and discharge of each pump. There are four dp switches monitoring each recirculation loop that are, in turn, connected to relays whose contacts are connected to two trip systems. The dp switches will trip when the dp across the pump is greater than a predetermined value. The contacts are arranged in a one-out-of-two taken twice logic for each recirculation pump. If the logic senses that either pump is not running, i.e., single loop operation, then a trip signal is sent to both recirculation pumps to eliminate the possibility of pipe breaks being masked by the operating recirculation pump pressure. However, the pump trip signal is delayed approximately 0.5 seconds to ensure that at least one pump is off since the break detection sensitivity is greater with both pumps running. If a pump trip signal is generated, reactor steam dome pressure must drop to a specified value before the logic will continue. This adjusts the selection time to optimize sensitivity and still ensure that LPCI injection is not unnecessarily delayed. The reactor steam dome pressure is sensed by four pressure switches that are, in turn, connected to relays whose contacts are connected to two trip systems. The contacts are arranged in a one-out-of-two taken twice logic. After the satisfaction of this pressure requirement or if both recirculation pumps indicate they are running, a 2 second time delay is provided to allow momentum effects to establish the maximum differential pressure for loop selection. Selection of the unbroken recirculation loop is then initiated. This is done by comparing the absolute pressure of the two recirculation riser loops. The broken loop is indicated by a lower pressure than the unbroken loop. The loop with the higher pressure is then used for LPCI injection. If, after a small time delay (approximately 0.5 seconds), the pressure in loop A is not indicating higher than loop B, the logic will provide a signal to close the B recirculation loop discharge valve, open the LPCI injection valve to the B recirculation loop and close the LPCI injection valve to the A recirculation loop. This is the "default" choice in the LPCI Loop Select Logic. If recirculation loop A pressure indicates higher than loop B pressure (> 1 psig), the recirculation discharge valve in loop A is closed, the LPCI injection valve to loop A is signaled to open and the LPCI injection valve to loop B is signaled to close. The four dp switches that provide input to this portion of the logic detect the pressure difference between the corresponding risers to the jet pumps in each recirculation loop. The four dp switches are connected to relays whose contacts are connected to two trip systems. The contacts in each trip system are arranged in a one-out-of-two taken twice logic.

BASES

BACKGROUND (continued)

There are two redundant trip systems in the LPCI Loop Select Logic. The complete logic in each trip system must actuate for operation of the LPCI Loop Select Logic.

High Pressure Coolant Injection System

The HPCI System may be initiated by either automatic or manual means. Automatic initiation occurs for conditions of Reactor Vessel Water Level - Low Low or Drywell Pressure - High. The Reactor Vessel Water Level - Low Low variable is monitored by four redundant transmitters, which are, in turn, connected to four trip units. The outputs of the trip units are connected to relays whose contacts are arranged in a one-out-of-two taken twice logic. The Drywell Pressure - High variable is monitored by four switches. The outputs of the switches are connected to relays whose contacts are arranged in a one-out-of-two taken twice logic.

The HPCI pump discharge flow is monitored by a flow switch. When an initiation signal is present (Reactor Vessel Water Level - Low Low or Drywell Pressure - High) and discharge flow is low enough so that pump overheating may occur, the minimum flow return line valve is opened. The valve is automatically closed if flow is above the minimum flow setpoint to allow the full system flow assumed in the accident analysis.

The HPCI test line return valves to the condensate storage tanks (CSTs) are closed upon receipt of a HPCI initiation signal to allow the full system flow assumed in the accident analysis.

The HPCI System also monitors the water levels in the two CSTs and the suppression pool because these are the two sources of water for HPCI operation. Reactor grade water in the CSTs is the normal source. Upon receipt of a HPCI initiation signal, the CST suction valve is automatically signaled to open (it is normally in the open position) unless both suppression pool suction valves are open. If the water level in any CST falls below a preselected level, first the suppression pool suction valves automatically open, and then the CST suction valve automatically closes. Two level switches are used to detect low water level in the CST (one on each CST). Either switch can cause the suppression pool suction valves to open and the CST suction valve to close. The suppression pool suction valves also automatically open and the CST suction valve closes if high water level is detected in the suppression pool (one-out-of-two logic). To prevent losing suction to the pump, the suction valves are interlocked so that one suction path must be open before the other automatically closes.

The HPCI System provides makeup water to the reactor until the reactor vessel water level reaches the Reactor Vessel Water Level - High trip, at

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BACKGROUND (continued)

which time the HPCI turbine trips, which causes the turbine's stop valve to close. The logic is two-out-of-two to provide high reliability of the HPCI System. The HPCI System automatically restarts if a Reactor Vessel Water Level - Low Low signal is subsequently received.

Automatic Depressurization System

The ADS may be initiated by either automatic or manual means, although manual initiation requires manipulation of each individual ADS valve control switch. Automatic initiation occurs when signals indicating Reactor Vessel Water Level - Low Low and CS or LPCI Pump Discharge Pressure - High are all present and the ADS Initiation Timer has timed out. There are two transmitters that monitor Reactor Vessel Water Level - Low Low in each of the two ADS trip systems. Each of these transmitters connects to a trip unit, which then drives a relay whose contacts form the initiation logic.

Each ADS trip system includes a time delay between satisfying the initiation logic and the actuation of the ADS valves. The ADS Initiation Timer time delay setpoint is chosen to be long enough that the HPCI has sufficient operating time to recover to a level above Low Low, yet not so long that the LPCI and CS Systems are unable to adequately cool the fuel if the HPCI fails to maintain that level. An alarm in the control room is annunciated when either of the timers is timing. Resetting the ADS initiation signals resets the ADS Initiation Timers.

The ADS also monitors the discharge pressures of the four LPCI pumps and the two CS pumps. Each ADS trip system includes two discharge pressure permissive switches from all CS and LPCI pumps. However, only the switches from the pumps in the associated division are required to be OPERABLE for each trip system (i.e., Division 1 CS A and LPCI subsystems A and C input to ADS trip system A, and Division 2 CS B and LPCI subsystems B and D input to ADS trip system B). The signals are used as a permissive for ADS actuation, indicating that there is a source of core coolant available once the ADS has depressurized the vessel. Any one of the six low pressure pumps is sufficient to permit automatic depressurization.

The ADS logic in each trip system is arranged in two strings. Each string has a contact from Reactor Vessel Water Level - Low Low. Each string also has a contact that represents a CS or LPCI pump discharge pressure signal. All contacts in both logic strings must close and the ADS initiation timer must time out to initiate an ADS trip system. Either the A or B trip system will cause all the ADS relief valves to open. The Reactor Vessel Water Level - Low Low signal in one string will seal in once both the Reactor Vessel Water Level - Low Low signal and the

BASES

BACKGROUND (continued)

associated CS or LPCI pump discharge pressure signal is present. The other Reactor Vessel Water Level - Low Low signal in the other string will seal in once both the Reactor Vessel Water Level - Low Low signal and the associated CS or LPCI pump discharge pressure signal is present and the ADS Initiation timer has timed out. The signals can be manually reset.

Manual inhibit switches are provided in the control room for the ADS; however, their function is not required for ADS OPERABILITY (provided ADS is not inhibited when required to be OPERABLE).

Emergency Diesel Generators (EDGs)

The EDGs may be initiated by either automatic or manual means. Automatic initiation occurs for conditions of Reactor Vessel Water Level - Low Low or Drywell Pressure - High. The EDGs are also initiated upon loss of voltage signals. (Refer to the Bases for LCO 3.3.8.1, "Loss of Power (LOP) Instrumentation," for a discussion of these signals.) The Reactor Vessel Water Level - Low Low variable is monitored by four redundant transmitters, which are, in turn, connected to four trip units. The outputs of the four trip units are connected to relays whose contacts are directed to two trip systems and the logic in each trip system is arranged in a one-out-of-two taken twice logic to initiate both EDGs. The Drywell Pressure - High variable is monitored by four switches. The outputs of the switches are connected to relays whose contacts are directed to two trip systems and the logic in each trip system is arranged in a one-out-of-two taken twice logic to initiate both EDGs. The EDGs receive their initiation signals from the CS System initiation logic. The EDGs can also be started manually from the control room and locally from the associated EDG room. Upon receipt of a loss of coolant accident (LOCA) initiation signal, each EDG is automatically started, is ready to load in approximately 10 seconds, and will run in standby conditions (rated voltage and speed, with the EDG output breaker open). The EDGs will only energize their respective 4.16 kV essential buses if a loss of offsite power occurs (Refer to Bases for LCO 3.3.8.1).

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

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

ECCS instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii). Certain instrumentation Functions are retained for other reasons and are described below in the individual Functions discussion.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The OPERABILITY of the ECCS instrumentation is dependent upon the OPERABILITY of the individual instrumentation channel Functions specified in Table 3.3.5.1-1. Each Function must have a required number of OPERABLE channels, with their setpoints within the specified Allowable Values, where appropriate. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions. Table 3.3.5.1-1 is modified by two footnotes. Footnote (a) is added to clarify that the associated functions are required to be OPERABLE in MODES 4 and 5 only when their supported ECCS are required to be OPERABLE per LCO 3.5.2, ECCS - Shutdown. Footnote (b) is added to show that certain ECCS instrumentation Functions also perform EDG initiation.

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

Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable. A channel is inoperable if its actual trip setpoint is not within its required Allowable Value. Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (e.g., reactor vessel water level), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., trip unit) changes state. The analytic limits are derived from the limiting values of the process parameters obtained from the safety analysis. The Allowable Values and nominal trip setpoints (NTSP) are derived, using the General Electric setpoint methodology guidance, as specified in the Monticello setpoint methodology. The Allowable Values are derived from the analytic limits. The difference between the analytic limit and the Allowable Value allows for channel instrument accuracy, calibration accuracy, process measurement accuracy, and primary element accuracy. The margin between the Allowable Value and the NTSP allows for instrument drift that might occur during the established surveillance period. Two separate verifications are performed for the calculated NTSP. The first, a Spurious Trip Avoidance Test, evaluates the impact of the NTSP on plant availability. The second verification, an LER Avoidance Test, calculates the probability of avoiding a Licensee Event Report (or exceeding the Allowable Value) due to instrument drift. These two verifications are statistical evaluations to provide additional assurance of the acceptability of the NTSP and may require changes to the NTSP. Use of these methods and verifications provides the assurance that if the setpoint is found conservative to the Allowable Value during surveillance testing, the instrumentation would

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

have provided the required trip function by the time the process reached the analytic limit for the applicable events.

In general, the individual Functions are required to be OPERABLE in the MODES or other specified conditions that may require ECCS (or EDG) initiation to mitigate the consequences of a design basis transient or accident. To ensure reliable ECCS and EDG function, a combination of Functions is required to provide primary and secondary initiation signals.

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

Core Spray and Low Pressure Coolant Injection Systems

1.a, 2.a. Reactor Vessel Water Level - Low Low

Low reactor pressure vessel (RPV) water level indicates that the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. The low pressure ECCS and associated EDGs are initiated at Low Low to ensure that core spray and flooding functions are available to prevent or minimize fuel damage. The Reactor Vessel Water Level - Low Low is one of the Functions assumed to be OPERABLE and capable of initiating the ECCS during the transients analyzed in Reference 2. In addition, the Reactor Vessel Water Level - Low Low Function is directly assumed in the analysis of the recirculation line break (Ref. 1). The core cooling function of the ECCS, along with the scram action of the Reactor Protection System (RPS), ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

Reactor Vessel Water Level - Low Low signals are initiated from four level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel.

The Reactor Vessel Water Level - Low Low Allowable Value is chosen to allow time for the low pressure core flooding systems to activate and provide adequate cooling.

Four channels of CS Reactor Vessel Water Level - Low Low Function are only required to be OPERABLE when CS and the EDGs are required to be OPERABLE to ensure that no single instrument failure can preclude CS and EDG initiation. Four channels of the LPCI Reactor Vessel Water Level - Low Low Function are only required to be OPERABLE when LPCI is required to be OPERABLE to ensure that no single instrument failure can preclude LPCI initiation. Per Footnote (a) to Table 3.3.5.1-1, these

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

ECCS Functions are only required to be OPERABLE in MODES 4 and 5 whenever the associated ECCS is required to be OPERABLE per LCO 3.5.2. Refer to LCO 3.5.1 and LCO 3.5.2 for Applicability Bases for the low pressure ECCS subsystems; LCO 3.8.1, "AC Sources - Operating," and LCO 3.8.2, "AC Sources - Shutdown," for Applicability Bases for the EDGs.

1.b, 2.b. Drywell Pressure – High

High pressure in the drywell could indicate a break in the reactor coolant pressure boundary (RCPB). The low pressure ECCS and associated EDGs are initiated upon receipt of the Drywell Pressure - High Function in order to minimize the possibility of fuel damage. The Drywell Pressure - High Function, along with the Reactor Water Level - Low Low Function, is directly assumed in the analysis of the recirculation line break (Ref. 1). The core cooling function of the ECCS, along with the scram action of the RPS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

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

The Drywell Pressure - High Function is required to be OPERABLE when the ECCS or EDG is required to be OPERABLE in conjunction with times when the primary containment is required to be OPERABLE. Thus, four channels of the CS and LPCI Drywell Pressure - High Functions are required to be OPERABLE in MODES 1, 2, and 3 to ensure that no single instrument failure can preclude ECCS and EDG initiation. In MODES 4 and 5, the Drywell Pressure - High Functions are not required, since there is insufficient energy in the reactor to pressurize the primary containment to Drywell Pressure - High setpoint. Refer to LCO 3.5.1 for Applicability Bases for the low pressure ECCS subsystems and to LCO 3.8.1 for Applicability Bases for the EDGs.

1.c, 2.c. Reactor Steam Dome Pressure - Low (Injection Permissive)

Low reactor steam dome pressure signals are used as permissives for the low pressure ECCS subsystems. This ensures that, prior to opening the injection valves of the low pressure ECCS subsystems, the reactor pressure has fallen to a value below these subsystems' maximum design pressure. The Reactor Steam Dome Pressure - Low (Injection Permissive) is one of the Functions assumed to be OPERABLE and capable of permitting initiation of the ECCS during the transients analyzed in Reference 2. In addition, the Reactor Steam Dome Pressure - Low (Injection Permissive) Function is directly assumed in the analysis of the

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

recirculation line break (Ref. 1). The core cooling function of the ECCS, along with the scram action of the RPS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

The Reactor Steam Dome Pressure - Low (Injection Permissive) signals are initiated from two pressure switches (shared by both CS and LPCI) that sense the reactor dome pressure.

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

Two channels of CS Reactor Steam Dome Pressure - Low (Injection Permissive) Function are only required to be OPERABLE when CS is required to be OPERABLE to ensure that no single instrument failure can preclude CS initiation. Two channels of the LPCI Reactor Steam Dome Pressure - Low (Injection Permissive) Function are only required to be OPERABLE when LPCI is required to be OPERABLE to ensure that no single instrument failure can preclude LPCI initiation. Per Footnote (a) to Table 3.3.5.1-1, these ECCS Functions are only required to be OPERABLE in MODES 4 and 5 whenever the associated ECCS is required to be OPERABLE per LCO 3.5.2. Refer to LCO 3.5.1 and LCO 3.5.2 for Applicability Bases for the low pressure ECCS subsystems.

<u>1.d, 2.d. Reactor Steam Dome Pressure - Low (Pump Permissive)</u>

Low reactor steam dome pressure signals are used as permissives for the low pressure ECCS subsystems. These channels delay CS and LPCI pump starts on Reactor Vessel Water Level - Low Low until reactor steam dome pressure is below the setpoint. This ensures that, prior to starting the pumps of the low pressure ECCS subsystems, the reactor pressure has fallen to a value below these subsystems' maximum design pressure. The Reactor Steam Dome Pressure - Low (Pump Permissive) is one of the Functions assumed to be OPERABLE and capable of permitting initiation of the ECCS during the transients analyzed in References 1 and 3. In addition, the Reactor Steam Dome Pressure - Low Function is directly assumed in the analysis of the recirculation line break (Ref. 2). The core cooling function of the ECCS, along with the scram action of the RPS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

The Reactor Steam Dome Pressure - Low signals are initiated from two pressure switches (shared by both CS and LPCI) that sense the reactor dome pressure.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The Allowable Value is high enough to ensure that the ECCS injection prevents the fuel peak cladding temperature from exceeding the limits of 10 CFR 50.46.

Two channels of CS Reactor Steam Dome Pressure - Low (Pump Permissive) Function are only required to be OPERABLE when the CS is required to be OPERABLE to ensure that no single instrument failure can preclude CS initiation. Two channels of LPCI Reactor Steam Dome Pressure - Low (Pump Permissive) Function are only required to be OPERABLE when the LPCI is required to be OPERABLE to ensure that no single instrument failure can preclude LPCI initiation. Per Footnote (a) to Table 3.3.5.1-1, these ECCS Functions are only required to be OPERABLE in MODES 4 and 5 whenever the associated ECCS is required to be OPERABLE per LCO 3.5.2. Refer to LCO 3.5.1 and LCO 3.5.2 for Applicability Bases for the low pressure ECCS subsystems.

<u>1.e, 2.e. Reactor Steam Dome Pressure - Bypass Timer (Pump Permissive)</u>

Low reactor steam dome pressure signals are used as permissives for the low pressure ECCS subsystems. The Bypass Timer channels allow the CS and LPCI pumps to start on Reactor Vessel Water Level - Low Low after the time delay times out, even if the reactor steam dome pressure is above its permissive setpoint. This ensures that, starting the pumps of the low pressure ECCS subsystems will occur on a Reactor Vessel Water Level - Low Low signal after an 18 minute time delay (Refs. 7 and 8). The Reactor Steam Dome Pressure - Time Delay (Pump Permissive) is one of the Functions assumed to be OPERABLE and capable of permitting initiation of the ECCS during the transients analyzed in References 1 and 3. The core cooling function of the ECCS, along with the scram action of the RPS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

The Reactor Steam Dome Pressure - Bypass Timer (Pump Permissive) signals are initiated from four time delay relays.

The Allowable Value is long enough to provide sufficient time for the operator to inhibit any unnecessary ADS actuation, yet short enough to limit the peak cladding temperature to less than 2200°F.

Two channels of CS Reactor Steam Dome Pressure - Bypass Timer (Pump Permissive) Function are only required to be OPERABLE when the CS is required to be OPERABLE to ensure that no single instrument failure can preclude CS initiation. Two channels of LPCI Reactor Steam Dome Pressure - Bypass Timer (Pump Permissive) Function are only required to be OPERABLE when the LPCI is required to be OPERABLE

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

to ensure that no single instrument failure can preclude LPCI initiation. Per Footnote (a) to Table 3.3.5.1-1, these ECCS Functions are only required to be OPERABLE in MODES 4 and 5 whenever the associated ECCS is required to be OPERABLE per LCO 3.5.2. Refer to LCO 3.5.1 and LCO 3.5.2 for Applicability Bases for the low pressure ECCS subsystems.

1.f, 2.f. Core Spray and Low Pressure Coolant Injection Pump Start - Time Delay Relay

The purpose of the time delay relays is to stagger the start of the CS and LPCI pumps that are in each of Divisions 1 and 2, thus limiting the starting transients on the 4.16 kV essential buses. The CS and LPCI Pump Start - Time Delay Relays are assumed to be OPERABLE in the accident and transient analyses requiring ECCS initiation. That is, the analyses assume that the pumps will initiate when required and excess loading will not cause failure of the power sources.

There are two CS Pump Start - Time Delay Relay channels, one in each of the CS pump start logic circuits. While each CS pump time delay relay is dedicated to a single pump start logic, a single failure of a CS Pump Start - Time Delay Relay channel could result in the failure of the three low pressure ECCS pumps, powered from the same 4.16 kV essential bus, to perform their intended function (e.g., as in the case where two ECCS pumps on one 4.16 kV essential bus start simultaneously due to an inoperable time delay relay). This still leaves three of the six low pressure ECCS pumps OPERABLE; thus, the single failure criterion is met (i.e., loss of one instrument does not preclude ECCS initiation). Sixteen Low Pressure Coolant Injection Pump Start - Time Delay Relay channels, four in each of the LPCI pump start logic circuits, are required to be OPERABLE to ensure that no single instrument failure can preclude the associated LPCI pump start. The Allowable Values for the CS and LPCI Pump Start - Time Delay Relays are chosen short enough so that ECCS operation is not degraded.

Each CS and LPCI Pump Start - Time Delay Relay Function is required to be OPERABLE only when the associated ECCS subsystem is required to be OPERABLE. Per Footnote (a) to Table 3.3.5.1-1, these ECCS Functions are only required to be OPERABLE in MODES 4 and 5 whenever the associated ECCS is required to be OPERABLE per LCO 3.5.2. Refer to LCO 3.5.1 and LCO 3.5.2 for Applicability Bases for the LPCI subsystems.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

2.g. Low Pressure Coolant Injection Pump Discharge Flow - Low (Bypass)

The minimum flow instruments are provided to protect the associated LPCI pump from overheating when the pump is operating and the associated injection valve is not fully open. The minimum flow line valve is opened when low flow is sensed, and the valve is automatically closed when the flow rate is adequate to protect the pump. The LPCI Pump Discharge Flow - Low (Bypass) Function is assumed to be OPERABLE and capable of closing the minimum flow valves to ensure that the LPCI flows assumed during the transients and accidents analyzed in References 1 and 2 are met. The core cooling function of the ECCS, along with the scram action of the RPS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

One flow switch per LPCI pump is used to detect the associated subsystems' flow rates. The logic is arranged such that each switch causes its associated minimum flow valve to open. The logic will close the minimum flow valve once the closure setpoint is exceeded. The LPCI minimum flow valves are time delayed such that the valves will not open for 10 seconds after the pump start. This delay can reduce the reactor vessel inventory loss (to the suppression pool) during the startup of the RHR pump while aligned in the shutdown cooling mode, since it provides time (prior to opening the minimum flow valve) to manually increase RHR flow above the minimum flow closure setpoint. The LPCI Pump Discharge Flow - Low (Bypass) Allowable Values are high enough to ensure that the pump flow rate is sufficient to protect the pump, yet low enough to ensure that the closure of the minimum flow valve is initiated to allow full flow into the core.

Each channel of LPCI Pump Discharge Flow - Low (Bypass) Function (four LPCI channels) is only required to be OPERABLE when the associated LPCI pump is required to be OPERABLE to ensure that no single instrument failure can preclude the LPCI function. Per Footnote (a) to Table 3.3.5.1-1, this LPCI Function is only required to be OPERABLE in MODES 4 and 5 whenever the associated LPCI pump is required to be OPERABLE per LCO 3.5.2. Refer to LCO 3.5.1 and LCO 3.5.2 for Applicability Bases for the LPCI subsystems.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

2.h, 2.k. Reactor Steam Dome Pressure - Low (Break Detection) and Reactor Steam Dome Pressure - Time Delay Relay (Break Detection)

The purpose of the Reactor Steam Dome Pressure - Low (Break Detection) and Reactor Steam Dome Pressure - Time Delay Relay (Break Detection) Functions are to optimize the LPCI Loop Select Logic sensitivity if the logic previously actuated recirculation pump trips. This is accomplished by preventing the logic from continuing on to the unbroken loop selection activity until reactor steam dome pressure has dropped below a specified value. These Functions are only required to be OPERABLE for the DBA LOCA analysis, i.e., if the break location is in the recirculation system suction piping (Ref. 2). For a DBA LOCA, the analysis assumes that the LPCI Loop Select Logic successfully identifies and directs LPCI flow to the unbroken recirculation loop so that core reflooding is accomplished in time to ensure that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46. For other LOCA events, (i.e., non-DBA recirculation system pipe breaks), or other RPV pipe breaks the success of the Loop Select Logic is less critical than for the DBA.

Reactor Steam Dome Pressure - Low (Break Detection) signals are initiated from four pressure switches that sense the reactor steam dome pressure. Reactor Steam Dome Pressure - Time Delay Relay (Break Detection) signals are initiated from two time delay relays.

The Reactor Steam Dome Pressure - Low (Break Detection) Allowable Value is chosen to allow for coastdown of any recirculation pump which has just tripped, thus optimizing the sensitivity of the LPCI Loop Select Logic while ensuring that LPCI injection is not delayed. The Reactor Steam Dome Pressure - Time Delay Relay (Break Detection) Allowable Value is chosen to allow momentum effects to establish the maximum differential pressure for break detection.

Four channels of the Reactor Steam Dome Pressure - Low (Break Detection) Function and two channels of the Reactor Steam Dome Pressure - Time Delay Relay (Break Detection) Function are only required to be OPERABLE in MODES 1, 2, and 3 to ensure that no single failure can prevent the LPCI Loop Select Logic from successfully selecting the unbroken recirculation loop for LPCI injection. These Functions are not required to be OPERABLE in MODES 4 and 5 because, in those MODES, the loop for selection is controlled by plant operating procedures, which ensure an OPERABLE LPCI flow path.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

2.i, 2.l. Recirculation Pump Differential Pressure - High (Break Detection) and Recirculation Pump Differential Pressure - Time Delay Relay (Break Detection)

Recirculation pump differential pressure signals are used by the LPCI Loop Select Logic to determine if either recirculation pump is running. If either pump is not running, i.e., single loop operation, the logic, after a short time delay, sends a trip signal to both recirculation pumps. This is necessary to eliminate the possibility of small pipe breaks being masked by a running recirculation pump. These Functions are only required to be OPERABLE for the DBA LOCA analysis, i.e., if the break location is in the recirculation system suction piping (Ref. 2). For a DBA LOCA, the analysis assumes that the LPCI Loop Select Logic successfully identifies and directs LPCI flow to the unbroken recirculation loop so that core reflooding is accomplished in time to ensure that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46. For other LOCA events (i.e., non-DBA recirculation system pipe breaks or other RPV pipe breaks), the success of the Loop Select Logic is less critical than for the DBA.

Recirculation Pump Differential Pressure - High (Break Detection) signals are initiated from eight differential pressure switches, four of which sense the pressure differential between the suction and discharge of each recirculation pump. Recirculation Pump Differential Pressure - Time Delay Relay (Break Detection) signals are initiated by two time delay relays.

The Recirculation Pump Differential Pressure - High (Break Detection) Allowable Value is chosen to be as low as possible, while still maintaining the ability to differentiate between a running and non-running recirculation pump. Recirculation Pump Differential Pressure - Time Delay Relay (Break Detection) Allowable Value is chosen to allow enough time to determine the status of the operating conditions of the recirculation pumps.

Eight channels of the Recirculation Pump Differential Pressure - High (Break Detection) Function and two channels of the Recirculation Pump Differential Pressure - Time Delay Relay (Break Detection) Function are only required to be OPERABLE in MODES 1, 2, and 3 to ensure that no single failure can prevent the LPCI Loop Select Logic from successfully determining if either recirculation pump is running. This Function is not required to be OPERABLE in MODES 4 and 5 because, in those MODES, the loop for selection is controlled by plant operating procedures, which ensure an OPERABLE LPCI flow path.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

2.j, 2.m. Recirculation Riser Differential Pressure - High (Break Detection) and Recirculation Riser Differential Pressure - Time Delay Relay (Break Detection)

Recirculation riser differential pressure signals are used by the LPCI Loop Select Logic to determine which, if any, recirculation loop is broken. This is accomplished by comparing the pressure of the two recirculation loops. A broken loop will be indicated by a lower pressure than an unbroken loop. The loop with the higher pressure is then selected, after a short delay, for LPCI injection. If neither loop is broken, the logic defaults to injecting into the "B" recirculation loop. These Functions are only required to be OPERABLE for the DBA LOCA analysis, i.e., if the break location is in the recirculation system suction piping (Ref. 2). For a DBA LOCA, the analysis assumes that the LPCI Loop Select Logic successfully identifies and directs LPCI flow to the unbroken recirculation loop, so that core reflooding is accomplished in time to ensure that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46. For other LOCA events, (i.e., non-DBA recirculation system pipe breaks), or other RPV pipe breaks, the success of the Loop Select Logic is less critical than for the DBA.

Recirculation Riser Differential Pressure - High (Break Detection) signals are initiated from four differential pressure switches that sense the pressure differential between the A recirculation loop riser and the B recirculation loop riser. If, after a small time delay, the pressure in loop A is not indicating higher than loop B pressure, the logic will select the B loop for injection. If recirculation loop A pressure is indicating higher than loop B pressure, the logic will select the A loop for LPCI injection. Recirculation Riser Differential Pressure - Time Delay - Relay (Break Detection) signals are initiated by two time delay relays.

The Recirculation Riser Differential Pressure - High (Break Detection) Allowable Value is chosen to be as low as possible, while still maintaining the ability to differentiate between a broken and unbroken recirculation loop. The Recirculation Riser Differential Pressure - Time Delay Relay (Break Detection) Allowable Value is chosen to provide a sufficient amount of time to determine which loop is broken.

Four channels of the Recirculation Riser Differential Pressure - High (Break Detection) Function and two channels of the Recirculation Riser Differential Pressure - Time Delay Relay (Break Detection) Function are only required to be OPERABLE in MODES 1, 2, and 3 to ensure that no single failure can prevent the LPCI Loop Select Logic from successfully

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

selecting the unbroken recirculation loop for LPCI injection. This Function is not required to be OPERABLE in MODES 4 and 5 because, in those MODES, the loop for selection is controlled by plant operating procedures, which ensure an OPERABLE LPCI flow path.

<u>HPCI System</u>

<u>3.a. Reactor Vessel Water Level - Low Low</u>

Low RPV water level indicates that the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. Therefore, the HPCI System is initiated at Low Low to maintain level above the top of the active fuel. The Reactor Vessel Water Level - Low Low is one of the Functions assumed to be OPERABLE and capable of initiating HPCI during the transients analyzed in Reference 2. Additionally, the Reactor Vessel Water Level - Low Low Function associated with HPCI along with the Drywell Pressure - High Function is directly assumed in the analysis of the recirculation line break (Ref. 1). The core cooling function of the ECCS, along with the scram action of the RPS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

Reactor Vessel Water Level - Low Low signals are initiated from four level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel.

The Reactor Vessel Water Level - Low Low Allowable Value is high enough such that for complete loss of feedwater flow when the reactor vessel is isolated, the Reactor Core Isolation Cooling (RCIC) System flow with HPCI assumed to fail will be sufficient to avoid injection of low pressure ECCS.

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

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

3.b. Drywell Pressure - High

High pressure in the drywell could indicate a break in the RCPB. The HPCI System is initiated upon receipt of the Drywell Pressure - High Function in order to minimize the possibility of fuel damage. The Drywell Pressure - High Function, along with the Reactor Vessel Water Level - Low Low Function, is directly assumed in the analysis of the recirculation line break (Ref. 1). The core cooling function of the ECCS, along with the scram action of the RPS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

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

Four channels of the Drywell Pressure - High Function are required to be OPERABLE when HPCI is required to be OPERABLE to ensure that no single instrument failure can preclude HPCI initiation. Refer to LCO 3.5.1 for the Applicability Bases for the HPCI System.

3.c. Reactor Vessel Water Level - High

High RPV water level indicates that sufficient cooling water inventory exists in the reactor vessel such that there is no danger to the fuel. Therefore, the Reactor Vessel Water Level - High signal is used to trip the HPCI turbine to prevent overflow into the main steam lines (MSLs). The Reactor Vessel Water Level - High Function is not assumed in the accident and transient analyses. It was retained since it is a potentially significant contributor to risk.

Reactor Vessel Water Level - High signals for HPCI are initiated from two level transmitters from the narrow range water level measurement instrumentation. Both signals are required in order to close the HPCI turbine's stop valve. This ensures that no single instrument failure can preclude HPCI initiation. The Reactor Vessel Water Level - High Allowable Value is chosen to prevent flow from the HPCI System from overflowing into the MSLs.

Two channels of Reactor Vessel Water Level - High Function are required to be OPERABLE only when HPCI is required to be OPERABLE. Refer to LCO 3.5.1 for HPCI Applicability Bases.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

3.d. Condensate Storage Tank Level - Low

Low level in a CST indicates the unavailability of an adequate supply of makeup water from this normal source. Normally the suction valves between HPCI and the CSTs are open and, upon receiving a HPCI initiation signal, water for HPCI injection would be taken from all aligned CSTs. However, if the water level in any CST falls below a preselected level, first the suppression pool suction valves automatically open, and then the CST suction valve automatically closes. This ensures that an adequate supply of makeup water is available to the HPCI pump. To prevent losing suction to the pump, the suction valves are interlocked so that the suppression pool suction valves must be open before the CSTs suction valve automatically closes. The Function is implicitly assumed in the accident and transient analyses (which take credit for HPCI) since the analyses assume that the HPCI suction source is the suppression pool.

Condensate Storage Tank Level - Low signals are initiated from two level switches (normally one associated with each CST). The logic is arranged such that either level switch can cause the suppression pool suction valves to open and the CSTs suction valve to close. The Condensate Storage Tank Level - Low Function Allowable Value is high enough to ensure adequate pump suction head while water is being taken from the CSTs. The Allowable Value is referenced from the bottom of the tank.

Two channels of the Condensate Storage Tank Level - Low Function are required to be OPERABLE only when HPCI is required to be OPERABLE to ensure that no single instrument failure can preclude HPCI swap to suppression pool source. Refer to LCO 3.5.1 for HPCI Applicability Bases.

3.e. Suppression Pool Water Level - High

Excessively high suppression pool water could result in the loads on the suppression pool exceeding design values should there be a blowdown of the reactor vessel pressure through the safety/relief valves. Therefore, signals indicating high suppression pool water level are used to transfer the suction source of HPCI from the CSTs to the suppression pool to eliminate the possibility of HPCI continuing to provide additional water from a source outside containment. To prevent losing suction to the pump, the suction valves are interlocked so that the suppression pool suction valves must be open before the CSTs suction valve automatically closes. This Function is implicitly assumed in the accident and transient analyses (which take credit for HPCI) since the analyses assume that the HPCI suction source is the suppression pool.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Suppression Pool Water Level - High signals are initiated from two level switches. The logic is arranged such that either switch can cause the suppression pool suction valves to open and the CSTs suction valve to close. The Allowable Value for the Suppression Pool Water Level - High Function is chosen to ensure that HPCI will be aligned for suction from the suppression pool before the water level reaches the point at which suppression pool design loads would be exceeded.

Two channels of Suppression Pool Water Level - High Function are required to be OPERABLE only when HPCI is required to be OPERABLE to ensure that no single instrument failure can preclude HPCI swap to suppression pool source. Refer to LCO 3.5.1 for HPCI Applicability Bases.

3.f. High Pressure Coolant Injection Pump Discharge Flow - Low (Bypass)

The minimum flow instruments are provided to protect the HPCI pump from overheating when the pump is operating and the associated injection valve is not fully open. The minimum flow line valve is opened when low flow is sensed, and the valve is automatically closed when the flow rate is adequate to protect the pump. The High Pressure Coolant Injection Pump Discharge Flow - Low (Bypass) Function is assumed to be OPERABLE and capable of closing the minimum flow valve to ensure that the ECCS flow assumed during the transients and accidents analyzed in References 1 and 2 are met. The core cooling function of the ECCS, along with the scram action of the RPS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

One flow switch is used to detect the HPCI System's flow rate. The logic is arranged such that the switch causes the minimum flow valve to open. The logic will close the minimum flow valve once the closure setpoint is exceeded.

The High Pressure Coolant Injection Pump Discharge Flow - Low (Bypass) Allowable Value is high enough to ensure that pump flow rate is sufficient to protect the pump, yet low enough to ensure that the closure of the minimum flow valve is initiated to allow full flow into the core.

One channel is required to be OPERABLE when the HPCI is required to be OPERABLE. Refer to LCO 3.5.1 for HPCI Applicability Bases.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Automatic Depressurization System

4.a, 5.a. Reactor Vessel Water Level - Low Low

Low RPV water level indicates that the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. Therefore, ADS receives one of the signals necessary for initiation from this Function. The Reactor Vessel Water Level - Low Low is one of the Functions assumed to be OPERABLE and capable of initiating the ADS during the accident analyzed in Reference 1. The core cooling function of the ECCS, along with the scram action of the RPS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

Reactor Vessel Water Level - Low Low signals are initiated from four level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. Four channels of Reactor Vessel Water Level - Low Low Function are required to be OPERABLE only when ADS is required to be OPERABLE to ensure that no single instrument failure can preclude ADS initiation. Two channels input to ADS trip system A, while the other two channels input to ADS trip system B. Refer to LCO 3.5.1 for ADS Applicability Bases.

The Reactor Vessel Water Level - Low Low Allowable Value is chosen to allow time for the low pressure core flooding systems to initiate and provide adequate cooling.

4.b, 5.b. Automatic Depressurization System Initiation Timer

The purpose of the Automatic Depressurization System Initiation Timer is to delay depressurization of the reactor vessel to allow the HPCI System time to maintain reactor vessel water level. Since the rapid depressurization caused by ADS operation is one of the most severe transients on the reactor vessel, its occurrence should be limited. By delaying initiation of the ADS Function, the operator is given the chance to monitor the success or failure of the HPCI System to maintain water level, and then to decide whether to allow ADS to automatically initiate or to delay or inhibit ADS initiation. The Automatic Depressurization System Initiation Timer Function is assumed to be OPERABLE for the accident analyses of Reference 1 that require ECCS initiation and assume failure of the HPCI System.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

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

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

<u>4.c, 4.d, 5.c, 5.d. Core Spray and Low Pressure Coolant Injection Pump Discharge Pressure - High</u>

The Pump Discharge Pressure - High signals from the CS and LPCI pumps are used as permissives for ADS initiation, indicating that there is a source of low pressure cooling water available once the ADS has depressurized the vessel. Pump Discharge Pressure - High is one of the Functions assumed to be OPERABLE and capable of permitting ADS initiation during the events analyzed in Reference 1 with an assumed HPCI failure. For these events the ADS depressurizes the reactor vessel so that the low pressure ECCS can perform the core cooling functions. This core cooling function of the ECCS, along with the scram action of the RPS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

Pump discharge pressure signals are initiated from twelve pressure switches, two on the discharge side of each of the six low pressure ECCS pumps. In order to generate an ADS permissive in one trip system, it is necessary that only one pump (both channels for the pump) indicate the high discharge pressure condition. The Pump Discharge Pressure - High Allowable Value is less than the pump discharge pressure when the pump is operating in a full flow mode and high enough to avoid any condition that results in a discharge pressure permissive when the CS and LPCI pumps are aligned for injection and the pumps are not running. The actual operating point of this function is not assumed in any transient or accident analysis.

Twelve channels of Core Spray and Low Pressure Coolant Injection Pump Discharge Pressure - High Function are only required to be OPERABLE when the ADS is required to be OPERABLE to ensure that no single instrument failure can preclude ADS initiation. Two CS

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

channels associated with CS pump A and four LPCI channels associated with LPCI pumps A and C are required for trip system A. Two CS channels associated with CS pump B and four LPCI channels associated with LPCI pumps B and D are required for trip system B. Refer to LCO 3.5.1 for ADS Applicability Bases.

ACTIONS

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

A.1

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

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

Required Actions B.1 and B.2 are intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same Function result in redundant automatic initiation capability being lost for the feature(s). Required Action B.1 features would be those that are initiated by Functions 1.a, 1.b, 2.a, 2.b, 2.f, 2.h, and 2.k (i.e., low pressure ECCS and associated EDG). The Required Action B.2 system would be HPCI. For Required Action B.1, redundant automatic initiation capability is lost if: (a) two or more Function 1.a channels are inoperable and untripped such that both trip systems lose initiation capability; (b) two or more Function 2.a channels are inoperable and untripped such that both trip systems lose initiation capability; (c) two or more Function 1.b channels are inoperable and untripped such that both trip systems lose initiation capability; (d) two or more Function 2.b channels are inoperable

BASES

ACTIONS (continued)

and untripped such that both trip systems lose initiation capability; (e) two or more Function 2.f channels are inoperable and untripped such that one or more pumps in both LPCI subsystems lose initiation (i.e., time delay) capability; (f) two or more Function 2.h channels are inoperable and untripped such that both trip systems lose initiation capability; or (g) two Function 2.k channels are inoperable and untripped. For low pressure ECCS, since each inoperable channel would have Required Action B.1 applied separately (refer to ACTIONS Note), each inoperable channel would only require the affected portion of the associated system of low pressure ECCS and EDGs to be declared inoperable. However, since channels in both associated low pressure ECCS subsystems (e.g., both CS subsystems) are inoperable and untripped, and the Completion Times started concurrently for the channels in both subsystems, this results in the affected portions in the associated low pressure ECCS and EDGs being concurrently declared inoperable.

For Required Action B.2, redundant automatic initiation capability is lost if two Function 3.a or two Function 3.b channels are inoperable and untripped in the same trip system (a trip system in this case is defined as channels associated with the parallel level in the logic arrangement).

In this situation (loss of redundant automatic initiation capability), the 24 hour allowance of Required Action B.3 is not appropriate and the feature(s) associated with the inoperable, untripped channels must be declared inoperable within 1 hour. As noted (Note 1 to Required Action B.1), Required Action B.1 is only applicable in MODES 1, 2, and 3. In MODES 4 and 5, the specific initiation time of the low pressure ECCS is not assumed and the probability of a LOCA is lower. Thus, a total loss of initiation capability for 24 hours (as allowed by Required Action B.3) is allowed during MODES 4 and 5. There is no similar Note provided for Required Action B.2 since HPCI instrumentation is not required in MODES 4 and 5; thus, a Note is not necessary. Notes are also provided (Note 2 to Required Action B.1 and the Note to Required Action B.2) to delineate which Required Action is applicable for each Function that requires entry into Condition B if an associated channel is inoperable. This ensures that the proper loss of initiation capability check is performed.

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." For Required Action B.1, the Completion Time only begins upon discovery that a redundant feature in the same system (e.g., both CS subsystems) cannot be automatically initiated due to inoperable, untripped channels within the same Function as described in the paragraph above. For Required Action B.2, the Completion Time

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ACTIONS (continued)

only begins upon discovery that the HPCI System cannot be automatically initiated due to two inoperable, untripped channels for the associated Function in the same trip system. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

Because of the diversity of sensors available to provide initiation signals and the redundancy of the ECCS design, an allowable out of service time of 24 hours has been shown to be acceptable (Ref. 3) to permit restoration of any inoperable channel to OPERABLE status. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be placed in the tripped condition per Required Action B.3. Placing the inoperable channel in trip would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. Alternately, if it is not desired to place the channel in trip (e.g., as in the case where placing the inoperable channel in trip would result in an initiation or as in the case where placing an inoperable channel in trip would result in an immediate initiation without time delay when an initiation signal is received), Condition H must be entered and its Required Action taken.

C.1 and C.2

Required Action C.1 is intended to ensure that appropriate actions are taken if multiple, inoperable channels within the same Function result in redundant automatic initiation capability being lost for the feature(s). Required Action C.1 features would be those that are initiated by Functions 1.c, 1.d, 1.e, 1.f, 2.c, 2.d, 2.e, 2.i, 2.j, 2.l, and 2.m (i.e., low pressure ECCS). Redundant automatic initiation capability is lost if: (a) two Function 1.c channels are inoperable; (b) two Function 2.c channels are inoperable; (c) two Function 1.d channels are inoperable; (d) two Function 2.d channels are inoperable; (e) two Function 1.e channels are inoperable; (f) two Function 2.e channels are inoperable; (g) two Function 1.f channels are inoperable; (h) two or more Function 2.i channels, associated with a recirculation pump are inoperable such that both trip systems lose initiation capability; (i) two or more Function 2.j channels are inoperable such that both trip systems lose initiation capability; (j) two Function 2.l channels are inoperable; or (k) two Function 2.m channels are inoperable. Since each inoperable channel would have Required Action C.1 applied separately (refer to ACTIONS Note), each inoperable channel would only require the affected portion

BASES

ACTIONS (continued)

of the associated system to be declared inoperable. However, since channels for both low pressure ECCS subsystems are inoperable (e.g., both CS subsystems), and the Completion Times started concurrently for the channels in both subsystems, this results in the affected portions in both subsystems being concurrently declared inoperable. For these Functions the affected portions are the associated low pressure ECCS pumps.

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

Note 2 states that Required Action C.1 is only applicable for Functions 1.c, 1.d, 1.e, 1.f, 2.c, 2.d, 2.e, 2.i, 2.j, 2.l, and 2.m. Required Action C.1 is not applicable to Function 3.c (which also requires entry into this Condition if a channel in this Function is inoperable), since the loss of one channel results in a loss of the Function (two-out-of-two logic). This loss was considered during the development of Reference 3 and considered acceptable for the 24 hours allowed by Required Action C.2.

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." For Required Action C.1, the Completion Time only begins upon discovery that the same feature in both subsystems (e.g., both CS subsystems) cannot be automatically initiated due to inoperable channels within the same Function as described in the paragraph above. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration of channels.

Because of the diversity of sensors available to provide initiation signals and the redundancy of the ECCS design, an allowable out of service time of 24 hours has been shown to be acceptable (Ref. 3) to permit restoration of any inoperable channel to OPERABLE status. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, Condition H must be entered and its

ACTIONS (continued)

Required Action taken. The Required Actions do not allow placing the channel in trip since this action would either cause the initiation or it would not necessarily result in a safe state for the channel in all events.

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

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

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." For Required Action D.1, the Completion Time only begins upon discovery that the HPCI System cannot be automatically aligned to the suppression pool due to two inoperable, untripped channels in the same Function. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

Because of the diversity of sensors available to provide initiation signals and the redundancy of the ECCS design, an allowable out of service time of 24 hours has been shown to be acceptable (Ref. 3) to permit restoration of any inoperable channel to OPERABLE status. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be placed in the tripped condition per Required Action D.2.1 or the suction source must be aligned to the suppression pool per Required Action D.2.2. Placing the inoperable channel in trip performs the intended function of the channel (shifting the suction source to the suppression pool). Performance of either of these two Required Actions will allow operation to continue. If Required Action D.2.1 or D.2.2 is performed, measures should be taken to ensure that the HPCI System piping remains filled with water. Alternately, if it is not desired to perform Required Actions D.2.1

BASES

ACTIONS (continued)

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

E.1 and E.2

Required Action E.1 is intended to ensure that appropriate actions are taken if multiple, inoperable channels within the Low Pressure Coolant Injection Pump Discharge Flow - Low (Bypass) Function results in redundant automatic initiation capability being lost for the feature(s). For Required Action E.1, the features would be those that are initiated by Function 2.g (i.e., LPCI). Redundant automatic initiation capability is lost if one or more Function 2.g channels associated with pumps in LPCI subsystem A and one or more Function 2.g channels associated with pumps in LPCI subsystem B are inoperable. Since each inoperable channel would have Required Action E.1 applied separately (refer to ACTIONS Note), each inoperable channel would only require the affected LPCI pump to be declared inoperable. However, since channels for more than one LPCI pump are inoperable, and the Completion Times started concurrently for the channels of the LPCI pumps, this results in the affected ECCS pumps being concurrently declared inoperable.

In this situation (loss of redundant automatic initiation capability), the 7 day allowance of Required Action E.2 is not appropriate and the subsystem associated with each inoperable channel must be declared inoperable within 1 hour. As noted (Note 1 to Required Action E.1), Required Action E.1 is only applicable in MODES 1, 2, and 3. In MODES 4 and 5, the specific initiation time of the ECCS is not assumed and the probability of a LOCA is lower. Thus, a total loss of initiation capability for 7 days (as allowed by Required Action E.2) is allowed during MODES 4 and 5. A Note is also provided (Note 2 to Required Action E.1) to delineate that Required Action E.1 is only applicable to the LPCI Function. Required Action E.1 is not applicable to HPCI Function 3.f since the loss of one channel results in a loss of the Function (one-out-of-one logic). This loss was considered during the development of Reference 3 and considered acceptable for the 7 days allowed by Required Action E.2. The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock."

BASES

ACTIONS (continued)

For Required Action E.1, the Completion Time only begins upon discovery that a redundant feature in the same system (i.e., both LPCI subsystems) cannot be automatically initiated due to inoperable channels within the same Function as described in the paragraph above. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration of channels.

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

<u>F.1 and F.2</u>

Required Action F.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within similar ADS trip system A and B Functions result in redundant automatic initiation capability being lost for the ADS. Redundant automatic initiation capability is lost if one Function 4.a channel and one Function 5.a channel are inoperable and untripped.

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

BASES

ACTIONS (continued)

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." For Required Action F.1, the Completion Time only begins upon discovery that the ADS cannot be automatically initiated due to inoperable, untripped channels within similar ADS trip system Functions as described in the paragraph above. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

Because of the diversity of sensors available to provide initiation signals and the redundancy of the ECCS design, an allowable out of service time of 8 days has been shown to be acceptable (Ref. 3) to permit restoration of any inoperable channel to OPERABLE status if both HPCI and RCIC are OPERABLE. If either HPCI or RCIC is inoperable, the time is shortened to 96 hours. If the status of HPCI or RCIC changes such that the Completion Time changes from 8 days to 96 hours, the 96 hours begins upon discovery of HPCI or RCIC inoperability. However, the total time for an inoperable, untripped channel cannot exceed 8 days. If the status of HPCI or RCIC changes such that the Completion Time changes from 96 hours to 8 days, the "time zero" for beginning the 8 day "clock" begins upon discovery of the inoperable, untripped channel. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be placed in the tripped condition per Required Action F.2. Placing the inoperable channel in trip would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. Alternately, if it is not desired to place the channel in trip (e.g., as in the case where placing the inoperable channel in trip would result in an initiation), Condition H must be entered and its Required Action taken.

G.1 and G.2

Required Action G.1 is intended to ensure that appropriate actions are taken if multiple, inoperable channels within similar ADS trip system Functions result in automatic initiation capability being lost for the ADS. Automatic initiation capability is lost if either: (a) one Function 4.b channel and one Function 5.b channel are inoperable; or (b) a combination of Functions 4.c, 4.d, 5.c, and 5.d channels are inoperable such that channels associated with five or more low pressure ECCS pumps are inoperable.

BASES

ACTIONS (continued)

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

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." For Required Action G.1, the Completion Time only begins upon discovery that the ADS cannot be automatically initiated due to inoperable channels within similar ADS trip system Functions as described in the paragraph above. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

Because of the diversity of sensors available to provide initiation signals and the redundancy of the ECCS design, an allowable out of service time of 8 days has been shown to be acceptable (Ref. 3) to permit restoration of any inoperable channel to OPERABLE status if both HPCI and RCIC are OPERABLE (Required Action G.2). If either HPCI or RCIC is inoperable, the time shortens to 96 hours. If the status of HPCI or RCIC changes such that the Completion Time changes from 8 days to 96 hours, the 96 hours begins upon discovery of HPCI or RCIC inoperability. However, the total time for an inoperable channel cannot exceed 8 days. If the status of HPCI or RCIC changes such that the Completion Time changes from 96 hours to 8 days, the "time zero" for beginning the 8 day "clock" begins upon discovery of the inoperable channel. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, Condition H must be entered and its Required Action taken. The Required Actions do not allow placing the channel in trip since this action would not necessarily result in a safe state for the channel in all events.

H.1

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

BASES

SURVEILLANCE REQUIREMENTS

As noted in the beginning of the SRs, the SRs for each ECCS instrumentation Function are found in the SRs column of Table 3.3.5.1-1. The Surveillances are modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours as follows: (a) for Functions 3.c and 3.f; and (b) for Functions other than 3.c and 3.f provided the associated Function or redundant Function maintains ECCS initiation capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. A channel that is shared between both trip systems is considered one channel. This Note is based on the reliability analysis (Ref. 3) assumption of the average time required to perform channel surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that the ECCS will initiate when necessary.

SR 3.3.5.1.1

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

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

The Frequency is based upon operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the channels required by the LCO.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.5.1.2, SR 3.3.5.1.5 and SR 3.3.5.1.9

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions.

Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

The Frequency of 92 days for SR 3.3.5.1.2 is based on the reliability analyses of Reference 3. The Frequency of 12 months for SR 3.3.5.1.5 is based on the known reliability of the equipment and the multichannel redundancy available, and has been shown to be acceptable through operating experience. The Frequency of 24 months for SR 3.3.5.1.9 is based on the known reliability of the equipment and the multichannel redundancy available, and has been shown to be acceptable through operating experience.

SR 3.3.5.1.3

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

The Frequency of 92 days is based on the reliability analysis of Reference 3.

SR 3.3.5.1.4, SR 3.3.5.1.6, and SR 3.3.5.1.7

A CHANNEL CALIBRATION is a complete check of the instrument loop and the sensor. This test verifies the channel responds to the measured parameter within the necessary range and accuracy. CHANNEL

BASES

SURVEILLANCE REQUIREMENTS (continued)

CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

The Frequency of SR 3.3.5.1.4 is based upon the assumption of a 92 day calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis. The Frequency of SR 3.3.5.1.6 is based upon the assumption of a 12 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis. The Frequency of SR 3.3.5.1.7 is based upon the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis, and for Function 2.j, a revised minimum detectable break area for the LPCI loop select logic (Refs. 5 and 6).

The SR 3.3.5.1.4 annotation in Table 3.3.5.1-1 for Functions 1.c, 1.d, 2.c, 2.d, 4.c, 4.d, 5.c, and 5.d has been modified by two Notes. The SR 3.3.5.1.7 annotation in Table 3.3.5.1-1 for Function 2.j has also been modified by these same two Notes. The first Note requires evaluation of channel performance for the condition where the as-found setting for the channel is outside its as-found tolerance but conservative with respect to the Allowable Value. Evaluation of instrument performance will verify that the instrument will continue to behave in accordance with design basis assumptions. The purpose of the assessment is to ensure confidence in the instrument performance prior to returning the instrument to service. These channels will also be identified in the Corrective Action Program. In accordance with procedures, entry into the Corrective Action Program will require review and documentation of the condition of OPERABILITY. The second Note requires the setting for the instrument be returned to within the as-left tolerance of the nominal trip setpoint. This will ensure that sufficient margin to the Safety Limit and /or Analytical Limit is maintained. If the setting for the instrument cannot be returned to within the as-left tolerance of the nominal trip setpoint, then the instrument channel shall be declared inoperable. The second Note also requires that the nominal trip setpoint and the methodology for calculating the as-left and the as-found tolerances be in a document controlled under 10 CFR 50.59 (i.e., Technical Requirements Manual (Ref. 4)).

SR 3.3.5.1.8

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

BASES

SURVEILLANCE REQUIREMENTS (continued)

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

REFERENCES

1. USAR, Section 14.7.2.

2. USAR, Chapter 14.

3. NEDC-30936-P-A, "BWR Owners' Group Technical Specification Improvement Analyses for ECCS Actuation Instrumentation, Parts 1 and 2," December 1988.

4. Technical Requirements Manual.

5. GE-NE-0000-0052-3113-P-R0, “SAFER/GESTR ECCS-LOCA Analysis – LPCI Loop Selection Detectable Break Area,” September 2006.

6. Amendment No. 161, “Monticello Nuclear Generating Plant - Issuance of Amendment Regarding Recirculation Riser Differential Pressure (TAC No. MD6864),” dated April 7, 2009. (ADAMS Accession No. ML083040608)

7. Calculation 03-036, Revision 2, “Instrument Setpoint Calculation Reactor Low Pressure Permissive Bypass Timer”

8. Amendment No. 176, “Monticello Nuclear Generating Plant – Issuance of Amendment No. 176 to Renewed Facility Operating License Regarding Extended Power Uprate,” (ADAMS Accession No. ML13316C459)

B 3.3 INSTRUMENTATION

B 3.3.5.2 Reactor Core Isolation Cooling (RCIC) System Instrumentation

BASES

BACKGROUND

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

The RCIC System may be initiated by either automatic or manual means. Automatic initiation occurs for conditions of Reactor Vessel Water Level - Low Low level. The variable is monitored by four transmitters that are connected to four trip units. The outputs of the trip units are connected to relays whose contacts are arranged in a one-out-of-two taken twice logic arrangement.

The RCIC test line return valves to the condensate storage tanks (CSTs) are closed on a RCIC initiation signal to allow full system flow.

The RCIC System also monitors the water level in the two CSTs since this is the normally aligned source of water for RCIC operation. Reactor grade water in the CSTs is the normal source. Upon receipt of a RCIC initiation signal, the CST suction valve is automatically signaled to open (it is normally in the open position) unless the pump suction from the suppression pool valves is open. If the water level in any CST falls below a preselected level, first the suppression pool suction valves automatically open, and then the CST suction valve automatically closes. Two level switches are used to detect low water level in the CST (one for each CST). Either switch can cause the suppression pool suction valves to open and the CST suction valve to close. To prevent losing suction to the pump, the suction valves are interlocked so that one suction path must be open before the other automatically closes.

The RCIC System provides makeup water to the reactor until the reactor vessel water level reaches the Reactor Vessel Water Level - High trip (two-out-of-two logic), at which time the RCIC steam admission valve and cooling water supply valves close. The RCIC System automatically restarts if a Reactor Vessel Water Level - Low Low signal is subsequently received.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The function of the RCIC System to provide makeup coolant to the reactor is used to respond to transient events. The RCIC System is not an Engineered Safety Feature System and no credit is taken in the safety analyses for RCIC System operation. The RCIC System instrumentation satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii). Certain instrumentation Functions are retained for other reasons and are described below in the individual Functions discussion.

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

Allowable Values are specified for each RCIC System instrumentation Function specified in the Table. Nominal trip setpoints are specified in the setpoint calculations. The nominal setpoints are selected to ensure that the setpoints do not exceed the Allowable Value between CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable. A channel is inoperable if its actual trip setpoint is not within its required Allowable Value. The Allowable Values and nominal trip setpoints (NTSP) are derived, using the General Electric setpoint methodology guidance, as specified in the Monticello setpoint methodology. The Allowable Values are derived from the analytic limits. The difference between the analytic limit and the Allowable Value allows for channel instrument accuracy, calibration accuracy, process measurement accuracy, and primary element accuracy. The margin between the Allowable Value and the NTSP allows for instrument drift that might occur during the established surveillance period. Two separate verifications are performed for the calculated NTSP. The first, a Spurious Trip Avoidance Test, evaluates the impact of the NTSP on plant availability. The second verification, an LER Avoidance Test, calculates the probability of avoiding a Licensee Event Report (or exceeding the Allowable Value) due to instrument drift. These two verifications are statistical evaluations to provide additional assurance of the acceptability of the NTSP and may require changes to the NTSP. Use of these methods and verifications provides the assurance that if the setpoint is found conservative to the Allowable Value during surveillance testing, the instrumentation would have provided the required trip function by the time the process reached the analytic limit for the applicable events.

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

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

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

1. Reactor Vessel Water Level - Low Low

Low reactor pressure vessel (RPV) water level indicates that normal feedwater flow is insufficient to maintain reactor vessel water level and that the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. Therefore, the RCIC System is initiated at Low Low to assist in maintaining water level above the top of the active fuel.

Reactor Vessel Water Level - Low Low signals are initiated from four level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel.

The Reactor Vessel Water Level - Low Low Allowable Value is set high enough such that for complete loss of feedwater flow when the reactor vessel is isolated, the RCIC System flow with high pressure coolant injection assumed to fail will be sufficient to avoid injection of low pressure ECCS.

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

2. Reactor Vessel Water Level - High

High RPV water level indicates that sufficient cooling water inventory exists in the reactor vessel such that there is no danger to the fuel. Therefore, the Reactor Vessel Water Level - High signal is used to close the RCIC steam admission valve and cooling water supply valves to prevent overflow into the main steam lines (MSLs).

Reactor Vessel Water Level - High signals for RCIC are initiated from two level transmitters from the narrow range water level measurement instrumentation, which sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel.

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

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

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

3. Condensate Storage Tank Level - Low

Low level in a CST indicates the unavailability of an adequate supply of makeup water from this normal source. Normally, the suction valve between the RCIC pump and the CSTs is open and, upon receiving a RCIC initiation signal, water for RCIC injection would be taken from all aligned CSTs. However, if the water level in any CST falls below a preselected level, first the suppression pool suction valves automatically open, and then the CST suction valve automatically closes. This ensures that an adequate supply of makeup water is available to the RCIC pump. To prevent losing suction to the pump, the suction valves are interlocked so that the suppression pool suction valves must be open before the CST suction valve automatically closes.

Two level switches are used to detect low water level in the CSTs (normally one associated with each CST). The Condensate Storage Tank Level - Low Function Allowable Value is set high enough to ensure adequate pump suction head while water is being taken from the CSTs. The Allowable Value is referenced from the bottom of the tank.

Two channels of Condensate Storage Tank Level - Low Function are available and are required to be OPERABLE when RCIC is required to be OPERABLE to ensure that no single instrument failure can preclude RCIC swap to suppression pool source. Refer to LCO 3.5.3 for RCIC Applicability Bases.

ACTIONS

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

BASES

ACTIONS (continued)

A.1

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

B.1 and B.2

Required Action B.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same Function result in a complete loss of automatic initiation capability for the RCIC System. In this case, automatic initiation capability is lost if two Function 1 channels in the same trip system are inoperable and untripped. In this situation (loss of automatic initiation capability), the 24 hour allowance of Required Action B.2 is not appropriate, and the RCIC System must be declared inoperable within 1 hour after discovery of loss of RCIC initiation capability.

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." For Required Action B.1, the Completion Time only begins upon discovery that the RCIC System cannot be automatically initiated due to two inoperable, untripped Reactor Vessel Water Level - Low Low channels in the same trip system. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

Because of the redundancy of sensors available to provide initiation signals and the fact that the RCIC System is not credited in any accident or transient analysis, an allowable out of service time of 24 hours has been shown to be acceptable (Ref. 1) to permit restoration of any inoperable channel to OPERABLE status. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be placed in the tripped condition per Required Action B.2. Placing the inoperable channel in trip would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. Alternately, if it is not desired to place the channel in trip (e.g., as in the case where placing the inoperable channel in trip would result in an initiation), Condition E must be entered and its Required Action taken.

BASES

ACTIONS (continued)

C.1

A risk based analysis was performed and determined that an allowable out of service time of 24 hours (Ref. 1) is acceptable to permit restoration of any inoperable channel to OPERABLE status (Required Action C.1). A Required Action (similar to Required Action B.1) limiting the allowable out of service time, if a loss of automatic RCIC initiation capability exists, is not required. This Condition applies to the Reactor Vessel Water Level - High Function whose logic is arranged such that any inoperable channel will result in a loss of automatic RCIC initiation (high water level trip) capability. As stated above, this loss of automatic RCIC initiation capability was analyzed and determined to be acceptable. The Required Action does not allow placing a channel in trip since this action would not necessarily result in a safe state for the channel in all events.

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

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

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." For Required Action D.1, the Completion Time only begins upon discovery that the RCIC System cannot be automatically aligned to the suppression pool due to two inoperable, untripped channels in the same Function. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

Because of the redundancy of sensors available to provide initiation signals and the fact that the RCIC System is not assumed in any accident or transient analysis, an allowable out of service time of 24 hours has been shown to be acceptable (Ref. 1) to permit restoration of any

BASES

ACTIONS (continued)

inoperable channel to OPERABLE status. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be placed in the tripped condition per Required Action D.2.1, which performs the intended function of the channel (shifting the suction source to the suppression pool). Alternatively, Required Action D.2.2 allows the manual alignment of the RCIC suction to the suppression pool, which also performs the intended function. If Required Action D.2.1 or D.2.2 is performed, measures should be taken to ensure that the RCIC System piping remains filled with water. If it is not desired to perform Required Actions D.2.1 and D.2.2 (e.g., as in the case where shifting the suction source could drain down the RCIC suction piping), Condition E must be entered and its Required Action taken.

E.1

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

SURVEILLANCE REQUIREMENTS

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

The Surveillances are modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed as follows: (a) for up to 6 hours for Function 2; and (b) for up to 6 hours for Functions 1 and 3, provided the associated Function maintains RCIC initiation capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the reliability analysis (Ref. 1) assumption of the average time required to perform channel surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that the RCIC will initiate when necessary.

SR 3.3.5.2.1

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

BASES

SURVEILLANCE REQUIREMENTS (continued)

approximately the same value. Significant deviations between the instrument channels could be an indication of excessive instrument drift in one of the channels or something even more serious. A CHANNEL CHECK will detect gross channel failure; thus, it is key to verifying the instrumentation continues to operate properly between each CHANNEL CALIBRATION.

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

The Frequency is based upon operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the channels required by the LCO.

SR 3.3.5.2.2

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions.

Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

The Frequency of 92 days is based on the reliability analysis of Reference 1.

SR 3.3.5.2.3

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

BASES

SURVEILLANCE REQUIREMENTS (continued)

conditions, the setpoint must be readjusted to be equal to or more conservative than accounted for in the appropriate setpoint methodology.

The Frequency of 92 days is based on the reliability analysis of Reference 1.

SR 3.3.5.2.4

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

The Frequency of SR 3.3.5.2.4 is based upon the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.5.2.5

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required initiation logic for a specific channel. The system functional testing performed in LCO 3.5.3 overlaps this Surveillance to provide complete testing of the safety function.

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

REFERENCES

1. GENE-770-06-2-A, "Addendum to Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications," December 1992.

B 3.3 INSTRUMENTATION

B 3.3.6.1 Primary Containment Isolation Instrumentation

BASES

BACKGROUND

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

The isolation instrumentation includes the sensors, relays, and switches that are necessary to cause initiation of primary containment and reactor coolant pressure boundary (RCPB) isolation. Most channels include electronic equipment (e.g., trip units) that compares measured input signals with pre-established setpoints. When the setpoint is exceeded, the channel output relay actuates, which then outputs a primary containment isolation signal to the isolation logic. Functional diversity is provided by monitoring a wide range of independent parameters. The input parameters to the isolation logics are (a) reactor vessel water level, (b) area ambient temperatures, (c) main steam line (MSL) flow measurement, (d) Standby Liquid Control (SLC) System initiation, (e) main steam line pressure, (f) high pressure coolant injection (HPCI) and reactor core isolation cooling (RCIC) steam line flow, (g) drywell pressure, (h) HPCI and RCIC steam line pressure, (i) reactor water cleanup (RWCU) flow, and (j) reactor steam dome pressure. Redundant sensor input signals from each parameter are provided for initiation of isolation. The only exception is SLC System initiation.

Primary containment isolation instrumentation has inputs to the trip logic of the isolation functions listed below.

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

Reactor Vessel Water Level - Low Low and Main Steam Line Pressure - Low Functions receive inputs from four channels. One channel associated with each Function inputs to one of four trip strings. Two trip strings make up a trip system and both trip systems must trip to cause an isolation of all main steam isolation valves (MSIVs), MSL drain valves, and reactor sample isolation valves. Any channel will trip the associated trip string. Only one trip string must trip to trip the associated trip system. The trip strings are arranged in a one-out-of-two taken twice logic to initiate isolation of all main steam isolation valves (MSIVs), MSL drain valves, and recirculation sample isolation valves.

BASES

BACKGROUND (continued)

The Main Steam Line Flow - High Function uses 16 flow channels, four for each steam line. One channel from each steam line inputs to one of the four trip strings. Two trip strings make up each trip system and both trip systems must trip to cause an isolation of the MSIVs, MSL drain valves, and reactor sample isolation valves. Each trip string has four inputs (one per MSL), any one of which will trip the trip string. The trip strings are arranged in a one-out-of-two taken twice logic. This is effectively a one-out-of-eight taken twice logic arrangement to initiate isolation.

The Main Steam Line Tunnel Temperature - High Function receives input from 16 channels (four from each of the four tunnel areas). The logic is arranged similar to the Main Steam Line Flow - High Function. One channel from each steam tunnel area inputs to one of four trip strings. Two trip strings make up a trip system, and both trip systems must trip to cause isolation.

MSL Isolation Functions isolate the Group 1 valves.

2. Primary Containment Isolation

The Reactor Vessel Water Level - Low and Drywell Pressure - High Functions receive inputs from four channels. One channel associated with each Function inputs to one of four trip strings. Two trip strings make up a trip system and both trip systems must trip to cause an isolation of the Group 2 primary containment isolation valves (i.e., drywell and sump). Any channel will trip the associated trip string. Only one trip string must trip to trip the associated trip system. The trip strings are arranged in a one-out-of-two taken twice logic to initiate isolation.

Primary Containment Isolation Drywell Pressure - High and Reactor Vessel Water Level - Low Functions isolate the Group 2 drywell and sump isolation valves.

3, 4. High Pressure Coolant Injection System Isolation and Reactor Core Isolation Cooling System Isolation

The HPCI and RCIC Steam Line Flow - High Functions receive input from two channels for each system. Each channel output for each system is connected to a time delay relay that provides an output signal to two trip systems. The output signal is arranged so that any channel that trips will provide a trip signal to the trip system (one-out-of-two logic in each trip system). Each trip system associated with HPCI or RCIC will provide a closure signal to the associated system isolation valves. The HPCI

BASES

BACKGROUND (continued)

Steam Supply Line Pressure - Low Function receives input from four channels. The outputs are arranged in a one-out-of-two-twice logic in one trip system. The trip system isolates all HPCI isolation valves. The RCIC Steam Supply Line Pressure - Low Function receives input from four channels. The outputs are arranged in a one-out-of-two twice logic. The output of the logic is directed to two trip systems. Each trip system is able, by itself, to isolate all RCIC isolation valves. The HPCI and RCIC Steam Line Area Temperature - High Functions receive input from 16 channels for each system. The outputs of the 16 channels are grouped in four sets of four detectors. Each set is arranged in one-out-two-twice logic. The outputs of each set provide trip signals to each of two separate isolation trip systems. Each trip system is able, by itself, to isolate all HPCI and RCIC isolation valves, as applicable.

HPCI Functions isolate the Group 4 valves and RCIC Functions isolate the Group 5 valves.

5. Reactor Water Cleanup System Isolation

The RWCU Room Temperature - High, Reactor Vessel Water Level - Low Low, Drywell Pressure - High, and RWCU Flow - High Functions receive inputs from four channels. One channel associated with each Function inputs to one of four trip strings. Two trip strings make up a trip system and both trip systems must trip to cause an isolation of the RWCU valves. Any channel will trip the associated trip string. Only one trip string must trip to trip the associated trip system. The trip strings are arranged in a one-out-of-two taken twice logic to initiate isolation of all RWCU isolation valves. The SLC System Initiation Function receives input from the SLC initiation switch. The switch provides trip signal inputs to both trip systems in any position other than "OFF." For the purpose of this Specification, the SLC initiation switch is considered to provide one channel input into each trip system. Each of the two trip systems is connected to one of the two valves on each RWCU penetration.

RWCU Functions isolate the Group 3 valves.

6. Shutdown Cooling System Isolation

The Reactor Vessel Water Level - Low Function receives input from four reactor vessel water level channels. One channel associated with each Function inputs to one of four trip strings. Two trip strings make up a trip system and both trip systems must trip to cause an isolation of the RHR

BASES

BACKGROUND (continued)

shutdown cooling supply isolation valves. Any channel will trip the associated trip string. Only one trip string must trip to trip the associated trip system. The trip strings are arranged in a one-out-of-two taken twice logic to initiate isolation of the RHR shutdown cooling supply isolation valves. The Reactor Steam Dome Pressure - High Function receives input from two channels, both of which provide input to two trip systems. Any trip channel will trip both trip systems to initiate isolation of the RHR shutdown cooling supply isolation valves.

Shutdown Cooling System Isolation Functions isolate the Group 2 RHR shutdown cooling supply isolation valves.

7. Traversing Incore Probe (TIP) System Isolation

The Reactor Vessel Water Level - Low and Drywell Pressure - High Functions receive inputs from four channels. One channel associated with each Function inputs to one of four trip strings. Two trip strings make up a trip system and both trip systems must trip to initiate a TIP drive isolation signal. Any channel will trip the associated trip string. Only one trip string must trip to trip the associated trip system. The trip strings are arranged in a one-out-of-two taken twice logic to initiate a TIP drive isolation signal.

When either Function actuates, the TIP drive mechanisms will withdraw the TIPs, if inserted, and close the inboard TIP System isolation ball valves when the TIPs are fully withdrawn. The outboard TIP System isolation valves are manual shear valves.

TIP System Isolation Functions isolate the Group 2 valves (TIP inboard isolation ball valves).

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The isolation signals generated by the primary containment isolation instrumentation are implicitly assumed in the safety analyses of References 1 and 2 to initiate closure of valves to limit offsite doses. Refer to LCO 3.6.1.3, "Primary Containment Isolation Valves (PCIVs)," Applicable Safety Analyses Bases for more detail of the safety analyses.

Primary containment isolation instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii). Certain instrumentation Functions are retained for other reasons and are described below in the individual Functions discussion.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

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

Allowable Values are specified for each Primary Containment Isolation Function specified in the Table. Nominal trip setpoints are specified in the setpoint calculations. The nominal setpoints are selected to ensure that the setpoints do not exceed the Allowable Value between CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable. A channel is inoperable if its actual trip setpoint is not within its required Allowable Value. Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (e.g., reactor vessel water level), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., trip unit) changes state. The analytic limits are derived from the limiting values of the process parameters obtained from the safety analysis. The Allowable Values and nominal trip setpoints (NTSP) are derived, using the General Electric setpoint methodology guidance, as specified in the Monticello setpoint methodology. The Allowable Values are derived from the analytic limits. The difference between the analytic limit and the Allowable Value allows for channel instrument accuracy, calibration accuracy, process measurement accuracy, and primary element accuracy. The margin between the Allowable Value and the NTSP allows for instrument drift that might occur during the established surveillance period. Two separate verifications are performed for the calculated NTSP. The first, a Spurious Trip Avoidance Test, evaluates the impact of the NTSP on plant availability. The second verification, an LER Avoidance Test, calculates the probability of avoiding a Licensee Event Report (or exceeding the Allowable Value) due to instrument drift. These two verifications are statistical evaluations to provide additional assurance of the acceptability of the NTSP and may require changes to the NTSP. Use of these methods and verifications provides the assurance that if the setpoint is found conservative to the Allowable Value during surveillance testing, the instrumentation would have provided the required trip function by the time the process reached the analytic limit for the applicable events.

Certain Emergency Core Cooling Systems (ECCS) valves (e.g., RHR test line suppression pool cooling isolation) also serve the dual function of automatic PCIVs. The signals that isolate these valves are also associated with the automatic initiation of the ECCS. The instrumentation requirements and ACTIONS associated with these signals are addressed

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

in LCO 3.3.5.1, "Emergency Core Cooling Systems (ECCS) Instrumentation," and are not included in this LCO.

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

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

Main Steam Line Isolation

1.a. Reactor Vessel Water Level - Low Low

Low reactor pressure vessel (RPV) water level indicates that the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. Therefore, isolation of the MSIVs and other interfaces with the reactor vessel occurs to prevent offsite dose limits from being exceeded. The Reactor Vessel Water Level - Low Low Function is one of the many Functions assumed to be OPERABLE and capable of providing isolation signals. The Reactor Vessel Water Level - Low Low Function associated with isolation is assumed in the analysis of the recirculation line break (Ref. 1). The isolation of the MSLs on Low Low supports actions to ensure that offsite dose limits are not exceeded for a DBA.

Reactor vessel water level signals are initiated from four differential pressure transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. Four channels of Reactor Vessel Water Level - Low Low Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Reactor Vessel Water Level - Low Low Allowable Value is chosen to be the same as the ECCS Reactor Vessel Water Level - Low Low Allowable Value (LCO 3.3.5.1) to ensure that the MSLs isolate on a potential loss of coolant accident (LOCA) to prevent offsite doses from exceeding 10 CFR 50.67 limits.

This Function isolates the Group 1 valves.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

1.b. Main Steam Line Pressure - Low

Low MSL pressure indicates that there may be a problem with the turbine pressure regulation, which could result in a low reactor vessel water level condition and the RPV cooling down more than 100°F/hr if the pressure loss is allowed to continue. The Main Steam Line Pressure - Low Function is directly assumed in the analysis of the pressure regulator failure (Ref. 3). For this event, the closure of the MSIVs ensures that the RPV temperature change limit (100°F/hr) is not reached. In addition, this Function supports actions to ensure that Safety Limit 2.1.1.1 is not exceeded. (This Function closes the MSIVs prior to pressure decreasing below 686 psig, which results in a scram due to MSIV closure, thus reducing reactor power to < 25% RTP.)

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

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

The Main Steam Line Pressure - Low Function is only required to be OPERABLE in MODE 1 since this is when the assumed transient can occur (Ref. 3).

This Function isolates the Group 1 valves.

1.c. Main Steam Line Flow - High

Main Steam Line Flow - High is provided to detect a break of the MSL and to initiate closure of the MSIVs. If the steam were allowed to continue flowing out of the break, the reactor would depressurize and the core could uncover. If the RPV water level decreases too far, fuel damage could occur. Therefore, the isolation is initiated on high flow to prevent or minimize core damage. The Main Steam Line Flow - High Function is one of the Functions assumed in the analysis of the main steam line break (MSLB) (Ref. 2). The isolation action, along with the scram function of the Reactor Protection System (RPS), ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46 and offsite doses do not exceed the 10 CFR 50.67 limits.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The MSL flow signals are initiated from 16 differential pressure indicating switches that are connected to the four MSLs (differential pressure indicating switches sense differential pressure across a flow restrictor). The differential pressure indicating switches are arranged such that, even though physically separated from each other, all four connected to one MSL would be able to detect the high flow. Four channels of Main Steam Line Flow - High Function for each MSL (two channels per trip system) are available and are required to be OPERABLE so that no single instrument failure will preclude detecting a break in any individual MSL.

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

This Function isolates the Group 1 valves.

<u>1.d. Main Steam Line Tunnel Temperature - High</u>

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

Main steam line tunnel temperature signals are initiated from bimetallic temperature switches located in the four areas being monitored. Even though physically separated from each other, any temperature switch in any of the four areas is able to detect a leak. Therefore, sixteen channels of Main Steam Line Tunnel Temperature - High Function are available but only eight channels (two channels in each of the four trip strings) are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Main Steam Line Tunnel Temperature - High Allowable Value is chosen to detect a leak equivalent to between 5 gpm and 10 gpm.

This Function isolates the Group 1 valves.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Primary Containment Isolation

2.a. Reactor Vessel Water Level - Low

Low RPV water level indicates that the capability to cool the fuel may be threatened. The valves whose penetrations communicate with the primary containment are isolated to limit the release of fission products. The isolation of the primary containment on low RPV water level supports actions to ensure that offsite dose limits of 10 CFR 50.67 are not exceeded. The Reactor Vessel Water Level - Low Function associated with isolation is implicitly assumed in the USAR analysis as these leakage paths are assumed to be isolated post LOCA.

Reactor Vessel Water Level - Low signals are initiated from level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. Four channels of Reactor Vessel Water Level - Low Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Reactor Vessel Water Low Level - Low Allowable Value was chosen to be the same as the RPS Reactor Vessel Water Level - Low Allowable Value (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation"), since isolation of these valves is not critical to orderly plant shutdown.

This Function isolates the Group 2 drywell and sump isolation valves.

2.b. Drywell Pressure - High

High drywell pressure can indicate a break in the RCPB inside the primary containment. The isolation of some of the primary containment isolation valves on high drywell pressure supports actions to ensure that offsite dose limits of 10 CFR 50.67 are not exceeded. The Drywell Pressure - High Function, associated with isolation of the primary containment, is implicitly assumed in the USAR accident analysis as these leakage paths are assumed to be isolated post LOCA.

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

The Allowable Value was selected to be the same as the ECCS Drywell Pressure - High Allowable Value (LCO 3.3.5.1), since this may be indicative of a LOCA inside primary containment.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

This Function isolates the Group 2 drywell and sump isolation valves.

High Pressure Coolant Injection and Reactor Core Isolation Cooling Systems Isolation

3.a, 4.a. HPCI and RCIC Steam Line Flow - High

Steam Line Flow - High Functions are provided to detect a break of the RCIC or HPCI steam lines and initiate closure of the steam line isolation valves of the appropriate system. If the steam is allowed to continue flowing out of the break, the reactor will depressurize and the core can uncover. Therefore, the isolations are initiated on high flow to prevent or minimize core damage. The isolation action, along with the scram function of the RPS, ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46. Specific credit for these Functions is not assumed in any USAR accident analyses since the bounding analysis is performed for large breaks such as recirculation and MSL breaks. However, these instruments prevent the RCIC or HPCI steam line breaks from becoming bounding. The HPCI and RCIC Steam Line Flow - High channels are each provided with a time delay relay to prevent false isolations on HPCI or RCIC Steam Line Flow - High, as applicable, during system startup transients and therefore improves system reliability.

The HPCI and RCIC Steam Line Flow - High signals are initiated from differential pressure switches (two for HPCI and two for RCIC) that are connected to the system steam lines. Two channels of both HPCI and RCIC Steam Line Flow - High Functions are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function. In addition, each flow channel is connected to a time delay relay to delay the tripping of the associated HPCI or RCIC isolation trip system for a short time.

The Allowable Values are chosen to be low enough to ensure that the trip occurs to prevent fuel damage and maintains the MSLB event as the bounding event. The Allowable Values associated with the time delay are chosen to be long enough to prevent false isolations due to system starts but not so long as to impact offsite dose calculations.

These Functions isolate the Groups 4 and 5 valves, as appropriate.

3.b, 4.b. HPCI and RCIC Steam Supply Line Pressure – Low

Low HPCI or RCIC steam supply line pressure indicates that the pressure of the steam in the HPCI or RCIC turbine, as applicable, may be too low to continue operation of the associated systems turbine. These isolations

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

are for equipment protection and are not assumed in any transient or accident analysis in the USAR. However, they also provide a diverse signal to indicate a possible system break. These instruments are included in Technical Specifications (TS) because of the potential for risk due to possible failure of the instruments preventing HPCI and RCIC initiations. Therefore, they meet Criterion 4 of 10 CFR 50.36(c)(2)(ii).

The HPCI and RCIC Steam Supply Line Pressure - Low signals are initiated from pressure switches (four for HPCI and four for RCIC) that are connected to the system steam line. Four channels of both HPCI and RCIC Steam Supply Line Pressure - Low Functions are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Allowable Values are selected to be high enough to prevent damage to the systems turbine.

These Functions isolate the Groups 4 and 5 valves, as appropriate.

<u>3.c, 4.c. HPCI and RCIC Steam Line Area Temperature - High</u>

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

HPCI and RCIC Steam Line Area Temperature - High signals are initiated from bimetallic temperature switches that are appropriately located to protect the system that is being monitored. Eight instruments monitor each area. Sixteen channels for each HPCI and RCIC Steam Line Area Temperature - High Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Allowable Values are set low enough to detect a break in the associated system piping to ensure the core will not be uncovered and the radiological consequences are bounded by the main steam line break analysis.

These Functions isolate the Groups 4 and 5 valves, as appropriate.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Reactor Water Cleanup System Isolation

5.a. RWCU Flow - High

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

The high flow signals are initiated from transmitters that monitor RWCU System flow. In addition, each flow channel is connected to a time delay relay to delay the tripping of the flow channel for a short time. Four channels of RWCU Flow - High Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The RWCU Flow - High Allowable Value ensures that a break of the RWCU piping is detected. The Allowable Value associated with the time delay is chosen to be long enough to prevent false isolations due to system starts but not so long as to impact offsite dose calculations.

This Function isolates the Group 3 valves.

5.b. RWCU Room Temperature - High

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

RWCU room temperature signals are initiated from temperature elements that are located in the room that is being monitored. Four resistance temperature detectors provide input to the RWCU Room Temperature - High Function. Four channels are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The RWCU Room Temperature - High Allowable Value is set low enough to detect a leak equivalent to 210 gpm.

This Function isolates the Group 3 valves.

5.c. Drywell Pressure - High

High drywell pressure can indicate a break in the RCPB inside the primary containment. The isolation of some of the primary containment isolation valves on high drywell pressure supports actions to ensure that offsite dose limits of 10 CFR 50.67 are not exceeded. The Drywell Pressure - High Function, associated with isolation of the primary containment, is implicitly assumed in the USAR accident analysis as these leakage paths are assumed to be isolated post LOCA.

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

The Allowable Value was selected to be the same as the ECCS Drywell Pressure - High Allowable Value (LCO 3.3.5.1), since this may be indicative of a LOCA inside primary containment.

This Function isolates the Group 3 valves.

5.d. SLC System Initiation

The isolation of the RWCU System is required when the SLC System has been initiated to prevent dilution and removal of the boron solution by the RWCU System (Ref. 4). SLC System initiation signals are initiated from the SLC initiation switch.

Two channels of the SLC System Initiation Function are available and are required to be OPERABLE only in MODES 1 and 2, since these are the only MODES where the reactor can be critical, and these MODES are consistent with the Applicability for the SLC System (LCO 3.1.7, "Standby Liquid Control (SLC) System").

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

This Function isolates the Group 3 valves.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

5.e. Reactor Vessel Water Level - Low Low

Low RPV water level indicates that the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. Therefore, isolation of some interfaces with the reactor vessel occurs to isolate the potential sources of a break. The isolation of the RWCU System on low low RPV water level supports actions to ensure that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46. The Reactor Vessel Water Level - Low Low Function associated with RWCU isolation is not directly assumed in the USAR safety analyses because the RWCU System line break is bounded by breaks of larger systems (recirculation and MSL breaks are more limiting).

Reactor Vessel Water Level - Low Low signals are initiated from four differential pressure transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. Four channels of Reactor Vessel Water Level - Low Low Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

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

This Function isolates the Group 3 valves.

Shutdown Cooling System Isolation

6.a. Reactor Steam Dome Pressure – High

The Reactor Steam Dome Pressure - High Function is provided to isolate the shutdown cooling portion of the Residual Heat Removal (RHR) System. This interlock is provided only for equipment protection to prevent an intersystem LOCA scenario, and credit for the interlock is not assumed in the accident or transient analysis in the USAR.

The Reactor Steam Dome Pressure - High signals are initiated from two transmitters that are connected to different taps on the RPV. Two channels of Reactor Steam Dome Pressure - High Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function. The Function is only required to be OPERABLE in MODES 1, 2, and 3, since these are the only MODES in which the reactor can be pressurized; thus, equipment

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

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

This Function isolates the Group 2 RHR shutdown cooling supply isolation valves.

6.b. Reactor Vessel Water Level - Low

Low RPV water level indicates that the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. Therefore, isolation of some reactor vessel interfaces occurs to begin isolating the potential sources of a break. The Reactor Vessel Water Level - Low Function associated with RHR Shutdown Cooling System isolation is not directly assumed in safety analyses because a break of the RHR Shutdown Cooling System is bounded by breaks of the recirculation and MSL. The RHR Shutdown Cooling System isolation on low RPV water level supports actions to ensure that the RPV water level does not drop below the top of the active fuel during a vessel draindown event caused by a leak (e.g., pipe break or inadvertent valve opening) in the RHR Shutdown Cooling System.

Reactor Vessel Water Level - Low signals are initiated from four differential pressure transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. Four channels (two channels per trip system) of the Reactor Vessel Water Level - Low Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function. As noted (footnote (a) to Table 3.3.6.1-1), only one channel per trip system (with an isolation signal available to one shutdown cooling pump supply isolation valve) of the Reactor Vessel Water Level - Low Function is required to be OPERABLE in MODES 4 and 5, provided RHR Shutdown Cooling System integrity is maintained. System integrity is maintained provided the piping is intact and no maintenance is being performed that has the potential for draining the reactor vessel through the system.

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

The Reactor Vessel Water Level - Low Function is only required to be OPERABLE in MODES 3, 4, and 5 to prevent this potential flow path from lowering the reactor vessel level to the top of the fuel. In MODES 1 and 2, another isolation (i.e., Reactor Steam Dome Pressure - High) and

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

administrative controls ensure that this flow path remains isolated to prevent unexpected loss of inventory via this flow path.

This Function isolates the Group 2 RHR shutdown cooling supply isolation valves.

Traversing Incore Probe System Isolation

7.a. Reactor Vessel Water Level - Low

Low RPV water level indicates that the capability to cool the fuel may be threatened. The valves whose penetrations communicate with the primary containment are isolated to limit the release of fission products. The isolation of the primary containment on low RPV water level supports actions to ensure that offsite dose limits of 10 CFR 50.67 are not exceeded. The Reactor Vessel Water Level - Low Function associated with isolation is implicitly assumed in the USAR analysis as these leakage paths are assumed to be isolated post LOCA.

Reactor Vessel Water Level - Low signals are initiated from differential pressure transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. Two channels of Reactor Vessel Water Level - Low Function are available and are required to be OPERABLE to ensure that no single instrument failure can initiate an inadvertent isolation actuation. The isolation function is ensured by the manual shear valve in each penetration.

The Reactor Vessel Water Level - Low Allowable Value was chosen to be the same as the RPS Reactor Vessel Water Level - Low Allowable Value (LCO 3.3.1.1), since isolation of these valves is not critical to orderly plant shutdown.

This Function isolates the Group 2 TIP inboard isolation ball valves.

7.b. Drywell Pressure - High

High drywell pressure can indicate a break in the RCPB inside the primary containment. The isolation of some of the primary containment isolation valves on high drywell pressure supports actions to ensure that offsite dose limits of 10 CFR 50.67 are not exceeded. The Drywell Pressure - High Function, associated with isolation of the primary containment, is implicitly assumed in the USAR accident analysis as these leakage paths are assumed to be isolated post LOCA.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

High drywell pressure signals are initiated from pressure transmitters that sense the pressure in the drywell. Two channels of Drywell Pressure - High Function are available and are required to be OPERABLE to ensure that no single instrument failure can initiate an inadvertent actuation. The isolation function is ensured by the manual shear valve in each penetration.

The Allowable Value was selected to be the same as the ECCS Drywell Pressure - High Allowable Value (LCO 3.3.5.1), since this may be indicative of a LOCA inside primary containment.

This Function isolates the Group 2 TIP inboard isolation ball valves.

ACTIONS

The ACTIONS are modified by two Notes. Note 1 allows penetration flow path(s) to be unisolated intermittently under administrative controls. These controls consist of stationing a dedicated operator at the controls of the valve, who is in continuous communication with the control room. In this way, the penetration can be rapidly isolated when a need for primary containment isolation is indicated. Note 2 has been provided to modify the ACTIONS related to primary containment isolation instrumentation channels. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition, discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable primary containment isolation instrumentation channels provide appropriate compensatory measures for separate inoperable channels. As such, a Note has been provided that allows separate Condition entry for each inoperable primary containment isolation instrumentation channel.

A.1

Because of the diversity of sensors available to provide isolation signals and the redundancy of the isolation design, an allowable out of service time of 12 hours or 24 hours, depending on the Function (12 hours for those Functions that have channel components common to RPS instrumentation and 24 hours for those Functions that do not have channel components common to RPS instrumentation), has been shown to be acceptable (Refs. 5 and 6) to permit restoration of any inoperable channel to OPERABLE status. This out of service time is only acceptable provided the associated Function is still maintaining isolation capability

BASES

ACTIONS (continued)

(refer to Required Action B.1 Bases). If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be placed in the tripped condition per Required Action A.1. Placing the inoperable channel in trip would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue with no further restrictions. Alternately, if it is not desired to place the channel in trip (e.g., as in the case where placing the inoperable channel in trip would result in an isolation), Condition C must be entered and its Required Action taken.

B.1

Required Action B.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same Function result in redundant primary containment isolation capability being lost for the associated penetration flow path(s). The MSL, Primary Containment, most of the RWCU System, Shutdown Cooling System Reactor Vessel Water Level - Low, and TIP Isolation Functions are considered to be maintaining primary containment isolation capability when sufficient channels are OPERABLE or in trip, such that both trip systems will generate a trip signal from the given Function on a valid signal. The other isolation Functions are considered to be maintaining primary containment isolation capability when sufficient channels are OPERABLE or in trip, such that one trip system will generate a trip signal from the given Function on a valid signal. This ensures that one of the two PCIVs in the associated penetration flow path can receive an isolation signal from the given Function. For Functions 1.a, 1.b, 2.a, 2.b, 5.a, 5.b, 5.c, 5.e, 6.b, 7.a, and 7.b, this would require both trip systems to have one channel OPERABLE or in trip. For Function 1.c, this would require both trip systems to have one channel, associated with each MSL, OPERABLE or in trip. Function 1.d channels monitor several locations within a given area (e.g., different locations within the main steam tunnel area). However, since any channel can detect a leak in any area, this would require both trip systems to have one channel OPERABLE or in trip. For Functions 3.a, 4.a, and 5.d, this would require one trip system to have one channel OPERABLE or in trip. For Function 3.b, this would require one channel in each trip string to be OPERABLE or in trip for the trip system. For Function 4.b, this would require one channel in each trip string to be OPERABLE or in trip for one trip system. For Functions 3.c and 4.c, eight channels monitor each area. These channels are arranged in two sets of four detectors, with each set of detectors arranged in a one-out-of-two-twice logic. Therefore, this would require a set in each area to have sufficient channels OPERABLE or in the tripped condition for one trip system.

BASES

ACTIONS (continued)

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

C.1

Required Action C.1 directs entry into the appropriate Condition referenced in Table 3.3.6.1-1. The applicable Condition specified in Table 3.3.6.1-1 is Function and MODE or other specified condition dependent and may change as the Required Action of a previous Condition is completed. Each time an inoperable channel has not met any Required Action of Condition A or B and the associated Completion Time has expired, Condition C will be entered for that channel and provides for transfer to the appropriate subsequent Condition.

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

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

E.1

If the channel is not restored to OPERABLE status or placed in trip within the allowed Completion Time, the plant must be placed in a MODE or other specified condition in which the LCO does not apply. This is done by placing the plant in at least MODE 2 within 6 hours.

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

BASES

ACTIONS (continued)

F.1

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

For the RWCU Room Temperature - High Function, the affected penetration flow path(s) may be considered isolated by isolating only that portion of the system in the associated room monitored by the inoperable channel. That is, if the RWCU pump room A area channel is inoperable, the pump room A area can be isolated while allowing continued RWCU operation utilizing the B RWCU pump.

The 1 hour Completion Time is acceptable because it minimizes risk while allowing sufficient time for plant operations personnel to isolate the affected penetration flow path(s).

G.1

If the channel is not restored to OPERABLE status or placed in trip within the allowed Completion Time, plant operations may continue if the affected penetration flow path(s) is isolated. Isolating the affected penetration flow path(s) accomplishes the safety function of the inoperable channels. The 24 hour Completion Time is acceptable due to the fact that these Functions provide a TIP System isolation, and the TIP System penetration is a small bore (approximately ½ inch), its isolation in a design basis event (with loss of offsite power) would be via the manually operated shear valves, and the ability to manually isolate by either the normal isolation valve or the shear valve is unaffected by the inoperable instrumentation.

H.1 and H.2

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

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

BASES

ACTIONS (continued)

I.1 and I.2

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

SURVEILLANCE REQUIREMENTS

As noted at the beginning of the SRs, the SRs for each Primary Containment Isolation instrumentation Function are found in the SRs column of Table 3.3.6.1-1.

The Surveillances are modified by a Note to indicate that when a channel (a channel that is directed to two trip systems is considered to be one channel) is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains primary containment isolation capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the reliability analysis (Refs. 5 and 6) assumption of the average time required to perform channel surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that the PCIVs will isolate the penetration flow path(s) when necessary.

SR 3.3.6.1.1

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

BASES

SURVEILLANCE REQUIREMENTS (continued)

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

The Frequency is based on operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the channels required by the LCO.

SR 3.3.6.1.2

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions.

Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

The 92 day Frequency of SR 3.3.6.1.2 is based on the reliability analyses described in References 5 and 6.

SR 3.3.6.1.3

Calibration of trip units provides a check of the actual trip setpoints (including any specified time delay). The channel must be declared inoperable if the trip setting is discovered to be less conservative than the Allowable Value specified in Table 3.3.6.1-1. If the trip setting is discovered to be less conservative than accounted for in the appropriate setpoint methodology, but is not beyond the Allowable Value, the channel performance is still within the requirements of the plant safety analysis. Under these conditions, the setpoint must be readjusted to be equal to or more conservative than that accounted for in the appropriate setpoint methodology.

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

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.6.1.4 and SR 3.3.6.1.5

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

The Frequency of SR 3.3.6.1.4 is based on the assumption of a 92 day calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis. The Frequency of SR 3.3.6.1.5 is based on the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.6.1.6

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required isolation logic for a specific channel. The system functional testing performed on PCIVs in LCO 3.6.1.3 overlaps this Surveillance to provide complete testing of the assumed safety function. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at the 24 month Frequency.

REFERENCES

1. USAR, Section 14.7.2.
2. USAR, Section 14.7.3.
3. USAR, Section 7.6.3.2.4.
4. USAR, Section 6.6.1.1.
5. NEDC-31677P-A, "Technical Specification Improvement Analysis for BWR Isolation Actuation Instrumentation," July 1990.
6. NEDC-30851P-A Supplement 2, "Technical Specifications Improvement Analysis for BWR Isolation Instrumentation Common to RPS and ECCS Instrumentation," March 1989.

BASES

REFERENCES (continued)

7. Amendment No. 185, “Issuance of Amendment to Reduce the Reactor Steam Dome Pressure Specified in the Reactor Core Safety Limits,” dated November 25, 2014. (ADAMS Accession No. ML14281A318)

B 3.3 INSTRUMENTATION

B 3.3.6.2 Secondary Containment Isolation Instrumentation

BASES

BACKGROUND

The secondary containment isolation instrumentation automatically initiates closure of appropriate secondary containment isolation valves (SCIVs) and starts the Standby Gas Treatment (SGT) System. The function of these systems, in combination with other accident mitigation systems, is to limit fission product release during and following postulated Design Basis Accidents (DBAs). The two DBA are a Loss of Coolant Accident (LOCA) and Fuel Handling Accident (FHA) involving recently irradiated fuel within secondary containment (Refs. 1 and 2). Secondary containment isolation and establishment of vacuum with the SGT System ensures that fission products that leak from primary containment following a DBA, or are released outside primary containment, or are released during certain operations when primary containment is not required to be OPERABLE are maintained within applicable limits.

The isolation instrumentation includes the sensors, relays, and switches that are necessary to cause initiation of secondary containment isolation. Most channels include electronic equipment (e.g., trip units) that compares measured input signals with pre-established setpoints. When the setpoint is exceeded, the channel output relay actuates, which then outputs a secondary containment isolation signal to the isolation logic. Functional diversity is provided by monitoring a wide range of independent parameters. The input parameters to the isolation logic are (1) reactor vessel water level, (2) drywell pressure, (3) reactor building ventilation exhaust high radiation, and (4) refueling floor high radiation. Redundant sensor input signals from each parameter are provided for initiation of isolation.

For both the Reactor Vessel Water Level - Low Low and Drywell Pressure - High Functions, the secondary containment isolation logic receives input from four channels. The outputs from two channels for both Functions provide input into two trip systems. One channel must trip to trip a trip system and both trip systems must trip to initiate the secondary containment isolation function (i.e., one-out-of-two taken twice logic arrangement). The secondary containment isolation function will provide a start signal to both SGT subsystems and isolate all reactor building isolation dampers. For both Reactor Building Ventilation Exhaust Radiation - High and Refueling Floor Radiation - High Functions, the secondary containment isolation trip system logic receives input from two channels. The outputs from each of the two channels for both Functions provide input into two trip systems. The logic for each Function in each trip system is arranged such that any channel can trip the trip system and initiate the secondary containment isolation function.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

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

The safety analysis for the FHA assumes the reactor has been subcritical for at least 24 hours prior to fuel movement. The secondary containment isolation instrumentation is needed to ensure the control room operator and offsite doses are within 10 CFR 50.67 limits during movement of recently irradiated fuel within secondary containment (i.e., fuel that has occupied part of a critical reactor core within the previous 24 hours).

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

The secondary containment isolation instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii). Certain instrumentation Functions are retained for other reasons and are described below in the individual Functions discussion.

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

Allowable Values are specified for each Function specified in the Table. Nominal trip setpoints are specified in the applicable setpoint calculations. The nominal setpoints are selected to ensure that the setpoints do not exceed the Allowable Value between CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable. A channel is inoperable if its actual trip setpoint is not within its required Allowable Value.

Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (e.g., reactor vessel water level), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., trip unit) changes state. The analytic limits are derived from the limiting values of the process parameters obtained from the safety analysis. For Functions 1 and 2, the Allowable Values and nominal trip setpoints (NTSP) are derived, using the General Electric setpoint methodology guidance, as specified in the Monticello setpoint methodology. The Allowable Values are derived from the analytic limits.

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APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The difference between the analytic limit and the Allowable Value allows for channel instrument accuracy, calibration accuracy, process measurement accuracy, and primary element accuracy. The margin between the Allowable Value and the NTSP allows for instrument drift that might occur during the established surveillance period. Two separate verifications are performed for the calculated NTSP. The first, a Spurious Trip Avoidance Test, evaluates the impact of the NTSP on plant availability. The second verification, an LER Avoidance Test, calculates the probability of avoiding a Licensee Event Report (or exceeding the Allowable Value) due to instrument drift. These two verifications are statistical evaluations to provide additional assurance of the acceptability of the NTSP and may require changes to the NTSP. Use of these methods and verifications provides the assurance that if the setpoint is found conservative to the Allowable Value during surveillance testing, the instrumentation would have provided the required trip function by the time the process reached the analytic limit for the applicable events. For Functions 3 and 4, the Allowable Values and NTSP are based on engineering judgment.

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

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

1. Reactor Vessel Water Level - Low Low

Low reactor pressure vessel (RPV) water level indicates that the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. An isolation of the secondary containment and actuation of the SGT System are initiated in order to minimize the potential of an offsite dose release. The Reactor Vessel Water Level - Low Low Function is one of the Functions assumed to be OPERABLE and capable of providing isolation and initiation signals. The isolation and initiation systems on Reactor Vessel Water Level - Low Low support actions to ensure that any offsite releases are within the limits calculated in the safety analysis.

Reactor Vessel Water Level - Low Low signals are initiated from level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. Four channels of Reactor Vessel Water Level - Low Low Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

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

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

2. Drywell Pressure - High

High drywell pressure can indicate a break in the reactor coolant pressure boundary (RCPB). An isolation of the secondary containment and actuation of the SGT System are initiated in order to minimize the potential of an offsite dose release. The Drywell Pressure - High Function is one of the Functions assumed to be OPERABLE and capable of providing isolation and initiation signals to ensure that any offsite releases are within the limits calculated in the safety analysis.

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

The Allowable Value was chosen to be the same as the Reactor Protection System (RPS) Drywell Pressure - High Function Allowable Value (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation") since this is indicative of a loss of coolant accident (LOCA).

The Drywell Pressure - High Function is required to be OPERABLE in MODES 1, 2, and 3 where considerable energy exists in the RCS; thus, there is a probability of pipe breaks resulting in significant releases of radioactive steam and gas. This Function is not required in MODES 4 and 5 because the probability and consequences of these events are low due to the RCS pressure and temperature limitations of these MODES.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

3, 4. Reactor Building Ventilation Exhaust and Refueling Floor Radiation - High

High reactor building ventilation exhaust radiation or refuel floor radiation is an indication of possible gross failure of the fuel cladding. The release may have originated from the primary containment due to a break in the RCPB or the refueling floor due to a fuel handling accident. When Reactor Building Ventilation Exhaust Radiation - High or Refueling Floor Radiation - High is detected, secondary containment isolation and actuation of the SGT System are initiated. These actions are required to mitigate the consequences of the LOCA or FHA involving recently irradiated fuel by limiting the release of fission products as assumed in the USAR safety analyses (Refs. 1 and 2).

The Reactor Building Ventilation Exhaust Radiation - High signals are initiated from radiation detectors that are located on the ventilation exhaust piping coming from the reactor building. The Refueling Floor Radiation - High signals are initiated for radiation detectors that are located to monitor the environment of the refuel floor area. The signal from each detector is input to an individual monitor whose trip outputs are assigned to an isolation channel. Two channels of Reactor Building Ventilation Exhaust Radiation - High Function and two channels of Refueling Floor Radiation - High Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Allowable Values are chosen to promptly detect gross failure of the fuel cladding.

The Reactor Building Ventilation Exhaust Radiation - High and Refueling Floor Radiation - High Functions are required to be OPERABLE in MODES 1, 2, and 3 where considerable energy exists in the RCS; thus, there is a probability of pipe breaks resulting in significant releases of radioactive steam and gas. In MODES 4 and 5, the probability and consequences of these events are low due to the RCS pressure and temperature limitations of these MODES; thus, these Functions are not required. In addition, the Functions are also required to be OPERABLE during OPDRVs and movement of recently irradiated fuel assemblies in the secondary containment, because the capability of detecting radiation releases due to fuel failures (due to fuel uncovery or dropped fuel assemblies) must be provided to ensure that offsite dose limits are not exceeded. Due to radioactive decay, these Functions are only required to isolate secondary containment during fuel handling accidents involving handling recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 24 hours).

BASES

ACTIONS

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

A.1

Because of the diversity of sensors available to provide isolation signals and the redundancy of the isolation design, an allowable out of service time of 12 hours for Functions 1 and 2, and 24 hours for Functions other than Functions 1 and 2, has been shown to be acceptable (Refs. 2 and 3) to permit restoration of any inoperable channel to OPERABLE status. This out of service time is only acceptable provided the associated Function is still maintaining isolation capability (refer to Required Action B.1 Bases). If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be placed in the tripped condition per Required Action A.1. Placing the inoperable channel in trip would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. Alternately, if it is not desired to place the channel in trip (e.g., as in the case where placing the inoperable channel in trip would result in an isolation), Condition C must be entered and its Required Actions taken.

B.1

Required Action B.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same Function result in a complete loss of isolation capability for the associated penetration flow path(s) or a complete loss of initiation capability for the SGT System. A Function is considered to be maintaining secondary containment isolation capability when sufficient channels are OPERABLE or in trip, such that the logic will generate a trip signal from the given Function on a valid signal. This ensures that one of the two SCIVs in the associated penetration flow path and one SGT subsystem can be initiated on an isolation signal from the given Function. For Functions 1 and 2, this would require one trip system to have one channel OPERABLE or in

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ACTIONS (continued)

trip in both trip strings (i.e., contacts in series). For Functions 3 and 4, this would require one trip system to have one channel OPERABLE or in trip.

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

C.1.1, C.1.2, C.2.1, and C.2.2

If any Required Action and associated Completion Time are not met, the ability to isolate the secondary containment and start the SGT System cannot be ensured. Therefore, further actions must be performed to ensure the ability to maintain the secondary containment function. Isolating the associated penetration flow path(s) (closing the ventilation supply and exhaust automatic isolation dampers) and starting the associated SGT subsystem (Required Actions C.1.1 and C.2.1) performs the intended function of the instrumentation and allows operation to continue. The method used to place the SGT subsystem in operation must provide for automatically reinitiating the subsystem upon restoration of power following a loss of power to the SGT subsystem.

Alternately, declaring the associated SCIVs or SGT subsystem(s) inoperable (Required Actions C.1.2 and C.2.2) is also acceptable since the Required Actions of the respective LCOs (LCO 3.6.4.2 and LCO 3.6.4.3) provide appropriate actions for the inoperable components.

One hour is sufficient for plant operations personnel to establish required plant conditions or to declare the associated components inoperable without unnecessarily challenging plant systems.

SURVEILLANCE REQUIREMENTS

As noted at the beginning of the SRs, the SRs for each Secondary Containment Isolation instrumentation Function are located in the SRs column of Table 3.3.6.2-1.

The Surveillances are modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains secondary containment isolation capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the reliability analysis (Refs. 3 and 4) assumption of the average time required to perform

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SURVEILLANCE REQUIREMENTS (continued)

channel surveillance. That analysis demonstrated the 6 hour testing allowance does not significantly reduce the probability that the SCIVs will isolate the associated penetration flow paths and that the SGT System will initiate when necessary.

SR 3.3.6.2.1

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

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

The Frequency is based on operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channel status during normal operational use of the displays associated with channels required by the LCO.

SR 3.3.6.2.2

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions.

Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The Frequency of 92 days is based on the reliability analysis of References 3 and 4.

SR 3.3.6.2.3

Calibration of trip units provides a check of the actual trip setpoints. The channel must be declared inoperable if the trip setting is discovered to be less conservative than the Allowable Value specified in Table 3.3.6.2-1. If the trip setting is discovered to be less conservative than accounted for in the appropriate setpoint methodology, but is not beyond the Allowable Value, performance is still within the requirements of the plant safety analysis. Under these conditions, the setpoint must be readjusted to be equal to or more conservative than accounted for in the appropriate setpoint methodology.

The Frequency of 92 days is based on the reliability analysis of References 3 and 4.

SR 3.3.6.2.4 and SR 3.3.6.2.5

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

The Frequencies of SR 3.3.6.2.4 and SR 3.3.6.2.5 are based on the assumption of a 92 day and a 24 month calibration interval, respectively, in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.6.2.6

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required isolation logic for a specific channel. The system functional testing performed on SCIVs and the SGT System in LCO 3.6.4.2 and LCO 3.6.4.3, respectively, overlaps this Surveillance to provide complete testing of the assumed safety function.

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

BASES

SURVEILLANCE REQUIREMENTS (continued)

potential for an unplanned transient if the Surveillance were performed with the reactor at power.

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

REFERENCES

1. USAR, Section 14.7.2.
2. USAR, Section 14.7.6.
3. NEDC-31677P-A, "Technical Specification Improvement Analysis for BWR Isolation Actuation Instrumentation," July 1990.
4. NEDC-30851P-A Supplement 2, "Technical Specifications Improvement Analysis for BWR Isolation Instrumentation Common to RPS and ECCS Instrumentation," March 1989.

B 3.3 INSTRUMENTATION

B 3.3.6.3 Low-Low Set (LLS) Instrumentation

BASES

BACKGROUND

The LLS logic and instrumentation is designed to mitigate the effects of postulated thrust loads on the safety/relief valve (S/RV) discharge lines by preventing subsequent actuations with an elevated water leg in the S/RV discharge line. It also mitigates the effects of postulated pressure loads on the torus shell or suppression pool by preventing multiple actuations in rapid succession of the S/RVs subsequent to their initial actuation.

The LLS logic includes preset opening and closing setpoints to three preselected S/RVs. These setpoints are selected such that the LLS S/RVs will stay open a sufficient amount of time; thus, releasing sufficient steam (energy) to the suppression pool, and hence a considerable amount of energy (and time) will be required for repressurization and subsequent S/RV openings. The LLS logic establishes a sufficient amount of time between (or prevents) subsequent actuations to allow the high water leg created from the initial S/RV opening to return to (or fall below) its normal water level; thus, reducing thrust loads from subsequent actuations to within their design limits. The setpoints for these valves ensure that they will be the first S/RVs to open and the last to close. In addition, the LLS is designed to limit S/RV subsequent actuations to the LLS valves so torus loads will also be reduced.

Each LLS S/RV has its own actuation logic, which consists of two trip systems (i.e., Division 1 and Division 2). Either trip system will open the associated LLS S/RV. A LLS S/RV will automatically open when signals indicating Reactor Scram Detection occur and reactor pressure reaches the opening setpoint. The logic in a LLS S/RV trip system receives input from two Reactor Scram Detection signals and two transmitters that monitor reactor pressure. The Reactor Scram Detection inputs are from the three Reactor Protection System (RPS) logic channels of the associated division (all three RPS logic channels input to both Reactor Scram Detection channels). The logic in the trip system will open the LLS S/RV if two Reactor Scram Detection signals are present and two reactor pressure signals reach the opening Low-Low Set Pressure Setpoints.

The LLS valve recloses when reactor pressure has decreased to the reclose setpoint of one of the two trip units used to open the valve (one-out-of-two logic). After the LLS S/RV opens the tailpipe discharge pressure will increase indicating the LLS S/RV is open. The opening of the LLS S/RV will actuate two tailpipe pressure switches and start two inhibit timers in each trip logic. The timers will prevent plant operators or

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BACKGROUND (continued)

the LLS S/RV logic from immediately re-opening the valve to allow the water leg in the S/RV discharge line to recede. Both tailpipe pressure switches must actuate and both inhibit timers must time out before the LLS S/RV can re-open.

This logic arrangement prevents single instrument failures from precluding the LLS S/RV function. The channels include electronic equipment (e.g., trip units) that compares measured input signals with pre-established setpoints. When the setpoint is exceeded, the channel output relay actuates, which then outputs a LLS initiation signal to the initiation logic.

APPLICABLE SAFETY ANALYSES

The LLS instrumentation and logic function ensures that the containment loads remain within the primary containment design basis (Ref. 1).

The LLS instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The LCO requires OPERABILITY of sufficient LLS instrumentation channels to ensure successfully accomplishing the LLS function assuming any single instrumentation channel failure within the LLS logic. Therefore, the OPERABILITY of the LLS instrumentation is dependent on the OPERABILITY of the instrumentation channel Function specified in Table 3.3.6.3-1. Each Function must have a required number of OPERABLE channels, with their setpoints within the specified Allowable Value. A channel is inoperable if its actual trip setpoint is not within its required Allowable Value. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions.

Allowable Values are specified for each LLS actuation Function in Table 3.3.6.3-1. Nominal trip setpoints are specified in the setpoint calculations. The nominal setpoints are selected to ensure the setpoints do not exceed the Allowable Value between CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable. Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (e.g., reactor vessel water level), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., trip unit) changes state. The analytic limits are derived from the limiting values of the process parameters obtained from the safety analysis. The Allowable Values and nominal trip setpoints (NTSP) are derived, using the General Electric setpoint methodology guidance, as specified in the Monticello setpoint methodology. The Allowable Values are derived from the analytic limits. The difference between the analytic limit and the Allowable Value allows for channel instrument accuracy, calibration accuracy, process measurement accuracy, and primary element

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LCO (continued)

accuracy. The margin between the Allowable Value and the NTSP allows for instrument drift that might occur during the established surveillance period. Two separate verifications are performed for the calculated NTSP. The first, a Spurious Trip Avoidance Test, evaluates the impact of the NTSP on plant availability. The second verification, an LER Avoidance Test, calculates the probability of avoiding a Licensee Event Report (or exceeding the Allowable Value) due to instrument drift. These two verifications are statistical evaluations to provide additional assurance of the acceptability of the NTSP and may require changes to the NTSP. Use of these methods and verifications provides the assurance that if the setpoint is found conservative to the Allowable Value during surveillance testing, the instrumentation would have provided the required trip function by the time the process reached the analytic limit for the applicable events.

Four channels of the Reactor Scram Detection Function for each LLS valve are required to be OPERABLE when the LLS S/RVs are required to be OPERABLE to ensure that no single instrument failure can preclude LLS S/RV initiation. There is no Allowable Value for this Function since the channels are derived from the RPS logic channels.

Four channels of the Low-Low Set Pressure Setpoints Function for each LLS valve are required to be OPERABLE to ensure that no single instrument failure can preclude LLS S/RV initiation and no single failure will cause spurious operation of a S/RV. The Allowable Values are staggered and chosen to be less than the S/RV safety lift setpoints specified in LCO 3.4.3, "Safety/Relief Valves (S/RVs)," to ensure they are the first valves to open and the last to close to ensure a sufficient blowdown range.

Four channels of the Tailpipe Pressure Switch Function for each LLS valve are required to be OPERABLE to ensure that no single instrument failure can preclude LLS S/RV initiation and no single failure will cause spurious operation of a S/RV. The Allowable Value is chosen to detect S/RV opening. The Allowable Value reflects the differential pressure between the S/RV downstream tailpipe pressure and the drywell atmosphere.

Four channels of the Inhibit Timers Function for each LLS valve are required to be OPERABLE to ensure that no single instrument failure can preclude LLS S/RV initiation and no single failure will cause spurious operation of a S/RV. The Allowable Value is chosen to ensure subsequent S/RV openings will not occur until after the elevated water leg in the respective discharge line is lowered to minimize water clearing thrust loads on the discharge line.

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APPLICABILITY

The LLS instrumentation is required to be OPERABLE in MODES 1, 2, and 3 since considerable energy is in the nuclear system and the S/RVs may be needed to provide pressure relief. If the S/RVs are needed, then the LLS function is required to ensure that the primary containment design basis is maintained. In MODES 4 and 5, the reactor pressure is low enough that the overpressure limit cannot be approached by assumed operational transients or accidents. Thus, LLS instrumentation and associated pressure relief is not required.

ACTIONS

A Note has been provided to modify the ACTIONS related to LLC valve 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 LLS valve instrumentation channels provide appropriate compensatory measures for separate LLS valves. As such, a Note has been provided that allows separate Condition entry for each LLS valve with inoperable LLS instrumentation channels.

<u>A.1 and A.2</u>

Required Action A.1 is intended to ensure that appropriate actions are taken if there are inoperable channels in both trip systems associated with any LLS S/RV. Loss of LLS valve initiation capability in both trip systems occurs if there is an inoperable channel in each trip system.

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." For Required Action A.1, the Completion Time only begins upon discovery that the LLS valve cannot be automatically initiated due to inoperable channels in both trip systems. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration of channels.

Because there are two independent trip systems, each capable of actuation of a LLS S/RV, an allowable out of service time of 72 hours has been shown to be acceptable to permit restoration of any inoperable channel to OPERABLE status (Required Action A.2). If the inoperable channel(s) cannot be restored to OPERABLE status within the allowable out of service time, Condition B must be entered and its Required Action taken. The Required Actions do not allow placing the channel in trip

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ACTIONS (continued)

since this action would not necessarily result in a safe state for a channel in all events.

B.1

If any Required Action and associated Completion Time are not met, the LLS valves may be incapable of performing their intended function. Therefore, the associated LLS valve must be declared inoperable immediately.

SURVEILLANCE REQUIREMENTS

As noted at the beginning of the SRs, the SRs for each LLS instrumentation Function are located in the SRs column of Table 3.3.6.3-1.

The Surveillances are modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains LLS initiation capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the reliability analysis (Ref. 2) assumption of the average time required to perform channel surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that the LLS valves will initiate when necessary.

SR 3.3.6.3.1

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

Agreement criteria are determined by the plant staff based on a combination of the channel instrument uncertainties, including indication

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SURVEILLANCE REQUIREMENTS (continued)

and readability. If a channel is outside the criteria, it may be an indication that the instrument has drifted outside its limit.

The Frequency is based upon operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with channels required by the LCO.

SR 3.3.6.3.2

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

The 92 day Frequency is based on the reliability analysis of Reference 2. As noted, for Function 1 the CHANNEL FUNCTIONAL TEST is only required to be performed prior to entering MODE 2 or 3 from MODE 4, since the plant must be shutdown to perform the test.

SR 3.3.6.3.3

The calibration of trip units provides a check of the actual trip setpoints. The channel must be declared inoperable if the trip setting is discovered to be less conservative than the Allowable Value. If the trip setting is discovered to be less conservative than accounted for in the appropriate setpoint methodology, but is not beyond the Allowable Value, the channel performance is still within the requirements of the plant safety analysis. Under these conditions, the setpoint must be readjusted to be equal to or more conservative than the setting accounted for in the appropriate setpoint methodology. The Frequency of every 92 days for SR 3.3.6.3.3 is based on the reliability analysis of Reference 2.

SR 3.3.6.3.4 and SR 3.3.6.3.5

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

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SURVEILLANCE REQUIREMENTS (continued)

parameter within the necessary range and accuracy. CHANNEL CALIBRATION leaves the channel adjusted to account for instrument drifts between successive calibrations consistent with the plant specific setpoint methodology.

The Frequency of once every 92 days for SR 3.3.6.3.4 is based on the assumption of a 92 day calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis. The Frequency of once every 24 months for SR 3.3.6.3.5 is based on the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.6.3.6

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required actuation logic for a specified channel. The system functional testing performed in LCO 3.4.3 and LCO 3.6.1.5, "Low-Low Set (LLS) Safety/Relief Valves (S/RVs)," for S/RVs overlaps this test to provide complete testing of the assumed safety function.

The Frequency of once every 24 months for SR 3.3.6.3.6 is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at the 24 month Frequency.

REFERENCES

1. USAR, Figure 4.4.2.3.
2. GENE-770-06-1-A, "Bases for Changes to Surveillance Test Intervals and Allowed Out-of-Service Times for Selected Instrumentation Technical Specifications," December 1992.

B 3.3 INSTRUMENTATION

B 3.3.7.1 Control Room Emergency Filtration (CREF) System Instrumentation

BASES

BACKGROUND

The CREF System is designed to provide a radiologically controlled environment to ensure the habitability of the control room envelope (the main control room and portions of the first and second floors of the Emergency Filtration Train (EFT) building) for the safety of control room operators under all plant conditions. Two independent CREF subsystems are each capable of fulfilling the stated safety function. The instrumentation and controls for the CREF System automatically initiate action to isolate and pressurize the control room envelope to provide a radiologically controlled environment from which the unit can be safety operated following postulated Design Basis Accidents (DBAs). The two DBAs are a Loss of Coolant Accident (LOCA) and a Fuel Handling Accident (FHA) involving recently irradiated fuel within secondary containment (Refs. 1 and 4).

In the event of a Reactor Vessel Water Level – Low Low, Drywell Pressure – High, Reactor Building Ventilation Exhaust Radiation – High, or Refueling Floor Radiation – High signal, the CREF System is automatically started in the pressurization mode. A system of dampers automatically isolates the control room envelope from untreated outside air. Outside air is taken in at the normal ventilation intake and is passed through one of the charcoal adsorber filter subsystems for removal of airborne radioactive particles. This air is then combined with return air from the control room envelope and passed through an exhaust/ recirculation fan, which is then passed through the air handling unit into the control room envelope to maintain the control room envelope slightly pressurized with respect to volumes adjacent to the control room envelope.

The CREF System instrumentation has two trip systems, either of which can initiate the CREF System. For both the Reactor Vessel Water Level – Low Low and Drywell Pressure – High Functions, the CREF System initiation logic receives input from four channels. The outputs from two channels for both Functions provide input into two trip systems. One channel must trip to actuate a trip system and both trip systems must trip to initiate the CREF system (i.e., one-out-of-two taken twice logic arrangement). For both Reactor Building Ventilation Exhaust Radiation – High, and the Refueling Floor Radiation – High Functions, the CREF System initiation logic receives input from two channels. The outputs from each of the two channels for both Functions provide input into two trip systems. The logic for each Function in each trip system is arranged such that any channel can actuate the trip system and initiate the CREF System. The channels include electronic equipment (e.g., trip units) that

BASES

BACKGROUND (continued)

compares measured input signals with pre-established setpoints. When the setpoint is exceeded, the channel output relay actuates, which then outputs a CREF System initiation signal to the initiation logic.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The ability of the CREF System to maintain the habitability of the control room envelope is explicitly assumed for the LOCA as discussed in the USAR safety analysis (Ref. 1). CREF System operation ensures that the radiation exposure of control room personnel, through the duration of the LOCA, does not exceed the limits set by GDC 19 of 10 CFR 50, Appendix A and 10 CFR 50.67.

The safety analysis for the FHA assumes the reactor has been subcritical for at least 24 hours prior to fuel movement. The CREF isolation instrumentation is needed to ensure the control room operator dose is within 10 CFR 50.67 limits during movement of recently irradiated fuel within secondary containment (i.e., fuel that has occupied part of a critical reactor core within the previous 24 hours).

CREF System instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

The OPERABILITY of the CREF System instrumentation is dependent upon the OPERABILITY of the individual instrumentation channel Functions specified in Table 3.3.7.1-1. Each Function must have the required number of OPERABLE channels with their setpoints set within the specified Allowable Values, as shown in Table 3.3.7.1-1. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions.

Allowable Values are specified for each CREF System Function specified in the Table. Nominal trip setpoints are specified in the applicable setpoint calculations. The nominal setpoints are selected to ensure that the setpoints do not exceed the Allowable Value between successive CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable. A channel is inoperable if its actual trip setpoint is not within its required Allowable Value.

Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (e.g., reactor vessel water level), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., trip unit) changes state.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The analytic limits are derived from the limiting values of the process parameters obtained from the safety analysis. For Functions 1 and 2, the Allowable Values and nominal trip setpoints (NTSP) are derived, using the General Electric setpoint methodology guidance, as specified in the Monticello setpoint methodology. The Allowable Values are derived from the analytic limits. The difference between the analytic limit and the Allowable Value allows for channel instrument accuracy, calibration accuracy, process measurement accuracy, and primary element accuracy. The margin between the Allowable Value and the NTSP allows for instrument drift that might occur during the established surveillance period. Two separate verifications are performed for the calculated NTSP. The first, a Spurious Trip Avoidance Test, evaluates the impact of the NTSP on plant availability. The second verification, an LER Avoidance Test, calculates the probability of avoiding a Licensee Event Report (or exceeding the Allowable Value) due to instrument drift. These two verifications are statistical evaluations to provide additional assurance of the acceptability of the NTSP and may require changes to the NTSP.

Use of these methods and verifications provides the assurance that if the setpoint is found conservative to the Allowable Value during surveillance testing, the instrumentation would have provided the required trip function by the time the process reached the analytic limit for the applicable events. For Functions 3 and 4, the Allowable Values and NTSP are based on engineering judgment.

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

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

1. Reactor Vessel Water Level - Low Low

Low reactor pressure vessel (RPV) water level indicates that the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. The CREF System is initiated to maintain the habitability of the control room envelope. The Reactor Vessel Water Level - Low Low Function is one of the Functions assumed to be OPERABLE and capable of providing an initiation signal. The initiation of the CREF System on Reactor Vessel Water Level - Low Low supports actions to ensure that the habitability of the control room envelope is within the limits calculated in the safety analysis.

Reactor Vessel Water Level - Low Low signals are initiated from level transmitters that sense the difference between the pressure due to a constant column of water (reference leg) and the pressure due to the actual water level (variable leg) in the vessel. Four channels of Reactor

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Vessel Water Level - Low Low Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

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

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

2. Drywell Pressure – High

High drywell pressure can indicate a break in the reactor coolant pressure boundary (RCPB). The CREF System is initiated to maintain the habitability of the control room envelope. The Drywell Pressure - High Function is one of the Functions assumed to be OPERABLE and capable of providing an initiation signal to ensure that control room doses are within the limits calculated in the safety analysis.

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

The Allowable Value was chosen to be the same as the Reactor Protection System (RPS) Drywell Pressure - High Function Allowable Value (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation") since this is indicative of a loss of coolant accident (LOCA).

The Drywell Pressure - High Function is required to be OPERABLE in MODES 1, 2, and 3 where considerable energy exists in the RCS; thus, there is a probability of pipe breaks resulting in significant releases of radioactive steam and gas. This Function is not required in MODES 4

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

and 5 because the probability and consequences of these events are low due to the RCS pressure and temperature limitations of these MODES.

<u>3, 4. Reactor Building Ventilation Exhaust and Refueling Floor Radiation - High</u>

High reactor building ventilation exhaust radiation or refuel floor radiation is an indication of possible gross failure of the fuel cladding. The release may have originated from the primary containment due to a break in the RCPB or the refueling floor due to a fuel handling accident. When Reactor Building Ventilation Exhaust Radiation - High or Refueling Floor Radiation - High is detected the CREF System is initiated. These actions are required to mitigate the consequences of the LOCA or FHA involving recently irradiated fuel by limiting the control room doses to less than the limits calculated in the safety analysis (Refs. 1 and 4).

The Reactor Building Ventilation Exhaust Radiation - High signals are initiated from radiation detectors that are located on the ventilation exhaust piping coming from the reactor building. The Refueling Floor Radiation - High signals are initiated for radiation detectors that are located to monitor the environment of the refuel floor area. The signal from each detector is input to an individual monitor whose trip outputs are assigned to an isolation channel. Two channels of Reactor Building Ventilation Exhaust Radiation - High Function and two channels of Refueling Floor Radiation - High Function are available and are required to be OPERABLE to ensure that no single instrument failure can preclude the isolation function.

The Allowable Values are chosen to promptly detect gross failure of the fuel cladding.

The Reactor Building Ventilation Exhaust Radiation - High and Refueling Floor Radiation - High Functions are required to be OPERABLE in MODES 1, 2, and 3 where considerable energy exists in the RCS; thus, there is a probability of pipe breaks resulting in significant releases of radioactive steam and gas. In MODES 4 and 5, the probability and consequences of these events are low due to the RCS pressure and temperature limitations of these MODES; thus, these Functions are not required. In addition, the Functions are also required to be OPERABLE during OPDRVs and movement of recently irradiated fuel assemblies in the secondary containment, because the capability of detecting radiation releases due to fuel failures (due to fuel un-covering or dropped fuel assemblies) must be provided to ensure that control room dose limits are not exceeded. Due to radioactive decay, these Functions are only required to initiate the CREF System during fuel handling accidents involving handling recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 24 hours).

BASES

ACTIONS

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

<u>A.1 and A.2</u>

Because of the diversity of sensors available to provide initiation signals and the redundancy of the CREF System design, an allowable out of service time of 12 hours has been shown to be acceptable to permit restoration of any inoperable channel to OPERABLE status. However, this out of service time is only acceptable provided the associated Function is till maintaining CREF System initiation capability. A Function is considered to be maintaining CREF System initiation capability when sufficient channels are OPERABLE or in trip such that one trip system will generate an initiation signal from the given Function on a valid signal. For Functions 1 and 2, this would require one trip system to have one channel per logic string OPERABLE or in trip (a logic string is the one-out-of-two portion of a one-out-of-two taken twice logic arrangement).

<u>B.1 and B.2</u>

With the Required Action and associated Completion Time not met, the associated CREF subsystem must be placed in the pressurization mode of operation (Required Action B.1) to ensure that control room personnel will be protected in the event of a DBA. The method used to place the CREF subsystem in operation must provide for automatically reinitiating the subsystem upon restoration of power following a loss of power to the CREF subsystem(s). Alternately, if it is not desired to start the associated CREF subsystem, the CREF subsystem associated with the inoperable channels(s) must be declared inoperable within 1 hour (Required Action B.2).

The 1 hour Completion Time is intended to allow the operator time to place the CREF subsystem in operation. The 1 hour Completion Time is acceptable because it minimizes risk while allowing time for restoration of channels, or for placing the associated CREF subsystem in operation.

BASES

SURVEILLANCE REQUIREMENTS

As noted at the beginning of the SRs, the SRs for each CREF System Instrumentation Function are located in the SRs column of Table 3.3.7.1-1. The Surveillances are modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6hours, provided the associated Function maintains CREF System initiation capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. The Notes are based on the reliability analysis (Refs. 2 and 3) assumption of the average time required to perform channel surveillance. That analysis demonstrated the 6 hour testing allowance does not significantly reduce the probability that the CREF System will initiate when necessary.

SR 3.3.7.1.1

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

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

The Frequency is based upon operating experience that demonstrates channel failure is rare. The CHANNEL CHECK supplements less formal, but more frequent, checks of channel status during normal operational use of the displays associated with channels required by the LCO.

SR 3.3.7.1.2

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required

BASES

SURVEILLANCE REQUIREMENTS (continued)

contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions.

Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

The Frequency of 92 days is based on the reliability analysis of References 2 and 3.

SR 3.3.7.1.3

The calibration of trip units provides a check of the actual trip setpoints. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology. The channel must be declared inoperable if the trip setting is discovered to be less conservative than the Allowable Value specified in Table 3.3.7.1-1. If the trip setting is discovered to be less conservative than accounted for in the appropriate setpoint methodology, but is not beyond the Allowable Value, the channel performance is still within the requirements of the plant safety analysis. Under these conditions, the setpoint must be readjusted to be equal to or more conservative than the setting accounted for in the appropriate setpoint methodology.

The Frequency of 92 days is based on the reliability analysis of References 2 and 3.

SR 3.3.7.1.4 and SR 3.3.7.1.5

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

The Frequencies of SR 3.3.7.1.4 and SR 3.3.7.1.5 are based on the assumption of a 92 day and a 24 month Calibration interval, respectively, in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.7.1.6

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required initiation logic for a specific channel. The system functional testing performed in LCO 3.7.4, "Control Room Emergency Filtration (CREF) System," overlaps this Surveillance to provide complete testing of the assumed safety function.

BASES

SURVEILLANCE REQUIREMENTS (continued)

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

REFERENCES

1. USAR, Section 14.7.2.
2. NEDC-31677P-A, "Technical Specification Improvement Analysis for BWR Isolation Actuation Instrumentation," July 1990.
3. NEDC-30851P-A Supplement 2, "Technical Specifications Improvement Analysis for BWR Isolation Instrumentation Common to RPS and ECCS Instrumentation," March 1989.

B 3.3 INSTRUMENTATION

B 3.3.7.2 Mechanical Vacuum Pump Isolation Instrumentation

BASES

BACKGROUND

The mechanical vacuum pump isolation instrumentation initiates a trip of the mechanical vacuum pump and isolation of the isolation valves following events in which main steam radiation monitors exceed a predetermined value. Tripping and isolating the mechanical vacuum pump limits control room and offsite doses in the event of a control rod drop accident (CRDA).

The mechanical vacuum pump isolation instrumentation includes sensors, relays and switches that are necessary to cause initiation of mechanical vacuum pump isolation. The channels include electronic equipment that compares measured input signals with pre-established setpoints. When the setpoint is exceeded, the channel output relay actuates, which then outputs an isolation signal to the mechanical vacuum pump isolation logic.

The isolation logic consists of two independent trip systems, with two channels of the Main Steam Line Tunnel Radiation - High Function in each trip system. The outputs from two channels provide input into one trip system and the other two channels provide input into the other trip system. One channel must trip to trip a trip system and both trip systems must trip to initiate the mechanical vacuum pump isolation function (i.e., one-out-of-two taken twice logic arrangement). There are one mechanical vacuum pump breaker and two mechanical vacuum pump isolation valves associated with this Function.

APPLICABLE SAFETY ANALYSES

The mechanical vacuum pump isolation is assumed in the safety analysis for the CRDA (Ref. 1). The mechanical vacuum pump isolation instrumentation initiates an isolation of the mechanical vacuum pump to limit control room and offsite doses resulting from fuel cladding failure in a CRDA. An Allowable Value of 6.9 R/hr will ensure that 10 CFR 50, Appendix A, General Design Criterion (GDC) 19 limits (Ref. 2) will not be exceeded in the control room in the event of a CRDA.

The mechanical vacuum pump isolation instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

The OPERABILITY of the mechanical vacuum pump isolation instrumentation is dependent on the OPERABILITY of the individual Main Steam Line Tunnel Radiation - High Function instrumentation channels, which must have a required number of OPERABLE channels in each trip system, with their setpoints within the specified Allowable Value of SR 3.3.7.2.3. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions. Channel OPERABILITY also includes the mechanical vacuum pump breaker and isolation valves. An Allowable Value is specified for the Main Steam Line Tunnel Radiation - High Function specified in the LCO. A nominal trip setpoint is specified in the setpoint calculations. The nominal trip setpoint is selected to ensure that the actual trip setpoints do not exceed the Allowable Value between successive CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable. A channel is inoperable if its actual trip setpoint is not within its required Allowable Value.

Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (i.e., main steam line tunnel radiation), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., trip unit) changes state. The analytic limits are derived from the limiting values of the process parameters obtained from the safety analysis. The Allowable Values and nominal trip setpoints (NTSP) are derived, using the General Electric setpoint methodology guidance, as specified in the Monticello setpoint methodology. The Allowable Values are derived from the analytic limits. The difference between the analytic limit and the Allowable Value allows for channel instrument accuracy, calibration accuracy, process measurement accuracy, and primary element accuracy. The margin between the Allowable Value and the NTSP allows for instrument drift that might occur during the established surveillance period. Two separate verifications are performed for the calculated NTSP. The first, a Spurious Trip Avoidance Test, evaluates the impact of the NTSP on plant availability. The second verification, an LER Avoidance Test, calculates the probability of avoiding a Licensee Event Report (or exceeding the Allowable Value) due to instrument drift. These two verifications are statistical evaluations to provide additional assurance of the acceptability of the NTSP and may require changes to the NTSP. Use of these methods and verifications provides the assurance that if the setpoint is found conservative to the Allowable Value during surveillance testing, the instrumentation would have provided the required trip function by the time the process reached the analytic limit for the applicable events.

BASES

APPLICABILITY

The mechanical vacuum pump isolation is required to be OPERABLE in MODES 1 and 2 when the mechanical vacuum pump is in service (i.e., taking suction on the main condenser) and any main steam line not isolated, to mitigate the consequences of a postulated CRDA. In this condition, fission products released during a CRDA could be discharged directly to the environment. Therefore, the mechanical vacuum pump isolation is necessary to assure conformance with the radiological evaluation of the CRDA. In MODE 3, 4 or 5 the consequences of a control rod drop are insignificant, and are not expected to result in any fuel damage or fission product releases. In MODES 1 or 2 when the mechanical vacuum pump is not in operation or the main steam lines are isolated, fission product releases via this pathway would not occur.

ACTIONS

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

<u>A.1 and A.2</u>

With one or more channels inoperable, but with mechanical vacuum pump isolation capability maintained (refer to Required Action B.1 Bases), the mechanical vacuum pump isolation instrumentation is capable of performing the intended function. However, the reliability and redundancy of the mechanical vacuum pump isolation instrumentation is reduced, such that a single failure in one of the remaining channels could result in the inability of the mechanical vacuum pump isolation instrumentation to perform the intended function. Therefore, only a limited time is allowed to restore the inoperable channels to OPERABLE status. Because of the low probability of extensive number of inoperabilities affecting multiple channels, and the low probability of an event requiring the initiation of the mechanical vacuum pump isolation, 12 hours has been shown to be acceptable (Ref. 3) to permit restoration of any inoperable channel to OPERABLE status (Required Action A.1). Alternately, the inoperable channel may be placed in trip (Required Action A.2), since this would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. As noted,

BASES

ACTIONS (continued)

placing the channel in trip with no further restrictions is not allowed if the inoperable channel is the result of an inoperable mechanical vacuum pump breaker or isolation valve, since this may not adequately compensate for the inoperable mechanical vacuum pump breaker or isolation valve (e.g., the breaker may be inoperable such that it will not trip). If it is not desired to place the channel in trip (e.g., as in the case where placing the inoperable channel in trip would result in loss of condenser vacuum), or if the inoperable channel is the result of an inoperable mechanical vacuum pump breaker or isolation valve, Condition C must be entered and its Required Actions taken.

B.1

Condition B is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels result in the Function not maintaining mechanical vacuum pump isolation capability. The Function is considered to be maintaining mechanical vacuum pump isolation capability when sufficient channels are OPERABLE or in trip such that the mechanical vacuum pump isolation instruments will generate a trip signal from a valid Main Steam Line Tunnel Radiation - High signal, and the mechanical vacuum pump will trip or the isolation valves will close. This requires one channel of the Function in each trip system to be OPERABLE or in trip, and the mechanical vacuum pump breaker or isolation valves to be OPERABLE.

C.1, C.2, and C.3

With any Required Action and associated Completion Time of Condition A or B not met, the plant must be brought to a MODE or other specified condition in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours (Required Action C.3). Alternately, the mechanical vacuum pump may be isolated (Required Action C.1) since this action performs the intended function of the instrumentation. An additional option is provided to isolate the main steam lines (Required Action C.2), which may allow operation to continue. Isolating the main steam lines effectively provides an equivalent level of protection by precluding fission product transport to the condenser. This isolation is accomplished by isolation of all main steam lines and all main steam line drains that bypass the main steam isolation valves.

BASES

SURVEILLANCE REQUIREMENTS

The Surveillances are modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into the associated Conditions and Required Actions may be delayed for up to 6 hours provided the associated Function maintains mechanical vacuum pump isolation trip capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the reliability analyses (Ref. 3) assumption of the average time required to perform channel Surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that the mechanical vacuum pump will isolate when necessary.

SR 3.3.7.2.1

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

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

The Frequency is based on the CHANNEL CHECK Frequency requirement of other instrumentation. The CHANNEL CHECK supplements less formal, but more frequent, checks of channels during normal operational use of the displays associated with the required channels of this LCO.

SR 3.3.7.2.2

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

The Frequency of 92 days is based on the reliability analysis of Reference 3.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.7.2.3

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

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

SR 3.3.7.2.4

The LOGIC SYSTEM FUNCTIONAL TEST demonstrates the OPERABILITY of the required trip logic for a specific channel. The system functional test of the mechanical vacuum pump breaker and actuation of the associated isolation valves are included as part of this Surveillance, to provide complete testing of the assumed safety function. Therefore, if the breaker is incapable of operating or an isolation valve is incapable of closing, the instrument channel 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 was performed with the reactor at power.

REFERENCES

1. USAR Section 14.7.1
2. 10 CFR 50, Appendix A, GDC 19.
3. NEDC-30851P-A Supplement 2, "Technical Specifications Improvement Analysis for BWR Isolation Instrumentation Common to RPS and ECCS Instrumentation," March 1989.
4. 10 CFR 50.67, “Accident Source Term”

B 3.3 INSTRUMENTATION

B 3.3.8.1 Loss of Power (LOP) Instrumentation

BASES

BACKGROUND

Successful operation of the required safety functions of the Emergency Core Cooling Systems (ECCS) is dependent upon the availability of adequate power sources for energizing the various components such as pump motors, motor operated valves, and the associated control components. The LOP instrumentation monitors the 4.16 kV essential buses. Offsite power is the preferred source of power for the 4.16 kV essential buses. If the monitors determine that insufficient power is available, the buses are disconnected from the offsite power sources and connected to the onsite emergency diesel generator (EDG) power sources.

Each 4.16 kV essential bus has its own independent LOP instrumentation and associated trip logic. The voltage for each bus is monitored at two levels, which can be considered as two different undervoltage Functions: 4.16 kV Essential Bus Loss of Voltage and 4.16 kV Essential Bus Degraded Voltage (Ref. 1). Each Function causes various bus transfers and disconnects. The 4.16 kV Essential Bus Loss of Voltage Function is monitored by four undervoltage relays for each emergency bus, whose outputs are arranged in a one-out-of-two twice logic configuration (i.e., one channel in each of two trip systems must trip for LOP actuation). The 4.16 kV Essential Bus Degraded Voltage Function is monitored by three undervoltage relays (with its associated time delay) for each emergency bus, whose outputs are arranged in a two-out-of-three logic configuration. Both LOP Functions provide an automatic start signal to both EDGs. However, only the automatic start signal to the associated EDG (the EDG in the same division) is required. If the 4.16 kV Essential Bus Loss of Voltage signal is present for approximately 5 seconds, it will trip the supply breaker (from bus 13 or 14, as applicable) to the associated essential bus and provide a transfer signal to the reserve auxiliary transformer (1AR). If the 4.16 kV Essential Bus Loss of Voltage signal is present for approximately 10 seconds (i.e., the transfer to 1AR fails or 1AR is deenergized) it will trip all supply breakers to the essential bus (from bus 13 and 14, as applicable and from 1AR) and provide a close signal to the EDG output breaker. If the 4.16 kV Essential Bus Degraded Voltage signal (normally 3920 Vac for approximately 9 seconds) is present, it will trip the supply breaker (from bus 13 or 14, as applicable) to the associated essential bus and provide a close signal to the EDG output breaker (Ref. 5).

BASES

BACKGROUND (continued)

The channels include electronic equipment (e.g., relays) that compares measured input signals with pre-established setpoints. When the setpoint is exceeded, the channel output relay actuates, which then outputs a LOP trip signal to the trip logic.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The LOP instrumentation is required for Engineered Safety Features to function in any accident with a loss of offsite power. The required channels of LOP instrumentation ensure that the ECCS and other assumed systems powered from the EDGs, provide plant protection in the event of any of the Reference 2, 3, and 4 analyzed accidents in which a loss of offsite power is assumed. The initiation of the EDGs on loss of offsite power, and subsequent initiation of the ECCS, ensure that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

Accident analyses credit the loading of the EDG based on the loss of offsite power during a loss of coolant accident. The diesel starting and loading times have been included in the delay time associated with each safety system component requiring EDG supplied power following a loss of offsite power.

The LOP Instrumentation satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

The OPERABILITY of the LOP instrumentation is dependent upon the OPERABILITY of the individual instrumentation channel Functions specified in Table 3.3.8.1-1. Each Function must have a required number of OPERABLE channels per 4.16 kV essential bus, with their setpoints within the specified Allowable Values. A channel is inoperable if its actual trip setpoint is not within its required Allowable Value. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions.

The Allowable Values are specified for each Function in the Table. Nominal trip setpoints are specified in the setpoint calculations. The nominal setpoints are selected to ensure that the setpoints do not exceed the Allowable Value between CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within the Allowable Value, is acceptable. Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (e.g., degraded voltage), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., trip unit) changes state. The analytic limits are derived from the limiting values of the process parameters obtained from the safety analysis. The Allowable Values and nominal trip setpoints (NTSP) are derived, using the General Electric setpoint methodology guidance, as specified in the Monticello setpoint

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

methodology. The Allowable Values are derived from the design limits. The difference between the design limit and the Allowable Value allows for channel instrument accuracy, calibration accuracy, process measurement accuracy, and primary element accuracy. The margin between the Allowable Value and the NTSP allows for instrument drift that might occur during the established surveillance period. Two separate verifications are performed for the calculated NTSP. The first, a Spurious Trip Avoidance Test, evaluates the impact of the NTSP on plant availability. The second verification, an LER Avoidance Test, calculates the probability of avoiding a Licensee Event Report (or exceeding the Allowable Value) due to instrument drift. These two verifications are statistical evaluations to provide additional assurance of the acceptability of the NTSP and may require changes to the NTSP. Use of these methods and verifications provides the assurance that if the setpoint is found conservative to the Allowable Value during surveillance testing, the instrumentation would have provided the required trip function by the time the process reached the design limit for the applicable events.

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

<u>1. 4.16 kV Essential Bus Loss of Voltage</u>

Loss of voltage on a 4.16 kV essential bus indicates that offsite power may be completely lost to the respective essential bus and is unable to supply sufficient power for proper operation of the applicable equipment. Therefore, the power supply to the bus is transferred from offsite power to EDG power when the voltage on the bus drops below the 4.16 kV Essential Bus Loss of Voltage Function Allowable Value. This ensures that adequate power will be available to the required equipment.

The 4.16 kV Essential Bus Loss of Voltage Allowable Values are low enough to prevent inadvertent power supply transfer, but high enough to ensure that power is available to the required equipment.

Four channels of 4.16 kV Essential Bus Loss of Voltage Function per associated essential bus are only required to be OPERABLE when the associated EDG is required to be OPERABLE to ensure that no single instrument failure can preclude the EDG function. (Four channels input to each of the two EDGs.) Refer to LCO 3.8.1, "AC Sources - Operating," and 3.8.2, "AC Sources - Shutdown," for Applicability Bases for the EDGs.

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

2. 4.16 kV Essential Bus Degraded Voltage

A reduced voltage condition on a 4.16 kV essential bus indicates that, while offsite power may not be completely lost to the respective essential bus, available power may be insufficient for starting large ECCS motors without risking damage to the motors that could disable the ECCS function. Therefore, power supply to the bus is transferred from offsite power to onsite EDG power when the voltage on the bus drops below the 4.16 kV Essential Bus Degraded Voltage Function Allowable Values (degraded voltage with a time delay). This ensures that adequate power will be available to the required equipment.

The 4.16 kV Essential Bus Degraded Voltage Allowable Values are low enough to prevent inadvertent power supply transfer, but high enough to ensure that sufficient power is available to the required equipment. The Time Delay Allowable Values are long enough to provide time for the offsite power supply to recover to normal voltages, but short enough to ensure that sufficient power is available to the required equipment.

Three channels of 4.16 kV Essential Bus Degraded Voltage Function per associated bus are only required to be OPERABLE when the associated EDG is required to be OPERABLE to ensure that no single instrument failure can preclude the EDG function. (Three channels input to each of the two essential buses and EDGs.) Refer to LCO 3.8.1 and LCO 3.8.2 for Applicability Bases for the EDGs.

ACTIONS

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

A.1

With one or more channels of a Function inoperable, the Function is not capable of performing the intended function. Therefore, only 1 hour is allowed to restore the inoperable channel to OPERABLE status. If the inoperable channel cannot be restored to OPERABLE status within the

BASES

ACTIONS (continued)

allowable out of service time, the channel must be placed in the tripped condition per Required Action A.1. Placing the inoperable channel in trip would conservatively compensate for the inoperability, restore capability to accommodate a single failure (within the LOP instrumentation), and allow operation to continue. Alternately, if it is not desired to place the channel in trip (e.g., as in the case where placing the channel in trip would result in an EDG initiation), Condition B must be entered and its Required Action taken.

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

B.1

If any Required Action and associated Completion Time are not met, the associated Function is not capable of performing the intended function. Therefore, the associated EDG is declared inoperable immediately. This requires entry into applicable Conditions and Required Actions of LCO 3.8.1 and LCO 3.8.2, which provide appropriate actions for the inoperable EDG.

SURVEILLANCE REQUIREMENTS

As noted at the beginning of the SRs, the SRs for each LOP Instrumentation Function are located in the SRs column of Table 3.3.8.1-1.

The Surveillances are modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 2 hours provided the associated Function maintains EDG initiation capability. Upon completion of the Surveillance, or expiration of the 2 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken.

SR 3.3.8.1.1

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required

BASES

SURVEILLANCE REQUIREMENTS (continued)

contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

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

SR 3.3.8.1.2 and SR 3.3.8.1.3

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

Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

The Frequency of SR 3.3.8.1.2 is based upon the assumption of a 92 day calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

The Frequency of SR 3.3.8.1.3 is based upon the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

SR 3.3.8.1.4

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

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

BASES

REFERENCES

1. USAR, Section 8.4.1.3.
2. USAR, Section 5.2.3.2.3.
3. USAR, Section 6.2.
4. USAR, Section 14.7.2.
5. Amendment No. 169, “Issuance of Amendment to Remove Automatic Transfer Capability of Essential Electrical Buses to the 1AR Transformer Due to Degraded Voltage Conditions (TAC No. ME8763),” dated August 27, 2012. (ADAMS Accession No. ML12216A269)

B 3.3 INSTRUMENTATION

B 3.3.8.2 Reactor Protection System (RPS) Electric Power Monitoring

BASES

BACKGROUND

RPS Electric Power Monitoring System is provided to isolate the RPS bus from the motor generator (MG) set or the alternate power supply in the event of overvoltage, undervoltage, or underfrequency. This system protects the loads connected to the RPS bus against unacceptable voltage and frequency conditions (Ref. 1) and forms an important part of the primary success path of the essential safety circuits. Some of the essential equipment powered from the RPS buses includes the RPS logic, scram solenoids, radiation and neutron monitoring equipment, and various valve isolation logic.

RPS electric power monitoring assembly will detect any abnormal high or low voltage or low frequency condition in the outputs of the two MG sets or the alternate power supply and will de-energize its respective RPS bus, thereby causing all safety functions normally powered by this bus to de-energize.

In the event of failure of an RPS Electric Power Monitoring System (e.g., both inseries electric power monitoring assemblies), the RPS loads may experience significant effects from the unregulated power supply. Deviation from the nominal conditions can potentially cause damage to the scram solenoids and other Class 1E devices.

In the event of a low voltage condition for an extended period of time, the scram solenoids can chatter and potentially lose their pneumatic control capability, resulting in a loss of primary scram action.

In the event of an overvoltage condition, the RPS logic relays and scram solenoids and isolation logic relays may experience a voltage higher than their design voltage. If the overvoltage condition persists for an extended time period, it may cause equipment degradation and the loss of plant safety function.

Two redundant Class 1E circuit breakers are connected in series between each RPS bus and its MG set, and between each RPS bus and the alternate power supply. Each of these circuit breakers has an associated independent set of Class 1E overvoltage, undervoltage, and underfrequency sensing logic. Together, a circuit breaker and its sensing logic constitute an electric power monitoring assembly. If the output of the inservice MG set or alternate power supply exceeds predetermined limits of overvoltage, undervoltage, or underfrequency, a trip coil driven by this logic circuitry opens the circuit breaker, which removes the associated power supply from service.

BASES

APPLICABLE SAFETY ANALYSES	The RPS Electric Power Monitoring is necessary to meet the assumptions of the safety analyses by ensuring that the equipment powered from the RPS buses can perform its intended function. RPS Electric Power Monitoring provides protection to the RPS and other systems that receive power from the RPS buses, by acting to disconnect the RPS bus from the power supply under specified conditions that could damage the RPS bus powered equipment. RPS Electric Power Monitoring satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	The OPERABILITY of each RPS electric power monitoring assembly is dependent on the OPERABILITY of the overvoltage, undervoltage, and underfrequency logic, as well as the OPERABILITY of the associated circuit breaker. Two electric power monitoring assemblies are required to be OPERABLE for each inservice power supply. This provides redundant protection against any abnormal voltage or frequency conditions to ensure that no single RPS electric power monitoring assembly failure can preclude the function of RPS bus powered components. Each of the inservice electric power monitoring assembly trip logic setpoints is required to be within the specified Allowable Value. The actual setpoint is calibrated consistent with applicable setpoint methodology assumptions. Allowable Values are specified for each RPS electric power monitoring assembly trip logic (refer to SR 3.3.8.2.2 and SR 3.3.8.2.3). Nominal trip setpoints are specified in the setpoint calculations. The nominal setpoints are selected to ensure that the setpoints do not exceed the Allowable Value between CHANNEL CALIBRATIONS. Operation with a trip setpoint less conservative than the nominal trip setpoint, but within its Allowable Value, is acceptable. A channel is inoperable if its actual trip setpoint is not within its required Allowable Value. Trip setpoints are those predetermined values of output at which an action should take place. The setpoints are compared to the actual process parameter (e.g., overvoltage), and when the measured output value of the process parameter exceeds the setpoint, the associated device (e.g., trip coil) changes state. The analytic limits are derived from the limiting values of the process parameters obtained from the safety analysis. The Allowable Values and nominal trip setpoints (NTSP) are derived, using the General Electric setpoint methodology guidance, as specified in the Monticello setpoint methodology. The Allowable Values are derived from the analytic limits. The difference between the analytic limit and the Allowable Value allows for channel instrument accuracy, calibration accuracy, process measurement accuracy, and primary element accuracy. The margin between the Allowable Value and the NTSP allows for instrument drift that might occur during the established surveillance period. Two separate verifications are performed for the calculated NTSP. The first, a Spurious Trip Avoidance Test, evaluates the impact of the NTSP on plant availability. The second verification, an LER

BASES

LCO (continued)

Avoidance Test, calculates the probability of avoiding a Licensee Event Report (or exceeding the Allowable Value) due to instrument drift. These two verifications are statistical evaluations to provide additional assurance of the acceptability of the NTSP and may require changes to the NTSP. Use of these methods and verifications provides the assurance that if the setpoint is found conservative to the Allowable Value during surveillance testing, the instrumentation would have provided the required trip function by the time the process reached the analytic limit for the applicable events.

The Allowable Values for the instrument settings are based on the RPS buses providing ≥ 57 Hz and 116 V ± 10% to all equipment. The Allowable Values are within the ratings of the RPS bus powered components and ensure their protection from sustained abnormal power.

APPLICABILITY

The operation of the RPS electric power monitoring assemblies is essential to disconnect the RPS bus powered components from the inservice MG set or alternate power supply during abnormal voltage or frequency conditions. Since the degradation of a nonclass 1E source supplying power to the RPS bus can occur as a result of any random single failure, the OPERABILITY of the RPS electric power monitoring assemblies is required when the RPS bus powered components are required to be OPERABLE. This results in the RPS Electric Power Monitoring System OPERABILITY being required in MODES 1, 2, and 3, in MODES 4 and 5 with both residual heat removal (RHR) shutdown cooling supply isolation valves open, in MODE 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies, during movement of recently irradiated fuel assemblies in the secondary containment, and during operations with a potential for draining the reactor vessel (OPDRVs).

ACTIONS

A.1

If one RPS electric power monitoring assembly for an inservice power supply (MG set or alternate) is inoperable, or one RPS electric power monitoring assembly on each inservice power supply is inoperable, the OPERABLE assembly will still provide protection to the RPS bus powered components under degraded voltage or frequency conditions. However, the reliability and redundancy of the RPS Electric Power Monitoring System is reduced, and only a limited time (72 hours) is allowed to restore the inoperable assembly to OPERABLE status. If the inoperable assembly cannot be restored to OPERABLE status, the associated power supply(s) must be removed from service (Required Action A.1). This

BASES

ACTIONS (continued)

places the RPS bus in a safe condition. An alternate power supply with OPERABLE power monitoring assemblies may then be used to power the RPS bus.

The 72 hour Completion Time takes into account the remaining OPERABLE electric power monitoring assembly and the low probability of an event requiring RPS electric power monitoring protection occurring during this period. It allows time for plant operations personnel to take corrective actions or to place the plant in the required condition in an orderly manner and without challenging plant systems.

Alternately, if it is not desired to remove the power supply 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, D, E, or F, as applicable, must be entered and its Required Actions taken.

B.1

If both power monitoring assemblies for an inservice power supply (MG set or alternate) are inoperable or both power monitoring assemblies in each inservice power supply are inoperable, the system protective function is lost. In this condition, 1 hour is allowed to restore one assembly to OPERABLE status for each inservice power supply. If one inoperable assembly for each inservice power supply cannot be restored to OPERABLE status, the associated power supply(s) must be removed from service within 1 hour (Required Action B.1). An alternate power supply with 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, D, E, or F, 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, a plant shutdown must be performed. This places the plant in a condition where minimal equipment, powered through the inoperable RPS electric power monitoring assembly(s), is required and ensures that the safety function of the RPS

BASES

ACTIONS (continued)

bus loads (e.g., scram of control rods) is not required. The plant shutdown is accomplished by placing the plant in MODE 3 within 12 hours and in MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

D.1 and D.2

If any Required Action and associated Completion Time of Condition A or B are not met in MODE 4 or 5 with both RHR shutdown cooling supply isolation valves open, action must be immediately initiated to either restore one electric power monitoring assembly to OPERABLE status for the inservice power source supplying the required instrumentation powered from the RPS bus (Required Action D.1) or to isolate the RHR Shutdown Cooling System (Required Action D.2). Required Action D.1 is provided because the RHR Shutdown Cooling System may be needed to provide core cooling. All actions must continue until the applicable Required Actions are completed.

E.1

If any Required Action and associated Completion Time of Condition A or B are not met in MODE 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies, the operator must immediately initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies. Required Action E.1 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.

F.1.1, F.1.2, F.2.1, F.2.2, F.3.1, and F.3.2

If any Required Action and associated Completion Time of Condition A or B are not met during movement of recently irradiated fuel assemblies in the secondary containment or during OPDRVs, the ability to isolate the secondary containment, start the Standby Gas Treatment (SGT) System, and start Control Room Emergency Filtration (CREF) System cannot be ensured. Therefore, actions must be immediately performed to ensure the ability to maintain the secondary containment isolation, SGT System, and CREF System functions. Isolating the affected penetration flow path(s) and starting the associated SGT subsystem(s) and CREF subsystem(s) (Required Actions F.1.1, F.2.1, and F.3.1) performs the

BASES

ACTIONS (continued)

intended function of the instrumentation the RPS electric power monitoring assemblies is protecting, and allows operations to continue.

Alternatively, immediately declaring the associated secondary containment isolation valve(s), SGT subsystem(s), or CREF subsystem(s) inoperable (Required Actions F.1.2, F.2.2, and F.3.2) is also acceptable since the Required Actions of the respective LCOs (LCO 3.6.4.2, "Secondary Containment Isolation Valves," LCO 3.6.4.3, "Standby Gas Treatment (SGT) System," and LCO 3.7.4, "Control Room Emergency Filtration (CREF) System") provide appropriate actions for the inoperable components.

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 channel will perform the intended function. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

The 184 day Frequency in the Surveillance is based on guidance provided in Generic Letter 91-09 (Ref. 2).

SR 3.3.8.2.2 and SR 3.3.8.2.3

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 of SR 3.3.8.2.2 is based on the assumption of a 184 day calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis. The Frequency of SR 3.3.8.2.3 is based on the assumption of a 24 month calibration interval in the determination of the magnitude of equipment drift in the setpoint analysis.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.8.2.4

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

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

REFERENCES

1. USAR, Section 8.6.2.

2. NRC Generic Letter 91-09, "Modification of Surveillance Interval for the Electrical Protective Assemblies in Power Supplies for the Reactor Protection System."

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.1 Recirculation Loops Operating

BASES

BACKGROUND

The Reactor Recirculation System is designed to provide forced coolant flow through the core to remove heat from the fuel. The forced coolant flow removes heat at a faster rate from the fuel than would be possible with just natural circulation. The forced flow, therefore, allows operation at significantly higher power than would otherwise be possible. The recirculation system also controls reactivity over a wide span of reactor power by varying the recirculation flow rate to control the void content of the moderator. The Reactor Recirculation System consists of two recirculation pump loops external to the reactor vessel. These loops provide the piping path for the driving flow of water to the reactor vessel jet pumps. Each external loop contains one variable speed motor driven recirculation pump, driven by a motor generator (MG) set to control pump speed, and associated piping, jet pumps, valves, and instrumentation. The recirculation loops are part of the reactor coolant pressure boundary and are located inside the drywell structure. The jet pumps are reactor vessel internals.

The recirculated coolant consists of saturated water from the steam separators and dryers that has been subcooled by incoming feedwater. This water passes down the annulus between the reactor vessel wall and the core shroud. A portion of the coolant flows from the vessel, through the two external recirculation loops, and becomes the driving flow for the jet pumps. Each of the two external recirculation loops discharges high pressure flow into an external manifold, from which individual recirculation inlet lines are routed to the jet pump risers within the reactor vessel. The remaining portion of the coolant mixture in the annulus becomes the suction flow for the jet pumps. This flow enters the jet pump at suction inlets and is accelerated by the driving flow. The drive flow and suction flow are mixed in the jet pump throat section and result in a partial pressure recovery. The total flow then passes through the jet pump diffuser section into the area below the core (lower plenum), gaining sufficient head in the process to drive the required flow upward through the core. The subcooled water enters the bottom of the fuel channels and contacts the fuel cladding, where heat is transferred to the coolant. As it rises, the coolant begins to boil, creating steam voids within the fuel channel that continue until the coolant exits the core. Because of reduced moderation, the steam voiding introduces negative reactivity that must be compensated for to maintain or to increase reactor power. The recirculation flow control allows operators to increase recirculation flow and sweep some of the voids from the fuel channel, overcoming the negative reactivity void effect. Thus, the reason for having variable recirculation flow is to compensate for reactivity effects of boiling over a

BASES

BACKGROUND (continued)

wide range of power generation (i.e., 60% to 100% of RTP) without having to move control rods and disturb desirable flux patterns. The recirculation flow also provides sufficient core flow to ensure thermal-hydraulic stability of the core is maintained.

Each recirculation loop is manually started from the control room. The MG set provides regulation of individual recirculation loop drive flows. The flow in each loop is manually controlled.

APPLICABLE SAFETY ANALYSES

NOTE: Certain AREVA safety analysis methods have been approved for use (Amendment 188); however, those methods may not be invoked in the analysis-of-record until AREVA fuel is loaded in the core. Until that time, General Electric – Hitachi (GEH) safety analysis methods will continue to support core operation and the description of the GEH methods in the TS Bases shall prevail. To the extent that approved AREVA methods may be described and referenced without conflicting with the GEH analysis-of-record, the TS Bases reflect both GEH and AREVA methods. Refer to CORE OPERATING LIMIT REPORT (COLR) Section 1.0 to determine whether GEH or AREVA methods were used for the current operating cycle.

The operation of the Reactor Recirculation System is an initial condition assumed in the design basis loss of coolant accident (LOCA) (Ref. 1). During a LOCA caused by a recirculation loop pipe break, the intact loop is assumed to provide coolant flow during the first few seconds of the accident. The initial core flow decrease is rapid because the recirculation pump in the broken loop ceases to pump reactor coolant to the vessel almost immediately. The pump in the intact loop coasts down relatively slowly. This pump coastdown governs the core flow response for the next several seconds until the jet pump suction is uncovered (Ref. 1). The analyses assume that both loops are operating at the same flow prior to the accident. However, the LOCA analysis was reviewed for the case with a flow mismatch between the two loops, with the pipe break assumed to be in the loop with the higher flow. While the flow coastdown and core response are potentially more severe in this assumed case (since the intact loop starts at a lower flow rate and the core response is the same as if both loops were operating at a lower flow rate), a small mismatch has been determined to be acceptable based on engineering judgment. The recirculation system is also assumed to have sufficient flow coastdown characteristics to maintain fuel thermal margins during abnormal operational transients (Ref. 2), which are analyzed in Chapter 14 of the USAR.

BASES

APPLICABLE SAFETY ANALYSES (continued)

A plant specific LOCA analysis has been performed assuming only one operating recirculation loop. This analysis has demonstrated that, in the event of a LOCA caused by a pipe break in the operating recirculation loop, the Emergency Core Cooling System response will provide adequate core cooling, provided the APLHGR requirements are modified accordingly (Refs. 3 and 8).

The transient analyses of Chapter 14 of the USAR have also been evaluated for single recirculation loop operation (Refs. 4, 5, 6, and 12) and demonstrate sufficient flow coastdown characteristics to maintain fuel thermal margins during the abnormal operational transients analyzed provided the MCPR requirements are modified. During single recirculation loop operation, modification to the Reactor Protection System (RPS) average power range monitor (APRM) Allowable Values is also required to account for the different relationships between recirculation drive flow and reactor core flow. The APLHGR and MCPR limits for single loop operation are specified in the COLR. The APRM Simulated Thermal Power – High Allowable Value is in LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation."

The Maximum Extended Load Line Limit Analysis Plus (MELLLA+) operating domain is not analyzed for single recirculation loop operation, and therefore cannot be utilized in single recirculation loop operation (Refs. 9 and 10).

Recirculation Loops Operating satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

Two recirculation loops are normally in operation with their flows matched within the limits specified in SR 3.4.1.1 to ensure that during a LOCA caused by a break of the piping of one recirculation loop the assumptions of the LOCA analysis are satisfied. With the limits specified in SR 3.4.1.1 not met, the recirculation loop with the lower flow must be considered not in operation. With only one recirculation loop in operation, modifications to the required APLHGR limits (LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)"), MCPR limits (LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)"), and APRM Simulated Thermal Power – High Allowable Value (LCO 3.3.1.1) must be applied to allow continued operation consistent with the assumptions of References 3 and 11.

BASES

APPLICABILITY

In MODES 1 and 2, requirements for operation of the Reactor Recirculation System are necessary since there is considerable energy in the reactor core and the limiting design basis transients and accidents are assumed to occur.

In MODES 3, 4, and 5, the consequences of an accident are reduced and the coastdown characteristics of the recirculation loops are not important.

ACTIONS

A.1

With the requirements of the LCO not met the recirculation loops must be restored to operation with matched flows within 24 hours. A recirculation loop is considered not in operation when the pump in that loop is idle or when the mismatch between total jet pump flows of the two loops is greater than required limits. The loop with the lower flow must be considered not in operation. Should a LOCA occur with one recirculation loop not in operation, the core flow coastdown and resultant core response may not be bounded by the LOCA analyses. Therefore, only a limited time is allowed to restore the loop to operating status.

Alternatively, if the single loop requirements of the LCO are applied to the APLHGR and MCPR operating limits and RPS Allowable Value, operation with only one recirculation loop would satisfy the requirements of the LCO and the initial conditions of the accident sequence.

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

This Required Action does not require tripping the recirculation pump in the lowest flow loop when the mismatch between total jet pump flows of the two loops is greater than the required limits. However, in cases where large flow mismatches occur, low flow or reverse flow can occur in the low flow loop jet pumps, causing vibration of the jet pumps. If zero or reverse flow is detected, the condition should be alleviated by changing pump speeds to re-establish forward flow or by tripping the pump.

B1

With no recirculation loops in operation or the Required Action and associated Completion Time of Condition A not met, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 12 hours. In this condition, the recirculation loops are not required to be operating because

BASES

ACTIONS (continued)

of the reduced severity of DBAs and minimal dependence on the recirculation loop coastdown characteristics. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.1.1

This SR ensures the recirculation loops are within the allowable limits for mismatch. At low core flow (i.e., < 70% of rated core flow), the MCPR requirements provide larger margins to the fuel cladding integrity Safety Limit and the APLHGR requirements reduce the average planar bundle power such that the potential adverse effect of early boiling transition during a LOCA is reduced. A larger flow mismatch can therefore be allowed when core flow is < 70% of rated core flow. The jet pump loop flow, as used in this Surveillance, is the summation of the flows from all of the jet pumps associated with a single recirculation loop. The mismatch is measured in terms of percent of rated core flow. If the flow mismatch exceeds the specified limits, the loop with the lower flow is considered not in operation. This SR is not required when both loops are not in operation since the mismatch limits are meaningless during single loop or natural circulation operation. The Surveillance must be performed within 24 hours after both loops are in operation. The 24 hour Frequency is consistent with the Surveillance Frequency for jet pump OPERABILITY verification and has been shown by operating experience to be adequate to detect off normal jet pump loop flows in a timely manner.

REFERENCES

1. USAR, Section 14.7.2.
2. USAR, Chapter 14.
3. Calculation 11-180, MNGP EPU Task Report T0407, “ECCS-LOCA SAFER/GESTR”
4. NEDO-24271, “Monticello Nuclear Generating Plant Single-Loop Operation," June 1980.
5. NEDC-30492, "Average Power Range Monitor, Rod Block Monitor and Technical Specification Improvement (ARTS) Program for Monticello Nuclear Power Generating Plant," April 1984.

BASES

REFERENCES (continued)

6. (Deleted)

7. USAR, Section 14.6.

8. Amendment No. 176, “Monticello Nuclear Generating Plant – Issuance of Amendment No. 176 to Renewed Facility Operating License Regarding Extended Power Uprate,” (ADAMS Accession No. ML13316C459)

9. NEDC-33006P-A, “Maximum Extended Load Line Limit Analysis Plus Licensing Topical Report,” Revision 3, June 2009.

10. Amendment No. 180, “Monticello Nuclear Generating Plant – Issuance of Amendment No. 180 to Renewed Facility Operating License Regarding MELLLA+,” March 28, 2014. (ADAMS Accession No. ML14035A248)

11. ANP-3212, Revision 0, “Monticello EPU LOCA-ECCS Analysis MAPLHGR Limits for ATRIUM™ 10XM Fuel,” AREVA NP, May 2013.

12. ANP-3213, Revision 1, “Monticello Fuel Transition Cycle 28 Reload Licensing Analysis (EPU/MELLLA),” AREVA NP, May 2013.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.2 Jet Pumps

BASES

BACKGROUND

The Reactor Recirculation System is described in the Background section of the Bases for LCO 3.4.1, "Recirculation Loops Operating," which discusses the operating characteristics of the system and how these characteristics affect the Design Basis Accident (DBA) analyses.

The jet pumps are part of the Reactor Recirculation System and are designed to provide forced circulation through the core to remove heat from the fuel. The jet pumps are located in the annular region between the core shroud and the vessel inner wall. Because the jet pump suction elevation is at two-thirds core height, the vessel can be reflooded and coolant level maintained at two-thirds core height even with the complete break of the recirculation loop pipe that is located below the jet pump suction elevation.

Each reactor recirculation loop contains ten jet pumps. Recirculated coolant passes down the annulus between the reactor vessel wall and the core shroud. A portion of the coolant flows from the vessel, through the two external recirculation loops, and becomes the driving flow for the jet pumps. Each of the two external recirculation loops discharges high pressure flow into an external manifold from which individual recirculation inlet lines are routed to the jet pump risers within the reactor vessel. The remaining portion of the coolant mixture in the annulus becomes the suction flow for the jet pumps. This flow enters the jet pump at suction inlets and is accelerated by the drive flow. The drive flow and suction flow are mixed in the jet pump throat section and result in a partial pressure recovery. The total flow then passes through the jet pump diffuser section into the area below the core (lower plenum), gaining sufficient head in the process to drive the required flow upward through the core.

APPLICABLE SAFETY ANALYSES

Jet pump OPERABILITY is an explicit assumption in the design basis loss of coolant accident (LOCA) analysis evaluated in Reference 1.

The capability of reflooding the core to two-thirds core height is dependent upon the structural integrity of the jet pumps. If the structural system, including the beam holding a jet pump in place, fails, jet pump displacement and performance degradation could occur, resulting in an increased flow area through the jet pump and a lower core flooding elevation. This could adversely affect the water level in the core during the reflood phase of a LOCA as well as the assumed blowdown flow during a LOCA.

Jet Pumps satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

The structural failure of any of the jet pumps could cause significant degradation in the ability of the jet pumps to allow reflooding to two-thirds core height during a LOCA. OPERABILITY of all jet pumps is required to ensure that operation of the Reactor Recirculation System will be consistent with the assumptions used in the licensing basis analysis (Ref. 1).

APPLICABILITY

In MODES 1 and 2, the jet pumps are required to be OPERABLE since there is a large amount of energy in the reactor core and since the limiting DBAs are assumed to occur in these MODES. This is consistent with the requirements for operation of the Reactor Recirculation System (LCO 3.4.1).

In MODES 3, 4, and 5, the Reactor Recirculation System is not required to be in operation, and when not in operation, sufficient flow is not available to evaluate jet pump OPERABILITY.

ACTIONS

A.1

An inoperable jet pump can increase the blowdown area and reduce the capability to reflood during a design basis LOCA. If one or more of the jet pumps are inoperable, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 12 hours. The Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.2.1

This SR is designed to detect significant degradation in jet pump performance that precedes jet pump failure (Ref. 2). This SR is required to be performed only when the loop has forced recirculation flow since surveillance checks and measurements can only be performed during jet pump operation. The jet pump failure of concern is a complete mixer displacement due to jet pump beam failure. Jet pump plugging is also of concern since it adds flow resistance to the recirculation loop. Significant degradation is indicated if the specified criteria confirm unacceptable deviations from established patterns or relationships. The allowable deviations from the established patterns have been developed based on the variations experienced at plants during normal operation and with jet pump assembly failures (Refs. 2 and 3). Each recirculation loop must satisfy one of the performance criteria provided. Since refueling activities (fuel assembly replacement or shuffle, as well as any modifications to fuel support orifice size or core plate bypass flow) can affect the relationship between core flow, jet pump flow, and recirculation loop flow, these relationships may need to be re-established each cycle. Similarly, initial

BASES

SURVEILLANCE REQUIREMENTS (continued)

entry into extended single loop operation may also require establishment of these relationships. During the initial weeks of operation under such conditions, while base-lining new "established patterns," engineering judgment of the daily surveillance results is used to detect significant abnormalities which could indicate a jet pump failure.

The recirculation pump speed operating characteristics (pump flow and loop flow versus pump speed) are determined by the flow resistance from the loop suction through the jet pump nozzles. A change in the relationship may indicate a plug, flow restriction, loss in pump hydraulic performance, leakage, or new flow path between the recirculation pump discharge and jet pump nozzle. For this criterion, the pump flow and loop flow versus pump speed relationship must be verified.

Individual jet pumps in a recirculation loop normally do not have the same flow. The unequal flow is due to the drive flow manifold, which does not distribute flow equally to all risers. The flow (or jet pump diffuser to lower plenum differential pressure) pattern or relationship of one jet pump to the loop average is repeatable. An appreciable change in this relationship is an indication that increased (or reduced) resistance has occurred in one of the jet pumps.

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

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

This SR is modified by two Notes. Note 1 allows this Surveillance not to be performed until 4 hours after the associated recirculation loop is in operation, since these checks can only be performed during jet pump operation. The 4 hours is an acceptable time to establish conditions appropriate for data collection and evaluation.

Note 2 allows this SR not to be performed until 24 hours after THERMAL POWER exceeds 25% RTP. During low flow conditions, jet pump noise approaches the threshold response of the associated flow instrumentation and precludes the collection of repeatable and meaningful data. The 24 hours is an acceptable time to establish conditions appropriate to perform this SR.

BASES

REFERENCES

1. USAR, Section 14.7.2.

2. GE Service Information Letter No. 330 including Supplement 1, "Jet Pump Beam Cracks," June 9, 1980.

3. NUREG/CR-3052, "Closeout of IE Bulletin 80-07: BWR Jet Pump Assembly Failure," November 1984.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.3 Safety/Relief Valves (S/RVs)

BASES

BACKGROUND

The ASME Boiler and Pressure Vessel Code requires the reactor pressure vessel be protected from overpressure during upset conditions by self-actuated safety valves. As part of the nuclear pressure relief system, the size and number of S/RVs are selected such that peak pressure in the nuclear system will not exceed the ASME Code limits for the reactor coolant pressure boundary (RCPB).

The S/RVs are located on the main steam lines between the reactor vessel and the first isolation valve within the drywell. The S/RVs can actuate by either of two modes: the safety mode or the relief mode. In the safety mode (or spring mode of operation), the spring loaded pilot valve opens when steam pressure at the valve inlet overcomes the spring force holding the pilot valve closed (i.e., it is self actuating). Opening the pilot valve allows a pressure differential to develop across the main valve piston and opens the main valve. This satisfies the Code requirement.

Each S/RV discharges steam through a discharge line to a point below the minimum water level in the suppression pool. The S/RVs that provide the relief mode are the low-low set (LLS) valves and the Automatic Depressurization System (ADS) valves. The LLS requirements are specified in LCO 3.6.1.5, "Low-Low Set (LLS) Valves," and the ADS requirements are specified in LCO 3.5.1, "ECCS - Operating."

APPLICABLE SAFETY ANALYSES

The overpressure protection system must accommodate the most severe pressurization transient. Evaluations have determined that the most severe transient is the closure of all main steam isolation valves (MSIVs), followed by reactor scram on high neutron flux (i.e., failure of the direct scram associated with MSIV position) (Ref. 1). For the purpose of the analyses, five S/RVs are assumed to operate in the safety mode. The analysis results demonstrate that the design S/RV capacity is capable of maintaining reactor pressure below the ASME Code limit of 110% of vessel design pressure (110% x 1250 psig = 1375 psig). This LCO helps to ensure that the acceptance limit of 1375 psig is met during the Design Basis Event.

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

S/RVs satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

The safety mode of five S/RVs are required to be OPERABLE to satisfy the assumptions of the safety analysis (Refs. 1 and 2). However, two additional S/RVs are required to be OPERABLE to provide additional relief capability. The requirements of this LCO are applicable only to the capability of the S/RVs to mechanically open to relieve excess pressure when the lift setpoint is exceeded (safety function).

The S/RV setpoints are established to ensure that the ASME Code limit on peak reactor pressure is satisfied. The ASME Code specifications require the lowest safety valve setpoint to be at or below vessel design pressure (1250 psig) and the highest safety valve to be set so that the total accumulated pressure does not exceed 110% of the design pressure for overpressurization conditions. The transient evaluations in the USAR are based on these setpoints, but also include the additional uncertainties of ± 5% of the nominal setpoint drift to provide an added degree of conservatism (Ref. 3).

Operation with fewer than five valves OPERABLE, or with setpoints outside the ASME limits, could result in a more severe reactor response to a transient than predicted, possibly resulting in the ASME Code limit on reactor pressure being exceeded.

APPLICABILITY

In MODES 1, 2, and 3, seven S/RVs must be OPERABLE, since considerable energy may be in the reactor core and the limiting design basis transients are assumed to occur in these MODES. The S/RVs may be required to provide pressure relief to discharge energy from the core until such time that the Residual Heat Removal (RHR) System is capable of dissipating the core heat.

In MODE 4, decay heat is low enough for the RHR System to provide adequate cooling, and reactor pressure is low enough that the overpressure limit is unlikely to be approached by assumed operational transients or accidents. In MODE 5, the reactor vessel head is unbolted or removed and the reactor is at atmospheric pressure. The S/RV function is not needed during these conditions.

ACTIONS

A.1

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

BASES

ACTIONS (continued)

The 14 day Completion Time to restore the inoperable required S/RVs to OPERABLE status is based on the relief capability of the remaining S/RVs, the low probability of an event requiring S/RV actuation, and a reasonable time to complete the Required Action.

B.1 and B.2

With less than the minimum number of required S/RVs OPERABLE, a transient may result in the violation of the ASME Code limit on reactor pressure. If the safety function of the inoperable required S/RVs cannot be restored to OPERABLE status within the associated Completion Time of Required Action A.1, or if the safety function of three or more required S/RVs is inoperable, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.3.1

This Surveillance requires that the required S/RVs will open at the pressures assumed in the safety analysis of Reference 1. The demonstration of the S/RV safety lift settings must be performed during shutdown, since this is a bench test, to be done in accordance with the Inservice Testing Program. The lift setting pressure shall correspond to ambient conditions of the valves at nominal operating temperatures and pressures. The S/RV setpoint is ± 3% for OPERABILITY; however, the valves are reset to ± 1% during the Surveillance to allow for drift.

SR 3.4.3.2

This Surveillance verifies that each S/RV is capable of being opened, which can be determined by either of two means, i.e., Method 1 or Method 2. Applying Method 1, approved in Reference 5, valve OPERABILITY and setpoints for overpressure protection are verified in accordance with the ASME OM Code. Applying Method 2, a manual actuation of the S/RV is performed to verify that the valve is functioning properly.

Method 1

Valve OPERABILITY and setpoints for overpressure protection are verified in accordance with the requirements of the ASME OM Code

BASES

SURVEILLANCE REQUIREMENTS (continued)

(Ref. 4). Proper S/RV function is verified through performance of inspections and overlapping tests on component assemblies, demonstrating the valve is capable of being opened. Testing is performed to demonstrate that each:

- S/RV main stage opens and passes steam when the associated pilot stage actuates; and
- S/RV second stage actuates to open the associated main stage when the pneumatic actuator is pressurized;
- S/RV solenoid valve ports pneumatic pressure to the associated S/RV actuator when energized;
- S/RV actuator stem moves when dry lift tested in-situ. (With exception of main and pilot stages this test demonstrates mechanical operation without steam.)

The solenoid valves and S/RV actuators are functionally tested once per cycle as part of the Inservice Testing Program. The S/RV assembly is bench tested as part of the certification process, at intervals determined in accordance with the Inservice Testing Program. Maintenance procedures ensure that the S/RV is correctly installed in the plant, and that the S/RV and associated piping remain clear of foreign material that might obstruct valve operation or full steam flow.

This methodology provides adequate assurance that the S/RV will operate when actuated, while minimizing the challenges to the valves and the likelihood of leakage or spurious operation.

<u>Method 2</u>

A manual actuation of each required S/RV is performed to verify that, mechanically, the valve is functioning properly and no blockage exists in the valve discharge line. This can be demonstrated by the response of the turbine bypass valves, by a change in the measured steam flow, or by any other method suitable to verify steam flow. Adequate steam flow must be passing through the turbine bypass valves to continue to control reactor pressure when the S/RVs divert steam flow upon opening. Sufficient time is therefore allowed after the required flow is achieved to perform this test. Adequate steam flow is represented by at least one turbine bypass valve 80% open. This SR is modified by a Note that states the Surveillance is not required to be performed until 12 hours after reactor steam flow is adequate to perform the test. Plant startup is allowed prior to performing this test because valve OPERABILITY and the

BASES

SURVEILLANCE REQUIREMENTS (continued)

setpoints for overpressure protection are verified, per ASME Code requirements, prior to valve installation. The 12 hours allowed for manual actuation after the required flow is reached is sufficient to achieve stable conditions for testing and provides a reasonable time to complete the SR. If a valve fails to actuate due only to the failure of the solenoid but is capable of opening on overpressure, the safety function of the S/RV is considered OPERABLE.

The Frequency of “In accordance with the Inservice Testing Program” is based on ASME OM Code requirements. Industry operating experience has shown that these components usually pass the SR when performed at the Code required Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. USAR, Section 14.5.1.
2. USAR, Section 14.4.
3. USAR, Section 14A.6.
4. ASME Operation and Maintenance (OM) Code.
5. Amendment No. 168, “Issuance of Amendment Re: Testing of Main Steam Safety/Relief Valves,” dated July 27, 2012. (ADAMS Accession No. ML12185A216)

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.4 RCS Operational LEAKAGE

BASES

BACKGROUND

The RCS includes systems and components that contain or transport the coolant to or from the reactor core. The pressure containing components of the RCS and the portions of connecting systems out to and including the isolation valves define the reactor coolant pressure boundary (RCPB). The joints of the RCPB components are welded or bolted.

During plant life, the joint and valve interfaces can produce varying amounts of reactor coolant LEAKAGE, through either normal operational wear or mechanical deterioration. Limits on RCS operational LEAKAGE are required to ensure appropriate action is taken before the integrity of the RCPB is impaired. This LCO specifies the types and limits of LEAKAGE. This protects the RCS pressure boundary described in 10 CFR 50.2, 10 CFR 50.55a(c), and USAR, Section 4.3.3.3 (Ref. 1).

The safety significance of RCS LEAKAGE from the RCPB varies widely depending on the source, rate, and duration. Therefore, detection of LEAKAGE in the primary containment is necessary. Methods for quickly separating the identified LEAKAGE from the unidentified LEAKAGE are necessary to provide the operators quantitative information to permit them to take corrective action should a leak occur that is detrimental to the safety of the facility or the public.

A limited amount of leakage inside primary containment is expected from auxiliary systems that cannot be made 100% leaktight. Leakage from these systems should be detected and isolated from the primary containment atmosphere, if possible, so as not to mask RCS operational LEAKAGE detection.

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

APPLICABLE SAFETY ANALYSES

The allowable RCS operational LEAKAGE limits are based on the predicted and experimentally observed behavior of pipe cracks. The normally expected background LEAKAGE due to equipment design and the detection capability of the instrumentation for determining system LEAKAGE were also considered. The evidence from experiments suggests that, for LEAKAGE even greater than the specified unidentified LEAKAGE limits, the probability is small that the imperfection or crack associated with such LEAKAGE would grow rapidly.

BASES

APPLICABLE SAFETY ANALYSIS (continued)

The unidentified LEAKAGE flow limit allows time for corrective action before the RCPB could be significantly compromised. The 5 gpm limit is a small fraction of the calculated flow from a critical crack in the primary system piping. Crack behavior from experimental programs (Refs. 2 and 3) shows that leakage rates of hundreds of gallons per minute will precede crack instability.

The low limit on increase in unidentified LEAKAGE assumes a failure mechanism of intergranular stress corrosion cracking (IGSCC) that produces tight cracks. This flow increase limit is capable of providing an early warning of such deterioration.

No applicable safety analysis assumes the total LEAKAGE limit. The total LEAKAGE limit considers RCS inventory makeup capability and drywell floor sump capacity.

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

LCO

RCS operational LEAKAGE shall be limited to:

a. Pressure Boundary LEAKAGE

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

b. Unidentified LEAKAGE

The 5 gpm of unidentified LEAKAGE is allowed as a reasonable minimum detectable amount that the drywell floor drain sump monitoring equipment can detect within a reasonable time period. Violation of this LCO could result in continued degradation of the RCPB.

c. Total LEAKAGE

The total LEAKAGE limit is based on a reasonable minimum detectable amount. The limit also accounts for LEAKAGE from known sources (identified LEAKAGE). Violation of this LCO indicates an unexpected amount of LEAKAGE and, therefore, could indicate new or additional degradation in an RCPB component or system.

BASES

LCO (continued)

d. Unidentified LEAKAGE Increase

An unidentified LEAKAGE increase of > 2 gpm within the previous 24 hour period indicates a potential flaw in the RCPB and must be quickly evaluated to determine the source and extent of the LEAKAGE. The increase is measured relative to the steady state value; temporary changes in LEAKAGE rate as a result of transient conditions (e.g., startup) are not considered. As such, the 2 gpm increase limit is only applicable in MODE 1 when operating pressures and temperatures are established. Violation of this LCO could result in continued degradation of the RCPB.

APPLICABILITY

In MODES 1, 2, and 3, the RCS operational LEAKAGE LCO applies, because the potential for RCPB LEAKAGE is greatest when the reactor is pressurized.

In MODES 4 and 5, RCS operational LEAKAGE limits are not required since the reactor is not pressurized and stresses in the RCPB materials and potential for LEAKAGE are reduced.

ACTIONS

A.1

With RCS unidentified or total LEAKAGE greater than the limits, actions must be taken to reduce the leak. Because the LEAKAGE limits are conservatively below the LEAKAGE that would constitute a critical crack size, 4 hours is allowed to reduce the LEAKAGE rates before the reactor must be shut down. If an unidentified LEAKAGE has been identified and quantified, it may be reclassified and considered as identified LEAKAGE; however, the total LEAKAGE limit would remain unchanged.

B.1 and B.2

An unidentified LEAKAGE increase of > 2 gpm within a 24 hour period is an indication of a potential flaw in the RCPB and must be quickly evaluated. Although the increase does not necessarily violate the absolute unidentified LEAKAGE limit, certain susceptible components must be determined not to be the source of the LEAKAGE increase within the required Completion Time. For an unidentified LEAKAGE increase greater than required limits, an alternative to reducing LEAKAGE increase to within limits (i.e., reducing the LEAKAGE rate such that the current rate is less than the "2 gpm increase in the previous 24 hours" limit; either by

BASES

ACTIONS (continued)

isolating the source or other possible methods) is to evaluate service sensitive type 304 and type 316 austenitic stainless steel piping that is subject to high stress or that contains relatively stagnant or intermittent flow fluids and determine it is not the source of the increased LEAKAGE. This type piping is very susceptible to IGSCC.

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

C.1 and C.2

If any Required Action and associated Completion Time of Condition A or B is not met or if pressure boundary LEAKAGE exists, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant safety systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.4.1

The RCS LEAKAGE is monitored by a variety of instruments designed to provide alarms when LEAKAGE is indicated and to quantify the various types of LEAKAGE. Leakage detection instrumentation is discussed in more detail in the Bases for LCO 3.4.5, "RCS Leakage Detection Instrumentation." Sump level and flow rate are typically monitored to determine actual LEAKAGE rates; however, an alternate method that may be used to quantify LEAKAGE is using drywell sump pump run times. In conjunction with alarms and other administrative controls, a 12 hour Frequency for this Surveillance is appropriate for identifying LEAKAGE and for tracking required trends (Ref. 4).

REFERENCES

1. USAR, Section 4.3.3.3.
2. GEAP-5620, "Failure Behavior in ASTM A106B Pipes Containing Axial Through-Wall Flows," April 1968.
3. NUREG-75/067, "Investigation and Evaluation of Cracking in Austenitic Stainless Steel Piping of Boiling Water Reactor Plants," October 1975.

BASES

REFERENCES (continued)

4. Generic Letter 88-01, "NRC Position on Intergranular Stress Corrosion Cracking (IGSCC) in BWR Austenitic Stainless Steel Piping," Supplement 1, February 1992.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.5 RCS Leakage Detection Instrumentation

BASES

BACKGROUND

USAR, Section 4.3.3.3 (Ref. 1), requires means for detecting and, to the extent practical, identifying the location of the source of RCS LEAKAGE. Regulatory Guide 1.45 (Ref. 2) describes acceptable methods for selecting leakage detection systems.

Limits on LEAKAGE from the reactor coolant pressure boundary (RCPB) are required so that appropriate action can be taken before the integrity of the RCPB is impaired (Ref. 2). Leakage detection systems for the RCS are provided to alert the operators when leakage rates above normal background levels are detected and also to supply quantitative measurement of leakage rates. The Bases for LCO 3.4.4, "RCS Operational LEAKAGE," discuss the limits on RCS LEAKAGE rates.

Systems for separating the LEAKAGE of an identified source from an unidentified source are necessary to provide prompt and quantitative information to the operators to permit them to take immediate corrective action.

LEAKAGE from the RCPB inside the drywell is detected by at least one of four independently monitored variables, such as drain sump flow, drain sump level changes, drain sump fill rate, and drywell particulate radioactivity levels. The primary means of quantifying LEAKAGE in the drywell is the drywell floor drain sump monitoring system.

The drywell floor drain sump monitoring system monitors the LEAKAGE collected in or pumped out of the floor drain sump, and is classified as unidentified LEAKAGE. The drywell floor drain sump has a transmitter that supplies a level recorder in the control room and one drywell floor sump fill rate computer point (rate of change) that alarms in the control room.

The drywell floor drain sump monitoring system also has a pump flow transmitter on the discharge line of the drywell floor drain sump pumps. Two drywell floor drain sump pumps take suction from the drywell floor drain sump and discharge to the floor drain collector tank. Three level switches are provided on the drywell floor drain sump. One level switch starts the auto pump, the second level switch starts the standby pump. The third level switch actuates a high level alarm in the control room. Hand switches for manual operation of the pumps and indicating lights are provided in the control room. The flow integrator monitors the flow when the pump(s) are operating. A flow transmitter in the discharge line of the drywell floor drain sump pumps provides flow indication (integrator) in the radwaste control room.

BASES

BACKGROUND (continued)

The drywell floor drain sump monitoring system measures the time interval between actuation of two level switches located in the drywell floor drain sump as it fills. At any time that the interval decreases over the previous minimum interval (indicating an increased leak rate) an alarm operates in the control room (computer point). Each method of LEAKAGE determination of the drywell floor drain sump monitoring system described above (level recorder in the control room, drywell floor sump fill rate, or flow integrator) is sensitive enough to detect leak rate changes better than one gallon per minute in a one hour period and therefore may be used to satisfy the LCO requirement.

The plant also includes a drywell equipment drain sump monitoring system. This monitoring system normally monitors identified LEAKAGE collected in or pumped out of the drywell equipment drain sump. This identified LEAKAGE consists of LEAKAGE piped from recirculation pump seals, valve stem leakoffs, reactor well bulkhead and bellow drains, and the reactor vessel flange leakoff. The drywell equipment drain sump monitoring system includes the same types of instruments described for the drywell floor drain sump. An alternate to the drywell floor drain sump monitoring system is the drywell equipment drain sump system. Because of the physical size of the sumps, it is possible through detection or calculation to verify the operational unidentified LEAKAGE limit (≤ 5 gpm) and unidentified LEAKAGE rate limit (≤ 2 gpm increase in unidentified LEAKAGE within the previous 24 hour period in MODE 1) during the period of time it takes to actually overflow from one sump to the other. Once the drywell floor drain sump is overflowing to the drywell equipment drain sump, the drywell equipment drain sump monitoring system can be used to quantify unidentified LEAKAGE. However, the alarm settings for the equipment drain sump instruments must be reset to detect the lower limit for unidentified leakage. In this condition, all additional LEAKAGE measured by the drywell equipment drain sump system is assumed to be unidentified LEAKAGE unless the leakage has been identified and quantified. Each method of LEAKAGE determination of the drywell equipment drain sump monitoring system (level recorder in the control room, drywell equipment sump fill rate, or flow integrator) as described for the drywell floor drain sump monitoring system is sensitive enough to detect leak rate changes better than one gallon per minute in a one hour period and therefore may be used to satisfy the LCO requirement.

The drywell particulate radioactivity monitoring system continuously monitors the primary containment atmosphere for airborne particulate radioactivity. A sudden increase of radioactivity, which may be attributed to RCPB steam or reactor water LEAKAGE, is annunciated in the control room. The drywell particulate radioactivity monitoring system is not capable of quantifying LEAKAGE rates, but is sensitive enough to monitor leakage at least as low as 1E-9 μCi/cc.

BASES

APPLICABLE SAFETY ANALYSES	A threat of significant compromise to the RCPB exists if the barrier contains a crack that is large enough to propagate rapidly. LEAKAGE rate limits are set low enough to detect the LEAKAGE emitted from a single crack in the RCPB (Refs. 3 and 4). The drywell floor drain sump monitoring system inside the drywell is designed with the capability of detecting LEAKAGE less than the established LEAKAGE rate limits and providing appropriate alarm of excess LEAKAGE in the control room. The drywell particulate radioactivity monitoring system provides a means to detect changes in LEAKAGE rates (Ref. 1). A control room alarm allows the operators to evaluate the significance of the indicated LEAKAGE and, if necessary, shut down the reactor for further investigation and corrective action. The allowed LEAKAGE rates are well below the rates predicted for critical crack sizes (Ref. 5). Therefore, these actions provide adequate response before a significant break in the RCPB can occur. RCS leakage detection instrumentation satisfies Criterion 1 of 10 CFR 50.36(c)(2)(ii).
LCO	Either the drywell floor drain sump monitoring system or the drywell equipment drain sump monitoring system with the drywell floor drain sump overflowing into the drywell equipment drain sump is required to quantify the unidentified LEAKAGE from the RCS. Thus, for the system to be considered OPERABLE, one of the three drywell floor drain sump monitoring system methods must be OPERABLE or one of the three drywell equipment drain sump monitoring system methods must be OPERABLE with the drywell floor drain sump overflowing into the drywell equipment drain sump. The other monitoring system provides early alarms to the operators so closer examination of other detection systems will be made to determine the extent of any corrective action that may be required. With the leakage detection systems inoperable, monitoring for LEAKAGE in the RCPB is degraded.
APPLICABILITY	In MODES 1, 2, and 3, leakage detection systems are required to be OPERABLE to support LCO 3.4.4. This Applicability is consistent with that for LCO 3.4.4.
ACTIONS	<u>A.1</u> With LCO 3.4.5.a not met, no other form of sampling can provide the equivalent information to quantify leakage. However, the drywell particulate radioactivity monitoring system will provide indication of changes in leakage. With LCO 3.4.5.a not met, but with RCS unidentified and total LEAKAGE being determined every 12 hours (SR 3.4.4.1), operation may continue for 30 days. The 30 day Completion Time of Required Action A.1 is

BASES

ACTIONS (continued)

acceptable, based on operating experience, considering the alternate form of leakage detection that is normally still available and the fact that the LEAKAGE is still being determined every 12 hours. Required Action A.1 is modified by a Note that states that the provisions of LCO 3.0.4.c are applicable. As a result, a MODE change is allowed when LCO 3.4.5.a is not met. This allowance is provided because other instrumentation is normally available to monitor RCS leakage.

B.1

With the drywell particulate radioactivity monitoring channel inoperable, grab samples of the primary containment atmosphere must be taken and analyzed to provide periodic leakage information. Provided a sample is obtained and analyzed every 12 hours, the plant may continue operation since at least one other form of drywell leakage detection (i.e., drywell floor drain sump monitoring system or the drywell equipment drain sump monitoring system with the drywell floor drain sump overflowing into the drywell equipment drain sump) is normally available.

The 12 hour interval provides periodic information that is adequate to detect LEAKAGE.

C.1

With all required monitors inoperable, no required automatic means of monitoring LEAKAGE are available. Therefore, either LCO 3.4.5.a must be satisfied or the drywell particulate radioactivity monitoring system must be restored to OPERABLE status within 1 hour. The 1 hour Completion Time is acceptable because the likelihood of an increase in LEAKAGE in this 1 hour period is small and ensures the plant will not be operated in a degraded configuration for a lengthy time period.

D.1 and D.2

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

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.5.1

This SR is for the performance of a CHANNEL CHECK of the required leakage detection instrumentation channels (both the required equipment specified in LCO 3.4.5.a and the drywell particulate radioactivity monitoring system). The check gives reasonable confidence that the channel is operating properly. The Frequency of 12 hours is based on instrument reliability and is reasonable for detecting off normal conditions.

SR 3.4.5.2

This SR is for the performance of a CHANNEL FUNCTIONAL TEST of the drywell particulate radioactivity monitoring system and the flow instrumentation of the required drain sump monitoring system (drywell floor or drywell equipment). The test ensures that the monitors can perform their function in the desired manner. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. The Frequency of 31 days considers instrument reliability, and operating experience has shown it proper for detecting degradation.

SR 3.4.5.3

This SR is for the performance of a CHANNEL CALIBRATION of required leakage detection instrumentation channels. The calibration verifies the accuracy of the instrument string, including the instruments located inside containment. The Frequency of 24 months is a typical refueling cycle and considers channel reliability. Operating experience has proven this Frequency is acceptable.

REFERENCES

1. USAR, Section 4.3.3.3.

2. Regulatory Guide 1.45, May 1973.

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

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

BASES

REFERENCES (continued)

5. USAR, Section 10.3.6.3.1.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.6 RCS Specific Activity

BASES

BACKGROUND	During circulation, the reactor coolant acquires radioactive materials due to release of fission products from fuel leaks into the reactor coolant and activation of corrosion products in the reactor coolant. These radioactive materials in the reactor coolant can plate out in the RCS, and, at times, an accumulation will break away to spike the normal level of radioactivity. The release of coolant during a Design Basis Accident (DBA) could send radioactive materials into the environment. Limits on the maximum allowable level of radioactivity in the reactor coolant are established to ensure that in the event of a release of any radioactive material to the environment during a DBA, radiation doses are maintained within the limits of 10 CFR 50.67 (Ref. 1). This LCO contains iodine specific activity limits. The iodine isotopic activities per gram of reactor coolant are expressed in terms of a DOSE EQUIVALENT I-131. The allowable levels are intended to limit the 2 hour radiation dose to an individual at the site boundary to a small fraction of the 10 CFR 50.67 limit.
APPLICABLE SAFETY ANALYSES	Analytical methods and assumptions involving radioactive material in the primary coolant are presented in the USAR (Ref. 2). The specific activity in the reactor coolant (the source term) is an initial condition for evaluation of the consequences of an accident due to a main steam line break (MSLB) outside containment. No fuel damage is postulated in the MSLB accident, and the release of radioactive material to the environment is assumed to end when the main steam isolation valves (MSIVs) close completely. This MSLB release forms the basis for determining offsite and control room doses (Ref. 2). The limits on the specific activity of the primary coolant ensure that the 2 hour Total Effective Dose Equivalent (TEDE) doses at the site boundary, resulting from an MSLB outside containment during steady state operation, will not exceed 10% of the dose guidelines of 10 CFR 50.67. The limits on the specific activity of the primary coolant also ensure the TEDE dose to control room operators, resulting from a MSLB outside containment during steady operation, will not exceed the limits of 10 CFR 50, Appendix A, GDC 19 (Ref. 3) and 10 CFR 50.67 (Ref. 1).

BASES

APPLICABLE SAFETY ANALYSES (continued)

The limit on specific activity is based on plant specific analysis of the radiological consequences of a MSLB accident (Ref. 2).

RCS specific activity satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The specific iodine activity is limited to ≤ 0.2 μCi/gm DOSE EQUIVALENT I-131. This limit ensures the source term assumed in the safety analysis for the MSLB is not exceeded, so any release of radioactivity to the environment during an MSLB is less than a small fraction of the 10 CFR 50.67 limits and is less than 10 CFR 50, Appendix A, GDC 19 (Ref. 3) limits.

APPLICABILITY

In MODE 1, and MODES 2 and 3 with any main steam line not isolated, limits on the primary coolant radioactivity are applicable since there is an escape path for release of radioactive material from the primary coolant to the environment in the event of an MSLB outside of primary containment.

In MODES 2 and 3 with the main steam lines isolated, such limits do not apply since an escape path does not exist. In MODES 4 and 5, no limits are required since the reactor is not pressurized and the potential for leakage is reduced.

ACTIONS

A.1 and A.2

When the reactor coolant specific activity exceeds the LCO DOSE EQUIVALENT I-131 limit, but is ≤ 2.0 μCi/gm, samples must be analyzed for DOSE EQUIVALENT I-131 at least once every 4 hours. In addition, the specific activity must be restored to the LCO limit within 48 hours. The Completion Time of once every 4 hours is based on the time needed to take and analyze a sample. The 48 hour Completion Time to restore the activity level provides a reasonable time for temporary coolant activity increases (iodine spikes or crud bursts) to be cleaned up with the normal processing systems.

A Note permits the use of the provisions of LCO 3.0.4.c. This allowance permits entry into the applicable MODE(S) while relying on the ACTIONS. This allowance is acceptable due to the significant conservatism incorporated into the specific activity limit, the low probability of an event which is limiting due to exceeding this limit, and the ability to restore transient specific activity excursions while the plant remains at, or proceeds to power operation.

BASES

ACTIONS (continued)

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

If the DOSE EQUIVALENT I-131 cannot be restored to ≤ 0.2 µCi/gm within 48 hours, or if at any time it is > 2.0 µCi/gm, it must be determined at least once every 4 hours and all the main steam lines must be isolated within 12 hours. Isolating the main steam lines precludes the possibility of releasing radioactive material to the environment in an amount that is more than the limits of 10 CFR 50.67 and 10 CFR 50, Appendix A, GDC 19 (Ref. 3) during a postulated MSLB accident.

Alternatively, the plant can be placed in MODE 3 within 12 hours and in MODE 4 within 36 hours. This option is provided for those instances when isolation of main steam lines is not desired (e.g., due to the decay heat loads). In MODE 4, the requirements of the LCO are no longer applicable.

The Completion Time of once every 4 hours is the time needed to take and analyze a sample. The 12 hour Completion Time is reasonable, based on operating experience, to isolate the main steam lines in an orderly manner and without challenging plant systems. Also, the allowed Completion Times for Required Actions B.2.2.1 and B.2.2.2 for placing the unit in MODES 3 and 4 are reasonable, based on operating experience, to achieve the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.6.1

This Surveillance is performed to ensure iodine remains within limit during normal operation. The 7 day Frequency is adequate to trend changes in the iodine activity level.

This SR is modified by a Note that requires this Surveillance to be performed only in MODE 1 because the level of fission products generated in other MODES is much less.

REFERENCES

1. 10 CFR 50.67, “Accident Source Term.”

2. USAR, Section 14.7.3.

3. 10 CFR 50, Appendix A, GDC 19.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.7 Residual Heat Removal (RHR) Shutdown Cooling System - Hot Shutdown

BASES

BACKGROUND	Irradiated fuel in the shutdown reactor core generates heat during the decay of fission products and increases the temperature of the reactor coolant. This decay heat must be removed to reduce the temperature of the reactor coolant to ≤ 212°F in preparation for performing Refueling or Cold Shutdown maintenance operations, or for keeping the reactor in the Hot Shutdown condition. The two redundant, manually controlled shutdown cooling subsystems of the RHR System provide decay heat removal. Each loop consists of two motor driven pumps, a heat exchanger, and associated piping and valves. Both loops have a common suction from the same recirculation loop. Each pump discharges the reactor coolant, after circulation through the respective heat exchanger, to the reactor via either recirculation loop. The RHR heat exchangers transfer heat to the RHR Service Water System (LCO 3.7.1, "Residual Heat Removal Service Water (RHRSW) System").
APPLICABLE SAFETY ANALYSES	Decay heat removal by operation of the RHR System in the shutdown cooling mode is not required for mitigation of any event or accident evaluated in the safety analyses. Decay heat removal is, however, an important safety function that must be accomplished or core damage could result. The RHR Shutdown Cooling System satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).
LCO	Two RHR shutdown cooling subsystems are required to be OPERABLE, and when no recirculation pump is in operation, one shutdown cooling subsystem must be in operation. An OPERABLE RHR shutdown cooling subsystem consists of one OPERABLE RHR pump, one heat exchanger, and the associated piping and valves. The two subsystems have a common suction source and are allowed to have a common heat exchanger and common discharge piping. Thus, to meet the LCO, both pumps in one loop or one pump in each of the two loops must be OPERABLE. Since the piping and heat exchangers are passive components that are assumed not to fail, they are allowed to be common to both subsystems. Each shutdown cooling subsystem is considered OPERABLE if it can be manually aligned (remote or local) in the shutdown cooling mode for removal of decay heat. In MODE 3, one RHR shutdown cooling subsystem can provide the required cooling, but two subsystems are required to be OPERABLE to provide redundancy. Operation of one subsystem can maintain or reduce the reactor coolant temperature as required. To ensure adequate core flow to allow for accurate average reactor coolant temperature monitoring, nearly continuous operation is required.

BASES

LCO (continued)

Note 1 permits both RHR shutdown cooling subsystems and recirculation pumps to be removed from 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 the performance of Surveillance tests. These tests may be on the affected RHR System or on some other plant system or component that necessitates placing the RHR System in an inoperable status during the performance. This is permitted because the core heat generation can be low enough and the heatup rate slow enough to allow some changes to the RHR subsystems or other operations requiring RHR flow interruption and loss of redundancy.

APPLICABILITY

In MODE 3 with reactor steam dome pressure below the RHR shutdown cooling supply isolation interlock (i.e., the actual pressure at which the interlock resets) the RHR Shutdown Cooling System must be OPERABLE and one RHR shutdown cooling subsystem may be operated in the shutdown cooling mode to remove decay heat to reduce or maintain coolant temperature. Otherwise, a recirculation pump is required to be in operation.

In MODES 1 and 2, and in MODE 3 with reactor steam dome pressure greater than or equal to the RHR shutdown cooling supply isolation interlock, 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 shutdown cooling supply isolation interlock is typically accomplished by condensing the steam in the main condenser. Additionally, in MODE 2, the OPERABILITY requirements for the Emergency Core Cooling Systems (ECCS) (LCO 3.5.1, "ECCS - Operating") do not allow placing the RHR shutdown cooling subsystem into operation.

The requirements for decay heat removal in MODES 4 and 5 are discussed in LCO 3.4.8, "Residual Heat Removal (RHR) Shutdown Cooling System - Cold Shutdown," LCO 3.9.7, "Residual Heat Removal (RHR) - High Water Level," and LCO 3.9.8, "Residual Heat Removal (RHR) - Low Water Level."

ACTIONS

A Note has been provided to modify the ACTIONS related to RHR shutdown cooling subsystems. Section 1.3, Completion Times, specifies once a Condition has been entered, subsequent divisions, subsystems, components or variables expressed in the Condition, discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies Required Actions of the Condition continue to apply for each additional failure, with Completion Times based

BASES

ACTIONS (continued)

on initial entry into the Condition. However, the Required Actions for inoperable shutdown cooling subsystems provide appropriate compensatory measures for separate inoperable shutdown cooling subsystems. As such, a Note has been provided that allows separate Condition entry for each inoperable RHR shutdown cooling subsystem.

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

With one required RHR shutdown cooling subsystem inoperable for decay heat removal, except as permitted by LCO Note 2, the inoperable subsystem must be restored to OPERABLE status without delay. In this condition, the remaining OPERABLE subsystem can provide the necessary decay heat removal. The overall reliability is reduced, however, because a single failure in the OPERABLE subsystem could result in reduced RHR shutdown cooling capability. Therefore, an alternate method of decay heat removal must be provided.

With both RHR shutdown cooling subsystems inoperable, an alternate method of decay heat removal must be provided in addition to that provided for the initial RHR shutdown cooling subsystem inoperability. This re-establishes backup decay heat removal capabilities, similar to the requirements of the LCO. The 1 hour Completion Time is based on the decay heat removal function and the probability of a loss of the available decay heat removal capabilities.

The required cooling capacity of the alternate method should be ensured by verifying (by calculation or demonstration) its capability to maintain or reduce temperature. Decay heat removal by ambient losses can be considered as, or contributing to, the alternate method capability. Alternate methods that can be used include (but are not limited to) the Condensate/Feed and Main Steam Systems and the Reactor Water Cleanup System.

However, due to the potentially reduced reliability of the alternate methods of decay heat removal, it is also required to reduce the reactor coolant temperature to the point where MODE 4 is entered.

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

With no RHR shutdown cooling subsystem and no recirculation pump in operation, except as permitted by LCO Note 1, reactor coolant circulation by the RHR shutdown cooling subsystem or recirculation pump must be restored without delay.

BASES

ACTIONS (continued)

Until RHR or recirculation pump operation is re-established, an alternate method of reactor coolant circulation must be placed into service. This will provide the necessary circulation for monitoring coolant temperature. The 1 hour Completion Time is based on the coolant circulation function and is modified such that the 1 hour is applicable separately for each occurrence involving a loss of coolant circulation. Furthermore, verification of the functioning of the alternate method must be reconfirmed every 12 hours thereafter. This will provide assurance of continued temperature monitoring capability.

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

SURVEILLANCE REQUIREMENTS

SR 3.4.7.1

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

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

REFERENCES

None.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.8 Residual Heat Removal (RHR) Shutdown Cooling System - Cold Shutdown

BASES

BACKGROUND

Irradiated fuel in the shutdown reactor core generates heat during the decay of fission products and increases the temperature of the reactor coolant. This decay heat must be removed to maintain the temperature of the reactor coolant ≤ 212°F in preparation for performing Refueling maintenance operations, or for keeping the reactor in the Cold Shutdown condition.

The two redundant, manually controlled shutdown cooling subsystems of the RHR System provide decay heat removal. Each loop consists of two motor driven pumps, a heat exchanger, and associated piping and valves. Both loops have a common suction from the same recirculation loop. Each pump discharges the reactor coolant, after circulation through the respective heat exchanger, to the reactor via either recirculation loop. The RHR heat exchangers transfer heat to the RHR Service Water System.

APPLICABLE SAFETY ANALYSES

Decay heat removal by operation of the RHR System in the shutdown cooling mode is not required for mitigation of any event or accident evaluated in the safety analyses. Decay heat removal is, however, an important safety function that must be accomplished or core damage could result. The RHR Shutdown Cooling System satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

LCO

Two RHR shutdown cooling subsystems are required to be OPERABLE, and when no recirculation pump is in operation, one RHR shutdown cooling subsystem must be in operation. An OPERABLE RHR shutdown cooling subsystem consists of one OPERABLE RHR pump, one heat exchanger, the associated piping and valves, and the necessary portions of the RHRSW System capable of providing cooling water to the heat exchanger. The two subsystems have a common suction source and are allowed to have a common heat exchanger and common discharge piping. Thus, to meet the LCO, both pumps in one loop or one pump in each of the two loops must be OPERABLE. Since the piping and heat exchangers are passive components that are assumed not to fail, they are allowed to be common to both subsystems. Additionally, each shutdown cooling subsystem is considered OPERABLE if it can be manually aligned (remote or local) in the shutdown cooling mode for removal of decay heat. In MODE 4, one RHR shutdown cooling

BASES

LCO (continued)

subsystem can provide the required cooling, but two subsystems are required to be OPERABLE to provide redundancy. Operation of one subsystem can maintain or reduce the reactor coolant temperature as required. To ensure adequate core flow to allow for accurate average reactor coolant temperature monitoring, nearly continuous operation is required.

Note 1 permits both RHR shutdown cooling subsystems and recirculation pumps to be removed from 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 the performance of Surveillance tests. These tests may be on the affected RHR System or on some other plant system or component that necessitates placing the RHR System in an inoperable status during the performance. This is permitted because the core heat generation can be low enough and the heatup rate slow enough to allow some changes to the RHR subsystems or other operations requiring RHR flow interruption and loss of redundancy.

APPLICABILITY

In MODE 4, the RHR Shutdown Cooling System must be OPERABLE and one RHR shutdown cooling subsystem may be operated in the shutdown cooling mode to remove decay heat to maintain coolant temperature below 212°F. Otherwise, a recirculation pump is required to be in operation.

In MODES 1 and 2, and in MODE 3 with reactor steam dome pressure greater than or equal to the RHR shutdown cooling supply isolation interlock, 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 shutdown cooling supply isolation interlock is typically accomplished by condensing the steam in the main condenser. Additionally, in MODE 2, the OPERABILITY requirements for the Emergency Core Cooling Systems (ECCS) (LCO 3.5.1, "ECCS - Operating") do not allow placing the RHR shutdown cooling subsystem into operation.

The requirements for decay heat removal in MODE 3 below the cut in permissive pressure and in MODE 5 are discussed in LCO 3.4.7, "Residual Heat Removal (RHR) Shutdown Cooling System - Hot Shutdown," LCO 3.9.7, "Residual Heat Removal (RHR) - High Water Level," and LCO 3.9.8, "Residual Heat Removal (RHR) - Low Water Level."

BASES

ACTIONS

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

A.1

With one of the two required RHR shutdown cooling subsystems inoperable, except as permitted by LCO Note 2, the remaining subsystem is capable of providing the required decay heat removal. However, the overall reliability is reduced. Therefore, an alternate method of decay heat removal must be provided. With both RHR shutdown cooling subsystems inoperable, an alternate method of decay heat removal must be provided in addition to that provided for the initial RHR shutdown cooling subsystem inoperability. This re-establishes backup decay heat removal capabilities, similar to the requirements of the LCO. The 1 hour Completion Time is based on the decay heat removal function and the probability of a loss of the available decay heat removal capabilities. Furthermore, verification of the functional availability of these alternate method(s) must be reconfirmed every 24 hours thereafter. This will provide assurance of continued heat removal capability.

The required cooling capacity of the alternate method should be ensured by verifying (by calculation or demonstration) its capability to maintain or reduce temperature. Decay heat removal by ambient losses can be considered as, or contributing to, the alternate method capability. Alternate methods that can be used include (but are not limited to) the Reactor Water Cleanup System by itself or using feed and bleed in combination with Control Rod Drive System or Condensate/Feed Systems.

BASES

ACTIONS (continued)

B.1 and B.2

With no RHR shutdown cooling subsystem and no recirculation pump in operation, except as permitted by LCO Note 1, and until RHR or recirculation pump operation is re-established, an alternate method of reactor coolant circulation must be placed into service. This will provide the necessary circulation for monitoring coolant temperature. The 1 hour Completion Time is based on the coolant circulation function and is modified such that the 1 hour is applicable separately for each occurrence involving a loss of coolant circulation. Furthermore, verification of the functioning of the alternate method must be reconfirmed every 12 hours thereafter. This will provide assurance of continued temperature monitoring capability.

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

SURVEILLANCE REQUIREMENTS

SR 3.4.8.1

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.

REFERENCES

None.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.9 RCS Pressure and Temperature (P/T) Limits

BASES

BACKGROUND

All components of the RCS are designed to withstand effects of cyclic loads due to system pressure and temperature changes. These loads are introduced by startup (heatup) and shutdown (cooldown) operations, power transients, and reactor trips. This LCO limits the pressure and temperature changes during RCS heatup and cooldown, within the design assumptions and the stress limits for cyclic operation.

The PTLR contains P/T limit curves for heatup, cooldown, inservice leak and hydrostatic testing, and criticality, and also limits for the maximum rate of change of reactor coolant temperature.

Each P/T limit curve defines an acceptable region for normal operation. The usual use of the curves is operational guidance during heatup or cooldown maneuvering, when pressure and temperature indications are monitored and compared to the applicable curve to determine that operation is within the allowable region.

The LCO establishes operating limits that provide a margin to brittle failure of the reactor vessel and piping of the reactor coolant pressure boundary (RCPB). The vessel is the component most subject to brittle failure. Therefore, the LCO limits apply mainly to the vessel.

10 CFR 50, Appendix G (Ref. 1), requires the establishment of P/T limits for material fracture toughness requirements of the RCPB materials. Reference 1 requires an adequate margin to brittle failure during normal operation, anticipated operational occurrences, and system hydrostatic tests. It mandates the use of the ASME Code, Section III, Appendix G (Ref. 2).

The actual shift in the RT_{NDT} of the vessel material will be established periodically by removing and evaluating the irradiated reactor vessel material specimens, in accordance with ASTM E 185 (Ref. 3) and Appendix H of 10 CFR 50 (Ref. 4). The operating P/T limit curves will be adjusted, as necessary, based on the evaluation findings and recommendations of Regulatory Guide 1.99, Revision 2 (Ref. 5).

The P/T limit curves are composite curves established by superimposing limits derived from stress analyses of those portions of the reactor vessel and head that are the most restrictive. At any specific pressure, temperature, and temperature rate of change, one location within the reactor vessel will dictate the most restrictive limit. Across the span of the P/T limit curves, different locations are more restrictive, and, thus, the curves are composites of the most restrictive regions.

BASES

BACKGROUND (continued)

During inservice leak and hydrostatic testing, the reactor vessel shell temperatures (reactor vessel shell adjacent to shell flange, reactor vessel shell or coolant temperature representative of the minimum temperature of the beltline region) shall be at or above the temperatures specified in the PTLR. The reactor vessel bottom head temperature shall be at or above the temperatures specified in the PTLR. During heatup by non-nuclear means and cooldown following nuclear shutdown the RCS temperatures (reactor vessel shell adjacent to shell flange, reactor vessel bottom drain, recirculation loops A and B, reactor vessel bottom head) shall be at or above the higher of the temperatures specified in the PTLR. The shift specified in the PTLR includes both the delta RT_{NDT} and margin, as required by Regulatory Guide 1.99, Revision 2.

The P/T criticality limits include the Reference 1 requirement that they be at least 40°F above the non-critical heatup curve or the cooldown curve and not lower than the minimum permissible temperature for the inservice leak and hydrostatic testing. During all operation with a critical reactor, the RCS temperatures (reactor vessel shell adjacent to shell flange, reactor vessel bottom head, and reactor vessel shell or coolant temperature representative of the minimum temperature of the beltline region) shall be at or above the higher of the temperatures specified in the PTLR.

The consequence of violating the LCO limits is that the RCS has been operated under conditions that can result in brittle failure of the RCPB, possibly leading to a nonisolable leak or loss of coolant accident. In the event these limits are exceeded, an evaluation must be performed to determine the effect on the structural integrity of the RCPB components. ASME Code, Section XI, Appendix E (Ref. 6), provides a recommended methodology for evaluating an operating event that causes an excursion outside the limits.

APPLICABLE SAFETY ANALYSES

The P/T limits are not derived from Design Basis Accident (DBA) analyses. They are prescribed during normal operation to avoid encountering pressure, temperature, and temperature rate of change conditions that might cause undetected flaws to propagate and cause nonductile failure of the RCPB, a condition that is unanalyzed. Reference 10 approved the PTLR, which includes the P/T curves required by this Specification.

BASES

APPLICABLE SAFETY ANALYSES (continued)

Since the P/T limits are not derived from any DBA, there are no acceptance limits related to the P/T limits. Rather, the P/T limits are acceptance limits themselves since they preclude operation in an unanalyzed condition.

RCS P/T limits satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).

LCO

The elements of this LCO are:

a. RCS pressure and temperature are within the limits specified in the PTLR, and during RCS heatup, cooldown, and inservice leak and hydrostatic testing, heatup and cooldown rates are within the limits specified in the PTLR;

b. The temperature difference between the reactor coolant in the respective recirculation loop and in the reactor vessel is within the limit specified in the PTLR during recirculation pump startup;

c. RCS pressure and temperature are within the criticality limits specified in the PTLR; and

d. The reactor vessel flange and the head flange temperatures are within the limits specified in the PTLR when tensioning the reactor vessel head bolting studs and when the reactor head is tensioned.

These limits define allowable operating regions and permit a large number of operating cycles while also providing a wide margin to nonductile failure.

The rate of change of temperature limits control the thermal gradient through the vessel wall and are used as inputs for calculating the heatup, cooldown, and inservice leak and hydrostatic testing P/T limit curves. Thus, the LCO for the rate of change of temperature restricts stresses caused by thermal gradients and also ensures the validity of the P/T limit curves.

Violation of the limits places the reactor vessel outside of the bounds of the stress analyses and can increase stresses in other RCS components. The consequences depend on several factors, as follows:

a. The severity of the departure from the allowable operating pressure temperature regime or the severity of the rate of change of temperature;

BASES

LCO (continued)

b. The length of time the limits were violated (longer violations allow the temperature gradient in the thick vessel walls to become more pronounced); and

c. The existence, size, and orientation of flaws in the vessel material.

APPLICABILITY

The potential for violating a P/T limit exists at all times. For example, P/T limit violations could result from ambient temperature conditions that result in the reactor vessel metal temperature being less than the minimum allowed temperature for boltup. Therefore, this LCO is applicable even when fuel is not loaded in the core.

ACTIONS

A.1 and A.2

Operation outside the P/T limits while in MODE 1, 2, or 3 must be corrected so that the RCPB is returned to a condition that has been verified by stress analyses.

The 30 minute Completion Time reflects the urgency of restoring the parameters to within the analyzed range. Most violations will not be severe, and the activity can be accomplished in this time in a controlled manner.

Besides restoring operation within limits, an evaluation is required to determine if RCS operation can continue. The evaluation must verify the RCPB integrity remains acceptable and must be completed if continued operation is desired. Several methods may be used, including comparison with pre-analyzed transients in the stress analyses, new analyses, or inspection of the components. ASME Code, Section XI, Appendix E (Ref. 6), may be used to support the evaluation. However, its use is restricted to evaluation of the vessel beltline.

The 72 hour Completion Time is reasonable to accomplish the evaluation of a mild violation. More severe violations may require special, event specific stress analyses or inspections. A favorable evaluation must be completed if continued operation is desired.

Condition A is modified by a Note requiring Required Action A.2 be completed whenever the Condition is entered. The Note emphasizes the need to perform the evaluation of the effects of the excursion outside the allowable limits. Restoration alone per Required Action A.1 is insufficient because higher than analyzed stresses may have occurred and may have affected the RCPB integrity.

BASES

ACTIONS (continued)

B.1 and B.2

If a Required Action and associated Completion Time of Condition A are not met, the plant must be placed in a lower MODE because either the RCS remained in an unacceptable P/T region for an extended period of increased stress, or a sufficiently severe event caused entry into an unacceptable region. Either possibility indicates a need for more careful examination of the event, best accomplished with the RCS at reduced pressure and temperature. With the reduced pressure and temperature conditions, the possibility of propagation of undetected flaws is decreased.

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

C.1 and C.2

Operation outside the P/T limits in other than MODES 1, 2, and 3 (including defueled conditions) must be corrected so that the RCPB is returned to a condition that has been verified by stress analyses. The Required Action must be initiated without delay and continued until the limits are restored.

Besides restoring the P/T limit parameters to within limits, an evaluation is required to determine if RCS operation is allowed. This evaluation must verify that the RCPB integrity is acceptable and must be completed before approaching criticality or heating up to > 212°F. Several methods may be used, including comparison with pre-analyzed transients, new analyses, or inspection of the components. ASME Code, Section XI, Appendix E (Ref. 6), may be used to support the evaluation; however, its use is restricted to evaluation of the beltline. Condition C is modified by a Note requiring Required Action C.2 be completed whenever the Condition is entered. The Note emphasizes the need to perform the evaluation of the effects of the excursion outside the allowable limits. Restoration alone per Required Action C.1 is insufficient because higher than analyzed stresses may have occurred and may have affected the RCPB integrity.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.9.1

Verification that operation is within limits is required every 30 minutes when RCS pressure and temperature conditions are undergoing planned changes. This Frequency is considered reasonable in view of the control room indication available to monitor RCS status. Also, since temperature rate of change limits are specified in hourly increments, 30 minutes permits a reasonable time for assessment and correction of minor deviations.

The following locations must be monitored during RCS heatup and cooldown operations: a) reactor vessel shell adjacent to shell flange; b) reactor vessel bottom drain; c) recirculation loops A and B; and d) reactor vessel bottom head. The following locations must be monitored during inservice leak and hydrostatic testing: a) reactor vessel shell adjacent to shell flange; b) reactor vessel bottom head; and c) reactor vessel shell or coolant temperature representative of the minimum temperature of the beltline region.

Surveillance for heatup and cooldown may be discontinued when three consecutive measurements at each location are within 5°F. Surveillance for inservice leak and hydrostatic testing may be discontinued when the criteria given in the relevant plant procedure for ending the activity are satisfied.

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

SR 3.4.9.2

A separate limit is used when the reactor is approaching criticality. Consequently, the RCS pressure and temperature must be verified within the appropriate limits before withdrawing control rods that will make the reactor critical.

Performing the Surveillance within 15 minutes before control rod withdrawal for the purpose of achieving criticality provides adequate assurance that the limits will not be exceeded between the time of the Surveillance and the time of the control rod withdrawal.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The following locations must be monitored to verify compliance with the P/T criticality curve limits: a) reactor vessel shell adjacent to shell flange; b) reactor vessel bottom drain; c) recirculation loops A and B; and d) reactor vessel bottom head.

SR 3.4.9.3

Differential temperature within the limit ensures that thermal stresses resulting from the startup of an idle recirculation pump will not exceed design allowances at the reactor nozzles and bottom head region. In addition, compliance with this limit ensures that the assumption of the analysis for the startup of an idle recirculation loop (Ref. 8) is satisfied.

Performing the Surveillance within 15 minutes before starting the idle recirculation pump provides adequate assurance that the limit will not be exceeded between the time of the Surveillance and the time of the idle pump start.

An acceptable means of demonstrating compliance with the temperature differential requirement in SR 3.4.9.3 is to compare the temperatures of the operating recirculation loop and the idle loop.

SR 3.4.9.3 has been modified by a Note that requires the Surveillance to be performed only in MODES 1, 2, 3, and 4. In MODE 5, the overall stress on limiting components is lower. Therefore, the ΔT limit is not required. The Note also states the SR is only required to be met during a recirculation pump startup, since this is when the stresses occur.

SR 3.4.9.4, SR 3.4.9.5, and SR 3.4.9.6

Limits on the reactor vessel flange and head flange temperatures are generally bounded by the other P/T limits during system heatup and cooldown. However, operations approaching MODE 4 from MODE 5 and in MODE 4 with RCS temperature less than or equal to certain specified values require assurance that these temperatures meet the LCO limits.

The flange temperatures must be verified to be above the limits 30 minutes before and while tensioning the vessel head bolting studs to ensure that once the head is tensioned the limits are satisfied. When in MODE 4 with RCS temperature ≤ 80°F, 30 minute checks of the flange temperatures are required because of the reduced margin to the limits. When in MODE 4 with RCS temperature ≤ 100°F, monitoring of the flange temperature is required every 12 hours to ensure the temperature is within the limits specified in the PTLR.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The 30 minute Frequency reflects the urgency of maintaining the temperatures within limits, and also limits the time that the temperature limits could be exceeded. The 12 hour Frequency is reasonable based on the rate of temperature change possible at these temperatures.

SR 3.4.9.4 is modified by a Note that requires the Surveillance to be performed only when tensioning the reactor vessel head bolting studs. SR 3.4.9.5 is modified by a Note that requires the Surveillance to be initiated 30 minutes after RCS temperature ≤ 80°F in MODE 4. SR 3.4.9.6 is modified by a Note that requires the Surveillance to be initiated 12 hours after RCS temperature ≤ 100°F in MODE 4. The Notes contained in these SRs are necessary to specify when the reactor vessel flange and head flange temperatures are required to be verified to be within the specified limits.

REFERENCES

1. 10 CFR 50, Appendix G.
2. ASME, Boiler and Pressure Vessel Code, Section III, Appendix G.
3. ASTM E 185-66, 1961.
4. 10 CFR 50, Appendix H.
5. Regulatory Guide 1.99, Revision 2, May 1988.
6. ASME, Boiler and Pressure Vessel Code, Section XI, Appendix E.
7. (Not used)
8. GE Service Information Letter No. 517, Supplement 1, "Analysis Basis for Idle Recirculation Loop Startup," dated August 26, 1998.
9. SIR-05-044-A, “Pressure-Temperature Limits Report Methodology for Boiling Water Reactors,” (latest approved version, see PTLR).
10. Amendment 172, “Issuance of Amendment to Revise and Relocate Pressure Temperature Curves to a Pressure Temperature Limits Report,” dated February 27, 2013. (ADAMS Accession No. ML13025A155)

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.10 Reactor Steam Dome Pressure

BASES

BACKGROUND	The reactor steam dome pressure is an assumed value in the determination of compliance with reactor pressure vessel overpressure protection criteria and is also an assumed initial condition of design basis accidents and transients.
APPLICABLE SAFETY ANALYSES	The reactor steam dome pressure of ≤ 1025.3 psig is an initial condition of the vessel overpressure protection analysis of Reference 1. This analysis assumes an initial maximum reactor steam dome pressure and evaluates the response of the pressure relief system, primarily the safety/relief valves, during the limiting pressurization transient. The determination of compliance with the overpressure criteria is dependent on the initial reactor steam dome pressure; therefore, the limit on this pressure ensures that the assumptions of the overpressure protection analysis are conserved. Reference 2 also assumes an initial reactor steam dome pressure for the analyses of design basis accidents and transients used to determine the limits for fuel cladding integrity (see Bases for LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)") and 1% cladding plastic strain (see Bases for LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)," and LCO 3.2.3, "LINEAR HEAT GENERATION RATE (LHGR)"). Reactor steam dome pressure satisfies the requirements of Criterion 2 of 10 CFR 50.36(c)(2)(ii).
LCO	The specified reactor steam dome pressure limit of ≤ 1025.3 psig ensures the plant is operated within the assumptions of the reactor overpressure protection analysis. Operation above the limit may result in a transient response more severe than analyzed.
APPLICABILITY	In MODES 1 and 2, the reactor steam dome pressure is required to be less than or equal to the limit. In these MODES, the reactor may be generating significant steam and events that may challenge the overpressure limits are possible. In MODES 3, 4, and 5, the limit is not applicable because the reactor is shut down. In these MODES, the reactor pressure is well below the required limit, and no anticipated events will challenge the overpressure limits.

BASES

ACTIONS

A.1

With the reactor steam dome pressure greater than the limit, prompt action should be taken to reduce pressure to below the limit and return the reactor to operation within the bounds of the analyses. The 15 minute Completion Time is reasonable considering the importance of maintaining the pressure within limits. This Completion Time also ensures that the probability of an accident occurring while pressure is greater than the limit is minimized.

B.1

If the reactor steam dome pressure cannot be restored to within the limit within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.4.10.1

Verification that reactor steam dome pressure is ≤ 1025.3 psig ensures that the initial conditions of the design basis accidents and transients are met. Operating experience has shown the 12 hour Frequency to be sufficient for identifying trends and verifying operation within safety analyses assumptions.

REFERENCES

1. USAR, Section 14.5.1.

2. USAR, Section 14.4.

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

B 3.5.1 ECCS - Operating

BASES

BACKGROUND

The ECCS is designed, in conjunction with the primary and secondary containment, to limit the release of radioactive materials to the environment following a loss of coolant accident (LOCA). The ECCS uses two independent methods (flooding and spraying) to cool the core during a LOCA. The ECCS network consists of the High Pressure Coolant Injection (HPCI) System, the Core Spray (CS) System, the low pressure coolant injection (LPCI) mode of the Residual Heat Removal (RHR) System, and the Automatic Depressurization System (ADS). The suppression pool provides the required source of water for the ECCS. Although no credit is taken in the safety analyses for the condensate storage tanks (CSTs), they are capable of providing a source of water for the HPCI, LPCI, and CS Systems.

On receipt of an initiation signal, ECCS pumps automatically start and the system aligns and the pumps inject water, taken either from the CSTs or suppression pool, into the Reactor Coolant System (RCS) as RCS pressure is overcome by the discharge pressure of the ECCS pumps. Although the system is initiated, ADS action is delayed, allowing the operator to interrupt the timed sequence if the system is not needed. The HPCI pump discharge pressure almost immediately exceeds that of the RCS, and the pump injects coolant into the vessel to cool the core. If the break is small, the HPCI System will maintain coolant inventory as well as vessel level while the RCS is still pressurized. If HPCI fails, it is backed up by ADS in combination with LPCI and CS. In this event, the ADS timed sequence would be allowed to time out and open the selected safety/relief valves (S/RVs) depressurizing the RCS, thus allowing the LPCI and CS to overcome RCS pressure and inject coolant into the vessel. If the break is large, RCS pressure initially drops rapidly and the LPCI and CS cool the core.

Water from the break returns to the suppression pool where it is used again and again. Water in the suppression pool is circulated through a heat exchanger cooled by the RHR Service Water System. Depending on the location and size of the break, portions of the ECCS may be ineffective; however, the overall design is effective in cooling the core regardless of the size or location of the piping break.

The combined operation of all ECCS subsystems are designed to ensure that no single active component failure will prevent automatic initiation and successful operation of the minimum required ECCS equipment.

BASES

BACKGROUND (continued)

The CS System (Ref. 1) is composed of two independent subsystems. Each subsystem consists of a motor driven pump, a spray sparger above the core, and piping and valves to transfer water from the suppression pool to the sparger. The CS System is designed to provide cooling to the reactor core when reactor pressure is low. Upon receipt of an initiation signal, the CS pumps in both subsystems are automatically started in approximately 15 seconds after AC power is available. When the RPV pressure drops sufficiently, CS System flow to the RPV begins. A full flow test line is provided to route water from and to the suppression pool to allow testing of the CS System without spraying water in the RPV.

LPCI is an independent operating mode of the RHR System. There are two LPCI subsystems (Ref. 2), each consisting of two motor driven pumps in the same RHR loop and piping and valves to transfer water from the suppression pool to the RPV via the selected recirculation loop. Each LPCI subsystem consists of a common suction line from the suppression pool, parallel flowpaths through the two RHR pumps, and a common injection line to the RPV. An inoperable “LPCI pump” refers to the condition where inoperable components associated with the flowpath through one of the two parallel RHR pumps renders that LPCI pump flowpath inoperable, but the common portions of the associated LPCI subsystem are OPERABLE.

The LPCI System is equipped with a loop select logic that determines which, if any, of the recirculation loops has been broken and selects the non-broken loop for injection. If neither loop is determined to be broken, a preselected loop is used for injection. The LPCI System cross-tie valve must be open to support OPERABILITY of both LPCI subsystems. Similarly, the LPCI swing bus, consisting of two motor control centers which are directly connected together, is required to be energized from the Division 1 power supply (normal source), with automatic transfer capability to the Division 2 power supply (backup source) to support both LPCI subsystems. The LPCI subsystems are designed to provide core cooling at low RPV pressure. Upon receipt of an initiation signal, all four LPCI pumps are automatically started (pumps A and B approximately 5 seconds after AC power is available and pumps C and D approximately 10 seconds after AC power is available). RHR System valves in the LPCI flow path are automatically positioned to ensure the proper flow path for water from the suppression pool to inject into the selected recirculation loop. When the RPV pressure drops sufficiently, the LPCI flow to the RPV, via the selected recirculation loop, begins. The water then enters the reactor through the jet pumps. Full flow test lines are provided for each LPCI subsystem to route water from and to the suppression pool, to allow testing of the LPCI pumps without injecting water into the RPV. These test lines also provide suppression pool cooling capability, as described in LCO 3.6.2.3, "RHR Suppression Pool Cooling." An intertie

BASES

BACKGROUND (continued)

line is provided to connect the RHR shutdown cooling suction line with the two RHR shutdown cooling loop return lines to the associated recirculation loop. This line includes two RHR intertie return line isolation valves that are normally closed and a RHR intertie suction line isolation valve that is normally open. The purpose of this line is to reduce the potential for water hammer in the recirculation and RHR systems. The isolation valves are opened during a cooldown to establish recirculation flow through the RHR suction line and return lines, thereby ensuring a uniform cooldown of this piping. The RHR intertie loop return line isolation valves receive a closure signal on LPCI initiation. In the event of an inoperable RHR intertie loop return line isolation valve, there is a potential for some of the LPCI flow to be diverted to the broken loop during a LOCA. This may cause early transition boiling during a LOCA but this condition was evaluated in the safety analysis and found acceptable. The RHR intertie line is to be isolated within 18 hours if discovered open in MODE 1 to eliminate the need to compensate for the small change in jet pump drive flow and a reduction in core flow during a loss of coolant accident.

The HPCI System (Ref. 3) consists of a steam driven turbine pump unit, piping, and valves to provide steam to the turbine, as well as piping and valves to transfer water from the suction source to the core via the feedwater system line, where the coolant is distributed within the RPV through the feedwater sparger. Suction piping for the system is provided from the CSTs and the suppression pool. Pump suction for HPCI is normally aligned to the CSTs to minimize injection of suppression pool water into the RPV. However, if the water level in any CST is low, or if the suppression pool level is high, an automatic transfer to the suppression pool water source ensures a water supply for continuous operation of the HPCI System. The steam supply to the HPCI turbine is piped from a main steam line upstream of the associated inboard main steam isolation valve.

The HPCI System is designed to provide core cooling for a wide range of reactor pressures (150 psig to 1120 psig). Upon receipt of an initiation signal, the HPCI turbine stop valve and turbine steam supply valve open and the turbine accelerates to a specified speed. As the HPCI flow increases, the turbine governor valve is automatically adjusted to maintain design flow. Exhaust steam from the HPCI turbine is discharged to the suppression pool. A full flow test line is provided to route water from and to the CSTs to allow testing of the HPCI System during normal operation without injecting water into the RPV.

The ECCS pumps are provided with minimum flow bypass lines, which discharge to the suppression pool. The valves in these lines automatically open or remain open to prevent pump damage due to

BASES

BACKGROUND (continued)

overheating when other discharge line valves are closed. To ensure rapid delivery of water to the RPV and to minimize water hammer effects, all ECCS pump discharge lines are filled with water. The LPCI and CS System discharge lines are kept full of water using a "keep fill" system (Condensate Service System). The HPCI System is normally aligned to the CSTs. The height of water in the CSTs maintains the piping full of water up to the first closed isolation valve in the discharge piping. The HPCI System discharge piping near the normally closed injection valve to the Feedwater System absorbs heat from the feedwater via conduction and valve leakage. This has the potential to form a localized steam void in the HPCI discharge piping and cause a momentum transient upon HPCI initiation. Although the momentum transient has been evaluated and shown not to adversely affect HPCI System operation, the Condensate System is utilized as a “keep-fill” system to maintain the HPCI discharge piping between the normally closed injection valve and the pump discharge check valve charged with water to prevent possible void formation and minimize momentum transient effects. This “keep-fill” system is relied upon during normal operation, but is not required for the operability of the HPCI System under normal plant conditions. Additional assessment of operability may be required under off-normal conditions, such as HPCI suction aligned to the suppression pool. The relative height of the feedwater line connection for HPCI is such that the water in the feedwater lines keeps the remaining portion of the HPCI discharge line full of water.

The ADS (Ref. 4) consists of three of the eight S/RVs. It is designed to provide depressurization of the RCS during a small break LOCA if HPCI fails or is unable to maintain required water level in the RPV. ADS operation reduces the RPV pressure to within the operating pressure range of the low pressure ECCS subsystems (CS and LPCI), so that these subsystems can provide coolant inventory makeup. The ADS valves are normally supplied by the Instrument Nitrogen System. This pneumatic supply will automatically transfer to the Instrument Air System on high or low Instrument Nitrogen System pressure. However, both of these pneumatic supplies are non-safety related and are not assumed to operate following an accident. The safety grade pneumatic supply to two of the ADS valves is the Alternate Nitrogen System and to the third ADS valve is the S/RV Accumulator bank. The Alternate Nitrogen System contains two independent trains (i.e., subsystems) of safety related replaceable gas cylinders that supply two of the three ADS valves (S/RVs A and C). One Alternate Nitrogen System train supplies one ADS valve and other non-ADS related pneumatic loads and the other Alternate Nitrogen System train supplies a different ADS valve and other non-ADS related pneumatic loads. The S/RV Accumulator Bank supplies the third ADS valve (S/RV D), and consists of a dedicated safety related backup accumulator bank and an associated inlet check valve.

BASES

APPLICABLE SAFETY ANALYSES

The ECCS performance is evaluated for the entire spectrum of break sizes for a postulated LOCA. The accidents for which ECCS operation is required are presented in References 5 and 6. The required analyses and assumptions are defined in Reference 7. The results of these analyses are also described in References 5 and 6.

This LCO helps to ensure that the following acceptance criteria for the ECCS (Ref. 8), established by 10 CFR 50.46 (Ref. 9), will be met following a LOCA, assuming the worst case single active component failure in the ECCS:

a. Maximum fuel element cladding temperature is ≤ 2200°F;

b. Maximum cladding oxidation is ≤ 0.17°times the total cladding thickness before oxidation;

c. Maximum hydrogen generation from a zirconium water reaction is ≤ 0.01 times the hypothetical amount that would be generated if all of the metal in the cladding surrounding the fuel, excluding the cladding surrounding the plenum volume, were to react;

d. The core is maintained in a coolable geometry; and

e. Adequate long term cooling capability is maintained.

The limiting single failures are discussed in Reference 10. For a large discharge pipe break LOCA, failure of the LPCI valve on the unbroken recirculation loop is considered the most limiting break/failure combination. For a small break LOCA, HPCI failure is the most severe failure. Extended Power Uprate removed the allowance for one ADS valve out-of-service (Ref. 17). The remaining OPERABLE ECCS subsystems provide the capability to adequately cool the core and prevent excessive fuel damage.

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

LCO

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

With less than the required number of ECCS subsystems OPERABLE, the potential exists that during a limiting design basis LOCA concurrent with the worst case single failure, the limits specified in Reference 9 could be exceeded. All ECCS subsystems must therefore be OPERABLE to satisfy the single failure criterion required by Reference 9.

BASES

LCO (continued)

As noted, LPCI subsystems may be considered OPERABLE during alignment and operation for decay heat removal when below the actual RHR shutdown cooling supply isolation interlock in MODE 3, if capable of being manually realigned (remote or local) to the LPCI mode and not otherwise inoperable. Alignment and operation for decay heat removal includes when the required RHR pump is not operating or when the system is realigned from or to the RHR shutdown cooling mode. This allowance is necessary since the RHR System may be required to operate in the shutdown cooling mode to remove decay heat and sensible heat from the reactor. At these low pressures and decay heat levels, a reduced complement of ECCS subsystems should provide the required core cooling, thereby allowing operation of RHR shutdown cooling when necessary.

APPLICABILITY

All ECCS subsystems are required to be OPERABLE during MODES 1, 2, and 3, when there is considerable energy in the reactor core and core cooling would be required to prevent fuel damage in the event of a break in the primary system piping. In MODES 2 and 3, when reactor steam dome pressure is ≤ 150 psig, ADS and HPCI are not required to be OPERABLE because the low pressure ECCS subsystems can provide sufficient flow below this pressure. ECCS requirements for MODES 4 and 5 are specified in LCO 3.5.2, "ECCS - Shutdown."

ACTIONS

A Note prohibits the application of LCO 3.0.4.b to an inoperable HPCI subsystem. There is an increased risk associated with entering a MODE or other specified condition in the Applicability with an inoperable HPCI subsystem and the provisions of LCO 3.0.4.b, which allow entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

A.1

If one LPCI pump is inoperable, the inoperable pump must be restored to OPERABLE status within 30 days. In this condition, the remaining OPERABLE pumps provide adequate core cooling during a LOCA. However, overall LPCI reliability is reduced, because a single failure in one of the remaining OPERABLE LPCI subsystems, concurrent with a LOCA, may result in the LPCI subsystems not being able to perform their intended safety function. The 30 day Completion Time is based on a reliability study cited in Reference 11 that evaluated the impact on ECCS availability, assuming various components and subsystems were taken out of service. The results were used to calculate the average availability of ECCS equipment needed to mitigate the consequences of a LOCA as a function of allowable repair times (i.e., Completion Times).

BASES

ACTIONS (continued)

B.1

If a LPCI subsystem is inoperable for reasons other than Condition A, or a CS subsystem is inoperable, the inoperable low pressure injection/spray subsystem must be restored to OPERABLE status within 7 days. In this condition, the remaining OPERABLE subsystems provide adequate core cooling during a LOCA. However, overall ECCS reliability is reduced, because a single failure in one of the remaining OPERABLE subsystems, concurrent with a LOCA, may result in the ECCS not being able to perform its intended safety function. The 7 day Completion Time is based on a reliability study (Ref. 11) that evaluated the impact on ECCS availability, assuming various components and subsystems were taken out of service. The results were used to calculate the average availability of ECCS equipment needed to mitigate the consequences of a LOCA as a function of allowed outage times (i.e., Completion Times).

C.1

If one LPCI pump in each subsystem is inoperable, one inoperable LPCI pump must be restored to OPERABLE status within 7 days. In this condition, the remaining OPERABLE ECCS subsystems provide adequate core cooling during a LOCA. However, overall ECCS reliability is reduced because a single failure in one of the remaining OPERABLE ECCS subsystems, concurrent with a LOCA, may result in the ECCS not being able to perform its intended safety function. The 7 day Completion Time is based on a reliability study (Ref. 11) that evaluated the impact on ECCS availability, assuming various components and subsystems were taken out of service. The results were used to calculate the average availability of ECCS equipment needed to mitigate the consequences of a LOCA as a function of allowed outage times (i.e., Completion Times).

D.1

If two LPCI subsystems are inoperable for reasons other than Condition C or G, one inoperable subsystem must be restored to OPERABLE status within 72 hours. In this condition, the remaining OPERABLE CS subsystems provide adequate core cooling during a LOCA. However, overall ECCS reliability is reduced, because a single failure in one of the remaining CS subsystems, concurrent with a LOCA, may result in ECCS not being able to perform its intended safety function. The 72 hour Completion Time is based on a reliability study cited in Reference 11 that evaluated the impact on ECCS availability, assuming various components and subsystems were taken out of service; and on previous BWR licensing precedents, and was approved for Monticello by Amendment

BASES

ACTIONS (continued)

162 (Reference 14). The results were used to calculate the average availability of ECCS equipment needed to mitigate the consequences of a LOCA as a function of allowable repair times (i.e., Completion Times).

E.1, E.2 and E.3

If any one low pressure CS subsystem is inoperable in addition to either one LPCI subsystem OR one or two LPCI pump(s), adequate core cooling is ensured by the OPERABILITY of HPCI and the remaining low pressure ECCS subsystems. This condition results in a complement of remaining OPERABLE low pressure ECCS (i.e., one CS and either two or three LPCI pumps) whose makeup capacity is bounded by the minimum makeup capacity evaluated in the accident analysis, which assumes the limiting single component failure (Reference 10). However, overall ECCS reliability is reduced, because a single active component failure in the remaining low pressure ECCS, concurrent with a design basis LOCA, could result in the minimum required ECCS equipment not being available. Since both a CS subsystem is inoperable and a reduction in the makeup capability of the LPCI System has occurred, a more restrictive Completion Time of 72 hours is required to restore either a CS subsystem or, either a LPCI subsystem OR the LPCI pump(s) to OPERABLE status. The Completion Time was developed using engineering judgment based on a reliability study cited in Reference 11, previous BWR licensing precedents, and approved for Monticello by Amendment 162 (Reference 14). This Completion Time has been found to be acceptable through operating experience.

BASES

ACTIONS (continued)

F.1 and F.2

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

G.1

If two LPCI subsystems are inoperable due to open RHR intertie return line isolation valve(s), the RHR intertie line must be isolated within 18 hours. The line can be isolated by closing both RHR intertie return line isolation valves or by closing one RHR intertie return line isolation valve and the RHR intertie suction line isolation valve. The 18 hour Completion Time is reasonable, considered the low probability of a DBA occurring during this period.

H.1

If the Required Action and associated Completion Time of Condition G is not met, the plant must be brought to a MODE in which the RHR intertie return line isolation valves are not required to be closed. To achieve this status, the plant must be brought to at least MODE 2 within 6 hours. 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.

I.1 and I.2

If the HPCI System is inoperable and the RCIC System is verified to be OPERABLE, the HPCI System must be restored to OPERABLE status within 14 days. In this condition, adequate core cooling is ensured by the OPERABILITY of the redundant and diverse low pressure ECCS injection/spray subsystems in conjunction with ADS. Also, the RCIC System will automatically provide makeup water at most reactor operating pressures. Verification of RCIC OPERABILITY is therefore required immediately when HPCI is inoperable. This may be performed as an administrative check by examining logs or other information to determine

BASES

ACTIONS (continued)

if RCIC is out of service for maintenance or other reasons. It does not mean to perform the Surveillances needed to demonstrate the OPERABILITY of the RCIC System. If the OPERABILITY of the RCIC System cannot be immediately verified, however, Condition M must be entered. In the event of component failures concurrent with a design basis LOCA, there is a potential, depending on the specific failures, that the minimum required ECCS equipment will not be available. A 14 day Completion Time is based on a reliability study cited in Reference 11 and has been found to be acceptable through operating experience.

J.1 and J.2

If any one low pressure ECCS injection/spray subsystem, or one LPCI pump in both LPCI subsystems, is inoperable in addition to an inoperable HPCI System, the inoperable low pressure ECCS injection/spray subsystem(s) or the HPCI System must be restored to OPERABLE status within 72 hours. In this condition, adequate core cooling is ensured by the OPERABILITY of the ADS and the remaining low pressure ECCS subsystems. However, the overall ECCS reliability is significantly reduced because a single failure in one of the remaining OPERABLE subsystems concurrent with a design basis LOCA may result in the ECCS not being able to perform its intended safety function. Since both a high pressure system (HPCI) and a low pressure subsystem(s) are inoperable, a more restrictive Completion Time of 72 hours is required to restore either the HPCI System or the low pressure ECCS injection/spray subsystem(s) to OPERABLE status. This Completion Time is based on a reliability study cited in Reference 11 and has been found to be acceptable through operating experience.

K.1

The LCO requires three ADS valves to be OPERABLE in order to provide the ADS function. Reference 12 contains the results of an analysis that evaluated the effect of one ADS valve being out of service. Per this analysis, operation of only two 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 cited in Reference 11 and has been found to be acceptable through operating experience.

BASES

ACTIONS (continued)

L.1 and L.2

If any Required Action and associated Completion Time of Condition I, J, or K is not met, or if one ADS valve is inoperable and Condition A, B, C, D, or G are entered, or if two or more ADS valves are inoperable, or if the HPCI System is inoperable and Condition D, E, or G are entered, then the plant must be brought to a condition in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and reactor steam dome pressure reduced to ≤ 150 psig within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

M.1

If two or more low pressure ECCS injection/spray systems are inoperable for reasons other than Conditions C, D, E, or G, 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.

For some cases, per the single failure assumptions of the accident analysis the plant may not be in an unanalyzed condition (Ref. 10) but the allowable duration for operation in the condition has not been justified, therefore LCO 3.0.3 must be entered immediately.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.1.1

The flow path piping has the potential to develop voids and pockets of entrained air. Maintaining the pump discharge lines of the CS System and LPCI subsystems full of water ensures that the ECCS will perform properly, injecting its full capacity into the RCS upon demand. This will also prevent a water hammer following an ECCS initiation signal. One acceptable method of ensuring that the lines are full is to vent at the high points. While the potential for developing voids in the HPCI System exists, the effects of a void have been analyzed and shown to be acceptable. The 31 day Frequency is based on the gradual nature of void buildup in the ECCS piping, the procedural controls governing system operation, and operating experience.

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 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 HPCI System, this SR also includes the steam flow path for the turbine and the flow controller position.

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

SR 3.5.1.3

Verification every 31 days that each ADS pneumatic pressure is within the analysis limits (S/RV Accumulator Bank header pressure ≥ 88.3 psig and Alternate Nitrogen System supply (ALT N2 TRAIN A (or B) SUPPLY) pressure ≥ 1060 psig (Ref. 13)) ensures adequate pressure for reliable ADS operation. The supply associated with each ADS valve provides pneumatic pressure for valve actuation. The design pneumatic supply pressure requirements for the S/RV accumulator bank and Alternate

BASES

SURVEILLANCE REQUIREMENTS (continued)

Nitrogen System trains (replaceable gas cylinders) are such that, following a failure of the pneumatic supply to them, at least five valve actuations can occur over a ten hour period (Ref. 10). The ECCS safety analysis assumes only one actuation to achieve the depressurization required for operation of the low pressure ECCS. The 31 day Frequency takes into consideration administrative controls over operation of the system and alarms for low pressure.

Each Alternate Nitrogen System is designed for the three upstream nitrogen bottles to maintain OPERABILITY while the fourth, downstream, bottle is being replaced with a fully charged bottle. During bottle changeout the capacity of the system is temporarily reduced. This is acceptable based on the remaining capacity (only one actuation is necessary to depressurize), the low rate of usage, the fact that procedures have been initiated for replenishment, and the low probability of an event during this brief period.

SR 3.5.1.4

Verification every 31 days that the RHR System intertie return line isolation valves are closed ensures that each LPCI subsystem will provide the required flow rate to the reactor pressure vessel. The 31 day Frequency has been found acceptable, considering that these valves are under strict administrative controls that will ensure the valves continue to remain closed.

The SR is modified by a Note stating that the SR is only required to be met in MODE 1. During MODE 1 operations with the RHR System intertie line isolation valves open, some of the LPCI flow may be diverted to the broken recirculation loop during a LOCA, potentially resulting in early transition boiling. In other MODES, the intertie line may be opened because the impact on the LOCA analyses is negligible.

SR 3.5.1.5

Verification of correct breaker alignment to the LPCI swing bus demonstrates that the normal AC electrical power source is powering the swing bus and the backup AC electrical power source is available to ensure proper operation of the LPCI injection valves and the recirculation pump discharge valves. If either the normal source is not powering the LPCI swing bus or the backup source is not available to the LPCI swing bus, one of the LPCI subsystems must be considered inoperable. The 31 day Frequency has been found acceptable based on engineering judgment and operating experience.

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.1.6

Cycling the recirculation pump discharge valves through one complete cycle of full travel demonstrates that the valves are mechanically OPERABLE and will close when required. Upon initiation of an automatic LPCI subsystem injection signal, these valves are required to be closed to ensure full LPCI subsystem flow injection in the reactor via the recirculation jet pumps. De-energizing the valve in the closed position will also ensure the proper flow path for the LPCI subsystem. Acceptable methods of de-energizing the valve include de-energizing breaker control power, racking out the breaker or removing the breaker.

The Frequency of this SR is in accordance with the Inservice Testing Program. If any recirculation pump discharge valve is inoperable and in the open position, both LPCI subsystems must be declared inoperable.

SR 3.5.1.7, SR 3.5.1.8, and SR 3.5.1.9

The performance requirements of the low pressure ECCS pumps are determined through application of the 10 CFR 50, Appendix K criteria (Ref. 7). This periodic Surveillance is performed (in accordance with the ASME Operation and Maintenance (OM) Code requirements for the ECCS pumps) to verify that the ECCS pumps will develop the flow rates required by the respective analyses. The low pressure ECCS pump flow rates ensure that adequate core cooling is provided to satisfy the acceptance criteria of Reference 9. The pump flow rates are verified against a system head equivalent to the reactor to containment pressure expected during a LOCA. In addition, for LPCI the system head for the tested pump must include a head correction that corresponds to two LPCI pumps delivering 7,740 gpm. The total system pump outlet pressure is adequate to overcome the elevation head pressure between the pump suction and the vessel discharge, the piping friction losses, and RPV pressure present during a LOCA. These values are established analytically.

The flow tests for the HPCI System are performed at two different pressure ranges such that system capability to provide rated flow against a system head corresponding to reactor pressure is tested at both the higher and lower operating ranges of the system. The required system head should overcome the RPV pressure and associated discharge line losses. Adequate reactor steam pressure must be available to perform the tests. Additionally, adequate steam flow must be passing through the main turbine or turbine bypass valves to continue to control reactor pressure when the HPCI System diverts steam flow. Therefore, sufficient time is allowed after adequate pressure and flow are achieved to perform

SURVEILLANCE REQUIREMENTS (continued)

these tests. Reactor steam pressure must be ≥ 950 psig to perform SR 3.5.1.8 and ≥ 150 psig to perform SR 3.5.1.9. Adequate steam flow is represented by at least one turbine bypass valve 80% open. Reactor startup is allowed prior to performing the low pressure Surveillance test because the reactor pressure is low and the time allowed to satisfactorily perform the Surveillance test is short. The reactor pressure is allowed to be increased to normal operating pressure since it is assumed that the low pressure test has been satisfactorily completed and there is no indication or reason to believe that HPCI is inoperable.

Therefore, SR 3.5.1.8 and SR 3.5.1.9 are modified by Notes that state the Surveillances are not required to be performed until 12 hours after the reactor steam pressure and flow are adequate to perform the test. The 12 hours allowed for performing the flow test after the required pressure and flow are reached is sufficient to achieve stable conditions for testing and provides reasonable time to complete the SRs. The Frequency for SR 3.5.1.7 and SR 3.5.1.8 is in accordance with the Inservice Testing Program requirements. The 24 month Frequency for SR 3.5.1.9 is based on the need to perform the Surveillance under the conditions that apply during a startup from a plant outage. Operating experience has shown that these components usually pass the SR when performed at the 24 month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.5.1.10

The ECCS subsystems are required to actuate automatically to perform their design functions. This Surveillance verifies that, with a required system initiation signal (actual or simulated), the automatic initiation logic of HPCI, CS, and LPCI will cause the systems or subsystems to operate as designed, including actuation of the system throughout its emergency operating sequence, automatic pump startup and actuation of all automatic valves to their required positions. This SR also ensures that the HPCI System will automatically restart on a Reactor Vessel Water Level - Low Low signal received subsequent to a Reactor Vessel Water Level - High trip and that the suction is automatically transferred from the CSTs to the suppression pool on a Suppression Pool Water Level - High or Condensate Storage Tank Level - Low signal. The LOGIC SYSTEM FUNCTIONAL TEST performed in LCO 3.3.5.1 overlaps this Surveillance to provide complete testing of the assumed safety function.

BASES

SURVEILLANCE REQUIREMENTS (continued)

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

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

This SR is modified by a Note that excludes vessel injection/spray during the Surveillance. Since all active components are testable and full flow can be demonstrated by recirculation through the test line, coolant injection into the RPV is not required during the Surveillance.

SR 3.5.1.11

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 3.5.1.12 and the LOGIC SYSTEM FUNCTIONAL TEST performed in LCO 3.3.5.1 overlap this Surveillance to provide complete testing of the assumed safety function.

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

This SR is modified by a Note that excludes valve actuation since the valves are individually tested in accordance with SR 3.5.1.12.

SR 3.5.1.12

This Surveillance verifies that each ADS valve is capable of being opened, which can be determined by either of two means, i.e., Method 1 or Method 2. Applying Method 1, approved in Reference 15, valve OPERABILITY and setpoints for overpressure protection are verified in

SURVEILLANCE REQUIREMENTS (continued)

accordance with the ASME OM Code. Applying Method 2, a manual actuation of the ADS valve is performed to verify the valve is functioning properly.

Method 1

Valve OPERABILITY and setpoints for overpressure protection are verified in accordance with the requirements of the ASME OM Code (Ref. 16). Proper ADS valve function is verified through performance of inspections and overlapping tests on component assemblies, demonstrating the valve is capable of being opened. Testing is performed to demonstrate that each:

- ADS S/RV main stage opens and passes steam when the associated pilot stage actuates; and
- ADS S/RV second stage actuates to open the associated main stage when the pneumatic actuator is pressurized;
- ADS S/RV solenoid valve ports pneumatic pressure to the associated S/RV actuator when energized;
- ADS S/RV actuator stem moves when dry lift tested in-situ. (With exception of main and pilot stages this test demonstrates mechanical operation without steam.)

The solenoid valves and S/RV actuators are functionally tested once per cycle as part of the Inservice Testing Program. The S/RV assembly is bench tested as part of the certification process, at intervals determined in accordance with the Inservice Testing Program. Maintenance procedures ensure that the S/RV is correctly installed in the plant, and that the S/RV and associated piping remain clear of foreign material that might obstruct valve operation or full steam flow.

This methodology provides adequate assurance that the ADS valves will operate when actuated, while minimizing the challenges to the valves and the likelihood of leakage or spurious operation.

Method 2

A manual actuation of each ADS valve is performed to verify that the valve and solenoid are functioning properly and that no blockage exists in the S/RV discharge lines. This is demonstrated by the response of the turbine bypass valves, by a change in the measured flow, or by any other method suitable to verify steam flow. Adequate steam flow must be

BASES

SURVEILLANCE REQUIREMENTS (continued)

passing through the turbine bypass valves to continue to control reactor pressure when the ADS valves divert steam flow upon opening.

Sufficient time is therefore allowed after the required flow is achieved to perform this SR. Adequate steam flow is represented by at least one turbine bypass valve 80% open. This SR is modified by a Note that states the Surveillance is not required to be performed until 12 hours after reactor steam flow is adequate to perform the test. Reactor startup is allowed prior to performing this SR because valve OPERABILITY and the setpoints for overpressure protection are verified, per ASME requirements, prior to valve installation. The 12 hours allowed for manual actuation after the required flow is reached is sufficient to achieve stable conditions and provides adequate time to complete the Surveillance.

SR 3.5.1.11 and the LOGIC SYSTEM FUNCTIONAL TEST performed in LCO 3.3.5.1, “ECCS Instrumentation,” overlap this Surveillance to provide complete testing of the assumed safety function.

The Frequency of “In accordance with the Inservice Testing Program” is based on ASME OM Code requirements. Industry operating experience has shown that these components usually pass the SR when performed at the Code required Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.5.1.13

The LPCI System injection valves, recirculation pump discharge valves, recirculation pump suction valves, and the RHR discharge intertie line isolation valves are powered from the LPCI swing bus, which must be energized after a single failure, including loss of power from the normal source to the swing bus. Therefore, the automatic transfer capability from the normal power source to the backup power source must be verified to ensure the automatic capability to detect loss of normal power and initiate an automatic transfer to the swing bus backup power source. Verification of this capability every 24 months ensures that AC electrical power is available for proper operation of the associated LPCI injection valves, recirculation pump discharge valves, recirculation pump suction valves, and the RHR discharge intertie line isolation valves. The swing bus automatic transfer scheme must be OPERABLE for both LPCI subsystems to be OPERABLE. The Frequency of 24 months is based on the need to perform the Surveillance under the conditions that apply during a startup from a plant outage. Operating experience has shown that the 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.

BASES

REFERENCES

1. USAR, Section 6.2.2.
2. USAR, Section 6.2.3.
3. USAR, Section 6.2.4.
4. USAR, Section 6.2.5.
5. USAR, Section 14.7.2.
6. USAR, Section 14.7.3.
7. 10 CFR 50, Appendix K.
8. USAR, Section 6.2.1.1.
9. 10 CFR 50.46.
10. USAR, Section 14.7.2.3.2.
11. Memorandum from R.L. Baer (NRC) to V. Stello, Jr. (NRC), "Recommended Interim Revisions to LCOs for ECCS Components," December 1, 1975.
12. USAR, Section 14.7.2.3.1.5.
13. Amendment No. 190, “Issuance of Amendment Re: Technical Specification Surveillance Requirement 3.5.1.3.B to Correct Alternate Nitrogen System Pressure,” dated August 1, 2016. (ADAMS Accession No. ML16196A303)
14. Amendment No. 162, “Issuance of Amendment Regarding Completion Time to Restore a Low-Pressure Emergency Core Cooling Subsystem to Operable Status,” dated July 10, 2009. (ADAMS Accession No. ML091480782)
15. Amendment No. 168, “Issuance of Amendment Re: Testing of Main Steam Safety/Relief Valves,” dated July 27, 2012. (ADAMS Accession No. ML12185A216)
16. ASME Operation and Maintenance (OM) Code.
17. Amendment No. 176, “Monticello Nuclear Generating Plant – Issuance of Amendment No. 176 to Renewed Facility Operating License Regarding Extended Power Uprate,” (ADAMS Accession No. ML13316C459)

BASES

REFERENCES (continued)

18. Amendment No. 184, “Monticello Nuclear Generating Plant – Issuance of Amendment to Revise Technical Specification 3.5.1, “ECCS [Emergency Core Cooling System] – Operating,” dated November 3, 2014. (ADAMS Accession No. ML14246A449) [Condition F previously allowed two Core Spray subsystems to be inoperable for 72 hours.]

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

B 3.5.2 ECCS - Shutdown

BASES

BACKGROUND

A description of the Core Spray (CS) System and the low pressure coolant injection (LPCI) mode of the Residual Heat Removal (RHR) System is provided in the Bases for LCO 3.5.1, "ECCS - Operating."

APPLICABLE SAFETY ANALYSES

The ECCS performance is evaluated for the entire spectrum of break sizes for a postulated loss of coolant accident (LOCA). The long term cooling analysis following a design basis LOCA (Ref. 1) demonstrates that only one low pressure ECCS injection/spray subsystem is required, post LOCA, to maintain adequate reactor vessel water level in the event of an inadvertent vessel draindown. It is reasonable to assume, based on engineering judgment, that while in MODES 4 and 5, one low pressure ECCS injection/spray subsystem can maintain adequate reactor vessel water level. To provide redundancy, a minimum of two low pressure ECCS injection/spray subsystems are required to be OPERABLE in MODES 4 and 5.

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

LCO

Two low pressure ECCS injection/spray subsystems are required to be OPERABLE. The low pressure ECCS injection/spray subsystems consist of two CS subsystems and two LPCI subsystems. Each CS subsystem consists of one motor driven pump, piping, and valves to transfer water from the suppression pool or one or two condensate storage tanks (CSTs) to the reactor pressure vessel (RPV). Each LPCI subsystem consists of one motor driven pump, piping, and valves to transfer water from the suppression pool or from one or two CSTs to the RPV. A single LPCI pump is required per subsystem because of similar injection capacity in relation to a CS subsystem. In addition, in MODES 4 and 5 the RHR System cross-tie valve is not required to be open.

As noted, one LPCI subsystem may be considered OPERABLE during alignment and operation for decay heat removal if capable of being manually realigned (remote or local) to the LPCI mode and is not otherwise inoperable. Alignment and operation for decay heat removal includes when the required RHR pump is not operating or when the system is realigned from or to the RHR shutdown cooling mode. This allowance is necessary since the RHR System may be required to operate in the shutdown cooling mode to remove decay heat and sensible heat from the reactor. Because of low pressure and low temperature

BASES

LCO (continued)

conditions in MODES 4 and 5, sufficient time will be available to manually align and initiate LPCI subsystem operation to provide core cooling prior to postulated fuel uncovery.

APPLICABILITY

OPERABILITY of the low pressure ECCS injection/spray subsystems is required in MODES 4 and 5 to ensure adequate coolant inventory and sufficient heat removal capability for the irradiated fuel in the core in case of an inadvertent draindown of the vessel. Requirements for ECCS OPERABILITY during MODES 1, 2, and 3 are discussed in the Applicability section of the Bases for LCO 3.5.1. ECCS subsystems are not required to be OPERABLE during MODE 5 with the spent fuel storage pool gates removed and the water level maintained at ≥ 21 ft 11 inches above the RPV flange. This provides sufficient coolant inventory to allow operator action to terminate the inventory loss prior to fuel uncovery in case of an inadvertent draindown.

The Automatic Depressurization System is not required to be OPERABLE during MODES 4 and 5 because the RPV pressure is ≤ 150 psig, and the CS System and the LPCI subsystems can provide core cooling without any depressurization of the primary system.

The High Pressure Coolant Injection System is not required to be OPERABLE during MODES 4 and 5 since the low pressure ECCS injection/spray subsystems can provide sufficient flow to the vessel.

ACTIONS

A.1 and B.1

If any one required low pressure ECCS injection/spray subsystem is inoperable, the inoperable subsystem must be restored to OPERABLE status in 4 hours. In this Condition, the remaining OPERABLE subsystem can provide sufficient vessel flooding capability to recover from an inadvertent vessel draindown. However, overall system reliability is reduced because a single failure in the remaining OPERABLE subsystem concurrent with a vessel draindown could result in the ECCS not being able to perform its intended function. The 4 hour Completion Time for restoring the required low pressure ECCS injection/spray subsystem to OPERABLE status is based on engineering judgment that considered the remaining available subsystem and the low probability of a vessel draindown event.

With the inoperable subsystem not restored to OPERABLE status in the required Completion Time, action must be immediately initiated to suspend operations with a potential for draining the reactor vessel (OPDRVs) to minimize the probability of a vessel draindown and the subsequent potential for fission product release. Actions must continue until OPDRVs are suspended.

BASES

ACTIONS (continued)

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

With both of the required ECCS injection/spray subsystems inoperable, all coolant inventory makeup capability may be unavailable. Therefore, actions must immediately be initiated to suspend OPDRVs to minimize the probability of a vessel draindown and the subsequent potential for fission product release. Actions must continue until OPDRVs are suspended. One ECCS injection/spray subsystem must also be restored to OPERABLE status within 4 hours.

If at least one low pressure ECCS injection/spray subsystem is not restored to OPERABLE status within the 4 hour Completion Time, additional actions are required to minimize any potential fission product release to the environment. This includes ensuring secondary containment is OPERABLE; one standby gas treatment subsystem is OPERABLE; and secondary containment isolation capability is available in each associated penetration flow path not isolated that is assumed to be isolated to mitigate radioactivity releases (i.e., one secondary containment isolation valve and associated instrumentation are OPERABLE or other acceptable administrative controls to assure isolation capability). These administrative controls consist of stationing a dedicated operator, who is in continuous communication with the control room, at the controls of the isolation device. In this way, the penetration can be rapidly isolated when a need for secondary containment isolation is indicated. OPERABILITY may be verified by an administrative check, or by examining logs or other information, to determine whether the components are out of service for maintenance or other reasons. It is not necessary to perform the Surveillances needed to demonstrate the OPERABILITY of the components. If, however, any required component is inoperable, then it must be restored to OPERABLE status. In this case, the Surveillance may need to be performed to restore the component to OPERABLE status. Actions must continue until all required components are OPERABLE.

The 4 hour Completion Time to restore at least one low pressure ECCS injection/spray subsystem to OPERABLE status ensures that prompt action will be taken to provide the required cooling capacity or to initiate actions to place the plant in a condition that minimizes any potential fission product release to the environment.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.5.2.1

The minimum water level of -3 ft required for the suppression pool is periodically verified to ensure that the suppression pool will provide adequate net positive suction head (NPSH) for the CS System and LPCI subsystem pumps, recirculation volume, and vortex prevention. With the suppression pool water level less than the required limit, all ECCS injection/spray subsystems are inoperable unless they are aligned to an OPERABLE CST.

When suppression pool level is < -3 ft, the CS and LPCI subsystems are considered OPERABLE only if they can take suction from the CST(s), and the CST(s) water level is sufficient to provide the required NPSH and vortex prevention for the CS pump or LPCI pump. Therefore, a verification that either the suppression pool water level is ≥ -3 ft or that the required low pressure ECCS injection/spray subsystems are aligned to take suction from the CST(s) and the CST(s) contain ≥ 58,000 gallons of water, equivalent to 4 ft in both CSTs when they are cross-tied (normal configuration) and 7 ft in one CST when they are not cross-tied, ensures that the required low pressure ECCS injection/spray subsystems can supply at least 50,000 available gallons of makeup water to the RPV. The low pressure ECCS injection/spray suction is uncovered at the 2366 gallon level. However, as noted, only one required low pressure ECCS injection/spray subsystem may take credit for the CST option during OPDRVs. During OPDRVs, the volume in the CST(s) may not provide adequate makeup if the RPV were completely drained. Therefore, only one low pressure ECCS injection/spray subsystem is allowed to use the CST(s). This ensures the other required ECCS subsystem has adequate makeup volume.

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

SR 3.5.2.2, SR 3.5.2.4, and SR 3.5.2.5

The Bases provided for SR 3.5.1.1, SR 3.5.1.7, and SR 3.5.1.10 are applicable to SR 3.5.2.2, SR 3.5.2.4, and SR 3.5.2.5, respectively.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.5.2.3

Verifying the correct alignment for manual, power operated, and automatic valves in the ECCS flow paths provides assurance that the proper flow paths will exist for ECCS operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these valves were verified to be in the correct position prior to locking, sealing, or securing. A valve that receives an initiation signal is allowed to be in a nonaccident position provided the valve will automatically reposition in the proper stroke time. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of potentially being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves. The 31 day Frequency is appropriate because the valves are operated under procedural control and the probability of their being mispositioned during this time period is low.

REFERENCES

1. USAR, Section 14.7.2.3.6.

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

B 3.5.3 RCIC System

BASES

BACKGROUND

The RCIC System is not part of the ECCS; however, the RCIC System is included with the ECCS section because of their similar functions.

The RCIC System is designed to operate either automatically or manually following reactor pressure vessel (RPV) isolation accompanied by a loss of coolant flow from the feedwater system to provide adequate core cooling and control of the RPV water level. Under these conditions, the High Pressure Coolant Injection (HPCI) and RCIC systems perform similar functions. The RCIC System design requirements ensure that the criteria of Reference 1 are satisfied.

The RCIC System (Ref. 1) consists of a steam driven turbine pump unit, piping, and valves to provide steam to the turbine, as well as piping and valves to transfer water from the suction source to the core via the feedwater system line, where the coolant is distributed within the RPV through the feedwater sparger. Suction piping is provided from the condensate storage tanks (CSTs) and the suppression pool. Pump suction is normally aligned to the CSTs to minimize injection of suppression pool water into the RPV. However, if the water supply is low in any CST, an automatic transfer to the suppression pool water source ensures a water supply for continuous operation of the RCIC System. The steam supply to the turbine is piped from a main steam line upstream of the associated inboard main steam line isolation valve.

The RCIC System is designed to provide core cooling for a wide range of reactor pressures (165 psia to 1135 psia). Upon receipt of an initiation signal, the RCIC turbine accelerates to a specified speed. As the RCIC flow increases, the turbine control valve is automatically adjusted to maintain design flow. Exhaust steam from the RCIC turbine is discharged to the suppression pool. A full flow test line is provided to route water from and to the CST to allow testing of the RCIC System during normal operation without injecting water into the RPV.

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

BASES

BACKGROUND (continued)

kept full of water. The RCIC System is normally aligned to the CSTs. The height of water in the CSTs is sufficient to maintain the piping full of water up to the first isolation valve in the discharge piping. The relative height of the feedwater line connection for RCIC is such that the water in the feedwater lines keeps the remaining portion of the RCIC discharge line full of water. Therefore, RCIC does not require a "keep fill" system.

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. The RCIC System satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

LCO

The OPERABILITY of the RCIC System provides adequate core cooling such that actuation of any of the low pressure ECCS subsystems is not required in the event of RPV isolation accompanied by a loss of feedwater flow. The RCIC System has sufficient capacity for maintaining RPV inventory during an isolation event.

APPLICABILITY

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

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 Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

A.1 and A.2

If the RCIC System is inoperable during MODE 1, or MODE 2 or 3 with reactor steam dome pressure > 150 psig, and the HPCI System is immediately verified to be OPERABLE, the RCIC System must be restored to OPERABLE status within 14 days. In this condition, loss of the RCIC System will not affect the overall plant capability to provide

BASES

ACTIONS (continued)

makeup inventory at high reactor pressure since the HPCI System is the only high pressure system assumed to function during a loss of coolant accident (LOCA). OPERABILITY of HPCI is therefore verified immediately when the RCIC System is inoperable. This may be performed as an administrative check, by examining logs or other information, to determine if HPCI is out of service for maintenance or other reasons. It does not mean it is necessary to perform the Surveillances needed to demonstrate the OPERABILITY of the HPCI System. If the OPERABILITY of the HPCI System cannot be immediately verified, however, Condition B must be entered. For transients and certain abnormal events with no LOCA, RCIC (as opposed to HPCI) is the preferred source of makeup coolant because of its relatively small capacity, which allows easier control of the RPV water level. Therefore, a limited time is allowed to restore the inoperable RCIC to OPERABLE status.

The 14 day Completion Time is based on a reliability study (Ref. 2) that evaluated the impact on ECCS availability, assuming various components and subsystems were taken out of service. The results were used to calculate the average availability of ECCS equipment needed to mitigate the consequences of a LOCA as a function of allowed outage times (AOTs). Because of similar functions of HPCI and RCIC, the AOTs (i.e., Completion Times) determined for HPCI are also applied to RCIC.

B.1 and B.2

If the RCIC System cannot be restored to OPERABLE status within the associated Completion Time, or if the HPCI System is simultaneously inoperable, the plant must be brought to a condition in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and reactor steam dome pressure reduced to ≤ 150 psig within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.5.3.1

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 valves were verified to be in the correct position prior to locking,

BASES

SURVEILLANCE REQUIREMENTS (continued)

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 once every 92 days. The Frequency of 31 days is further justified because the valves are operated under procedural control and because improper valve position would affect only the RCIC System. This Frequency has been shown to be acceptable through operating experience.

<u>SR 3.5.3.2 and SR 3.5.3.3</u>

The RCIC pump flow rates ensure that the system can maintain reactor coolant inventory during pressurized conditions with the RPV isolated. The flow tests for the RCIC System are performed at two different pressure ranges such that system capability to provide rated flow against a system head corresponding to reactor pressure is tested both at the higher and lower operating ranges of the system. The required system head should overcome the RPV pressure and associated discharge line losses. Adequate reactor steam pressure must be available to perform these tests. Additionally, adequate steam flow must be passing through the turbine bypass valves to continue to control reactor pressure when the RCIC System diverts steam flow. Therefore, sufficient time is allowed after adequate pressure and flow are achieved to perform these SRs. Reactor steam pressure must be ≥ 950 psig to perform SR 3.5.3.2 and ≥ 150 psig to perform SR 3.5.3.3. Adequate steam flow is represented by at least one turbine bypass valve 80% open. Reactor startup is allowed prior to performing the low pressure Surveillance because the reactor pressure is low and the time allowed to satisfactorily perform the Surveillance is short. The reactor pressure is allowed to be increased to normal operating pressure since it is assumed that the low pressure Surveillance has been satisfactorily completed and there is no indication or reason to believe that RCIC is inoperable. Therefore, these SRs are modified by Notes that state the Surveillances are not required to be performed until 12 hours after the reactor steam pressure and flow are

BASES

SURVEILLANCE REQUIREMENTS (continued)

adequate to perform the test. The 12 hours allowed for performing the flow test after the required pressure and flow are reached is sufficient to achieve stable conditions for testing and provides reasonable time to complete the SRs.

The Frequency of SR 3.5.3.2 is consistent with the Inservice Testing Program requirements. The 24 month Frequency for SR 3.5.3.3 is based on the need to perform the Surveillance under conditions that apply during a startup from a plant outage. Operating experience has shown that these components usually pass the SR when performed at the 24 month Frequency, which is based on the refueling cycle. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

<u>SR 3.5.3.4</u>

The RCIC System is required to actuate automatically in order to verify its design function satisfactorily. This Surveillance verifies that, with a required system initiation signal (actual or simulated), the automatic initiation logic of the RCIC System will cause the system to operate as designed, i.e., actuation of the system throughout its emergency operating sequence; which includes automatic pump startup and actuation of all automatic valves to their required positions. This Surveillance also ensures the RCIC System will automatically restart on a Reactor Vessel Water Level - Low Low signal received subsequent to a Reactor Vessel Water Level - High trip and that the suction is automatically transferred from the CSTs to the suppression pool on a Condensate Storage Tank Level - Low signal. The LOGIC SYSTEM FUNCTIONAL TEST performed in LCO 3.3.5.2 overlaps this Surveillance to provide complete testing of the assumed safety function.

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

This SR is modified by a Note that excludes vessel injection during the Surveillance. Since all active components are testable and full flow can be demonstrated by recirculation through the test line, coolant injection into the RPV is not required during the Surveillance.

BASES

REFERENCES

1. USAR, Section 10.2.5.

2. Memorandum from R.L. Baer (NRC) to V. Stello, Jr. (NRC), "Recommended Interim Revisions to LCOs for ECCS Components," December 1, 1975.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.1 Primary Containment

BASES

BACKGROUND

The function of the primary containment is to isolate and contain fission products released from the Reactor Primary System following a design basis loss of coolant accident (LOCA) and to confine the postulated release of radioactive material. The primary containment consists of a drywell, which is a steel pressure vessel enclosed in reinforced concrete, and a suppression chamber, which is a steel torus-shaped pressure vessel, connected to the drywell by vent pipes. The primary containment surrounds the Reactor Primary System and provides an essentially leak tight barrier against an uncontrolled release of radioactive material to the environment.

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

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

    1. Capable of being closed by an OPERABLE automatic containment isolation system; or

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

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

c. All equipment hatches and manways are closed.

This Specification ensures that the performance of the primary containment, in the event of a Design Basis Accident (DBA), meets the assumptions used in the safety analyses of References 1 and 2. SR 3.6.1.1.1 leakage rate requirements are in conformance with 10 CFR 50, Appendix J, Option B (Ref. 3), as modified by approved exemptions.

BASES

APPLICABLE SAFETY ANALYSES	The safety design basis for the primary containment is that it must withstand the pressures and temperatures of the limiting DBA without exceeding the design leakage rate. The DBA that postulates the maximum release of radioactive material within primary containment is a LOCA. In the analysis of this accident, it is assumed that primary containment is OPERABLE such that release of fission products to the environment is controlled by the rate of primary containment leakage. Analytical methods and assumptions involving the primary containment are presented in References 1 and 2. The safety analyses assume a nonmechanistic fission product release following a DBA, which forms the basis for determination of offsite doses. The fission product release is, in turn, based on an assumed leakage rate from the primary containment. OPERABILITY of the primary containment ensures that the leakage rate assumed in the safety analyses is not exceeded. The maximum allowable leakage rate for the primary containment (L_a) is 1.2% by weight of the containment air per 24 hours at the design basis LOCA maximum peak containment pressure (P_a) of 44.1 psig (Refs. 1 and 4). Primary containment satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	Primary containment OPERABILITY is maintained by limiting leakage to ≤ 1.0 L_a, except prior to the first startup after performing a required Primary Containment Leakage Rate Testing Program leakage test. At this time the applicable leakage limits must be met. Compliance with this LCO will ensure a primary containment configuration, including equipment hatches and manways, that is structurally sound and that will limit leakage to those leakage rates assumed in the safety analyses. Individual leakage rates specified for the primary containment air lock are addressed in LCO 3.6.1.2.
APPLICABILITY	In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, primary containment is not required to be OPERABLE in MODES 4 and 5 to prevent leakage of radioactive material from primary containment.

BASES

ACTIONS

A.1

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

B.1 and B.2

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

SURVEILLANCE REQUIREMENTS

SR 3.6.1.1.1

Maintaining the primary containment OPERABLE requires compliance with the visual examinations and leakage rate test requirements of the Primary Containment Leakage Rate Testing Program. Failure to meet air lock leakage testing (SR 3.6.1.2.1) or resilient seal primary containment purge and vent valve leakage testing (SR 3.6.1.3.11) does not necessarily result in a failure of this SR. The impact of the failure to meet these SRs must be evaluated against the Type A, B, and C acceptance criteria of the Primary Containment Leakage Rate Testing Program. As left leakage prior to the first startup after performing a required Primary Containment Leakage Rate Testing Program leakage test is required to be $< 0.6\ L_a$ for combined Type B and C leakage, and $\leq 0.75\ L_a$ for overall Type A leakage. At all other times between required leakage rate tests, the acceptance criteria is based on an overall Type A leakage limit of $\leq 1.0\ L_a$. At $\leq 1.0\ L_a$ the offsite dose consequences are bounded by the assumptions of the safety analysis. The Frequency is required by the Primary Containment Leakage Rate Testing Program.

SR 3.6.1.1.2

Maintaining the pressure suppression function of primary containment requires limiting the leakage from the drywell to the suppression chamber. Thus, if an event were to occur that pressurized the drywell, the steam

BASES

SURVEILLANCE REQUIREMENTS (continued)

would be directed through the downcomers into the suppression pool. This SR measures drywell to suppression chamber differential pressure during a 25 minute period to ensure that the leakage paths that would bypass the suppression pool are within allowable limits.

Satisfactory performance of this SR can be achieved by establishing a known differential pressure between the drywell and the suppression chamber and verifying that the bypass leakage is less than that equivalent to a one inch diameter orifice. The leakage test is performed every 24 months. The 24 month Frequency was developed considering it is prudent that this Surveillance be performed during a unit outage and also in view of the fact that component failures that might have affected this test are identified by other primary containment SRs. Two consecutive 24 month test failures, however, would indicate unexpected primary containment degradation; in this event, as the Note indicates, increasing the Frequency to once every 12 months is required until the situation is remedied as evidenced by passing two consecutive 12 month tests.

REFERENCES

1. USAR, Section 5.2.
2. USAR, Section 14.7.2.
3. 10 CFR 50, Appendix J, Option B.
4. Amendment No. 176, “Monticello Nuclear Generating Plant – Issuance of Amendment No. 176 to Renewed Facility Operating License Regarding Extended Power Uprate,” (ADAMS Accession No. ML13316C459)

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.2 Primary Containment Air Lock

BASES

BACKGROUND

One double door primary containment air lock has been built into the primary containment to provide personnel access to the drywell and to provide primary containment isolation during the process of personnel entering and exiting the drywell. The air lock is designed to withstand the same loads, temperatures, and peak design internal and external pressures as the primary containment (Ref. 1). As part of the primary containment, the air lock limits the release of radioactive material to the environment during normal unit operation and through a range of transients and accidents up to and including postulated Design Basis Accidents (DBAs).

Each air lock door has been designed and tested to certify its ability to withstand a pressure in excess of the maximum expected pressure following a DBA in primary containment. Each of the doors contains a single gasketed seal. To effect a leak tight seal, the air lock design uses pressure seated doors (i.e., an increase in primary containment internal pressure results in increased sealing force on each door).

The air lock is nominally a right circular cylinder, 8 ft 6 inches in diameter, with doors at each end that are interlocked to prevent simultaneous opening. The air lock is provided with limit switches on both doors that provide a control room alarm if either door is open. During periods when primary containment is not required to be OPERABLE, the air lock interlock mechanism may be disabled, allowing both doors of an air lock to remain open for extended periods when frequent primary containment entry is necessary. Under some conditions as allowed by this LCO, the primary containment may be accessed through the air lock, when the interlock mechanism has failed, by manually performing the interlock function.

The primary containment air lock forms part of the primary containment pressure boundary. As such, air lock integrity and leak tightness are essential for maintaining primary containment leakage rate to within limits in the event of a DBA. Not maintaining air lock integrity or leak tightness may result in a leakage rate in excess of that assumed in the safety analysis.

BASES

APPLICABLE SAFETY ANALYSES	The DBA that postulates the maximum release of radioactive material within primary containment is a loss of coolant accident (LOCA). In the analysis of this accident, it is assumed that primary containment is OPERABLE, such that release of fission products to the environment is controlled by the rate of primary containment leakage. The primary containment is designed with a maximum allowable leakage rate (L_a) of 1.2% by weight of the containment air per 24 hours at the design basis LOCA maximum peak containment pressure (P_a) of 44.1 psig (Refs. 2 and 3). This allowable leakage rate forms the basis for the acceptance criteria imposed on the SRs associated with the air lock. Primary containment air lock OPERABILITY is also required to minimize the amount of fission product gases that may escape primary containment through the air lock and contaminate and pressurize the secondary containment. The primary containment air lock satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	As part of the primary containment pressure boundary, the air lock's safety function is related to control of containment leakage rates following a DBA. Thus, the air lock's structural integrity and leak tightness are essential to the successful mitigation of such an event. The primary containment air lock is required to be OPERABLE. For the air lock to be considered OPERABLE, the air lock interlock mechanism must be OPERABLE, the air lock must be in compliance with the Type B air lock leakage test, and both air lock doors must be OPERABLE. The interlock allows only one air lock door to be opened at a time. This provision ensures that a gross breach of primary containment does not exist when primary containment is required to be OPERABLE. Closure of a single door in the air lock is sufficient to provide a leak tight barrier following postulated events. Nevertheless, both doors are kept closed when the air lock is not being used for normal entry or exit from primary containment.
APPLICABILITY	In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, the primary containment air lock is not required to be OPERABLE in MODES 4 and 5 to prevent leakage of radioactive material from primary containment.

BASES

ACTIONS

The ACTIONS are modified by Note 1, which allows entry and exit to perform repairs of the affected air lock component. If the outer door is inoperable, then it may be easily accessed to repair. If the inner door is the one that is inoperable, however, then a short time exists when the containment boundary is not intact (during access through the OPERABLE outer door). The allowance to open the OPERABLE door, even if it means the primary containment boundary is temporarily not intact, is acceptable due to the low probability of an event that could pressurize the primary containment during the short time in which the OPERABLE door is expected to be open. The OPERABLE door must be immediately closed after each entry and exit.

The ACTIONS are modified by a second Note, which ensures appropriate remedial measures are taken when necessary. Pursuant to LCO 3.0.6, actions are not required, even if primary containment is exceeding its leakage limit. Therefore, the Note is added to require ACTIONS for LCO 3.6.1.1, "Primary Containment," to be taken in this event.

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

With one primary containment air lock door inoperable, the OPERABLE door must be verified closed (Required Action A.1) in the air lock. This ensures that a leak tight primary containment barrier is maintained by the use of an OPERABLE air lock door. This action must be completed within 1 hour. The 1 hour Completion Time is consistent with the ACTIONS of LCO 3.6.1.1, which requires that primary containment be restored to OPERABLE status within 1 hour.

In addition, the air lock penetration must be isolated by locking closed the OPERABLE air lock door within the 24 hour Completion Time. The 24 hour Completion Time is considered reasonable for locking the OPERABLE air lock door, considering that the OPERABLE door is being maintained closed.

Required Action A.3 ensures that the air lock penetration has been isolated by the use of a locked closed OPERABLE air lock door. This ensures that an acceptable primary containment leakage boundary is maintained. The Completion Time of once per 31 days is based on engineering judgment and is considered adequate in view of the low likelihood of a locked door being mispositioned and other administrative controls. Required Action A.3 is modified by a Note that applies to air

BASES

ACTIONS (continued)

lock doors located in high radiation areas or areas with limited access due to inerting and allows these doors to be verified locked closed by use of administrative controls. Allowing verification by administrative controls is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment of the door, once it has been verified to be in the proper position, is small.

The Required Actions have been modified by two Notes. Note 1 ensures that only the Required Actions and associated Completion Times of Condition C are required if both doors in the air lock are inoperable. With both doors in the air lock inoperable, an OPERABLE door is not available to be closed. Required Actions C.1 and C.2 are the appropriate remedial actions. The exception of Note 1 does not affect tracking the Completion Time from the initial entry into Condition A; only the requirement to comply with the Required Actions. Note 2 allows use of the air lock for entry and exit for 7 days under administrative controls. Primary containment entry may be required to perform Technical Specifications (TS) Surveillances and Required Actions, as well as other activities inside primary containment that are required by TS or activities that support TS-required equipment. This Note is not intended to preclude performing other activities (i.e., non-TS-related activities) if the primary containment was entered, using the inoperable air lock, to perform an allowed activity listed above. This allowance is acceptable due to the low probability of an event that could pressurize the primary containment during the short time that the OPERABLE door is expected to be open.

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

With an air lock interlock mechanism inoperable, the Required Actions and associated Completion Times are consistent with those specified in Condition A.

The Required Actions have been modified by two Notes. Note 1 ensures that only the Required Actions and associated Completion Times of Condition C are required if both doors in the air lock are inoperable. With both doors in the air lock inoperable, an OPERABLE door is not available to be closed. Required Actions C.1 and C.2 are the appropriate remedial actions. Note 2 allows entry into and exit from the primary containment under the control of a dedicated individual stationed at the air lock to ensure that only one door is opened at a time (i.e., the individual performs the function of the interlock).

BASES

ACTIONS (continued)

Required Action B.3 is modified by a Note that applies to air lock doors located in high radiation areas or areas with limited access due to inerting and that allows these doors to be verified locked closed by use of administrative controls. Allowing verification by administrative controls is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment of the door, once it has been verified to be in the proper position, is small.

C.1, C.2, and C.3

If the air lock is inoperable for reasons other than those described in Condition A or B, Required Action C.1 requires action to be immediately initiated to evaluate containment overall leakage rates using current air lock leakage test results. An evaluation is acceptable since it is overly conservative to immediately declare the primary containment inoperable if both doors in an air lock have failed a seal test or if the overall air lock leakage is not within limits. In many instances (e.g., only one seal per door has failed), primary containment remains OPERABLE, yet only 1 hour (according to LCO 3.6.1.1) would be provided to restore the air lock door to OPERABLE status prior to requiring a plant shutdown. In addition, even with both doors failing the seal test, the overall containment leakage rate can still be within limits.

Required Action C.2 requires that one door in the primary containment air lock must be verified closed. This action must be completed within the 1 hour Completion Time. This specified time period is consistent with the ACTIONS of LCO 3.6.1.1, which require that primary containment be restored to OPERABLE status within 1 hour.

Additionally, the air lock must be restored to OPERABLE status within 24 hours (Required Action C.3). The 24 hour Completion Time is reasonable for restoring an inoperable air lock to OPERABLE status considering that at least one door is maintained closed in the air lock.

D.1 and D.2

If the inoperable primary containment air lock cannot be restored to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are 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 3.6.1.2.1

Maintaining the primary containment air lock OPERABLE requires compliance with the leakage rate test requirements of the Primary Containment Leakage Rate Testing Program. This SR reflects the leakage rate testing requirements with respect to air lock leakage (Type B leakage tests). The acceptance criteria were established during initial air lock and primary containment OPERABILITY testing. The periodic testing requirements verify that the air lock leakage does not exceed the allowed fraction of the overall primary containment leakage rate. The Frequency is required by the Primary Containment Leakage Rate Testing Program.

The SR has been modified by two Notes. Note 1 states that an inoperable air lock door does not invalidate the previous successful performance of the overall air lock leakage test. This is considered reasonable since either air lock door is capable of providing a fission product barrier in the event of a DBA. Note 2 has been added to this SR requiring the results to be evaluated against the acceptance criteria which is applicable to SR 3.6.1.1.1. This ensures that air lock leakage is properly accounted for in determining the combined Types B and C primary containment leakage.

SR 3.6.1.2.2

The air lock interlock mechanism is designed to prevent simultaneous opening of both doors in the air lock. Since both the inner and outer doors of an air lock are designed to withstand the maximum expected post accident primary containment pressure, closure of either door will support primary containment OPERABILITY. Thus, the interlock feature supports primary containment OPERABILITY while the air lock is being used for personnel transit in and out of the containment. Periodic testing of this interlock demonstrates that the interlock will function as designed and that simultaneous inner and outer door opening will not inadvertently occur. Due to the purely mechanical nature of this interlock, and given that the interlock mechanism is not normally challenged when the primary containment airlock door is used for entry and exit (procedures require strict adherence to single door opening), this test is only required to be performed every 24 months. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage, and the potential for loss of primary containment OPERABILITY if the Surveillance were performed with the reactor at power. The 24 month Frequency is based on engineering judgment and is considered adequate given that the interlock is not challenged during the use of the air lock.

BASES

REFERENCES

1. USAR, Section 5.2.4.2.
2. USAR, Section 5.2.
3. Amendment No. 176, “Monticello Nuclear Generating Plant – Issuance of Amendment No. 176 to Renewed Facility Operating License Regarding Extended Power Uprate,” (ADAMS Accession No. ML13316C459)

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.3 Primary Containment Isolation Valves (PCIVs)

BASES

BACKGROUND

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

The OPERABILITY requirements for PCIVs help ensure that an adequate primary containment boundary is maintained during and after an accident by minimizing potential paths to the environment. Therefore, the OPERABILITY requirements provide assurance that the primary containment function assumed in the safety analyses will be maintained. These isolation devices are either passive or active (automatic). Manual valves, de-activated automatic valves secured in their closed position (including check valves with flow through the valve secured), blind flanges (which include plugs and caps as listed in Reference 1), and closed systems are considered passive devices. Check valves, or other automatic valves designed to close without operator action following an accident, are considered active devices. Two barriers in series are provided for each penetration, except for penetrations isolated by excess flow check valves, so that no single credible failure or malfunction of an active component can result in a loss of isolation or leakage that exceeds limits assumed in the safety analyses. One of these barriers may be a closed system.

The reactor building-to-suppression chamber vacuum breakers serve a dual function, one of which is primary containment isolation. However, since the other safety function of the vacuum breakers would not be available if the normal PCIV actions were taken, the PCIV OPERABILITY requirements are not applicable to the reactor building-to-suppression chamber vacuum breakers valves. Similar Surveillance Requirements in LCO 3.6.1.6, "Reactor Building-to-Suppression Chamber Vacuum Breakers," provide assurance that the isolation capability is available without conflicting with the vacuum relief function.

The primary containment purge valves are 18 inches in diameter; vent valves are 18 inches in diameter. The 18 inch primary containment purge and vent valves are normally maintained closed in MODES 1, 2, and 3 to ensure the primary containment boundary is maintained. The isolation valves on the 18 inch vent lines have 2 inch bypass lines around them for use during normal reactor operation. Use of the 2 inch vent will prevent

BASES

BACKGROUND (continued)

high pressure from reaching the Standby Gas Treatment (SGT) System filter trains in the unlikely event of a loss of coolant accident (LOCA) during venting. The 18 inch purge and vent valves are capable of closing in the environment of a LOCA.

APPLICABLE SAFETY ANALYSES

The PCIVs LCO was derived from the assumptions related to minimizing the loss of reactor coolant inventory, and establishing the primary containment boundary during major accidents. As part of the primary containment boundary, PCIV OPERABILITY supports leak tightness of primary containment. Therefore, the safety analysis of any event requiring isolation of primary containment is applicable to this LCO.

The DBAs that result in a release of radioactive material for which the consequences are mitigated by PCIVs are a LOCA and a main steam line break (MSLB) (Refs. 2 and 3, respectively). In the analysis for each of these accidents, it is assumed that PCIVs are either closed or close within the required isolation times following event initiation. This ensures that potential paths to the environment through PCIVs (including primary containment purge and vent valves) are minimized. The radiological consequences of the LOCA are discussed in Reference 4 while the radiological consequences of the MSLB are discussed in Reference 5. The MSIVs are required to close within 3 to 9.9 seconds. The 3 second closure time is assumed in the MSIV closure (the most severe overpressurization transient) analysis (Ref. 6). The 9.9 second closure time is assumed in the MSLB analysis (The analysis assumes a total time of 10.5 seconds of which 0.6 seconds is assumed for instrument response). The safety analyses do not make any explicit assumptions concerning the purge and vent valves position at event initiation. However, the purge and vent valves have been designed to close prior to the onset of fuel failure following a LOCA. Likewise, it is assumed that the primary containment is isolated such that release of fission products to the environment is controlled.

The DBA analysis assumes that isolation of the primary containment is complete and leakage is terminated, except for the maximum allowable leakage rate, L_a, prior to fuel damage.

The single failure criterion required to be imposed in the conduct of unit safety analyses was considered in the original design of the primary containment purge and vent valves. Two valves in series on each purge and vent line provide assurance that both the supply and exhaust lines could be isolated even if a single failure occurred.

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

BASES

LCO

PCIVs form a part of the primary containment boundary. The PCIV safety function is related to establishing the primary containment boundary during a DBA and minimizing the loss of reactor coolant inventory. The valves covered by this LCO are listed with their associated primary containment penetrations in Reference 1.
Although not listed in Reference 1, some manual valves are also part of the containment boundary and must be controlled as PCIVs. For example, manual valves for leak rate test connections, vent paths, and drain paths inboard and between PCIVs are part of the containment boundary.

The power operated, automatic isolation valves are required to have isolation times within limits and actuate on an automatic isolation signal. These valves are listed with their associated stroke times in Reference 7.

The 18 inch purge and vent valves must be maintained blocked to prevent full opening. While the reactor building-to-suppression chamber vacuum breakers isolate primary containment penetrations, they are excluded from this Specification. Controls on their isolation function are adequately addressed in LCO 3.6.1.6, "Reactor Building-to-Suppression Chamber Vacuum Breakers."

The normally closed manual PCIVs are considered OPERABLE when valves are closed or open in accordance with appropriate administrative controls, automatic valves are de-activated and secured in their closed position, blind flanges are in place, and closed systems are intact. These passive isolation valves and devices are those listed in Reference 1.

Purge and vent valves with resilient seals must meet leakage rate requirements consistent with Type C testing requirements. Other PCIV leakage rates are addressed by LCO 3.6.1.1, "Primary Containment," as Type B or C testing.

This LCO provides assurance that the PCIVs will perform their designed safety functions to minimize the loss of reactor coolant inventory and establish the primary containment boundary during accidents.

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, most PCIVs are not required to be OPERABLE in MODES 4 and 5. Certain valves (i.e., residual heat removal (RHR) shutdown cooling supply isolation valves), however, are required to be OPERABLE to prevent inadvertent reactor vessel draindown. These valves are those whose associated instrumentation is required to be OPERABLE per LCO 3.3.6.1, "Primary

BASES

APPLICABILITY (continued)

Containment Isolation Instrumentation." (This does not include the valves that isolate the associated instrumentation.)

ACTIONS

The ACTIONS are modified by a Note allowing penetration flow path(s) to be unisolated intermittently under administrative controls. These controls consist of stationing a dedicated individual at the controls of the valve, who is in continuous communication with the control room. In this way, the penetration can be rapidly isolated when a need for primary containment isolation is indicated.

A second Note has been added to provide clarification that, for the purpose of this LCO, separate Condition entry is allowed for each penetration flow path. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable PCIV. Complying with the Required Actions may allow for continued operation, and subsequent inoperable PCIVs are governed by subsequent Condition entry and application of associated Required Actions.

The ACTIONS are modified by Notes 3 and 4. Note 3 ensures that appropriate remedial actions are taken, if necessary, if the affected system(s) are rendered inoperable by an inoperable PCIV (e.g., an Emergency Core Cooling System subsystem is inoperable due to a failed open test return valve). Note 4 ensures appropriate remedial actions are taken when the primary containment leakage limits are exceeded. Pursuant to LCO 3.0.6, these actions are not required even when the associated LCO is not met. Therefore, Notes 3 and 4 are added to require the proper actions be taken.

<u>A.1 and A.2</u>

With one or more penetration flow paths with one PCIV inoperable, except for purge and vent valve leakage rate not within limits, the affected penetration flow paths must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, a blind flange, and a check valve with flow through the valve secured. A de-activated automatic valve means the valve is either electrically or pneumatically disarmed or otherwise secured in the closed position. For a penetration isolated in accordance with Required Action A.1, the device used to isolate the penetration should be the closest available valve to the primary containment. The Required Action must be completed within the 4 hour Completion Time (8 hours for main steam

BASES

ACTIONS (continued)

lines). The Completion Time of 4 hours is reasonable considering the time required to isolate the penetration and the relative importance of supporting primary containment OPERABILITY during MODES 1, 2, and 3. For the main steam lines, an 8 hour Completion Time is allowed. The Completion Time of 8 hours for the main steam lines allows a period of time to restore the MSIVs to OPERABLE status given the fact that MSIV closure will result in isolation of the main steam line(s) and a potential for plant shutdown.

For affected penetrations that have been isolated in accordance with Required Action A.1, the affected penetration flow path(s) must be verified to be isolated on a periodic basis. This is necessary to ensure that primary containment penetrations required to be isolated following an accident, and no longer capable of being automatically isolated, will be in the isolation position should an event occur. This Required Action does not require any testing or device manipulation. Rather, it involves verification that those devices outside primary containment and capable of potentially being mispositioned are in the correct position. The Completion Time of "once per 31 days for isolation devices outside primary containment" is appropriate because the devices are operated under administrative controls and the probability of their misalignment is low. For the devices inside primary containment, the time period specified "prior to entering MODE 2 or 3 from MODE 4 if primary containment was de-inerted while in MODE 4, if not performed within the previous 92 days" is based on engineering judgment and is considered reasonable in view of the inaccessibility of the devices and other administrative controls ensuring that device misalignment is an unlikely possibility.

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

Required Action A.2 is modified by two Notes. Note 1 applies to isolation devices located in high radiation areas, and allows them to be verified by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Note 2 applies to isolation devices that are locked, sealed, or otherwise secured in position and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since the function of locking, sealing, or securing components is to ensure that these devices are not inadvertently repositioned. Therefore, the probability of misalignment, once they have been verified to be in the proper position, is low.

BASES

ACTIONS (continued)

B.1

With one or more penetration flow paths with two PCIVs inoperable, except for purge and vent valve leakage rate not within limit, either the inoperable PCIVs must be restored to OPERABLE status or the affected penetration flow path must be isolated within 1 hour. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, and a blind flange. A de-activated automatic valve means the valve is either electrically or pneumatically disarmed or otherwise secured in the closed position. The 1 hour Completion Time is consistent with the ACTIONS of LCO 3.6.1.1.

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

C.1 and C.2

With one or more penetration flow paths with one PCIV inoperable, except for purge and vent valve leakage rate not within limit, the inoperable valve must be restored to OPERABLE status or the affected penetration flow path must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, and a blind flange. A de-activated automatic valve means the valve is either electrically or pneumatically disarmed or otherwise secured in the closed position. A check valve may not be used to isolate the affected penetration.

The Completion Time of 4 hours for valves other than EFCVs and penetrations with a closed system is reasonable considering the time required to isolate the penetration and the relative importance of supporting primary containment OPERABILITY during MODES 1, 2, and 3. The Completion Time of 72 hours for penetrations with a closed system is reasonable considering the relative stability of the closed system (hence, reliability) to act as a penetration isolation boundary and the relative importance of supporting primary containment OPERABILITY during MODES 1, 2, and 3. A closed system penetrates the primary containment, but does not communicate with the reactor vessel or with the containment free space. The Completion Time of 72 hours for EFCVs is also reasonable considering the instrument and the small pipe diameter of penetration (hence, reliability) to act as a penetration isolation

BASES

ACTIONS (continued)

boundary and the small pipe diameter of the affected penetrations. In the event the affected penetration flow path is isolated in accordance with Required Action C.1, the affected penetration must be verified to be isolated on a periodic basis. This is necessary to ensure that primary containment penetrations required to be isolated following an accident are isolated. This Required Action does not require any testing or valve manipulation. Rather, it involves verification that these devices outside containment capable of potentially being mispositioned are in the correct position. The Completion Time of "once per 31 days for isolation devices outside primary containment" is appropriate because the devices are operated under administrative controls and the probability of their misalignment is low. For the devices inside primary containment, the time period specified "prior to entering MODE 2 or 3 from MODE 4 if primary containment was de-inerted while in MODE 4, if not performed within the previous 92 days" is based on engineering judgment and is considered reasonable in view of the inaccessibility of the devices and other administrative controls ensuring that device misalignment is an unlikely possibility.

Condition C is modified by a Note indicating that this Condition is only applicable to penetration flow paths with only one PCIV. For penetration flow paths with two PCIVs, Conditions A and B provide the appropriate Required Actions. This Note is necessary since this Condition is written specifically to address those penetrations with a single PCIV.

Required Action C.2 is modified by two Notes. Note 1 applies to isolation devices located in high radiation areas and allows them to be verified by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Note 2 applies to isolation devices that are locked, sealed, or otherwise secured in position and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since the function of locking, sealing, or securing components is to ensure that these devices are not inadvertently repositioned. Therefore, the probability of misalignment, once they have been verified to be in the proper position, is low.

D.1 and D.2

In the event one or more 18 inch primary containment purge and vent valves are not within the purge and vent valve leakage limits, purge and vent valve leakage must be restored to within limits or the affected penetration must be isolated. The method of isolation must be by the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed

BASES

ACTIONS (continued)

and de-activated automatic valve, closed manual valve, and blind flange. If a purge or vent valve with resilient seals is utilized to satisfy Required Action D.1, it must have been demonstrated to meet the leakage requirements of SR 3.6.1.3.11. The specified Completion Time is reasonable, considering that one containment purge or vent valve remains closed so that a gross breach of primary containment does not exist.

In accordance with Required Action D.2, this penetration flow path must be verified to be isolated on a periodic basis. The periodic verification is necessary to ensure that containment penetrations required to be isolated following an accident, which are no longer capable of being automatically isolated, will be in the isolation position should an event occur. This Required Action does not require any testing or valve manipulation. Rather, it involves verification that those isolation devices outside containment and potentially capable of being mispositioned are in the correct position. The Completion Time of "once per 31 days for isolation devices outside primary containment" is appropriate because the devices are operated under administrative controls and the probability of their misalignment is low.

Required Action D.2 is modified by two Notes. Note 1 applies to isolation devices located in high radiation areas and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Note 2 applies to isolation devices that are locked, sealed, or otherwise secured in position and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since the function of locking, sealing, or securing components is to ensure that these devices are not inadvertently repositioned.

E.1

With one or more penetration flow paths with one or more MSIVs not within leakage limits, the assumptions of the safety analysis may not be met. Therefore, the leakage must be restored to within limits within 8 hours. Restoration can be accomplished by isolating the penetration that caused the limit to be exceeded by use of one closed and de-activated automatic valve, closed manual valve, or blind flange. When a penetration is isolated, the leakage rate for the isolated penetration is assumed to be the actual pathway leakage through the isolation device. If two isolation devices are used to isolate the penetration, the leakage rate is assumed to be the lesser actual pathway leakage of the two devices.

BASES

ACTIONS (continued)

The 8 hour Completion Time is reasonable considering the time required to restore the leakage by isolating the penetration, the fact that MSIV closure will result in isolation of the main steam line(s) and a potential for plant shutdown, and the relative importance of MSIV or main steam pathway leakage to the overall containment function.

F.1 and F.2

If any Required Action and associated Completion Time cannot be met in MODE 1, 2, or 3, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

G.1 and G.2

If any Required Action and associated Completion Time cannot be met for PCIV(s) required OPERABLE in MODE 4 or 5, the unit must be placed in a condition in which the LCO does not apply. Action must be immediately initiated to suspend operations with a potential for draining the reactor vessel (OPDRVs) to minimize the probability of a vessel draindown and subsequent potential for fission product release. Actions must continue until OPDRVs are suspended. If suspending an OPDRV would result in closing the RHR shutdown cooling supply isolation valves, an alternative Required Action is provided to immediately initiate action to restore the valve(s) to OPERABLE status. This allows RHR shutdown cooling to remain in service while actions are being taken to restore the valve.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.1

This SR ensures that the 18 inch primary containment purge and vent valves are closed as required or, if open, open for an allowable reason. If a purge or vent valve is open in violation of this SR, the valve is considered inoperable. If the inoperable valve is not otherwise known to have excessive leakage when closed, it is not considered to have leakage outside of limits. The SR is modified by a Note stating that the SR is not required to be met when the purge and vent valves are open for the stated reasons. The Note states that these valves may be opened for inerting, de-inerting, pressure control, ALARA or air quality considerations for personnel entry, or Surveillances that require the valves to be open.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The 18 inch purge and vent valves are capable of closing in the environment following a LOCA. Therefore, these valves are allowed to be open for limited periods of time. The 31 day Frequency is consistent with other PCIV requirements discussed in SR 3.6.1.3.2.

SR 3.6.1.3.2

This SR verifies that each primary containment isolation manual valve and blind flange that is located outside primary containment and not locked, sealed, or otherwise secured and is required to be closed during accident conditions, is closed. The SR helps to ensure that post accident leakage of radioactive fluids or gases outside the primary containment boundary is within design limits.

This SR does not require any testing or valve manipulation. Rather, it involves verification that those PCIVs outside primary containment, and capable of being mispositioned, are in the correct position. Since verification of position for PCIVs outside primary containment is relatively easy, the 31 day Frequency was chosen to provide added assurance that the PCIVs are in the correct positions. This SR does not apply to valves that are locked, sealed, or otherwise secured in the closed position, since these were verified to be in the correct position upon locking, sealing, or securing.

Two Notes have been added to this SR. The first Note allows valves and blind flanges located in high radiation areas to be verified by use of administrative controls. Allowing verification by administrative controls is considered acceptable since access to these areas is typically restricted for ALARA reasons. Therefore, the probability of misalignment of these PCIVs, once they have been verified to be in the proper position, is low. A second Note has been included to clarify that PCIVs open under administrative controls are not required to meet the SR during the time that the PCIVs are open. These controls consist of stationing a dedicated individual at the controls of the valve, who is in continuous communication with the control room. In this way, the penetration can be rapidly isolated when a need for primary containment isolation is indicated.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.1.3.3

This SR verifies that each primary containment manual isolation valve and blind flange that is located inside primary containment and not locked, sealed, or otherwise secured and is required to be closed during accident conditions is closed. The SR helps to ensure that post accident leakage of radioactive fluids or gases outside the primary containment boundary is within design limits. For PCIVs inside primary containment, the Frequency of "prior to entering MODE 2 or 3 from MODE 4 if primary containment was de-inerted while in MODE 4, if not performed within the previous 92 days" is appropriate since these PCIVs are operated under administrative controls and the probability of their misalignment is low. This SR does not apply to valves that are locked, sealed, or otherwise secured in the closed position, since these were verified to be in the correct position upon locking, sealing, or securing.

Two Notes have been added to this SR. The first Note allows valves and blind flanges located in high radiation areas to be verified by use of administrative controls. Allowing verification by administrative controls is considered acceptable since the primary containment is inerted and access to these areas is typically restricted during MODES 1, 2, and 3 for ALARA reasons. Therefore, the probability of misalignment of these PCIVs, once they have been verified to be in their proper position, is low. A second Note has been included to clarify that PCIVs that are open under administrative controls are not required to meet the SR during the time that the PCIVs are open. These controls consist of stationing a dedicated individual at the controls of the valve, who is in continuous communication with the control room. In this way, the penetration can be rapidly isolated when a need for primary containment isolation is indicated.

SR 3.6.1.3.4

The traversing incore probe (TIP) shear isolation valves are actuated by explosive charges. Surveillance of explosive charge continuity provides assurance that TIP valves will actuate when required. Other administrative controls, such as those that limit the shelf life of the explosive charges, must be followed. The 31 day Frequency is based on operating experience that has demonstrated the reliability of the explosive charge continuity.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.1.3.5

Verifying the isolation time of each power operated, automatic PCIV is within limits is required to demonstrate OPERABILITY. MSIVs may be excluded from this SR since MSIV full closure isolation time is demonstrated by SR 3.6.1.3.6. The isolation time test ensures that the valve will isolate in a time period less than or equal to that assumed in the safety analyses. The Frequency of this SR is 24 months.

SR 3.6.1.3.6

Verifying that the isolation time of each MSIV is within the specified limits is required to demonstrate OPERABILITY. The isolation time test ensures that the MSIV will isolate in a time period that does not exceed the times assumed in the DBA and transient analyses. This ensures that the calculated radiological consequences of these events remain within 10 CFR 50.67 limits. The Frequency of this SR is 24 months.

SR 3.6.1.3.7

Automatic PCIVs close on a primary containment isolation signal to prevent leakage of radioactive material from primary containment following a DBA. This SR ensures that each automatic PCIV will actuate to its isolation position on a primary containment isolation signal. The LOGIC SYSTEM FUNCTIONAL TEST in LCO 3.3.6.1 overlaps this SR to provide complete testing of the safety function. The 24 month Frequency was developed considering it is prudent that this Surveillance be performed only during a unit outage since isolation of penetrations would eliminate cooling water flow and disrupt the normal operation of many critical components. Operating experience has shown that these components usually pass this Surveillance when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.6.1.3.8

This SR requires a demonstration that each reactor instrumentation line excess flow check valve (EFCV) is OPERABLE by verifying that the valve reduces flow to ≤ 2 gpm on a simulated instrument line break.

SURVEILLANCE REQUIREMENTS (continued)

This SR provides assurance that the instrumentation line EFCVs will perform as designed (Ref. 9). The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown that these components usually pass this Surveillance when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.6.1.3.9

Verifying each 18 inch primary containment purge and vent valve is blocked to restrict opening to ≤ 40° is required to ensure that the valves can close under DBA conditions. The 24 month Frequency is appropriate because the blocking devices are typically removed only during a refueling outage.

SR 3.6.1.3.10

The TIP shear isolation valves are actuated by explosive charges. An in place functional test is not possible with this design. The explosive squib is removed and tested to provide assurance that the valves will actuate when required. The replacement charge for the explosive squib shall be from the same manufactured batch as the one fired or from another batch that has been certified by having one of the batch successfully fired. The Frequency of 24 months on a STAGGERED TEST BASIS is considered adequate given the administrative controls on replacement charges and the frequent checks of circuit continuity (SR 3.6.1.3.4).

SR 3.6.1.3.11

For the 18 inch primary containment purge and vent valves with resilient seals, leakage rate testing consistent with the test requirements of 10 CFR 50, Appendix J, Option B (Ref. 8), is required to ensure OPERABILITY. The Frequency of this SR is in accordance with the Primary Containment Leakage Rate Testing Program.

SR 3.6.1.3.12

The Alternative Source Term DBA LOCA analyses are based on the specified leakage rate. Leakage through each MSIV must be ≤ 100 scfh when tested at ≥ 44.1 psig (P_a) or ≤ 75.3 scfh (Ref. 10) when tested

BASES

SURVEILLANCE REQUIREMENTS (continued)

at ≥ 25 psig (P_t). This ensures that MSIV leakage is properly accounted for in determining the overall primary containment leakage rate. The Frequency of this SR is in accordance with the Primary Containment Leakage Rate Testing Program.

SR 3.6.1.3.13

The Alternative Source Term DBA LOCA analyses are based on the specified leakage rate. Leakage through the main steam pathway (i.e., the four main steam lines and the main steam line drains) must be ≤ 200 scfh when tested at ≥ 44.1 psig (P_a) or ≤ 150.6 scfh (Ref. 10) when tested at ≥ 25 psig (P_t). Compliance with the SR should be based on minimum pathway leakage rates when considering As-Found testing results, and maximum pathway leakage rates for results of As-Left testing. This ensures that MSIV leakage is properly accounted for in determining the overall primary containment leakage rate. The Frequency is required by the Primary Containment Leakage Rate Testing Program.

REFERENCES

1. USAR, Table 5.2-3a.
2. USAR, Section 14.7.2.
3. USAR, Section 14.7.3.
4. USAR, Section 14.7.2.4.
5. USAR, Section 14.7.3.2.
6. USAR, Section 14.5.1.
7. USAR, Table 5.2-3b.
8. 10 CFR 50, Appendix J, Option B.
9. Letter from L. O. Mayer (NSP) to J. F. O'Leary (NRC), dated July 27, 1973.
10. Amendment No. 176, “Monticello Nuclear Generating Plant – Issuance of Amendment No. 176 to Renewed Facility Operating License Regarding Extended Power Uprate,” (ADAMS Accession No. ML13316C459)

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.4 Drywell Air Temperature

BASES

BACKGROUND	The drywell contains the reactor vessel and piping, which add heat to the airspace. Drywell coolers remove heat and maintain a suitable environment. The average airspace temperature affects the calculated response to postulated Design Basis Accidents (DBAs). The limitation on the drywell average air temperature was developed as reasonable, based on operating experience. The limitation on drywell air temperature is used in References 1 and 2 safety analyses.
APPLICABLE SAFETY ANALYSES	Primary containment performance is evaluated for a spectrum of break sizes for postulated loss of coolant accidents (LOCAs) (Ref. 3). Among the inputs to the design basis analysis is the initial drywell average air temperature (Ref. 4). Analyses assume an initial average drywell air temperature of 135°F. This limitation ensures that the safety analysis remains valid by maintaining the expected initial conditions and ensures that the peak LOCA drywell temperature does not exceed the maximum allowable temperature of 281°F (Ref. 5). Exceeding this design temperature may result in the degradation of the primary containment structure under accident loads. Equipment inside primary containment required to mitigate the effects of a DBA is designed to operate and be capable of operating under environmental conditions expected for the accident. Drywell air temperature satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).
LCO	In the event of a DBA, with an initial drywell average air temperature less than or equal to the LCO temperature limit, the resultant accident temperature profile assures that the drywell structural temperature is maintained below its design temperature and that required safety related equipment will continue to perform its function.
APPLICABILITY	In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations of these MODES. Therefore, maintaining drywell average air temperature within the limit is not required in MODE 4 or 5.

BASES

ACTIONS	<u>A.1</u> With drywell average air temperature not within the limit of the LCO, drywell average air temperature must be restored within 8 hours. The Required Action is necessary to return operation to within the bounds of the primary containment analysis. The 8 hour Completion Time is acceptable, considering the sensitivity of the analysis to variations in this parameter, and provides sufficient time to correct minor problems. <u>B.1 and B.2</u> If the drywell average air temperature cannot be restored to within the limit within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.
SURVEILLANCE REQUIREMENTS	<u>SR 3.6.1.4.1</u> Verifying that the drywell average air temperature is within the LCO limit ensures that operation remains within the limits assumed for the primary containment analyses. Drywell air temperature is monitored in all quadrants and at various elevations (referenced to mean sea level). Due to the shape of the drywell, a volumetric average is used to determine an accurate representation of the actual average temperature. The 24 hour Frequency of the SR was developed based on operating experience related to drywell average air temperature variations and temperature instrument drift during the applicable MODES and the low probability of a DBA occurring between surveillances. Furthermore, the 24 hour Frequency is considered adequate in view of other indications available in the control room, including alarms, to alert the operator to an abnormal drywell air temperature condition.
REFERENCES	1. USAR, Section 5.2.3.3. 2. USAR, Section 5.2.3.9. 3. USAR, Section 5.2.3.2. 4. USAR, Table 5.2-7. 5. USAR, Section 5.2.1.1.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.5 Low-Low Set (LLS) Valves

BASES

BACKGROUND	The safety/relief valves (S/RVs) can actuate in either the safety mode, the Automatic Depressurization System mode, or the LLS mode. In the LLS mode (or power actuated mode of operation), a pneumatic diaphragm and stem assembly overcomes the spring force and opens the second stage pilot valve. As in the safety mode, opening the second stage pilot valve allows a differential pressure to develop across the main valve piston and opens the main valve. The main valve can stay open with valve inlet steam pressure as low as 50 psig. Below this pressure, steam pressure may not be sufficient to hold the main valve open against the spring force of the main valve. The pneumatic operator is arranged so that its malfunction will not prevent the main valve from lifting if steam inlet pressure exceeds the safety mode pressure setpoints. Three of the S/RVs are equipped to provide the LLS function. The LLS logic causes the LLS valves to be opened at a lower pressure than the relief or safety mode pressure setpoints and stay open longer, so that reopening of non-LLS S/RVs 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 no subsequent opening of non-LLS S/RVs and a subsequent actuation interval of > 5.75 seconds for the LLS valves. In other words, multiple simultaneous openings of non-LLS 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 simultaneous S/RV openings occur only on the initial actuation for DBAs. Even though three LLS S/RVs are specified, only two LLS S/RVs are required to operate in any DBA analysis. LLS valves satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO	Three LLS valves are required to be OPERABLE to satisfy the assumptions of the safety analyses (Ref. 1). The requirements of this LCO are applicable to the mechanical and electrical/pneumatic capability of the LLS valves to function for controlling the opening and closing of the S/RVs.
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 valves and the low probability of an event in which the remaining LLS valve capability would be inadequate.

B.1 and B.2

If two or more LLS valves are inoperable or if the inoperable LLS valve cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.5.1

This Surveillance verifies that each LLS valve is capable of being opened, which can be determined by either of two means, i.e., Method 1 or Method 2. Applying Method 1, approved in Reference 3, valve OPERABILITY and setpoints for overpressure protection are verified in accordance with the ASME OM Code. Applying Method 2, a manual actuation of the LLS valve is performed to verify the valve is functioning properly.

Method 1

Valve OPERABILITY and setpoints for overpressure protection are verified in accordance with the requirements of the ASME OM Code

BASES

SURVEILLANCE REQUIREMENTS (continued)

(Ref. 2). Proper LLS valve function is verified through performance of inspections and overlapping tests on component assemblies, demonstrating the valve is capable of being opened. Testing is performed to demonstrate that each:

- LLS S/RV main stage opens and passes steam when the associated pilot stage actuates; and

- LLS S/RV second stage actuates to open the associated main stage when the pneumatic actuator is pressurized;

- LLS S/RV solenoid valve ports pneumatic pressure to the associated S/RV actuator when energized;

- LLS S/RV actuator stem moves when dry lift tested in-situ. (With exception of main and pilot stages this test demonstrates mechanical operation without steam.)

The solenoid valves and S/RV actuators are functionally tested once per cycle as part of the Inservice Testing Program. The S/RV assembly is bench tested as part of the certification process, at intervals determined in accordance with the Inservice Testing Program. Maintenance procedures ensure that the S/RV is correctly installed in the plant, and that the S/RV and associated piping remain clear of foreign material that might obstruct valve operation or full steam flow.

This methodology provides adequate assurance that the LLS valves will operate when actuated, while minimizing the challenges to the valves and the likelihood of leakage or spurious operation.

<u>Method 2</u>

A manual actuation of each LLS valve is performed to verify that the valve and solenoids are functioning properly and no blockage exists in the valve discharge line. This can be demonstrated by the response of the turbine bypass valves, by a change in the measured steam flow, or by any other method that is suitable to verify steam flow. Adequate steam flow must be passing through the 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 flow is achieved to perform this test. Adequate steam flow is represented by at least one turbine bypass valve 80% open. This SR is modified by a Note that states the Surveillance is not required to be performed until 12 hours after reactor steam flow is adequate to perform the test. Unit startup is allowed prior to performing the test because valve OPERABILITY is verified by

BASES

SURVEILLANCE REQUIREMENTS (continued)

Reference 2 prior to valve installation. The 12 hours allowed for manual actuation after the required flow is reached is sufficient to achieve stable conditions for testing and provides a reasonable time to complete the Surveillance.

SR 3.6.1.5.2 and the LOGIC SYSTEM FUNCTIONAL TEST performed in LCO 3.3.6.3, “LLS Instrumentation,” overlap this Surveillance to provide complete testing of the assumed safety function.

The Frequency of “In accordance with the Inservice Testing Program” is based on ASME OM Code requirements. Industry operating experience has shown that these components usually pass the SR when performed at the Code required Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.6.1.5.2

The LLS designated 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 LLS function operate as designed when initiated either by an actual or simulated automatic initiation signal. The LOGIC SYSTEM FUNCTIONAL TEST in LCO 3.3.6.3, "Low-Low Set (LLS) Instrumentation," overlaps this SR to provide complete testing of the safety function.

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

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

REFERENCES

1. USAR, Section 4.4.3.
2. ASME Operation and Maintenance (OM) Code.
3. Amendment No. 168, “Issuance of Amendment Re: Testing of Main Steam Safety/Relief Valves,” dated July 27, 2012. (ADAMS Accession No. ML12185A216)

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.6 Reactor Building-to-Suppression Chamber Vacuum Breakers

BASES

BACKGROUND

The function of the reactor building-to-suppression chamber vacuum breakers is to relieve vacuum when primary containment depressurizes below reactor building pressure. If the drywell depressurizes below reactor building pressure, the negative differential pressure is mitigated by flow through the reactor building-to-suppression chamber vacuum breakers and through the suppression-chamber-to-drywell vacuum breakers. The design of the external (reactor building-to-suppression chamber) vacuum relief provisions consists of two vacuum breakers (a self-actuating swing check vacuum breaker and an air operated butterfly valve), located in series in each of two parallel 20 inch lines from the reactor building to a common 20 inch line connected to the suppression chamber airspace. The butterfly valve is actuated by a differential pressure switch. The swing check vacuum breaker is self actuating and can be locally operated for testing purposes. The two vacuum breakers in series must be closed to ensure a leak tight primary containment boundary.

A negative differential pressure across the drywell wall is caused by depressurization of the drywell. Events that cause this depressurization are cooling cycles, inadvertent drywell spray actuation, and steam condensation in the event of a primary system rupture. Reactor building-to-suppression chamber vacuum breakers prevent an excessive negative differential pressure across the primary containment boundary. Cooling cycles result in minor pressure transients in the drywell, which occur slowly and are normally controlled by ventilation equipment. Inadvertent spray actuation results in a more significant pressure transient and becomes important in sizing the external (reactor building-to-suppression chamber) vacuum breakers.

The external vacuum breakers are sized on the basis of the air flow from the secondary containment that is required to mitigate the depressurization transient and limit the maximum negative containment (drywell and suppression chamber) pressure to within design limits. The maximum depressurization rate is a function of the primary containment spray flow rate and temperature and the assumed initial conditions of the primary containment atmosphere. Low spray temperatures and atmospheric conditions that yield the minimum amount of contained noncondensible gases are assumed for conservatism.

BASES

APPLICABLE SAFETY ANALYSES

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

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

Three cases were considered in the safety analyses to determine the adequacy of the external vacuum breakers:

a. A loss of coolant accident followed by actuation of both drywell spray loops;

b. Inadvertent actuation of both drywell spray loops during normal operation; and

c. A postulated DBA assuming ECCS runout flow with a condensation effectiveness of 100%.

The results of these three cases show that the external vacuum breakers, with an opening setpoint of 0.5 psid, are capable of maintaining the differential pressure within design limits.

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

LCO

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

BASES

APPLICABILITY

In MODES 1, 2, and 3, a DBA could result in excessive negative differential pressure across the drywell wall caused by the rapid depressurization of the drywell. The event that results in the limiting rapid depressurization of the drywell is the primary system rupture, which purges the drywell of air and fills the drywell free airspace with steam. Subsequent condensation of the steam would result in depressurization of the drywell, which, after the suppression chamber-to-drywell vacuum breakers open (due to excessive differential pressure between the suppression chamber and drywell), would result in depressurization of the suppression chamber. The limiting pressure and temperature of the primary system prior to a DBA occur in MODES 1, 2, and 3. Excessive negative pressure inside primary containment could occur due to inadvertent initiation of drywell sprays.

In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining reactor building-to-suppression chamber vacuum breakers OPERABLE is not required in MODE 4 or 5.

ACTIONS

A Note has been added to provide clarification that, for the purpose of this LCO, separate Condition entry is allowed for each reactor building-to-suppression chamber vacuum breaker line.

A.1

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

B.1

With one or more lines with two vacuum breakers not closed, primary containment integrity is not maintained. Therefore, one open vacuum breaker must be closed within 1 hour. This Completion Time is consistent with the ACTIONS of LCO 3.6.1.1, "Primary Containment," which requires that primary containment be restored to OPERABLE status within 1 hour.

BASES

ACTIONS (continued)

C.1

With one line with one or more vacuum breakers inoperable for opening, the leak tight primary containment boundary is intact and the remaining OPERABLE vacuum breakers in the other line are capable of providing the vacuum relief function. However, overall system reliability is reduced because a single failure (to open) of one of the vacuum breakers in the other line results in a loss of the vacuum breaker function. Therefore, the inoperable vacuum breaker must be restored to OPERABLE status within 72 hours. This is consistent with the Completion Time for Condition A and the fact that the leak tight primary containment boundary is being maintained.

D.1

With two lines with one or more vacuum breakers inoperable for opening, the primary containment boundary is intact. However, in the event of a containment depressurization, the function of the vacuum breakers is lost. Therefore, all vacuum breakers in one line must be restored to OPERABLE status within 1 hour. This Completion Time is consistent with the ACTIONS of LCO 3.6.1.1, which requires that primary containment be restored to OPERABLE status within 1 hour.

E.1 and E.2

If all the vacuum breakers in one line cannot be closed or restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To 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 3.6.1.6.1

Each vacuum breaker is verified to be closed to ensure that a potential breach in the primary containment boundary is not present. This Surveillance is performed by observing local or control room indications of vacuum breaker position. The 14 day Frequency is based on engineering judgment, is considered adequate in view of other indications of vacuum breaker status available to operations personnel, and has been shown to be acceptable through operating experience.

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

SR 3.6.1.6.2

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

SR 3.6.1.6.3

Demonstration of vacuum breaker opening setpoint is necessary to ensure that the safety analysis assumption regarding vacuum breaker full open differential pressure of ≤ 0.5 psid is valid. The 92 day Frequency has been shown to be acceptable, based on operating experience.

REFERENCES

1. USAR, Section 5.2.1.2.3.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.7 Suppression Chamber-to-Drywell Vacuum Breakers

BASES

BACKGROUND

The function of the suppression chamber-to-drywell vacuum breakers is to relieve vacuum in the drywell. There are eight internal vacuum breakers located on the vent header of the vent system between the drywell and the suppression chamber, which allow air and steam flow from the suppression chamber to the drywell when the drywell is at a negative pressure with respect to the suppression chamber. Therefore, suppression chamber-to-drywell vacuum breakers prevent an excessive negative differential pressure across the suppression chamber-drywell boundary. Each vacuum breaker is a self actuating valve, similar to a check valve, which can be remotely operated for testing purposes.

A negative differential pressure across the drywell wall is caused by depressurization of the drywell. Events that cause this depressurization are cooling cycles, inadvertent drywell spray actuation, and steam condensation from sprays or subcooled water reflood of a break in the event of a primary system rupture. Cooling cycles result in minor pressure transients in the drywell that occur slowly and are normally controlled by ventilation equipment. Spray actuation or spill of subcooled water out of a break results in more significant pressure transients and becomes important in sizing the internal vacuum breakers.

In the event of a primary system rupture, steam condensation within the drywell results in the most severe pressure transient. Following a primary system rupture, air in the drywell is purged into the suppression chamber free airspace, leaving the drywell full of steam. Subsequent condensation of the steam can be caused in two possible ways, namely, Emergency Core Cooling Systems flow from a recirculation line break, or drywell spray actuation following a loss of coolant accident (LOCA). These two cases determine the maximum depressurization rate of the drywell.

In addition, the waterleg in the Mark I Vent System downcomer is controlled by the drywell-to-suppression chamber differential pressure. If the drywell pressure is less than the suppression chamber pressure, there will be an increase in the vent waterleg. This will result in an increase in the water clearing inertia in the event of a postulated LOCA, resulting in an increase in the peak drywell pressure. This in turn will result in an increase in the pool swell dynamic loads. The internal vacuum breakers limit the height of the waterleg in the vent system during normal operation.

BASES

APPLICABLE SAFETY ANALYSES	Analytical methods and assumptions involving the suppression chamber-to-drywell vacuum breakers are presented in Reference 1 as part of the accident response of the primary containment systems. Internal (suppression chamber-to-drywell) and external (reactor building-to-suppression chamber) vacuum breakers are provided as part of the primary containment to limit the negative differential pressure across the drywell and suppression chamber walls that form part of the primary containment boundary. The safety analyses assume that the internal vacuum breakers are closed initially and are fully open at a differential pressure of 0.5 psid (Ref. 1). Additionally, two of the eight internal vacuum breakers are assumed to fail in a closed position (Ref. 1). The results of the analyses show that the design pressure is not exceeded even under the worst case accident scenario. The vacuum breaker opening differential pressure setpoint and the requirement that seven of eight vacuum breakers be OPERABLE are a result of the requirement placed on the vacuum breakers to limit the vent system waterleg height. The vacuum breakers are sized based on the Bodega Bay Pressure Suppression System tests. These tests were conducted by simulating a small break LOCA, which tends to cause downcomer water level variations, as a preliminary step in the large rupture test sequence. The vacuum breaker capacity selected is more than adequate to limit the pressure differential between the suppression chamber and drywell, post LOCA. Design Basis Accident (DBA) analyses assume the vacuum breakers to be closed initially and to remain closed and leak tight until the suppression chamber is at a positive pressure relative to the drywell. The suppression chamber-to-drywell vacuum breakers satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	Only seven of the eight vacuum breakers must be OPERABLE for opening. All suppression chamber-to-drywell vacuum breakers, however, are required to be closed (except during testing, when the vacuum breakers are performing their intended design function, or when a vacuum breaker is open during primary containment inerting or de-inerting operations). The vacuum breaker OPERABILITY requirement provides assurance that the drywell-to-suppression chamber negative differential pressure remains below the design value. The requirement that the vacuum breakers be closed ensures that there is no excessive bypass leakage should a LOCA occur.
APPLICABILITY	In MODES 1, 2, and 3, a DBA could result in excessive negative differential pressure across the drywell wall, caused by the rapid depressurization of the drywell. The event that results in the limiting rapid depressurization of the drywell is the primary system rupture that purges the drywell of air and fills the drywell free airspace with steam. Subsequent condensation of the steam would result in depressurization

BASES

APPLICABILITY (continued)

of the drywell, which, after the suppression chamber-to-drywell vacuum breakers open (due to excessive differential pressure between the suppression chamber and drywell), would result in depressurization of the suppression chamber. The limiting pressure and temperature of the primary system prior to a DBA occur in MODES 1, 2, and 3. Excessive negative pressure inside the drywell could occur due to inadvertent actuation of drywell sprays.

In MODES 4 and 5, the probability and consequences of these events are reduced by the pressure and temperature limitations in these MODES; therefore, maintaining suppression chamber-to-drywell vacuum breakers OPERABLE is not required in MODE 4 or 5.

ACTIONS

A.1

With one of the required vacuum breakers inoperable for opening (e.g., the vacuum breaker is not open and may be stuck closed or not within its opening setpoint limit, so that it would not function as designed during an event that depressurized the drywell), the remaining six OPERABLE vacuum breakers are capable of providing the vacuum relief function. However, overall system reliability is reduced because a single failure in one of the remaining vacuum breakers could result in an excessive suppression chamber-to-drywell differential pressure during a DBA. Therefore, with one of the seven required vacuum breakers inoperable, 72 hours is allowed to restore at least one of the inoperable vacuum breakers to OPERABLE status so that plant conditions are consistent with those assumed for the design basis analysis. The 72 hour Completion Time is considered acceptable due to the low probability of an event in which the remaining vacuum breaker capability would not be adequate.

B.1

An open vacuum breaker allows communication between the drywell and suppression chamber airspace, and, as a result, there is the potential for suppression chamber overpressurization due to this bypass leakage if a LOCA were to occur. Therefore, the open vacuum breaker must be closed. A short time is allowed to close the vacuum breaker due to the low probability of an event that would pressurize primary containment. If vacuum breaker position indication is not reliable, an alternate method of verifying that the vacuum breakers are closed is to verify that the differential pressure decay between the suppression chamber and drywell is maintained within the Allowable Region of Figure B 3.6.1.7-1. The Figure was originally developed from a test performed with a shim holding each vacuum breaker 1/16 inch open at the bottom. The required 12 hour Completion Time is considered adequate to perform this test.

BASES

ACTIONS (continued)

C.1 and C.2

If the inoperable suppression chamber-to-drywell vacuum breaker cannot be closed or restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.7.1

Each vacuum breaker is verified closed to ensure that this potential large bypass leakage path is not present. This Surveillance is performed by observing the vacuum breaker position indication or by verifying that the differential pressure decay between the suppression chamber and drywell is maintained within the Allowable Region of Figure B 3.6.1.7-1. The 14 day Frequency is based on engineering judgment, is considered adequate in view of other indications of vacuum breaker status available to operations personnel, and has been shown to be acceptable through operating experience. This verification is also required within 12 hours after any operation that causes the drywell-to-suppression chamber differential pressure to be reduced by ≥ 0.5 psid.

Three Notes are added to this SR. The first Note allows suppression chamber-to-drywell vacuum breakers opened in conjunction with the performance of a Surveillance to not be considered as failing this SR. These periods of opening vacuum breakers are controlled by plant procedures and do not represent inoperable vacuum breakers. The second Note is included to clarify that vacuum breakers open due to an actual differential pressure are not considered as failing this SR. The third Note is included to clarify that vacuum breakers open, one at a time, during primary containment inerting or de-inerting operations are not considered as failing this SR. This allowance is necessary to assist in purging air or nitrogen from the suppression chamber vent header.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.1.7.2

Each required vacuum breaker must be cycled to ensure that it opens adequately to perform its design function and returns to the fully closed position. This ensures that the safety analysis assumptions are valid. The 31 day Frequency of this SR was developed, based on Inservice Testing Program requirements to perform valve testing at least once every 92 days. A 31 day Frequency was chosen to provide additional assurance that the vacuum breakers are OPERABLE, since they are located in a harsh environment (the suppression chamber airspace).

SR 3.6.1.7.3

Verification of the vacuum breaker opening setpoint is necessary to ensure that the safety analysis assumption regarding vacuum breaker full open differential pressure of 0.5 psid (acting on the suppression chamber face of the valve disc) is valid. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. For this facility, the 24 month Frequency has been shown to be acceptable, based on operating experience, and is further justified because of other surveillances performed at shorter Frequencies that convey the proper functioning status of each vacuum breaker.

REFERENCES

1. USAR, Section 5.2.1.2.3.

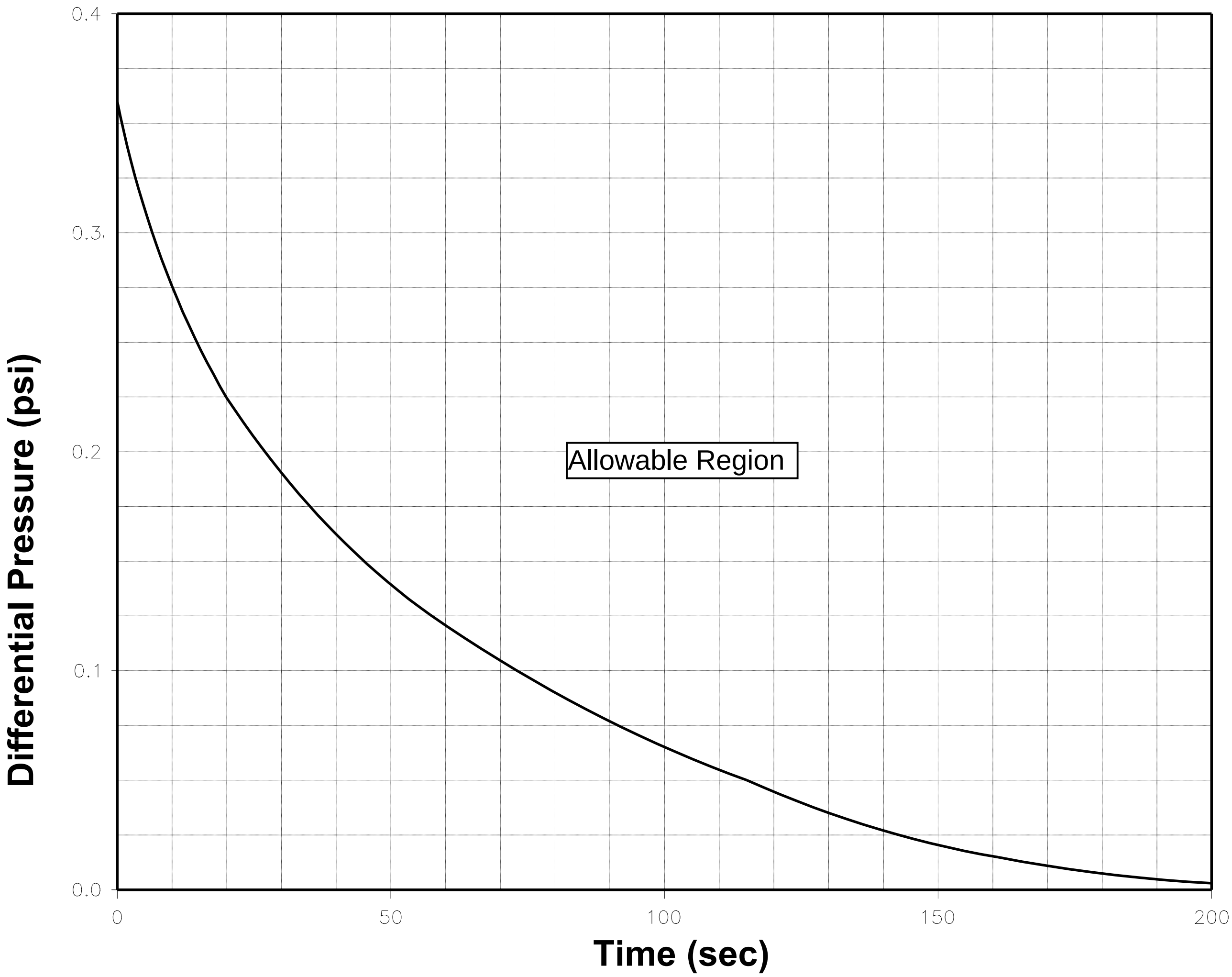

Figure B 3.6.1.7-1 (Page 1 of 1)
Drywell-Suppression Chamber Differential Pressure Decay

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.8 Residual Heat Removal (RHR) Drywell Spray

BASES

BACKGROUND

Following a Design Basis Accident (DBA), the RHR Drywell Spray System condenses any steam that may exist in the drywell thereby lowering drywell pressure and temperature. The RHR Drywell Spray mode of operation is not credited in the DBA loss of coolant accident (LOCA), however it is credited for the evaluation of steam line breaks inside the drywell. For these events, the RHR Drywell Spray System will ensure that the drywell air temperature is within the peak drywell air temperature limit of 338°F (Refs. 2 and 3) specified for the drywell temperature envelope for equipment qualification and will also ensure that the drywell wall temperature is within the design limit of 281°F. This function is provided by two redundant RHR drywell spray subsystems. The purpose of this LCO is to ensure that both subsystems are OPERABLE in applicable MODES.

Each of the two RHR drywell spray subsystems contains two pumps and one heat exchanger, which are manually initiated and independently controlled. The two subsystems perform the drywell spray function by circulating water from the suppression pool through the RHR heat exchangers and returning most of it to the associated drywell spray header. RHR service water, circulating through the tube side of the heat exchangers, exchanges heat with the suppression pool water and discharges this heat to the ultimate heat sink. Either RHR drywell spray subsystem is sufficient to condense the steam that may exist in the drywell during the postulated DBA.

APPLICABLE SAFETY ANALYSES

Reference 1 contains the results of analyses used to predict drywell temperature following various sizes of steam line breaks. The intent of the analyses is to demonstrate that the temperature reduction capacity of the RHR Drywell Spray System is adequate to maintain the primary containment conditions within design limits. The time history for primary containment temperature is calculated to demonstrate that the maximum temperature remains below the design limit.

The RHR Drywell Pool System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

In the event of a DBA, a minimum of one RHR drywell spray subsystem is required to mitigate the consequences of steam line breaks in the drywell and maintain the primary containment peak temperature below the design limits (Ref. 1). To ensure that these requirements are met, two RHR drywell spray subsystems must be OPERABLE with power from two safety related independent power supplies. Therefore, in the event of an

BASES

LCO (continued)

accident, at least one subsystem is OPERABLE assuming the worst case single active failure. An RHR drywell spray subsystem is OPERABLE when one of the pumps, the heat exchanger, and associated piping (including drywell spray header and nozzles), valves, instrumentation, and controls are OPERABLE.

APPLICABILITY

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

ACTIONS

A.1

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

B.1

With both RHR drywell spray subsystems inoperable, at least one subsystem must be restored to OPERABLE status within 8 hours. In this condition, there is a substantial loss of the drywell spray 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 and C.2

If the inoperable RHR drywell spray subsystem cannot be restored to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.8.1

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

The 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 3.6.1.8.2

This Surveillance is performed every 10 years to verify that the drywell spray nozzles are not obstructed and that spray flow will be provided when required. The 10 year Frequency is adequate to detect degradation in performance due to the passive nozzle design and has been shown to be acceptable through operating experience.

REFERENCES

1. USAR, Section 5.2.3.9.

2. Calculation 11-173, MNGP EPU Task Report T0400, Revision 3, “Containment System Response”

3. Amendment No. 176, “Monticello Nuclear Generating Plant – Issuance of Amendment No. 176 to Renewed Facility Operating License Regarding Extended Power Uprate,” (ADAMS Accession No. ML13316C459)

B 3.6 CONTAINMENT SYSTEMS

B 3.6.2.1 Suppression Pool Average Temperature

BASES

BACKGROUND

The suppression chamber is a toroidal shaped, steel pressure vessel containing a volume of water called the suppression pool. The suppression pool is designed to absorb the decay heat and sensible energy released during a reactor blowdown from safety/relief valve discharges or from Design Basis Accidents (DBAs). The suppression pool must quench all the steam released through the downcomer lines during a loss of coolant accident (LOCA). This is the essential mitigative feature of a pressure suppression containment that ensures that the peak containment pressure is maintained below the maximum allowable pressure for DBAs (62 psig). The suppression pool must also condense steam from steam exhaust lines in the turbine driven systems (i.e., the High Pressure Coolant Injection System and Reactor Core Isolation Cooling System). Suppression pool average temperature (along with LCO 3.6.2.2, "Suppression Pool Water Level") is a key indication of the capacity of the suppression pool to fulfill these requirements.

The technical concerns that lead to the development of suppression pool average temperature limits are as follows:

a. Complete steam condensation - the original limit for the end of a LOCA blowdown was 170°F, based on the Bodega Bay and Humboldt Bay Tests;

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

c. Condensation oscillation loads - maximum allowable initial temperature is 110°F; and

d. Chugging loads - these only occur at < 135°F; therefore, there is no initial temperature limit because of chugging.

APPLICABLE SAFETY ANALYSES

The postulated DBA against which the primary containment performance is evaluated is the entire spectrum of postulated pipe breaks within the primary containment. Inputs to the safety analyses include initial suppression pool water volume and suppression pool temperature (Reference 2 for LOCAs and Reference 3 for the pool temperature analyses required by Reference 3). An initial pool temperature of 90°F is assumed for the Reference 2 and Reference 3 analyses. Reactor shutdown at a pool temperature of 110°F and vessel depressurization at a pool temperature of 120°F are assumed for the Reference 3 analyses. Amendment 126 eliminated the local suppression pool temperature limits (Ref. 4).

BASES

APPLICABLE SAFETY ANALYSES (continued)

The limit of 100°F, at which testing is terminated, is not used in the safety analyses because DBAs are assumed to not initiate during unit testing.

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

LCO

A limitation on the suppression pool average temperature is required to provide assurance that the containment conditions assumed for the safety analyses are met. This limitation subsequently ensures that peak primary containment pressures and temperatures do not exceed maximum allowable values during a postulated DBA or any transient resulting in heatup of the suppression pool. The LCO requirements are:

a. Average temperature ≤ 90°F with THERMAL POWER > 1% RATED THERMAL POWER (RTP) and no testing that adds heat to the suppression pool is being performed. This requirement ensures that licensing bases initial conditions are met.

b. Average temperature ≤ 100°F with THERMAL POWER > 1% RTP and testing that adds heat to the suppression pool is being performed. This required value ensures that the unit has testing flexibility, and was selected to provide margin below the 110°F limit at which reactor shutdown is required. When testing ends, temperature must be restored to ≤ 90°F within 24 hours according to Required Action A.2. Therefore, the time period that the temperature is > 90°F is short enough not to cause a significant increase in unit risk.

c. Average temperature ≤ 110°F with THERMAL POWER ≤ 1% RTP. This requirement ensures that the unit will be shut down at > 110°F. The pool is designed to absorb decay heat and sensible heat but could be heated beyond design limits by the steam generated if the reactor is not shut down.

At 1% RTP, heat input is approximately equal to normal system heat losses.

APPLICABILITY

In MODES 1, 2, and 3, a DBA could cause significant heatup of the suppression pool. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining suppression pool average temperature within limits is not required in MODE 4 or 5.

BASES

ACTIONS

A.1 and A.2

With the suppression pool average temperature above the specified limit when not performing testing that adds heat to the suppression pool and when above the specified power limit, the initial conditions exceed the conditions assumed for the References 2, 3, and 5 analyses. However, primary containment cooling capability still exists, and the primary containment pressure suppression function will occur at temperatures well above those assumed for safety analyses. Therefore, continued operation is allowed for a limited time. The 24 hour Completion Time is adequate to allow the suppression pool average temperature to be restored below the limit. Additionally, when suppression pool temperature is > 90°F, increased monitoring of the suppression pool temperature is required to ensure that it remains ≤ 110°F. The once per hour Completion Time is adequate based on past experience, which has shown that pool temperature increases relatively slowly except when testing that adds heat to the suppression pool is being performed. Furthermore, the once per hour Completion Time is considered adequate in view of other indications in the control room, including alarms, to alert the operator to an abnormal suppression pool average temperature condition.

B.1

If the suppression pool average temperature cannot be restored to within limits within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the power must be reduced to ≤ 1% RTP within 12 hours. The 12 hour Completion Time is reasonable, based on operating experience, to reduce power from full power conditions in an orderly manner and without challenging plant systems.

C.1

Suppression pool average temperature is allowed to be > 90°F with THERMAL POWER > 1% RTP, when testing that adds heat to the suppression pool is being performed. However, if temperature is > 100°F, all testing must be immediately suspended to preserve the heat absorption capability of the suppression pool. With the testing suspended, Condition A is entered and the Required Actions and associated Completion Times are applicable.

BASES

ACTIONS (continued)

D.1 and D.2

Suppression pool average temperature > 110°F requires that the reactor be shut down immediately. This is accomplished by placing the reactor mode switch in the shutdown position. Further cooldown to MODE 4 within 36 hours is required at normal cooldown rates (provided pool temperature remains ≤ 120°F). Additionally, when suppression pool temperature is > 110°F, increased monitoring of pool temperature is required. The once per 30 minute Completion Time is adequate, based on operating experience. Given the high suppression pool average temperature in this condition, the monitoring Frequency is increased to twice that of Required Action A.1. Furthermore, the 30 minute Completion Time is considered adequate in view of other indications available in the control room, including alarms, to alert the operator to an abnormal suppression pool average temperature condition. Additionally, 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 4 within 36 hours. The allowed Completion Time is reasonable, based on operating experience, to reach the required plant condition from full power conditions in an orderly manner and without challenging plant systems.

E.1

If suppression pool average temperature cannot be maintained at ≤ 120°F, the reactor pressure must be reduced to < 200 psig within 12 hours. 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 addition of heat to the suppression pool with suppression pool temperature > 120°F could result in exceeding the design basis maximum allowable values for primary containment temperature or pressure. Furthermore, if a blowdown were to occur when the temperature was > 120°F, the maximum allowable bulk and local temperatures could be exceeded very quickly.

SURVEILLANCE REQUIREMENTS

SR 3.6.2.1.1

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

BASES

SURVEILLANCE REQUIREMENTS (continued)

being added to the suppression pool by testing, however, it is necessary to monitor suppression pool temperature more frequently. The 5 minute Frequency during testing is justified by the rates at which tests will heat up the suppression pool, has been shown to be acceptable based on operating experience, and provides assurance that allowable pool temperatures are not exceeded. The Frequencies are further justified in view of other indications available in the control room, including alarms, to alert the operator to an abnormal suppression pool average temperature condition.

REFERENCES

1. USAR, Section 5.2.1.1.
2. USAR, Section 5.2.3.
3. NEDC-23487-P, "Monticello Nuclear Generating Plant Suppression Pool Temperature Response," December 1981.
4. Amendment 126, “Monticello Nuclear Generating Plant – Issuance of Amendment Re: Elimination of Local Suppression Pool Temperature Limits (TAC No. MB2064),” dated January 18, 2002.
5. NEDE-24539-P, "Mark I Containment Program," April 1979.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.2.2 Suppression Pool Water Level

BASES

BACKGROUND	The suppression chamber is a toroidal shaped, steel pressure vessel containing a volume of water called the suppression pool. The suppression pool is designed to absorb the energy associated with decay heat and sensible heat released during a reactor blowdown from safety/relief valve (S/RV) discharges or from a Design Basis Accident (DBA). The suppression pool must quench all the steam released through the downcomer lines during a loss of coolant accident (LOCA). This is the essential mitigative feature of a pressure suppression containment, which ensures that the peak containment pressure is maintained below the maximum allowable pressure for DBAs (62 psig). The suppression pool must also condense steam from the steam exhaust lines in the turbine driven systems (i.e., High Pressure Coolant Injection (HPCI) System and Reactor Core Isolation Cooling (RCIC) System) and provides the main emergency water supply source for the reactor vessel. The suppression pool volume ranges between 68,000 ft^3 at the low water level limit of - 4.0 inches and 72,910 ft^3 at the high water level limit of + 3.0 inches. If the suppression pool water level is too low, an insufficient amount of water would be available to adequately condense the steam from the S/RV quenchers, main vents, or HPCI and RCIC turbine exhaust lines. Low suppression pool water level could also result in an inadequate emergency makeup water source to the Emergency Core Cooling System. The lower volume would also absorb less steam energy before heating up excessively. Therefore, a minimum suppression pool water level is specified. If the suppression pool water level is too high, it could result in excessive clearing loads from S/RV discharges and excessive pool swell loads during a DBA LOCA. Therefore, a maximum pool water level is specified. This LCO specifies an acceptable range to prevent the suppression pool water level from being either too high or too low.
APPLICABLE SAFETY ANALYSES	Initial suppression pool water level affects suppression pool temperature response calculations, calculated drywell pressure during vent clearing for a DBA, calculated pool swell loads for a DBA LOCA, and calculated loads due to S/RV discharges. Suppression pool water level must be maintained within the limits specified so that the safety analysis of Reference 1 remains valid. Suppression pool water level satisfies Criteria 2 and 3 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO	A limit that suppression pool water level be ≥ - 4.0 inches and ≤ + 3.0 inches is required to ensure that the primary containment conditions assumed for the safety analyses are met. Either the high or low water level limits were used in the safety analyses, depending upon which is more conservative for a particular calculation.
APPLICABILITY	In MODES 1, 2, and 3, a DBA would cause significant loads on the primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. The requirements for maintaining suppression pool water level within limits in MODE 4 or 5 is addressed in LCO 3.5.2, "ECCS - Shutdown."

ACTIONS

A.1

With suppression pool water level outside the limits, the conditions assumed for the safety analyses are not met. If water level is below the minimum level, the pressure suppression function still exists as long as downcomer lines are covered, HPCI and RCIC turbine exhausts are covered, and S/RV quenchers are covered. If suppression pool water level is above the maximum level, protection against overpressurization still exists due to the margin in the peak containment pressure analysis and the capability of the Drywell Spray System. Therefore, continued operation for a limited time is allowed. The 2 hour Completion Time is sufficient to restore suppression pool water level to within limits. Also, it takes into account the low probability of an event impacting the suppression pool water level occurring during this interval.

B.1 and B.2

If suppression pool water level cannot be restored to within limits within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

BASES

SURVEILLANCE REQUIREMENTS	SR 3.6.2.2.1 Verification of the suppression pool water level is to ensure that the required limits are satisfied. The 24 hour Frequency has been shown to be acceptable based on operating experience. Furthermore, the 24 hour Frequency is considered adequate in view of other indications available in the control room, including alarms, to alert the operator to an abnormal suppression pool water level condition.
REFERENCES	1. USAR, Section 5.2.3.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.2.3 Residual Heat Removal (RHR) Suppression Pool Cooling

BASES

BACKGROUND

Following a Design Basis Accident (DBA), the RHR Suppression Pool Cooling System removes heat from the suppression pool. The suppression pool is designed to absorb the sudden input of heat from the primary system. In the long term, the pool continues to absorb residual heat generated by fuel in the reactor core. Some means must be provided to remove heat from the suppression pool so that the temperature inside the primary containment remains within design limits. This function is provided by two redundant RHR suppression pool cooling subsystems. The purpose of this LCO is to ensure that both subsystems are OPERABLE in applicable MODES.

Each RHR subsystem contains two pumps and one heat exchanger and is manually initiated and independently controlled. The two subsystems perform the suppression pool cooling function by circulating water from the suppression pool through the RHR heat exchangers and returning it to the suppression pool. RHR service water, circulating through the tube side of the heat exchangers, exchanges heat with the suppression pool water and discharges this heat to the ultimate heat sink.

The heat removal capability of one RHR pump in one subsystem is sufficient to meet the overall DBA pool cooling requirement for loss of coolant accidents (LOCAs) and transient events such as a turbine trip or stuck open safety/relief valve (S/RV). S/RV leakage and high pressure core injection and Reactor Core Isolation Cooling System testing increase suppression pool temperature more slowly. The RHR Suppression Pool Cooling System is also used to lower the suppression pool water bulk temperature following such events.

APPLICABLE SAFETY ANALYSES

Reference 1 contains the results of analyses used to predict primary containment pressure and temperature following large and small break LOCAs. The intent of the analyses is to demonstrate that the heat removal capacity of the RHR Suppression Pool Cooling System is adequate to maintain the primary containment conditions within design limits. The suppression pool temperature is calculated to remain below the design limit.

The RHR Suppression Pool Cooling System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO	During a DBA, a minimum of one RHR suppression pool cooling subsystem is required to maintain the primary containment peak pressure and temperature below design limits (Ref. 1). To ensure that these requirements are met, two RHR suppression pool cooling subsystems must be OPERABLE with power from two safety related independent power supplies. 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 one of the pumps, the heat exchanger, and associated piping, valves, instrumentation, and controls are OPERABLE.
APPLICABILITY	In MODES 1, 2, and 3, a DBA could cause a release of radioactive material to primary containment and cause a heatup and pressurization of primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Therefore, the RHR Suppression 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 OPERABLE 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

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.

BASES

ACTIONS (continued)

C.1 and C.2

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

SURVEILLANCE REQUIREMENTS

SR 3.6.2.3.1

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

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

SR 3.6.2.3.2

Verifying that each RHR pump develops a flow rate ≥ 3870 gpm while operating in the suppression pool cooling mode with flow through the associated heat exchanger ensures that pump performance has not degraded during the cycle. Flow is a normal test of centrifugal pump performance required by ASME OM Code (Ref. 2). This test confirms one point on the pump design curve, and the results are indicative of overall performance. Such inservice tests 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.

BASES

REFERENCES

1. USAR, Section 5.2.3.
2. ASME Operation and Maintenance (OM) Code.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.3.1 Primary Containment Oxygen Concentration

BASES

BACKGROUND

The primary containment was designed to withstand events that generate hydrogen either due to the zirconium metal water reaction in the core or due to radiolysis. The primary method to control hydrogen is to inert the primary containment with nitrogen gas. With the primary containment inerted, that is, oxygen concentration < 4.0 volume percent (v/o), a combustible mixture cannot be present in the primary containment for any hydrogen concentration. An event that rapidly generates hydrogen from zirconium metal water reaction will result in excessive hydrogen in primary containment, but oxygen concentration will remain < 4.0 v/o and no combustion can occur. This LCO ensures that oxygen concentration does not exceed 4.0 v/o during operation in the applicable conditions.

APPLICABLE SAFETY ANALYSES

The Reference 1 calculations assume that the primary containment is inerted when a Design Basis Accident loss of coolant accident occurs. Thus, the hydrogen assumed to be released to the primary containment as a result of metal water reaction in the reactor core will not produce combustible gas mixtures in the primary containment.

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

LCO

The primary containment oxygen concentration is maintained < 4.0 v/o to ensure that an event that produces any amount of hydrogen and oxygen does not result in a combustible mixture inside primary containment.

APPLICABILITY

The primary containment oxygen concentration must be within the specified limit when primary containment is inerted, except as allowed by the relaxations during startup and shutdown addressed below. The primary containment must be inert in MODE 1, since this is the condition with the highest probability of an event that could produce hydrogen and oxygen.

Inerting the primary containment is an operational problem because it prevents containment access without an appropriate breathing apparatus. Therefore, the primary containment is inerted as late as possible in the plant startup and de-inerted as soon as possible in the plant shutdown. As long as reactor power is ≤ 15% RTP, the potential for an event that generates significant hydrogen and oxygen is low and the primary containment need not be inert. Furthermore, the probability of an event

BASES

APPLICABILITY (continued)

that generates hydrogen occurring within the first 24 hours of a startup, or within the last 24 hours before a shutdown, is low enough that these "windows," when the primary containment is not inerted, are also justified. The 24 hour time period is a reasonable amount of time to allow plant personnel to perform inerting or de-inerting.

ACTIONS

A.1

If oxygen concentration is ≥ 4.0 v/o at any time while operating in MODE 1, with the exception of the relaxations allowed during startup and shutdown, oxygen concentration must be restored to < 4.0 v/o within 24 hours. The 24 hour Completion Time is allowed when oxygen concentration is ≥ 4.0 v/o because of the low probability and long duration of an event that would generate significant amounts of hydrogen and oxygen occurring during this period.

B.1

If oxygen concentration cannot be restored to within limits within the required Completion Time, the plant must be brought to ≤ 15% RTP because the potential for an event that generates significant hydrogen and oxygen is low. To achieve this status, power must be reduced to ≤ 15% RTP within 8 hours. The 8 hour Completion Time is reasonable, based on operating experience, to reduce reactor power from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.3.1.1

The primary containment must be determined to be inerted by verifying that oxygen concentration is < 4.0 v/o. The 7 day Frequency is based on the slow rate at which oxygen concentration can change and on other indications of abnormal conditions (which could lead to more frequent checking by operators in accordance with plant procedures). Also, this Frequency has been shown to be acceptable through operating experience.

REFERENCES

1. USAR, Section 5.2.3.5.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.4.1 Secondary Containment

BASES

BACKGROUND	The function of the secondary containment is to contain, dilute, and hold up fission products that may leak from primary containment or are released outside of primary containment following postulated Design Basis Accidents (DBAs). The two DBAs are a Loss of Coolant Accident (LOCA) and a Fuel Handling Accident (FHA) involving recently irradiated fuel within secondary containment (Refs.1 and 2). In conjunction with operation of the Standby Gas Treatment (SGT) System and closure of certain valves whose lines penetrate the secondary containment, the secondary containment is designed to reduce the activity level of the fission products prior to release to the environment and to isolate and contain fission products that are released during certain operations that take place inside primary containment, when primary containment is not required to be OPERABLE, or that take place outside primary containment. The secondary containment is a structure that completely encloses the primary containment. This structure forms a control volume that serves to hold up and dilute the fission products. It is possible for the pressure in the control volume to rise relative to the environmental pressure (e.g., due to pump and motor heat load additions). To prevent ground level exfiltration while allowing the secondary containment to be designed as a conventional structure, the secondary containment requires support systems to maintain the control volume pressure at less than the external pressure. Requirements for these systems are specified separately in LCO 3.6.4.2, "Secondary Containment Isolation Valves (SCIVs)," and LCO 3.6.4.3, "Standby Gas Treatment (SGT) System."
APPLICABLE SAFETY ANALYSES	There are two principal accidents for which credit is taken for secondary containment OPERABILITY. These are a loss of coolant accident (LOCA) (Ref. 1) and a fuel handling accident involving handling recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 24 hours) inside secondary containment (Ref. 2). The secondary containment performs no active function in response to each of these limiting events; however, its leak tightness is required to ensure that the release of radioactive materials from the primary containment is restricted to those leakage paths and associated leakage rates assumed in the accident analysis and that fission products entrapped within the secondary containment structure will be treated by the SGT System prior to discharge to the environment. Secondary containment satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO	An OPERABLE secondary containment provides a control volume into which fission products that bypass or leak from primary containment, or are released from the reactor coolant pressure boundary components located in secondary containment, can be diluted and processed prior to release to the environment. For the secondary containment to be considered OPERABLE, it must have adequate leak tightness to ensure that the required vacuum can be established and maintained.
APPLICABILITY	In MODES 1, 2, and 3, a LOCA could lead to a fission product release to primary containment that leaks to secondary containment. Therefore, secondary containment OPERABILITY is required during the same operating conditions that require primary containment OPERABILITY. In MODES 4 and 5, the probability and consequences of the LOCA are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining secondary containment OPERABLE is not required in MODE 4 or 5 to ensure a control volume, except for other situations for which significant releases of radioactive material can be postulated, such as during operations with a potential for draining the reactor vessel (OPDRVs) or during movement of recently irradiated fuel assemblies in the secondary containment. Due to radioactive decay, secondary containment is only required to be OPERABLE during fuel handling involving handling 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 and B.2 If secondary containment cannot be restored to OPERABLE status within the required Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

BASES

ACTIONS (continued)

C.1 and C.2

Movement of recently irradiated fuel assemblies in the secondary containment and OPDRVs can be postulated to cause significant fission product release to the secondary containment. In such cases, the secondary containment is the only barrier to release of fission products to the environment. Therefore, movement of recently irradiated fuel assemblies must be immediately suspended if the secondary containment is inoperable.

Suspension of these activities shall not preclude completing an action that involves moving a component to a safe position. Also, action must be immediately initiated to suspend OPDRVs to minimize the probability of a vessel draindown and subsequent potential for fission product release. Actions must continue until OPDRVs are suspended.

Required Action C.1 has been modified by a Note stating that LCO 3.0.3 is not applicable. If moving 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.

SURVEILLANCE REQUIREMENTS

SR 3.6.4.1.1

This SR ensures that the secondary containment boundary is sufficiently leak tight to preclude exfiltration under expected wind conditions. The 24 hour Frequency of this SR was developed based on operating experience related to secondary containment vacuum variations during the applicable MODES and the low probability of a DBA occurring.

Furthermore, the 24 hour Frequency is considered adequate in view of other indications available in the control room, including alarms, to alert the operator to an abnormal secondary containment vacuum condition.

SR 3.6.4.1.2 and SR 3.6.4.1.3

Verifying that secondary containment equipment hatches and one access door in each access opening are closed ensures that the infiltration of outside air of such a magnitude as to prevent maintaining the desired negative pressure does not occur. Verifying that all such openings are closed provides adequate assurance that exfiltration from the secondary

BASES

SURVEILLANCE REQUIREMENTS (continued)

containment will not occur. In this application, the term "sealed" has no connotation of leak tightness. Maintaining secondary containment OPERABILITY requires verifying one door in the access opening is closed. An access opening contains one inner and one outer door. In some cases, secondary containment access openings are shared such that a secondary containment barrier may have multiple inner or multiple outer doors. The intent is to not breach the secondary containment at any time when secondary containment is required. This is achieved by maintaining the inner or outer portion of the barrier closed at all times. However, all secondary containment access doors are normally kept closed, except when the access opening is being used for entry and exit or when maintenance is being performed on an access opening. The 31 day Frequency for these SRs has been shown to be adequate, based on operating experience, and is considered adequate in view of the other indications of door and hatch status that are available to the operator.

<u>SR 3.6.4.1.4</u>

The SGT System exhausts the secondary containment atmosphere to the environment through appropriate treatment equipment. To ensure that all fission products released to the secondary containment are treated, SR 3.6.4.1.4 verifies that a pressure in the secondary containment that is less than the lowest postulated pressure external to the secondary containment boundary can be maintained. When the SGT System is operating as designed, the maintenance of secondary containment pressure cannot be accomplished if the secondary containment boundary is not intact. SR 3.6.4.1.4 demonstrates that the pressure in the secondary containment can be maintained ≥ 0.25 inches of vacuum water gauge for 1 hour using one SGT subsystem at a flow rate ≤ 4000 cfm. The 1 hour test period allows secondary containment to be in thermal equilibrium at steady state conditions. The primary purpose of this SR is to ensure secondary containment boundary integrity. The test is normally performed under calm wind (< 5 mph) conditions. If calm wind conditions do not exist during this testing, the test data is to be corrected to calm wind conditions. The secondary purpose of this SR is to ensure that the SGT subsystem being tested functions as designed. There is a separate LCO with Surveillance Requirements which serves the primary purpose of ensuring OPERABILITY of the SGT System. This SR need not be performed with each SGT subsystem. The SGT subsystem used for this Surveillance 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

BASES

SURVEILLANCE REQUIREMENTS (continued)

of this Surveillance relative to the secondary containment OPERABILITY. Operating experience has shown the secondary containment boundary usually passes this Surveillance when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. USAR, Section 14.7.2.
2. USAR, Section 14.7.6.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.4.2 Secondary Containment Isolation Valves (SCIVs)

BASES

BACKGROUND

The function of the SCIVs, in combination with other accident mitigation systems, is to limit fission product release during and following postulated Design Basis Accidents (DBAs). The two DBAs are a Loss of Coolant Accident (LOCA) and a Fuel Handling Accident (FHA) involving recently irradiated fuel within secondary containment (Refs. 1 and 2). Secondary containment isolation within the time limits specified for those isolation valves designed to close automatically ensures that fission products that leak from primary containment following a DBA, or that are released during certain operations when primary containment is not required to be OPERABLE or take place outside primary containment, are maintained within the secondary containment boundary.

The OPERABILITY requirements for SCIVs help ensure that an adequate secondary containment boundary is maintained during and after an accident by minimizing potential paths to the environment. These isolation devices consist of either passive devices or active (automatic) devices. Manual valves, de-activated automatic valves secured in their closed position (including check valves with flow through the valve secured), and blind flanges (which include plugs and caps as listed in Reference 3) are considered passive devices.

Automatic SCIVs (i.e., dampers) close on a secondary containment isolation signal to establish a boundary for untreated radioactive material within secondary containment following a DBA or other accidents.

Other penetrations required to be closed during accident conditions are isolated by the use of valves in the closed position or blind flanges.

APPLICABLE SAFETY ANALYSES

The SCIVs must be OPERABLE to ensure the secondary containment barrier to fission product releases is established. The principal accidents for which the secondary containment boundary is required are a loss of coolant accident (Ref. 1) and a fuel handling accident involving handling recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 24 hours) (Ref. 2). The secondary containment performs no active function in response to either of these limiting events, but the boundary established by SCIVs is required to ensure that leakage from the primary containment or fission products released outside of primary containment are processed by the Standby Gas Treatment (SGT) System before being released to the environment.

Maintaining SCIVs OPERABLE with isolation times within limits ensures that fission products will remain trapped inside secondary containment so

BASES

APPLICABLE SAFETY ANALYSES (continued)	that they can be treated by the SGT System prior to discharge to the environment. SCIVs satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	SCIVs form a part of the secondary containment boundary. The SCIV safety function is related to control of offsite radiation releases resulting from DBAs. The power operated, automatic isolation valves are considered OPERABLE when their isolation times are within limits and the valves actuate on an automatic isolation signal. The valves covered by this LCO, along with their associated stroke times, are listed in Reference 3. The normally closed manual SCIVs are considered OPERABLE when the valves are closed and blind flanges in place, or open under administrative controls. These passive isolation valves or devices are listed in Reference 3.
APPLICABILITY	In MODES 1, 2, and 3, a DBA could lead to a fission product release to the primary containment that leaks to the secondary containment. Therefore, the OPERABILITY of SCIVs is required. In MODES 4 and 5, the probability and consequences of these events are reduced due to pressure and temperature limitations in these MODES. Therefore, maintaining SCIVs OPERABLE is not required in MODE 4 or 5, except for other situations under which significant radioactive releases 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 secondary containment. Moving recently irradiated fuel assemblies in the secondary containment may also occur in MODES 1, 2, and 3. Due to radioactive decay, SCIVs are only required to be OPERABLE during fuel handling involving handling recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 24 hours).
ACTIONS	The ACTIONS are modified by three Notes. The first Note allows penetration flow paths to be unisolated intermittently under administrative controls. These controls consist of stationing a dedicated individual, who is in continuous communication with the control room, at the controls of the isolation device. In this way, the penetration can be rapidly isolated when a need for secondary containment isolation is indicated. The second Note provides clarification that, for the purpose of this LCO, separate Condition entry is allowed for each penetration flow path. This is acceptable, since the Required Actions for each Condition provide

BASES

ACTIONS (continued)

appropriate compensatory actions for each inoperable SCIV. Complying with the Required Actions may allow for continued operation, and subsequent inoperable SCIVs are governed by subsequent Condition entry and application of associated Required Actions.

The third Note ensures appropriate remedial actions are taken, if necessary, if the affected system(s) are rendered inoperable by an inoperable SCIV.

A.1 and A.2

In the event that there are one or more penetration flow paths with one SCIV inoperable, the affected penetration flow path(s) must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic SCIV, a closed manual valve, and a blind flange. For penetrations isolated in accordance with Required Action A.1, the device used to isolate the penetration should be the closest available device to secondary containment. The Required Action must be completed within the 8 hour Completion Time. The specified time period is reasonable considering the time required to isolate the penetration, and the probability of a DBA, which requires the SCIVs to close, occurring during this short time is very low.

For affected penetrations that have been isolated in accordance with Required Action A.1, the affected penetration must be verified to be isolated on a periodic basis. This is necessary to ensure that secondary containment penetrations required to be isolated following an accident, but no longer capable of being automatically isolated, will be in the isolation position should an event occur. The Completion Time of once per 31 days is appropriate because the isolation devices are operated under administrative controls and the probability of their misalignment is low. This Required Action does not require any testing or device manipulation. Rather, it involves verification that the affected penetration remains isolated.

Required Action A.2 is modified by two Notes. Note 1 applies to isolation devices located in high radiation areas and allows them to be verified closed by use of administrative controls. Allowing verification by administrative controls is considered acceptable, since access to these areas is typically restricted. Note 2 applies to isolation devices that are locked, sealed, or otherwise secured in position and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since the function of

BASES

ACTIONS (continued)

locking, sealing, or securing components is to ensure that these devices are not inadvertently repositioned. Therefore, the probability of misalignment, once they have been verified to be in the proper position, is low.

B.1

With two SCIVs in one or more penetration flow paths inoperable, the affected penetration flow path must be isolated within 4 hours. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, and a blind flange. The 4 hour Completion Time is reasonable considering the time required to isolate the penetration and the probability of a DBA, which requires the SCIVs to close, occurring during this short time, is very low.

The Condition has been modified by a Note stating that Condition B is only applicable to penetration flow paths with two isolation valves. This clarifies that only Condition A is entered if one SCIV is inoperable in each of two penetrations.

C.1 and C.2

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

D.1 and D.2

If any Required Action and associated Completion Time are not met, the plant must be placed in a condition in which the LCO does not apply. If applicable, the movement of recently irradiated fuel assemblies in the secondary containment must be immediately suspended. Suspension of these activities shall not preclude completion of movement of a component to a safe position. Also, if applicable, actions must be immediately initiated to suspend OPDRVs in order to minimize the probability of a vessel draindown and the subsequent potential for fission product release. Actions must continue until OPDRVs are suspended.

BASES

ACTIONS (continued)

Required Action D.1 has 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 fuel while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, in either case, inability to suspend movement of recently irradiated fuel assemblies would not be a sufficient reason to require a reactor shutdown.

SURVEILLANCE REQUIREMENTS

SR 3.6.4.2.1

This SR verifies that each secondary containment manual isolation valve and blind flange that is not locked, sealed, or otherwise secured and is required to be closed during accident conditions is closed. The SR helps to ensure that post accident leakage of radioactive fluids or gases outside of the secondary containment boundary is within design limits. This SR does not require any testing or valve manipulation. Rather, it involves verification that those SCIVs in secondary containment that are capable of being mispositioned are in the correct position.

Since these SCIVs are readily accessible to personnel during normal operation and verification of their position is relatively easy, the 31 day Frequency was chosen to provide added assurance that the SCIVs are in the correct positions. This SR does not apply to valves that are locked, sealed, or otherwise secured in the closed position, since these were verified to be in the correct position upon locking, sealing, or securing.

Two Notes have been added to this SR. The first Note applies to valves and blind flanges located in high radiation areas and allows them to be verified by use of administrative controls. Allowing verification by administrative controls is considered acceptable, since access to these areas is typically restricted during MODES 1, 2, and 3 for ALARA reasons. Therefore, the probability of misalignment of these SCIVs, once they have been verified to be in the proper position, is low.

A second Note has been included to clarify that SCIVs that are open under administrative controls are not required to meet the SR during the time the SCIVs are open.

SR 3.6.4.2.2

Verifying that the isolation time of each power operated, automatic SCIV is within limits is required to demonstrate OPERABILITY. The isolation time test ensures that the SCIV will isolate in a time period less than or equal to that assumed in the safety analyses. The Frequency of this SR is 92 days.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.6.4.2.3

Verifying that each automatic SCIV closes on a secondary containment isolation signal is required to prevent leakage of radioactive material from secondary containment following a DBA or other accidents. This SR ensures that each automatic SCIV will actuate to the isolation position on a secondary containment isolation signal. The LOGIC SYSTEM FUNCTIONAL TEST in LCO 3.3.6.2, "Secondary Containment Isolation Instrumentation," overlaps this SR to provide complete testing of the safety function. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a plant outage and the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown these components usually pass the Surveillance when performed at the 24 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

REFERENCES

1. USAR, Section 14.7.2.
2. USAR, Section 14.7.6.
3. Technical Requirements Manual.

B 3.6 CONTAINMENT SYSTEMS

B 3.6.4.3 Standby Gas Treatment (SGT) System

BASES

BACKGROUND

The SGT System is required by USAR, Section 1.2.4.e (Ref. 1). The function of the SGT System is to ensure that radioactive materials that leak from the primary containment or are released outside of primary containment into the secondary containment following postulated Design Basis Accidents (DBAs) are filtered and adsorbed prior to exhausting to the environment. The two DBAs are a Loss of Coolant Accident (LOCA) and a Fuel Handling Accident (FHA) involving recently irradiated fuel within secondary containment (Refs. 3 and 4).

The SGT System consists of two fully redundant subsystems, each with its own set of ductwork, dampers, charcoal filter train, and controls.

Each charcoal filter train consists of (components listed in order of the direction of the air flow):

a. A demister;

b. An electric heater (not required for subsystem OPERABILITY);

c. A high efficiency particulate air (HEPA) filter;

d. A charcoal adsorber;

e. A second HEPA filter; and

f. A centrifugal fan.

The sizing of the SGT System equipment and components is based on the results of an infiltration analysis, as well as an exfiltration analysis of the secondary containment. Exfiltration from the secondary containment does not exceed 4,000 cfm with wind speeds on the order of 40 mph, from a start condition of negative internal pressure of 0.25 inches water gauge under calm wind conditions.

The demister is provided to remove entrained water in the air, while the electric heater reduces the relative humidity of the airstream to less than 70% (Ref. 2). The heater function was determined to not be required for iodine removal efficiency since the charcoal is tested at 95% relative humidity (Ref. 5). The HEPA filter removes fine particulate matter and protects the charcoal from fouling. The charcoal adsorber removes gaseous elemental iodine and organic iodides, and the final HEPA filter collects any carbon fines exhausted from the charcoal adsorber.

BASES

BACKGROUND (continued)

The SGT System automatically starts and operates in response to actuation signals indicative of conditions or an accident that could require operation of the system. The SGT System is initiated by Reactor Vessel Water Level - Low Low, Drywell Pressure - High, Reactor Building Ventilation Exhaust Radiation - High, and Refueling Floor Radiation - High signals. Following initiation, the SGT subsystem A starts and both the inlet and outlet dampers of the reactor building ventilation ducts are isolated. A failure of the SGT subsystem A to start within the required time delay will initiate the automatic start and alignment of SGT subsystem B. Automatic valves provide for isolation of each SGT subsystem. Each subsystem can draw air to remove radioactive decay heat from the charcoal adsorber.

APPLICABLE SAFETY ANALYSES

The design basis for the SGT System is to mitigate the consequences of a loss of coolant accident and fuel handling accidents involving handling recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 24 hours) (Refs. 3 and 4). For all events analyzed, the SGT System is shown to be automatically initiated to reduce, via filtration and adsorption, the radioactive material released to the environment.

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

LCO

Following a DBA, a minimum of one SGT subsystem is required to maintain the secondary containment at a negative pressure with respect to the environment and to process gaseous releases. Meeting the LCO requirements for two OPERABLE subsystems ensures operation of at least one SGT subsystem in the event of a single active failure.

APPLICABILITY

In MODES 1, 2, and 3, a DBA could lead to a fission product release to primary containment that leaks to secondary containment. Therefore, SGT System OPERABILITY is required during these MODES.

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

BASES

ACTIONS

A.1

With one SGT subsystem inoperable, the inoperable subsystem must be restored to OPERABLE status in 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 System and the low probability of a DBA occurring during this period.

B.1 and B.2

If the SGT subsystem cannot be restored to OPERABLE status within the required Completion Time in MODE 1, 2, or 3, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

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

During movement of recently irradiated fuel assemblies, in the secondary containment or during OPDRVs, when Required Action A.1 cannot be completed within the required Completion Time, the OPERABLE SGT subsystem should immediately be placed in operation. This action ensures that the remaining subsystem is OPERABLE, that no failures that could prevent automatic actuation will occur, and that any other failure would be readily detected.

An alternative to Required Action C.1 is to immediately suspend activities that represent a potential for releasing a significant amount of radioactive material to the secondary containment, thus placing the plant in a condition that minimizes risk. If applicable, movement of recently irradiated fuel assemblies must immediately be suspended. Suspension of these activities must not preclude completion of movement of a component to a safe position. Also, if applicable, actions must immediately be initiated to suspend OPDRVs in order to minimize the probability of a vessel draindown and subsequent potential for fission product release. Actions must continue until OPDRVs are suspended.

BASES

ACTIONS (continued)

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 SGTS subsystems are inoperable in MODE 1, 2, or 3, the SGT system may not be capable of supporting the required radioactivity release control function. Therefore, actions are required to enter LCO 3.0.3 immediately.

E.1 and E.2

When two SGT subsystems are inoperable, if applicable, movement of recently irradiated fuel assemblies in secondary containment must immediately be suspended. Suspension of these activities shall not preclude completion of movement of a component to a safe position. Also, if applicable, action must immediately be initiated to suspend OPDRVs in order to minimize the probability of a vessel draindown and subsequent potential for fission product release. Actions must continue until OPDRVs are suspended.

Required Action E.1 has 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.

SURVEILLANCE REQUIREMENTS

SR 3.6.4.3.1

Operating each SGT subsystem for ≥ 15 continuous minutes (Ref. 5) 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.

BASES

SURVEILLANCE REQUIREMENTS (continued)

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). Specific test frequencies and additional information are discussed in detail in the VFTP.

SR 3.6.4.3.3

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

REFERENCES

1. USAR, Section 1.2.4.e.
2. USAR, Section 5.3.
3. USAR, Section 14.7.2.
4. USAR, Section 14.7.6.
5. Amendment No. 181, Monticello Nuclear Generating Plant – Issuance of Amendment to Adopt TSTF Traveler TSTF-522, Revision 0, “Revise Ventilation System Surveillance Requirements to Operate for 10 Hours per Month,” dated May 2, 2014. (ADAMS Accession No. ML14058A825)

B 3.7 PLANT SYSTEMS

B 3.7.1 Residual Heat Removal Service Water (RHRSW) System

BASES

BACKGROUND

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

The RHRSW System consists of two independent and redundant subsystems. Each subsystem is made up of a header, two 3500 gpm pumps, a suction source, valves, piping, heat exchanger, and associated instrumentation. Either of the two subsystems is capable of providing the required cooling capacity with one pump operating to maintain safe shutdown conditions. The two subsystems are separated from each other by a normally closed manual 1 inch cross tie valve, so that failure of one subsystem will not affect the OPERABILITY of the other subsystem. This 1 inch cross tie line is installed between the two subsystems to allow both subsystems to be pressurized by one operating RHRSW pump. The RHRSW System is designed with sufficient redundancy so that no single active component failure can prevent it from achieving its design function. The RHRSW System is described in the USAR, Section 10.4.2, Reference 1.

Cooling water is pumped by the RHRSW pumps from the Mississippi River through the tube side of the RHR heat exchangers, and discharges to the reactor building service water discharge line, which discharges to the circulating water discharge line.

The system is initiated manually from the control room. If operating during a loss of coolant accident (LOCA), the system is automatically tripped to allow the emergency diesel generators to automatically power only that equipment necessary to reflood the core. The system can be manually started any time the LOCA signal is manually overridden or clears.

APPLICABLE SAFETY ANALYSES

The RHRSW System removes heat from the suppression pool to limit the suppression pool temperature and primary containment pressure following a LOCA. This ensures that the primary containment can perform its function of limiting the release of radioactive materials to the environment following a LOCA. The ability of the RHRSW System to support long term cooling of the reactor or primary containment is

BASES

APPLICABLE SAFETY ANALYSES (continued)

discussed in the USAR, Section 5.2.3 (Ref. 2). This analysis explicitly assumes that the RHRSW System will provide adequate cooling support to the equipment required for safe shutdown. This analysis includes the evaluation of the long term primary containment response after a design basis LOCA.

The safety analysis for long term cooling was performed for various combinations of RHR System failures. The worst case single failure that would affect the performance of the RHRSW System is any failure that would disable one subsystem of the RHRSW System. As discussed in the USAR, Section 5.2.3 (Ref. 2), for this analysis, manual initiation of the OPERABLE RHRSW subsystem and the associated RHR System is assumed to occur 10 minutes after a DBA. The RHRSW flow assumed in the analysis is 3500 gpm with one pump operating in one loop. In this case, the maximum suppression chamber water temperature is 203°F (using variable K-Value for RHR heat exchanger capacity), this is below the torus attached piping design limit of 212°F (Refs. 3 and 4).

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

LCO

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

An RHRSW subsystem is considered OPERABLE when:

a. One pump is OPERABLE; and

b. An OPERABLE flow path is capable of taking suction from the intake structure and transferring the water to the RHR heat exchangers at the assumed flow rate. Opening the RHRSW cross tie valve (which allows the two RHRSW loops to be connected) renders the operating system inoperable. Instrument uncertainty and potential flow diversion may prevent the assumed RHRSW flow rate from reaching the RHR heat exchanger while maintaining the RHRSW System pressure at the heat exchanger greater than the RHR System pressure.

An adequate suction source is not addressed in this LCO since the minimum net positive suction head (899 ft mean sea level in the service water basin) is bounded by the emergency service water pump requirements (LCO 3.7.2, "Emergency Service Water (ESW) System and Ultimate Heat Sink (UHS)").

BASES

APPLICABILITY

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

Although the LCO for the RHRSW System is not applicable In MODES 4 and 5, the capability of the RHRSW System to perform its necessary related support functions may be required for OPERABILITY of the supported systems.

ACTIONS

A.1

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

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

B.1

With both RHRSW subsystems inoperable, the RHRSW System is not capable of performing its intended function. At least one subsystem must be restored to OPERABLE status within 8 hours. The 8 hour Completion Time for restoring one RHRSW subsystem to OPERABLE status, is based on the Completion Times provided for the RHR suppression pool cooling function.

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

BASES

ACTIONS (continued)

C.1 and C.2

If the RHRSW subsystems cannot be not restored to OPERABLE status within the associated Completion Times, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 12 hours and in MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.1.1

Verifying the correct alignment for each manual, power operated, and automatic valve in each RHRSW subsystem flow path provides assurance that the proper flow paths will exist for RHRSW operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position, since these valves are verified to be in the correct position prior to locking, sealing, or securing. A valve is also allowed to be in the nonaccident position, and yet considered in the correct position, provided it can be realigned to its accident position. This is acceptable because the RHRSW System is a manually initiated system. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves.

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

REFERENCES

1. USAR, Section 10.4.2.
2. USAR, Section 5.2.3.
3. Calculation 11-173, MNGP EPU Task Report T0400, Revision 3, “Containment System Response”
4. Amendment No. 176, “Monticello Nuclear Generating Plant – Issuance of Amendment No. 176 to Renewed Facility Operating License Regarding Extended Power Uprate,” (ADAMS Accession No. ML13316C459)

B 3.7 PLANT SYSTEMS

B 3.7.2 Emergency Service Water (ESW) System and Ultimate Heat Sink (UHS)

BASES

BACKGROUND

The ESW System is designed to provide cooling water for the removal of heat from equipment, such as the core spray (CS) pump coolers, residual heat removal (RHR) pump coolers, and room coolers for Emergency Core Cooling System equipment, required for a safe reactor shutdown following a Design Basis Accident (DBA) or transient. The ESW System also provides cooling to the condensers of the control room air conditioning units upon a loss of offsite power. Upon receipt of an emergency diesel generator (EDG) breaker closure or a 4.16 kV essential bus transfer to the alternate offsite power source, one ESW pump is automatically started in each division.

The ESW System consists of the UHS and two independent and redundant subsystems. Each of the two ESW subsystems is made up of a header, one 200 gpm pump, a suction source, valves, piping and associated instrumentation. Either of the two subsystems is capable of providing the required cooling capacity to support the systems assumed in the safety analysis. The two subsystems are separated from each other so failure of one subsystem will not affect the OPERABILITY of the other system.

Cooling water is pumped from the Mississippi River by the ESW pumps to the essential components through the two main headers. After removing heat from the components, the water is discharged through the service water discharge line, which discharges to the circulating water discharge line.

APPLICABLE SAFETY ANALYSES

Sufficient water inventory is available for all ESW System post LOCA cooling requirements for a 30 day period with no additional makeup water source available. The ability of the ESW System to support long term cooling of the reactor containment is assumed in evaluations of the equipment required for safe reactor shutdown presented in the USAR, Section 5.2.3 (Ref. 1). This analysis includes the evaluation of the long term primary containment response after a design basis LOCA.

The ability of the ESW System to provide adequate cooling to the identified safety equipment is an implicit assumption for the safety analysis evaluated in Reference 1. The long term cooling capability of the RHR and core spray pumps is dependent on the cooling provided by the ESW System.

The ESW System, together with the UHS, satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

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

A subsystem is considered OPERABLE when it has an OPERABLE UHS, one OPERABLE pump, and an OPERABLE flow path capable of taking suction from the intake structure and transferring the water to the appropriate equipment.

The OPERABILITY of the UHS is based on having a minimum water level in the pump well of the intake structure of 899 ft mean sea level and a maximum water temperature of 90°F.

The isolation of the ESW System to components or systems may render those components or systems inoperable, but does not affect the OPERABILITY of the ESW System. The core spray pump motors do not require emergency service water flow through the motor cooler for the core spray pump to remain OPERABLE. However, cooling water flow shall be restored to extend the motor thrust bearing's oil life (Ref. 2). Cooling water flow should be restored at the next available opportunity.

APPLICABILITY

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

Although the LCO for the ESW System and UHS is not applicable in MODES 4 and 5, the capability of the ESW System and UHS to perform their necessary related support functions may be required for OPERABILITY of the supported systems.

ACTIONS

A.1

With one ESW subsystem inoperable, the ESW subsystem must be restored to OPERABLE status within 72 hours. With the unit in this condition, the remaining OPERABLE ESW subsystem is adequate to perform the heat removal function. However, the overall reliability is reduced because a single failure in the OPERABLE ESW subsystem could result in loss of ESW function.

The 72 hour Completion Time is based on the redundant ESW System capabilities afforded by the OPERABLE subsystem and the low probability of an accident occurring during this time period.

BASES

ACTIONS (continued)

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

B.1 and B.2

If the ESW subsystem cannot be restored to OPERABLE status within the associated Completion Time, or both ESW subsystems are inoperable, or the UHS is determined inoperable, the unit must be placed in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 12 hours and in MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.2.1

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

SR 3.7.2.2

Verification of the UHS temperature ensures that the heat removal capability of the ESW System is within the assumptions of the DBA analysis. The 24 hour Frequency is based on operating experience related to trending of the parameter variations during the applicable MODES.

SR 3.7.2.3

Verifying the correct alignment for each manual and automatic valve in each ESW subsystem flow path provides assurance that the proper flow paths will exist for ESW 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. This SR does not require any testing or valve manipulation;

BASES

SURVEILLANCE REQUIREMENTS (continued)

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.

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

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

SR 3.7.2.4

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

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

REFERENCES

1. USAR, Section 5.2.3.
2. Calculation 96-106, CSP Motor – Oil and Bearing Operating Temperatures Without Water Cooling.

B 3.7 PLANT SYSTEMS

B 3.7.3 Emergency Diesel Generator-Emergency Service Water (EDG-ESW) System

BASES

BACKGROUND	The EDG-ESW System is designed to provide cooling water for the removal of heat from the EDGs. The EDGs are the only components served by the EDG-ESW System. The EDG-ESW pumps autostart upon receipt of an associated EDG start signal when power is available to the pump's electrical bus. Cooling water is pumped from the Mississippi River by the EDG-ESW pumps to the essential EDG components through the EDG-ESW supply header. After removing heat from the components, the water is discharged to the unit storm drains. In the event the EDG-ESW pumps do not start, the capability exists to manually cross connect the Service Water System to supply essential EDG components. However, the Service Water System capability is not required to be OPERABLE as part of this Specification. A complete description of the EDG-ESW System is presented in the USAR, Section 10.4.4 (Ref. 1).
APPLICABLE SAFETY ANALYSES	The ability of the EDG-ESW System to provide adequate cooling to the EDGs is an implicit assumption for the safety analyses presented in the USAR, Section 14.7.2.3.1.1 (Ref. 2). The ability to provide onsite emergency AC power is dependent on the ability of the EDG-ESW System to cool the EDGs. The EDG-ESW System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	The EDG-ESW subsystems are independent of each other to the degree that each has separate controls, power supplies, and the operation of one subsystem does not depend on the other subsystem. In the event of a DBA, one EDG-ESW subsystem is required to provide the minimum heat removal capability assumed in the safety analysis for the associated EDG. To ensure this requirement is met, two EDG-ESW subsystems must be OPERABLE. At least one subsystem will operate, if the worst single active failure occurs coincident with the loss of offsite power. A subsystem is considered OPERABLE when it has an OPERABLE pump and an OPERABLE flow path capable of taking suction from the intake structure and transferring the water to the associated EDG.

BASES

LCO (continued)

An adequate suction source is not addressed in this LCO since the minimum net positive suction head of the EDG-ESW pumps is bounded by the ESW requirements (LCO 3.7.2, "Emergency Service Water ESW) System and Ultimate Heat Sink (UHS)").

APPLICABILITY

In MODES 1, 2, and 3, the EDG-ESW System is required to be OPERABLE to support OPERABILITY of the EDGs. Therefore, the EDG-ESW System is required to be OPERABLE in these MODES.

In MODES 4 and 5, the OPERABILITY requirements of the EDG-ESW System are determined by the systems it supports. Therefore, the requirements are not the same for all facets of operation in MODES 4 and 5. LCO 3.8.2, "AC Sources - Shutdown," will govern EDG-ESW System OPERABILITY requirements in MODES 4 and 5.

ACTIONS

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

A.1

With one or more EDG-ESW subsystems inoperable, the associated EDG cannot perform its intended function and must be immediately declared inoperable. In accordance with LCO 3.0.6, this also requires entering the applicable Conditions and Required Actions of LCO 3.8.1, "AC Sources - Operating."

SURVEILLANCE REQUIREMENTS

SR 3.7.3.1

Verifying the correct alignment for manual valves in each EDG-ESW subsystem flow path provides assurance that the proper flow paths will exist for EDG-ESW System operation. This SR does not apply to valves that are locked, sealed, or otherwise secured in position since these valves were verified to be in the correct position prior to locking, sealing, or securing. This SR does not require any testing or valve manipulation;

BASES

SURVEILLANCE REQUIREMENTS (continued)

rather, it involves verification that those valves capable of being mispositioned are in the correct position. This SR does not apply to valves that cannot be inadvertently misaligned, such as check valves.

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

SR 3.7.3.2

This SR ensures that each EDG-ESW subsystem pump will automatically start to provide required cooling to the associated EDG when the associated EDG starts and the respective bus is energized.

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

REFERENCES

1. USAR, Section 10.4.4.

2. USAR, Section 14.7.2.3.1.1.

B 3.7 PLANT SYSTEMS

B 3.7.4 Control Room Emergency Filtration (CREF) System

BASES

BACKGROUND

The CREF System provides a protected environment from which occupants can control the unit following an uncontrolled release of radioactivity, hazardous chemicals, or smoke.

The safety related function of the CREF System includes two independent and redundant high efficiency air filtration subsystems for emergency treatment of outside supply air and a Control Room envelope (CRE) boundary that limits the in-leakage of unfiltered air. Each CREF subsystem consists of a low efficiency filter, an electric heater, a high efficiency particulate air (HEPA) filter, two activated charcoal adsorber sections, a second HEPA filter, an emergency filter fan, an air handling unit (excluding the condensing unit), an exhaust/recirculation fan, and the associated ductwork, valves or dampers, doors, barriers, and instrumentation. Low efficiency filters and HEPA filters remove particulate matter, which may be radioactive. The charcoal adsorbers provide a holdup period for gaseous iodine, allowing time for decay.

The CRE is the area within the confines of the CRE boundary that contains the spaces that control room occupants inhabit to control the unit during normal and accident conditions. This area encompasses the control room, and may encompass other non-critical areas to which frequent personnel access or continuous occupancy is not necessary in the event of an accident. The CRE is protected during normal operation, natural events, and accident conditions. The CRE boundary is the combination of walls, floor, roof, ducting, doors, penetrations and equipment that physically form the CRE. The OPERABILITY of the CRE boundary must be maintained to ensure that the in-leakage of unfiltered air into the CRE will not exceed the in-leakage assumed in the licensing basis analysis of design basis accident (DBA) consequences to CRE occupants. The two DBAs are a Loss of Coolant Accident (LOCA) and a Fuel Handling Accident (FHA) involving recently irradiated fuel within secondary containment (Refs. 1 and 7). The CRE and its boundary are defined in the Control Room Envelope Habitability Program, which was added under Amendment 160 (Ref. 5).

The CREF System is a standby system, parts of which also operate during normal unit operations to maintain the CRE environment. Upon receipt of a Reactor Vessel Water Level – Low Low, Drywell Pressure – High, Refueling Floor Radiation – High or Reactor Building Ventilation Exhaust Radiation – High initiation signal the CREF System automatically switches to the pressurization mode of operation to minimize infiltration of contaminated air into the CRE (the main control room and portions of the first and second floors of the Emergency Filtration Train (EFT) building).

BASES

BACKGROUND (continued)

A system of dampers isolates the CRE from untreated outside air. Outside air is taken in at the normal ventilation intake and is passed through one of the charcoal adsorber filter subsystems for removal of airborne radioactive particles. This air is then combined with return air from the CRE and passed through an exhaust/recirculation fan, which is then passed through the air handling unit into the CRE.

The CREF System is designed to maintain the CRE environment for a 30 day continuous occupancy after a DBA without exceeding 5 rem TEDE. A single CREF subsystem operating at a flowrate of ≤ 1100 cfm will pressurize the CRE relative to external areas adjacent to the CRE boundary to minimize infiltration of air from all surrounding areas adjacent to the CRE boundary. CREF System operation in maintaining CRE habitability is discussed in the USAR, Section 14.7.2 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The ability of the CREF System to maintain the habitability of the CRE is an explicit assumption for the LOCA analysis presented in the USAR, Section 14.7.2 (Ref. 1). The pressurization mode of the CREF System is assumed to operate following a DBA. No single active failure will prevent the CREF System from performing its safety function.

The safety analysis for the FHA assumes the reactor has been subcritical for at least 24 hours prior to fuel movement. The CREF System is needed to ensure the control room operator dose is within 10 CFR 50.67 limits during movement of recently irradiated fuel within secondary containment (i.e., fuel that has occupied part of a critical reactor core within the previous 24 hours) (Ref. 7).

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

LCO

Two redundant subsystems of the CREF System are required to be OPERABLE to ensure that at least one is available, if a single active failure disables the other subsystem. Total CREF System failure could result in exceeding a dose of 5 rem TEDE to the CRE occupants in the event of a DBA.

Each CREF subsystem is considered OPERABLE when the individual components necessary to limit CRE occupant exposure are OPERABLE. A subsystem is considered OPERABLE when its associated:

a. Emergency filter fan (V-ERF-11 or 12), exhaust/recirculation fan (V-ERF-14A or B), and air handling unit (V-EAC-14A or B) (excluding the condenser unit) are OPERABLE;

BASES

LCO (continued)

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

Note: The in-line heater remains In the system, but the heater function requirement was removed by Amendment 181.

c. Ductwork and dampers are OPERABLE, and air circulation can be maintained.

In order for the CREF subsystems to be considered OPERABLE, the CRE boundary must be maintained such that the CRE occupant dose from a large radioactive release does not exceed the calculated dose in the licensing basis consequence analyses for DBAs, and that CRE occupants are protected from hazardous chemicals and smoke.

The LCO is modified by a Note allowing the CRE boundary to be opened intermittently under administrative controls. This Note only applies to openings in the CRE boundary that can be rapidly restored to the design condition, such as doors, hatches, floor plugs, and access panels. For entry and exit through doors, the administrative control of the opening is performed by the person(s) entering or exiting the area. For other openings, these controls should be proceduralized and consist of stationing a dedicated individual at the opening who is in continuous communication with the operators in the CRE. This individual will have a method to rapidly close the opening and to restore the CRE boundary to a condition equivalent to the design condition when a need for main control room envelope isolation is indicated.

APPLICABILITY

In MODES 1, 2, and 3, the CREF System must be OPERABLE to ensure that the CRE will remain habitable during and following a DBA LOCA, since the DBA LOCA could lead to a fission product release.

In MODES 4 and 5, the probability and consequences of a DBA LOCA are reduced because of the pressure and temperature limitations in these MODES. Therefore, maintaining the CREF System OPERABLE is not required in MODE 4 or 5, except for the following situations under which significant radioactive releases can be postulated:

a. During operations with a potential for draining the reactor vessel (OPDRVs); and

b. During movement of recently irradiated fuel assemblies in the secondary containment. Due to radioactive decay, the CREF System is only required to be OPERABLE during fuel handling involving handling recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 24 hours).

BASES

ACTIONS

A.1

With one CREF subsystem inoperable, for reasons other than an inoperable CRE boundary, the inoperable CREF subsystem must be restored to OPERABLE status within 7 days. With the unit in this condition, the remaining OPERABLE CREF subsystem is adequate to perform the CRE occupant protection function. However, the overall reliability is reduced because a failure in the OPERABLE subsystem could result in loss of the CREF System function capability. The 7 day Completion Time is based on the low probability of a DBA occurring during this time period, and that the remaining subsystem can provide the required capabilities.

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

If the unfiltered in-leakage of potentially contaminated air past the CRE boundary and into the CRE can result in CRE occupant radiological dose greater than the calculated dose of the licensing basis analyses of DBA consequences (5 rem TEDE), or inadequate protection of CRE occupants from hazardous chemicals or smoke, the CRE boundary is inoperable. Actions must be taken to restore an OPERABLE CRE boundary within 90 days.

During the period that the CRE boundary is considered inoperable, action must be initiated to implement mitigating actions to lessen the effect on CRE occupants from the potential hazards of a radiological or chemical event or a challenge from smoke. Actions must be taken within 24 hours to verify that in the event of a DBA, the mitigating actions will ensure that CRE occupant radiological exposures will not exceed the calculated dose of the licensing basis analyses of DBA consequences, and that CRE occupants are protected from hazardous chemicals and smoke. These mitigating actions (i.e., actions that are taken to offset the consequences of the inoperable CRE boundary) should be preplanned for implementation upon entry into the condition, regardless of whether entry is intentional 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 possibly repair, and test most problems with the CRE boundary.

BASES

ACTIONS (continued)

C.1 and C.2

In MODE 1, 2, or 3, if the inoperable CREF subsystem or the CRE boundary cannot be restored to OPERABLE status within the associated Completion Time, the unit must be placed in a MODE that minimizes accident risk. To achieve this status, the unit must be placed in at least MODE 3 within 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.

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

The Required Actions of Condition D are modified by a Note indicating that LCO 3.0.3 does not apply. If moving recently irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, inability to suspend movement of recently irradiated fuel assemblies is not sufficient reason to require a reactor shutdown.

During movement of recently irradiated fuel assemblies in the secondary containment or during OPDRVs, if the inoperable CREF subsystem cannot be restored to OPERABLE status within the required Completion Time, the OPERABLE CREF subsystem may be placed in the pressurization mode. This action ensures that the remaining subsystem is OPERABLE, that no failures that would prevent automatic actuation will occur, and that any active failure will be readily detected.

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

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

ACTIONS (continued)

E.1

If both CREF subsystems are inoperable in MODE 1, 2, or 3 for reasons other than an inoperable CRE boundary (i.e., Condition B), the CREF System may not be capable of performing the intended function and the unit is in a condition outside of the accident analyses. Therefore, LCO 3.0.3 must be entered immediately.

F.1 and F.2

The Required Actions of Condition F are modified by a Note indicating that LCO 3.0.3 does not apply. If moving recently irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, inability to suspend movement of recently irradiated fuel assemblies is not sufficient reason to require a reactor shutdown.

During movement of recently irradiated fuel assemblies in the secondary containment or during OPDRVs, with two CREF subsystems inoperable, or with one or more CREF subsystems inoperable due to an inoperable CRE boundary, action must be taken immediately to suspend activities that present a potential for releasing radioactivity that might require isolation of the CRE boundary. This places the unit in a condition that minimizes the accident risk.

If applicable, movement of recently irradiated fuel assemblies in the secondary containment must be suspended immediately. Suspension of these activities shall not preclude completion of movement of a component to a safe position. If applicable, actions must be initiated immediately to suspend OPDRVs to minimize the probability of a vessel draindown and subsequent potential for fission product release. Actions must continue until the OPDRVs are suspended.

BASES

SURVEILLANCE REQUIREMENTS

SR 3.7.4.1

This SR verifies that a subsystem in a standby mode starts on demand from the control room 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 (Ref. 6) demonstrates OPERABILITY of the system. Periodic operation ensures that blockage, 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 3.7.4.2

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

SR 3.7.4.3

This SR verifies that on an actual or simulated initiation signal, each CREF subsystem starts and operates. The LOGIC SYSTEM FUNCTIONAL TEST in LCO 3.3.7.1, "Control Room Emergency Filtration (CREF) Instrumentation," overlaps this SR to provide complete testing of the safety function. Operating experience has shown that these components usually pass the Surveillance when performed at the 24 month Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

SR 3.7.4.4

This SR verifies the OPERABILITY of the CRE boundary by testing for unfiltered air in-leakage past the CRE boundary and into the CRE. The details of the testing are specified in the Control Room Envelope Habitability Program.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The CRE is considered habitable when the radiological dose to CRE occupants calculated in the licensing basis analyses of DBA consequences is no more than 5 rem TEDE and the CRE occupants are protected from hazardous chemicals and smoke. This SR verifies that the unfiltered air inleakage into the CRE is no greater than the flow rate assumed in the licensing basis analyses of DBA consequences. When unfiltered air inleakage is greater than the assumed flow rate. Condition 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 Reg. Guide 1.196, Section C.2.7.3, (Ref. 2) which endorses, with exceptions, NEI 99-03, Section 8.4 and Appendix F (Ref. 3). 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. 4). 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 in-leakage test may not be necessary to establish that the CRE boundary has been restored to OPERABLE status.

REFERENCES

1. USAR, Section 14.7.2.

2. Regulatory Guide 1.196.

3. NEI 99-03, “Control Room Habitability Assessment,” June 2001.

4. Letter from Eric J. Leeds (NRC) to James W. Davis (NEI) dated January 30, 2004, “NEI Draft White Paper, Use of Generic Letter 91-18 Process and Alternative Source Terms in the Context of Control Room Habitability.” (ADAMS Accession No. ML040300694)

5. Amendment No. 160, “Monticello Nuclear Generating plant (MNGP) – Issuance of Amendment Regarding Control Room Envelope Habitability,” March 17, 2009 (TSTF-448, Revision 3). (ADAMS Accession No. ML052910355)

6. Amendment No. 181, Monticello Nuclear Generating Plant – Issuance of Amendment to Adopt TSTF Traveler TSTF-522, Revision 0, “Revise Ventilation System Surveillance Requirements to Operate for 10 Hours per Month,” dated May 2, 2014. (ADAMS Accession No. ML14058A825)

7. UDAR, Section 14.7.6.

B 3.7 PLANT SYSTEMS

B 3.7.5 Control Room Ventilation System

BASES

BACKGROUND

The Control Room Ventilation System provides temperature control for the control room envelope following isolation of the control room. The control room envelope includes the main control room and portions of the first and second floors of the Emergency Filtration Train (EFT) building.

The Control Room Ventilation System consists of two independent, redundant subsystems that provide cooling and heating of recirculated control room envelope and outside air. Each subsystem consists of heating coils (not required for OPERABILITY), cooling coils, fans, compressors, ductwork, dampers, and instrumentation and controls to provide for control room envelope temperature control.

The Control Room Ventilation System is designed to provide a controlled environment under both normal and accident conditions. A single subsystem provides the required temperature control to maintain a suitable control room envelope environment for a sustained occupancy of 10 persons. The system is designed to maintain the control room envelope at 78°F during the summer and 72°F in the winter. The maximum design condition in the control room and most of the EFT is 104°F. The Control Room Ventilation System operation in maintaining the control room envelope temperature is discussed in USAR, Section 6.7 (Ref. 1).

APPLICABLE SAFETY ANALYSES

The design basis of the Control Room Ventilation System is to maintain the control room envelope temperature for a 30 day continuous occupancy following a postulated Design Basis Accident (DBA). The two DBAs are a Loss of Coolant Accident (LOCA) and a Fuel Handling Accident (FHA) involving recently irradiated fuel within secondary containment (Refs. 3 and 4.)

The Control Room Ventilation System components are arranged in redundant safety related subsystems. During emergency operation, the Control Room Ventilation System maintains a habitable environment and ensures the OPERABILITY of components in the control room envelope. A single failure of a component of the Control Room Ventilation System, assuming a loss of offsite power, does not impair the ability of the system to perform its design function. Redundant detectors and controls are provided for control room envelope temperature control. The Control Room Ventilation System is designed in accordance with Seismic Category I requirements. The Control Room Ventilation System is capable of removing sensible and latent heat loads from the control room

BASES

APPLICABLE SAFETY ANALYSES (continued)	envelope, including consideration of equipment heat loads and personnel occupancy requirements to ensure equipment OPERABILITY. The Control Room Ventilation System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	Two independent and redundant subsystems of the Control Room Ventilation 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 Ventilation System is considered OPERABLE when the individual components necessary to maintain the control room envelope temperature are OPERABLE in both subsystems. These components include the cooling coils, fans, compressors, ductwork, dampers, and associated instrumentation and controls. As described in LCO 3.7.4, an OPERABLE exhaust/recirculation fan (V-ERF-14A or B) and air handling unit (V-EAC-14A or B) (excluding the condenser unit), from the same subsystem, are required to provide flow to support OPERABILITY of the associated CREF subsystem.
APPLICABILITY	In MODE 1, 2, or 3, the Control Room Ventilation System must be OPERABLE to ensure that the control room envelope temperature will not exceed equipment OPERABILITY limits following control room envelope boundary isolation. In MODES 4 and 5, the probability and consequences of a DBA LOCA (Ref. 3) are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining the Control Room Ventilation System OPERABLE is not required in MODE 4 or 5, except for the following situations under which significant radioactive releases can be postulated: a. During operations with a potential for draining the reactor vessel (OPDRVs); and b. During movement of recently irradiated fuel assemblies in the secondary containment. Due to radioactive decay, the Control Room Ventilation System is only required to be OPERABLE during fuel handling involving recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 24 hours).

BASES

ACTIONS

A.1

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

B.1 and B.2

--- NOTE ---
An OPERABLE exhaust/recirculation fan (V-ERF-14A or B) and air handling unit (V-EAC-14A or B) (excluding the condenser unit), from the same subsystem, are required to provide flow to support OPERABILITY of the associated CREF subsystem (LCO 3.7.4).

If both control room ventilation subsystems are inoperable, the Control Room Ventilation 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, 72 hours is allowed to restore a control room ventilation subsystem to OPERABLE status. This Completion time is reasonable considering that the control room temperature is being maintained within limits and the low probability of an event occurring requiring control room isolation (Ref. 2).

C.1 and C.2

In MODE 1, 2, or 3, if the inoperable control room ventilation subsystem(s) cannot be restored to OPERABLE status within the associated Completion Time, the unit must be placed in a MODE that minimizes risk. To achieve this status, the unit must be placed in at least MODE 3 within 12 hours and in MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

BASES

ACTIONS (continued)

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

The Required Actions of Condition D are modified by a Note indicating that LCO 3.0.3 does not apply. If moving recently irradiated fuel assemblies, although not feasible, while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, inability to suspend movement of recently irradiated fuel assemblies is not sufficient reason to require a reactor shutdown.

During movement of recently irradiated fuel assemblies in the secondary containment or during OPDRVs, if Required Action A.1 cannot be completed within the required Completion Time, the OPERABLE control room ventilation subsystem may be placed immediately in operation. This action ensures that the remaining subsystem is OPERABLE, that no failures that would prevent actuation will occur, and that any active failure will be readily detected.

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

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

E.1 and E.2

The Required Actions of Condition E are modified by a Note indicating that LCO 3.0.3 does not apply. If moving recently irradiated fuel assemblies, although not feasible, while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, inability to suspend movement of recently irradiated fuel assemblies is not a sufficient reason to require a reactor shutdown.

During movement of recently irradiated fuel assemblies in the secondary containment or during OPDRVs, if Required Actions B.1 and B.2 cannot be met within the required Completion Times, 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.

BASES

ACTIONS (continued)

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

SURVEILLANCE REQUIREMENTS

SR 3.7.5.1

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

REFERENCES

1. USAR, Section 6.7.
2. Amendment No. 154, “Issuance of Amendment Re: Two Inoperable Control Room Ventilation Subsystems Using the Guidance of TSTF-477,” dated January 23, 2008.
3. USAR, Section 14.7.2.
4. USAR, Section 14.7.6.

B 3.7 PLANT SYSTEMS

B 3.7.6 Main Condenser Offgas

BASES

BACKGROUND	During unit operation, steam from the low pressure turbine is exhausted directly into the condenser. Air and noncondensible gases are collected in the condenser, then exhausted through the steam jet air ejectors (SJAEs) to the Main Condenser Offgas System. The offgas from the main condenser normally includes radioactive gases. The Main Condenser Offgas System has been incorporated into the unit design to reduce the gaseous radwaste emission. This system uses a catalytic recombiner to recombine radiolytically dissociated hydrogen and oxygen. The gaseous mixture is cooled by the offgas condenser; the water and condensibles are stripped out by the offgas condenser. The radioactivity of the remaining gaseous mixture is monitored at the outlet of the offgas condenser prior to entering the holdup line.
APPLICABLE SAFETY ANALYSES	The main condenser offgas gross gamma activity rate is an initial condition of an event that inadvertently releases the main condenser effluent directly to the environment without treatment. The gross gamma activity rate is controlled to ensure that, during the event, the calculated offsite doses will be well within the limits of 10 CFR 50.67 (Ref.1). The main condenser offgas limits satisfy Criterion 2 of 10 CFR 50.36(c)(2)(ii).
LCO	To ensure compliance with the assumptions of an event that inadvertently releases the main condenser effluent directly to the environment without treatment, the fission product release rate must be ≤ 260 mCi/second after decay of 30 minutes.
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	<u>A.1</u> If the offgas radioactivity rate limit is exceeded, 72 hours is allowed to restore the gross gamma activity rate to within the limit. The 72 hour Completion Time is reasonable, based on engineering judgment, the time required to complete the Required Action, the large margins associated

BASES

ACTIONS (continued)

with permissible dose and exposure limits, and the low probability of an event that inadvertently releases the main condenser effluent directly to the environment without treatment.

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

If the gross gamma activity rate is not restored to within the limits in the associated Completion Time, all main steam lines or the SJAE must be isolated. This isolates the Main Condenser Offgas System from the source of the radioactive steam. The main steam lines are considered isolated if at least one main steam isolation valve in each main steam line is closed, and at least one main steam line drain valve in each drain line is closed. The 12 hour Completion Time is reasonable, based on operating experience, to perform the actions from full power conditions in an orderly manner and without challenging unit systems.

An alternative to Required Actions B.1 and B.2 is to place the unit in a MODE in which the LCO does not apply. To achieve this status, the unit must be placed in at least MODE 3 within 12 hours and in MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.6.1

This SR, on a 31 day Frequency, requires an isotopic analysis of an offgas sample to ensure that the required limits are satisfied. The noble gases to be sampled are Xe-133, Xe-135, Xe-138, Kr-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, to ensure that the increase is not indicative of a sustained increase in the radioactivity rate. The 31 day Frequency is adequate in view of other instrumentation that continuously monitor the offgas, and is acceptable, based on operating experience.

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

REFERENCES

1. 10 CFR 50.67.

B 3.7 PLANT SYSTEMS

B 3.7.7 Main Turbine Bypass System

BASES

BACKGROUND	The Main Turbine Bypass System is designed to control steam pressure when reactor steam generation exceeds turbine requirements during unit startup, sudden load reduction, and cooldown. It allows excess steam flow from the reactor to the condenser without going through the turbine. The bypass capacity of the system is approximately 11.5% (Refs. 4 and 5) of the Nuclear Steam Supply System rated steam flow. Sudden load reductions within the capacity of the steam bypass can be accommodated without reactor scram. The Main Turbine Bypass System consists of two valves connected to the main steam lines between the main steam isolation valves and the turbine stop valve bypass valve chest. Each of the two valves is operated by hydraulic cylinders. The bypass valves are controlled by the pressure regulation function of the Turbine Electrical Pressure Regulator or the Mechanical Pressure Regulator, as discussed in the USAR, Section 7.7.2.2 (Ref. 1). The bypass valves are normally closed, and the pressure regulator controls the turbine control valves that direct all steam flow to the turbine. If the speed governor or the load limiter restricts steam flow to the turbine, the pressure regulator controls the system pressure by opening the bypass valves. When the bypass valves open, the steam flows from the bypass chest, through connecting piping, to the pressure reducer assemblies, where the steam pressure is reduced before the steam enters the condenser.
APPLICABLE SAFETY ANALYSES	The Main Turbine Bypass System is assumed to function during the feedwater controller failure (maximum demand) and pneumatic system degradation, turbine trip with bypass - reduced scram speeds transients, as discussed in the USAR, Sections 14.4.4 and 14A.4 (Refs. 2 and 3), respectively. Opening the bypass valves during the pressurization event mitigates the increase in reactor vessel pressure, which affects the MCPR during the event. The Main Turbine Bypass System satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	The Main Turbine Bypass System is required to be OPERABLE to limit peak pressure in the main steam lines and maintain reactor pressure within acceptable limits during events that cause rapid pressurization, so that the Safety Limit MCPR is not exceeded. An OPERABLE Main Turbine Bypass System requires the bypass valves to open in response to increasing main steam line pressure. This response is within the assumptions of the applicable analyses (Refs. 2 and 3).

BASES

APPLICABILITY

The Main Turbine Bypass System is required to be OPERABLE at ≥ 25% RTP to ensure that the fuel cladding integrity Safety Limit and the cladding 1% plastic strain limit are not violated during the feedwater controller failure (maximum demand) and pneumatic system degradation, turbine trip with bypass - reduced scram speeds transients. As discussed in the Bases for LCO 3.2.1 and LCO 3.2.2, sufficient margin to these limits exists at < 25% RTP. Therefore, these requirements are only necessary when operating at or above this power level.

ACTIONS

A.1

If the Main Turbine Bypass System is inoperable (one or more bypass valves inoperable), the assumptions of the design basis transient analysis may not be met. Under such circumstances, prompt action should be taken to restore the Main Turbine Bypass System to OPERABLE status. The 2 hour Completion Time is reasonable, based on the time to complete the Required Action and the low probability of an event occurring during this period requiring the Main Turbine Bypass System.

B.1

If the Main Turbine Bypass System cannot be restored to OPERABLE status, THERMAL POWER must be reduced to < 25% RTP. As discussed in the Applicability section, operation at < 25% RTP results in sufficient margin to the required limits, and the Main Turbine Bypass System is not required to protect fuel integrity during the feedwater controller failure (maximum demand) and pneumatic system degradation, turbine trip with bypass - reduced scram speeds transients. 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 92 day Frequency is based on engineering judgment, is consistent with the procedural controls governing valve operation, and ensures correct valve positions. Operating experience has shown that these components usually pass the SR when performed at the 92 day Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

BASES

SURVEILLANCE REQUIREMENTS (continued)

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

SR 3.7.7.3

This SR ensures that the TURBINE BYPASS SYSTEM RESPONSE TIME is in compliance with the assumptions of the appropriate safety analyses. The response time limits are specified in the COLR. The 24 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit outage and because of the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown 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.

REFERENCES

1. USAR, Section 7.7.2.2.
2. USAR, Section 14.4.4.
3. USAR, Section 14A.4.
4. Calculation 09-239, Revision 0a, “Turbine Bypass Valve Capacity for EPU”
5. Amendment No. 176, “Monticello Nuclear Generating Plant – Issuance of Amendment No. 176 to Renewed Facility Operating License Regarding Extended Power Uprate,” (ADAMS Accession No. ML13316C459)

B 3.7 PLANT SYSTEMS

B 3.7.8 Spent Fuel Storage Pool Water Level

BASES

BACKGROUND

The minimum water level in the spent fuel storage pool meets the assumptions of iodine decontamination factors following a fuel handling accident.

A general description of the spent fuel storage pool design is found in the USAR, Section 10.2.1 (Ref. 1). The assumptions of the fuel handling accident are found in the USAR, Section 14.7.6 (Ref. 2).

APPLICABLE SAFETY ANALYSES

The water level above the irradiated fuel assemblies is an explicit assumption of the fuel handling accident. A fuel handling accident is evaluated to ensure that the radiological consequences (total effective dose equivalent (TEDE) at the exclusion area and low population zone boundaries) are within 10 CFR 50.67 (Ref. 3) exposure guidelines. A fuel handling accident could release a fraction of the fission product inventory by breaching the fuel rod cladding as discussed in the Regulatory Guide 1.25 (Ref. 4).

The fuel handling accident is evaluated for the dropping of an irradiated fuel assembly onto the reactor core. The consequences of a fuel handling accident over the spent fuel storage pool are no more severe than those of the fuel handling accident over the reactor core, as discussed in the USAR, Section 14.7.6.3.1 (Ref. 5). The water level in the spent fuel storage pool provides for absorption of water soluble fission product gases and transport delays of soluble and insoluble gases that must pass through the water before being released to the secondary containment atmosphere. This absorption and transport delay reduces the potential radioactivity of the release during a fuel handling accident.

The spent fuel storage pool water level satisfies Criteria 2 and 3 of 10 CFR 50.36(c)(2)(ii).

LCO

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

APPLICABILITY

This LCO applies during movement of irradiated fuel assemblies in the spent fuel storage pool since the potential for a release of fission products exists.

BASES

ACTIONS	<u>A.1</u> Required Action A.1 is modified by a Note indicating that LCO 3.0.3 does not apply. If moving irradiated fuel assemblies while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Therefore, inability to suspend movement of irradiated fuel assemblies is not a sufficient reason to require a reactor shutdown. When the initial conditions for an accident cannot be met, action must be taken to preclude the accident from occurring. If the spent fuel storage pool level is less than required, the movement of irradiated fuel assemblies in the spent fuel storage pool is suspended immediately. Suspension of this activity shall not preclude completion of movement of an irradiated fuel assembly to a safe position. This effectively precludes a spent fuel handling accident from occurring.
SURVEILLANCE REQUIREMENTS	<u>SR 3.7.8.1</u> This SR verifies that sufficient water is available in the event of a fuel handling accident. The water level in the spent fuel storage pool must be checked periodically. The 7 day Frequency is acceptable, based on operating experience, considering that the water volume in the pool is normally stable, and all water level changes are controlled by unit procedures.
REFERENCES	1. USAR, Section 10.2.1. 2. USAR, Section 14.7.6. 3. 10 CFR 50.67. 4. Regulatory Guide 1.25, March 1972. 5. USAR, Section 14.7.6.3.1.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.1 AC Sources - Operating

BASES

BACKGROUND

AC sources to the Class 1E AC Electrical Power Distribution System consist of the offsite power sources (primary station auxiliary (2R), reserve (1R), and reserve auxiliary (1AR) transformers) and the onsite standby power sources (emergency diesel generators (EDGs) 11 and 12). As required by USAR, Section 1.2.6 (Ref. 1), the design of the AC electrical power system provides independence and redundancy to ensure an available source of power to the Engineered Safety Feature (ESF) systems.

The Class 1E AC distribution system is divided into redundant divisions (Divisions 1 and 2), so loss of any one division does not prevent the minimum safety functions from being performed. Each division has connections to three offsite power sources and a single EDG.

Offsite power is supplied to the Monticello switchyard via three 345 kV and three 115 kV transmission line connections. From the switchyard, independent and redundant circuits provide AC power to the 4.16 kV auxiliary buses and essential buses. The 4.16 kV essential buses 15 and 16 are capable of being supplied from the 345 kV bus via transformer 2R, from the 115 kV substation via transformer 1R, and from either the 345 kV or 115 kV system via transformer 1AR. A detailed description of the offsite power network and circuits to the onsite Class 1E 4.16 kV essential buses is found in USAR, Section 8.2 (Ref. 2).

A qualified offsite circuit consists of all breakers, transformers, switches, interrupting devices, cabling, and controls required to transmit power from the offsite transmission network to the onsite Class 1E 4.16 kV essential bus.

Transformer 2R provides the normal source of power to the 4.16 kV auxiliary buses and essential buses 15 and 16. If normal power from transformer 2R is lost, transformer 1R will automatically energize plant buses, including 4.16 kV essential buses 15 and 16. Bus 11 will be reenergized by 1R unless it is locked out. Bus 12 will only be reenergized by 1R if Bus 11 is locked out or if the No. 11 Reactor Feed Pump was not running at the time of the event. If power from transformer 1R is lost, transformer 1AR will automatically energize only the 4.16 kV essential buses 15 and 16.

BASES

BACKGROUND (continued)

The onsite standby power source for 4.16 kV essential buses 15 and 16 consists of two EDGs. EDGs 11 and 12 are dedicated to 4.16 kV essential buses 15 and 16, respectively. An EDG starts automatically on a loss of coolant accident (LOCA) signal (i.e., a Core Spray System Reactor Vessel Water Level - Low Low or Drywell Pressure - High signal) or on a 4.16 kV Essential Bus Loss of Voltage or 4.16 kV Essential Bus Degraded Voltage signal. After the EDG has started, it automatically ties to its respective bus after offsite power is tripped as a consequence of a 4.16 kV Essential Bus Loss of Voltage or Degraded Voltage signal, independent of or coincident with a LOCA signal. The EDGs also start and operate in the standby mode without tying to the 4.16 kV essential bus on a LOCA signal alone. Following the trip of offsite power, transfer relays strip nonpermanent loads from the 4.16 kV essential bus. When the EDG is tied to the 4.16 kV essential bus, loads are then sequentially connected to its respective 4.16 kV essential bus by individual time delay relays. The individual time delay relays control the starting signals to motor breakers to prevent overloading the EDG.

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

Certain required plant loads are returned to service in a predetermined sequence in order to prevent overloading of the EDGs in the process. Within 42 seconds after the initiating signal is received, all automatic and permanently connected loads needed to recover the unit or maintain it in a safe condition are returned to service.

Ratings for the EDGs are consistent with the requirements of Regulatory Guide 1.9 (Ref. 3). EDGs 11 and 12 have the following ratings:

a. 2500 kW - continuous;

b. 2750 kW - 2000 hours; and

c. 3050 kW - 30 minutes.

Each EDG has its own day tank and base tank. Both EDGs utilize a common fuel oil storage tank. The EDG fuel oil transfer system includes an independent and redundant fuel oil transfer subsystem for each EDG. Each fuel oil transfer subsystem automatically transfers fuel oil from the common fuel oil storage tank to the associated EDG day tank. The fuel oil transfer pump arrangement consists of two fuel oil transfer pumps (P-160A/C) in the Division 1 subsystem and two fuel oil transfer pumps (P-160B/D) in the Division 2 subsystem (Ref. 14).

BASES

BACKGROUND (continued)

One fuel oil transfer pump in each subsystem operates continuously to maintain level in the EDG day tank for that subsystem. A loss of fuel oil flow to the associated EDG is annunciated in the control room and the second fuel oil transfer pump in the subsystem is manually started locally (Ref. 14).

Overflow from each EDG day tank will be returned by separate return lines to the fuel oil storage tank. The EDG fuel oil transfer system design provides separation and redundancy such that no single active or passive component failure can prevent operation of one EDG. One fuel oil transfer pump has sufficient capacity to maintain the associated EDG day tank full with the EDG operating at full load.

The fuel oil transfer system also includes two day tank fuel oil transfer subsystems. Each day tank fuel oil transfer subsystem is capable of automatically transferring fuel oil from the day tank to the associated base tank. Each day tank fuel oil transfer subsystem includes two pumps, and each pump starts automatically on a level signal from one base tank level switch. One pump starts when the level in the base tank drops below the normal level and the second pump starts when the base tank level drops to the low level.

APPLICABLE SAFETY ANALYSES

The initial conditions of DBA and transient analyses in USAR, Chapter 5 (Ref. 4) and Chapter 14 (Ref. 5), assume ESF systems are OPERABLE. The AC electrical power sources are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System (RCS), and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.5, Emergency Core Cooling System (ECCS) and Reactor Core Isolation Cooling (RCIC) System; and Section 3.6, Containment Systems.

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

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

b. A worst case single failure.

AC Sources - Operating satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

Two qualified circuits between the offsite transmission network and the onsite Class 1E Distribution System and two separate and independent EDGs (11 and 12) ensure availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after an anticipated operational occurrence (AOO) or a postulated DBA.

Each offsite circuit must be capable of maintaining rated frequency and voltage, and accepting required loads during an accident, while connected to the 4.16 kV essential buses. One offsite circuit consists of incoming disconnects to the 2R transformer, associated 2R transformer, and the respective circuit path including buses and feeder breakers to both 4.16 kV essential buses. The second circuit consists of incoming disconnects to the 1R transformer, associated 1R transformer, and the respective circuit path including buses and feeder breakers to both 4.16 kV essential buses. The third qualified offsite circuit consists of incoming disconnects to the 1AR transformer, associated 1AR transformer, and the respective circuit path including feeder breakers to both 4.16 kV essential buses.

Each EDG must be capable of starting, accelerating to rated speed and voltage, and connecting to its respective 4.16 kV essential bus on detection of bus undervoltage. This sequence must be accomplished within 10 seconds. Each EDG must also be capable of accepting required loads within the assumed loading sequence intervals, and must continue to operate until offsite power can be restored to the 4.16 kV essential buses. These capabilities are required to be met from a variety of initial conditions, such as EDG in standby with the engine hot and EDG in standby with the engine at ambient condition. Additional EDG capabilities must be demonstrated to meet required Surveillances, e.g., capability of the EDG to reject the single largest post-accident load while maintaining a specified margin to the overspeed trip.

Proper sequencing of loads, including tripping of nonessential loads, is a required function for EDG OPERABILITY.

The AC sources must be separate and independent (to the extent possible) of other AC sources. For the EDGs, the separation and independence are complete. For the offsite AC sources, the separation and independence are to the extent practical. A circuit may be connected to more than one 4.16 kV essential bus, with automatic transfer capability to the other circuit OPERABLE, and not violate separation criteria. A circuit that is not connected to a 4.16 kV essential bus is required to have OPERABLE automatic transfer interlock mechanisms to the 4.16 kV essential buses to support OPERABILITY of that circuit.

BASES

LCO (continued)

In addition, fuel oil level in the day tank and base tank must be met for each EDG. For each fuel oil transfer subsystem, one of the two fuel oil transfer pumps in each subsystem must be capable of transferring fuel oil from the common fuel oil storage tank to the associated EDGs day tank.

In each subsystem one fuel oil transfer pump operates continuously to maintain level in the associated EDG day tank. If both fuel oil transfer pumps in a subsystem operate simultaneously, with the associated EDG running, level in the common fuel oil storage tank will ultimately decrease to a level precluding pump operation (due to gas coming out of solution) above the level required to operate the EDG for the required 7-day duration. Prior to entering two fuel oil transfer pump operation in a subsystem, if planned, or upon discovery, the associated EDG is declared inoperable. Following securing one of the two fuel oil transfer pumps the associated EDG is restored to OPERABLE status.

For each day tank fuel oil transfer subsystem, only one of the two transfer pumps must be capable of transferring fuel from the day tank to the associated base tank.

APPLICABILITY

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

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

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

The AC power requirements for MODES 4 and 5 and other conditions in which AC sources are required are covered in LCO 3.8.2, “AC Sources – Shutdown.”

ACTIONS

A Note prohibits the application of LCO 3.0.4.b to an inoperable EDG. There is an increased risk associated with entering a MODE or other specified condition in the Applicability with an inoperable EDG and the provisions of LCO 3.0.4.b, which allow entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

BASES

ACTIONS (continued)

A.1

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

A.2

Required Action A.2, which only applies if the division cannot be powered from an offsite source, is intended to provide assurance that an event with a coincident single failure of the associated EDG does not result in a complete loss of safety function of critical systems. These features are designed with redundant safety related divisions (i.e., single division systems are not included). Redundant required features failures consist of inoperable features associated with a division redundant to the division that has no offsite power.

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

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

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

If, at any time during the existence of this condition (one required offsite circuit inoperable) a redundant required feature subsequently becomes inoperable, this Completion Time would begin to be tracked.

Discovering no offsite power to one 4.16 kV essential bus of the onsite Class 1E AC Electrical Power Distribution System coincident with one or more inoperable redundant required support or supported features, or both, that are associated with the other 4.16 kV essential bus that has offsite power, results in starting the Completion Time for the Required Action. Twenty-four hours is acceptable because it minimizes risk while allowing time for restoration before the unit is subjected to transients associated with shutdown.

BASES

ACTIONS (continued)

The remaining OPERABLE required offsite circuit and EDGs are adequate to supply electrical power to the onsite Class 1E AC Electrical Power Distribution System. Thus, on a component basis, single failure protection may have been lost for the required feature's function; however, function is not lost. The 24 hour Completion Time takes into account the component OPERABILITY of the redundant counterpart to the inoperable required feature. Additionally, the 24 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

A.3

Consistent with Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition A for a period that should not exceed 72 hours. With one required offsite circuit inoperable, the reliability of the offsite system is degraded, and the potential for a loss of offsite power is increased, with attendant potential for a challenge to the plant safety systems. In this condition, however, the remaining OPERABLE required offsite circuit and EDGs are adequate to supply electrical power to the onsite Class 1E Distribution System.

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

B.1

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

B.2

Required Action B.2 is intended to provide assurance that a loss of offsite power, during the period that an EDG is inoperable, does not result in a complete loss of safety function of critical systems. These features are designed with redundant safety related divisions (i.e., single division

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systems are not included). Redundant required features failures consist of inoperable features associated with a division redundant to the division that has an inoperable EDG.

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

a. An inoperable EDG exists; and

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

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

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

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

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

Required Action B.3.1 provides an allowance to avoid unnecessary testing of the OPERABLE EDG. If it can be determined that the cause of the inoperable EDG does not exist on the OPERABLE EDG, SR 3.8.1.2 does not have to be performed. If the cause of inoperability exists on the other EDG, it is declared inoperable upon discovery, and Condition E of

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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 EDG cannot be confirmed not to exist on the remaining EDG, performance of SR 3.8.1.2 suffices to provide assurance of continued OPERABILITY of that EDG.

In the event the inoperable EDG is restored to OPERABLE status prior to completing either B.3.1 or B.3.2, the plant corrective action program will continue to evaluate the common cause possibility. This continued evaluation, however, is no longer under the 24 hour constraint imposed while in Condition B.

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

B.4

In Condition B, the remaining OPERABLE EDG and required offsite circuits are adequate to supply electrical power to the onsite Class 1E AC Electrical Power Distribution System. The 7 day Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

C.1 and C.2

Required Action C.1 addresses actions to be taken in the event of inoperability of redundant required features concurrent with inoperability of two required offsite circuits. Required Action C.1 reduces the vulnerability to a loss of function. The Completion Time for taking these actions is reduced to 12 hours from that allowed with one division without offsite power (Required Action A.2). The rationale for the reduction to 12 hours is that Regulatory Guide 1.93 (Ref. 6) allows a Completion Time of 24 hours for two required offsite circuits inoperable, based upon the assumption that two complete safety divisions are OPERABLE. When a concurrent redundant required feature failure exists, this assumption is not the case, and a shorter Completion Time of 12 hours is appropriate. These features are designed with redundant safety related divisions, (i.e., single division systems are not included in the list). Redundant required features failures consist of any of these features that are inoperable because any inoperability is on a division redundant to a division with inoperable offsite circuits.

BASES

ACTIONS (continued)

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

a. All required offsite circuits are inoperable; and

b. A redundant required feature is inoperable.

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

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

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

a. The configuration of the redundant AC electrical power system that remains available is not susceptible to a single bus or switching failure; and

b. The time required to detect and restore an unavailable offsite power source is generally much less than that required to detect and restore an unavailable onsite AC source.

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

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

D.1 and D.2

Pursuant to LCO 3.0.6, the Distribution Systems - Operating ACTIONS would not be entered even if all AC sources to it were inoperable, resulting in de-energization. Therefore, the Required Actions of Condition D are modified by a Note to indicate that when Condition D is entered with no AC source to any 4.16 kV essential bus (i.e., the bus is de-energized), ACTIONS for LCO 3.8.7, "Distribution Systems - Operating," must be immediately entered. This allows Condition D to provide requirements for the loss of the required offsite circuit and one EDG without regard to whether a division is de-energized. LCO 3.8.7 provides the appropriate restrictions for a de-energized division.

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition D for a period that should not exceed 12 hours. In Condition D, individual redundancy is lost in both the offsite electrical power system and the onsite AC electrical power system. Since power system redundancy is provided by two diverse sources of power, however, the reliability of the power systems in this Condition may appear higher than that in Condition C (loss of both required offsite circuits). This difference in reliability is offset by the susceptibility of this power system configuration to a single bus or switching failure. The 12 hour Completion Time takes into account the capacity and capability of the remaining AC sources, reasonable time for repairs, and the low probability of a DBA occurring during this period.

E.1

With two EDGs inoperable, there is no remaining standby AC source. Thus, with an assumed loss of offsite electrical power, insufficient standby AC sources are available to power the minimum required ESF functions. Since the offsite electrical power system is the only source of AC power for the majority of ESF equipment at this level of degradation, the risk associated with continued operation for a very short time could be less than that associated with an immediate controlled shutdown. (The immediate shutdown could cause grid instability, which could result in a total loss of AC power.) Since any inadvertent unit generator trip could

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also result in a total loss of offsite AC power, however, the time allowed for continued operation is severely restricted. The intent here is to avoid the risk associated with an immediate controlled shutdown and to minimize the risk associated with this level of degradation. According to Regulatory Guide 1.93 (Ref. 6), with both EDGs inoperable, operation may continue for a period that should not exceed 2 hours.

F.1 and F.2

If the inoperable AC electrical power sources cannot be restored to OPERABLE status within the associated Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

G.1

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

SURVEILLANCE REQUIREMENTS

The AC sources are designed to permit inspection and testing of all important areas and features, especially those that have a standby function, in accordance with USAR, Chapter 8 (Ref. 8). Periodic component tests are supplemented by extensive functional tests during refueling outages (under simulated accident conditions). The SRs for demonstrating the OPERABILITY of the EDGs are consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3), Regulatory Guide 1.108 (Ref. 9), and Regulatory Guide 1.137 (Ref. 10).

Where the SRs discussed herein specify voltage and frequency tolerances, the following summary is applicable. The minimum steady state output voltage of 3975 V is based on the degraded voltage setpoint. It also allows for voltage drops to motors and other equipment down through the 120 V level where minimum operating voltage is also usually specified as 90% of name plate rating. The specified maximum steady state output voltage of 4400 V is equal to the maximum operating voltage

BASES

SURVEILLANCE REQUIREMENTS (continued)

specified for 4000 V motors. It ensures that for a lightly loaded distribution system, the voltage at the terminals of 4000 V motors is no more than the maximum rated operating voltages. The specified minimum and maximum frequencies of the EDG are 58.8 Hz and 61.2 Hz, respectively. These values are equal to ± 2% of the 60 Hz nominal frequency and are derived from the recommendations found in Regulatory Guide 1.9 (Ref. 3).

SR 3.8.1.1

This SR ensures proper circuit continuity for the offsite AC electrical power supply to the onsite distribution network and availability of offsite AC electrical power. The breaker alignment verifies that each breaker is in its correct position to ensure that distribution buses and loads are connected to their preferred power source and that appropriate independence of offsite circuits is maintained. The 7 day Frequency is adequate since breaker position is not likely to change without the operator being aware of it and because its status is displayed in the control room.

SR 3.8.1.2

This SR helps to ensure the availability of the standby electrical power supply to mitigate DBAs and transients and maintain the unit in a safe shutdown condition.

To minimize the wear on moving parts that do not get lubricated when the engine is not running, this SR has been modified by a Note (Note 1) to indicate that all EDG starts for this Surveillance may be preceded by an engine prelube period and followed by a warmup prior to loading.

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

In order to reduce stress and wear on diesel engines, the manufacturer has recommended a modified start in which the starting speed of EDGs is limited, warmup is limited to this lower speed, and the EDGs are gradually accelerated to synchronous speed prior to loading. These start procedures are the intent of Note 2.

The 31 day Frequency is consistent with Regulatory Guide 1.9 (Ref. 3). This Frequency provides adequate assurance of EDG OPERABILITY, while minimizing degradation resulting from testing.

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SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.3

Consistent with Regulatory Guide 1.9 (Ref. 3), this Surveillance verifies that the EDGs are capable of synchronizing and accepting loads 90% to 100% of the continuous rating of the EDG. A minimum run time of 60 minutes is required to stabilize engine temperatures, while minimizing the time that the EDG is connected to the offsite source.

Although no power factor requirements are established by this SR, the EDG is normally operated at a power factor between 0.8 lagging and 1.0. The 0.8 power factor value is the design rating of the machine, while the 1.0 power factor value is an operational limitation to ensure circulating currents are minimized. The load band is provided to avoid routine overloading of the EDG. Routine overloading may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain EDG OPERABILITY.

The 31 day Frequency for this Surveillance is consistent with Regulatory Guide 1.9 (Ref. 3).

Note 1 modifies this Surveillance to indicate that diesel engine runs for this Surveillance may include gradual loading, as recommended by the manufacturer, so that mechanical stress and wear on the diesel engine are minimized.

Note 2 modifies this Surveillance by stating that momentary transients because of changing bus loads do not invalidate this test. Similarly, momentary power factor transients above the limit do not invalidate the test.

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

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

SR 3.8.1.4

Microbiological fouling is a major cause of fuel oil degradation. There are numerous bacteria that can grow in fuel oil and cause fouling, but all must have a water environment in order to survive. Removal of water from the fuel oil day and base tanks once every 31 days eliminates the necessary environment for bacterial survival. This is the most effective means of

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SURVEILLANCE REQUIREMENTS (continued)

controlling microbiological fouling. In addition, it eliminates the potential for water entrainment in the fuel oil during EDG operation. Water may come from any of several sources, including condensation, ground water, rain water, contaminated fuel oil, and breakdown of the fuel oil by bacteria. Frequent checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. The Surveillance Frequencies are established by Regulatory Guide 1.137 (Ref. 10). This SR is for preventive maintenance. The presence of water does not necessarily represent a failure of this SR provided that accumulated water is removed during performance of this Surveillance.

<u>SR 3.8.1.5</u>

This Surveillance demonstrates that each fuel oil transfer subsystem can transfer fuel oil from the common fuel oil storage tank to the associated EDG day tank with one pump. This Surveillance also demonstrates that each day tank fuel oil transfer subsystem can transfer fuel oil from its associated day tank to its associated base tank with one pump. It is required to support continuous operation of standby power sources. This Surveillance provides assurance that the required fuel oil transfer pumps are OPERABLE, the fuel oil piping system is intact, the fuel delivery piping is not obstructed, and the controls and control systems for automatic fuel transfer systems are OPERABLE.

The Frequency for this SR is consistent with the Frequency for testing the EDGs in SR 3.8.1.2.

<u>SR 3.8.1.6</u>

Transfer of each 4.16 kV essential bus power supply from the normal offsite circuit (i.e., either transformer 2R or 1R) to the alternate offsite circuit (i.e., either transformer 1R or 1AR) demonstrates the OPERABILITY of the alternate circuit distribution network to power the shutdown loads. The 24 month on a STAGGERED TEST BASIS for each division Frequency of the Surveillance is based on engineering judgment taking into consideration the plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths. Operating experience has shown that these components usually

BASES

SURVEILLANCE REQUIREMENTS (continued)

pass the SR when performed on the 24 month on a STAGGERED TEST BASIS for each division Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

This SR is modified by a Note. The reason for the Note is that, during operation with the reactor critical, performance of this SR could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, plant safety systems. This restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed Surveillance, a successful Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when the Surveillance is performed in MODE 1 or 2. Risk insights or deterministic methods may be used for this assessment. Credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.7

Each EDG 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 EDG load response characteristics and capability to reject the largest single load while maintaining a specified margin to the overspeed trip. The largest single load for each EDG is a core spray pump (800 hp). This Surveillance may be accomplished by either:

a. Tripping the EDG output breaker with the EDG carrying greater than or equal to its associated single largest post-accident load while paralleled to offsite power, or while solely supplying the bus; or

b. Tripping its associated single largest post-accident load with the EDG solely supplying the bus.

Consistent with Regulatory Guide 1.9 (Ref. 3), the load rejection test is acceptable if the diesel speed does not exceed the normal (synchronous)

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SURVEILLANCE REQUIREMENTS (continued)

speed plus 75% of the difference between nominal speed and the overspeed trip setpoint, or 115% of nominal speed, whichever is lower. For EDGs 11 and 12, this represents 67.5 Hz, equivalent to 75% of the difference between nominal speed and the overspeed trip setpoint.

The 24 month Frequency is based on engineering judgment, taking into consideration plant conditions required to perform the Surveillance and is intended to be consistent with expected fuel cycle lengths. Operating experience has shown that these components usually pass the SR when performed at the 24 month Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

This SR is modified by two Notes. The reason for Note 1 is 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. This restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed Surveillance, a successful Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when the Surveillance is performed in MODE 1 or 2. Risk insights or deterministic methods may be used for this assessment. Credit may be taken for unplanned events that satisfy this SR. Note 2 ensures that the EDG is tested under load conditions that are as close to design basis conditions as possible. When synchronized with offsite power, testing should be performed within the power factor limit. This power factor is representative of the actual inductive loading an EDG would see under design basis accident conditions. The power factor limit is ≤ 0.85 for Division 1 and ≤ 0.88 for Division 2. Under certain conditions, however, Note 2 allows the surveillance to be conducted outside the power factor limit. These conditions occur when grid voltage may be such that the EDG excitation levels needed to obtain a power factor within limit are not achievable and may be in excess of those recommended for the EDG. In such cases, the power factor shall be maintained as close as practicable to the power factor limit without exceeding the EDG excitation limits.

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SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.8

Consistent with Regulatory Guide 1.9 (Ref. 3), paragraph c.2.2.5, this Surveillance demonstrates that permanently connected loads remain energized from the offsite circuit and emergency loads are auto-connected through the time delay relays from the offsite electrical power system on a LOCA signal without loss of offsite power.

The requirement to verify the connection and power supply of permanent and auto-connected loads is intended to satisfactorily show the relationship of these loads to the loading logic for loading onto offsite power. In certain circumstances, many of these loads cannot actually be connected or loaded without undue hardship or potential for undesired operation. For instance, ECCS injection valves are not desired to be stroked open, high pressure injection systems are not capable of being operated at full flow, or RHR systems performing a decay heat removal function are not desired to be realigned to the ECCS mode of operation. In lieu of actual demonstration of the connection and loading of these loads, testing that adequately shows the capability of the EDG system to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

The Frequency of 24 months is based on engineering judgment, taking into consideration plant conditions required to perform the Surveillance and is intended to be consistent with the expected fuel cycle lengths. Operating experience has shown that these components usually pass the SR when performed at the 24 month Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

This SR is modified by a Note. The reason for the Note is that during operation with the reactor critical, performance of this Surveillance could potentially cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, plant safety systems. This restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow portions of the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed partial Surveillance, a successful partial Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the partial Surveillance; as well as the operator procedures available to cope with these outcomes.

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SURVEILLANCE REQUIREMENTS (continued)

These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when portions of the Surveillance are performed in MODE 1 or 2. Risk insights or deterministic methods may be used for the assessment. Credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.9

This Surveillance demonstrates the EDGs can start and run continuously at full load capability (90% to 100% of the EDG continuous rating) for an interval of not less than 8 hours - 6 hours of which is at a load equivalent to 90% to 100% of the continuous rating of the EDG, and 2 hours of which is at a load equivalent to 105% to 110% of the continuous rating of the EDG. The run duration of 8 hours and the load ranges and duration are consistent with IEEE Standard 387-1995 (Ref. 13). The EDG 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.

A load band is provided to avoid routine overloading of the EDG. Routine overloading may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain EDG OPERABILITY.

The 24 month Frequency is based on engineering judgment, taking into consideration plant conditions required to perform the Surveillance and is intended to be consistent with expected fuel cycle lengths. Operating experience has shown that these components usually pass the SR when performed at the 24 month Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

This Surveillance has been modified by three Notes. Note 1 states that momentary transients due to changing bus loads do not invalidate this test. Similarly, momentary power factor transients above the limit do not invalidate the test. The reason for Note 2 is that during operation with the reactor critical, performance of this Surveillance could cause perturbations to the electrical distribution systems that would challenge continued steady state operation and, as a result, plant safety systems. This restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or

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SURVEILLANCE REQUIREMENTS (continued)

enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed Surveillance, a successful Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when the Surveillance is performed in MODE 1 or 2. Risk insights or deterministic methods may be used for this assessment. Credit may be taken for unplanned events that satisfy this SR. When an EDG is tested at a load equivalent to 90% to 100% of the continuous rating, Note 3 ensures that the EDG is tested under load conditions that are as close to design basis conditions as possible. When synchronized with offsite power, testing should be performed within the power factor limit. This power factor is representative of the actual inductive loading an EDG would see under design basis accident conditions. The power factor limit is ≤ 0.85 for Division 1 and ≤ 0.88 for Division 2. Under certain conditions, however, Note 3 allows the surveillance to be conducted outside of the power factor limit. These conditions occur when grid voltage may be such that the EDG excitation levels needed to obtain a power factor within limit are not achievable and may be in excess of those recommended for the EDG. In such cases, the power factor shall be maintained as close as practicable to the power factor limit without exceeding the EDG excitation limits. During EDG testing at a load equivalent to 105% to 110% of the EDG continuous rating the power factor limit does not have to be met since the EDGs are not required to mitigate the consequences of an accident at these loads.

SR 3.8.1.10

This Surveillance demonstrates that the diesel engine can restart from a hot condition, such as subsequent to shutdown from normal Surveillances, and achieve the required voltage and frequency within 10 seconds. The 10 second time is derived from the requirements of the accident analysis to respond to a design basis large break LOCA. The 24 month Frequency is based on engineering judgment, taking into consideration plant conditions required to perform the Surveillance, and is intended to be consistent with the expected fuel cycle lengths. Operating experience has shown that these components usually pass the SR when performed at the 24 month Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

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SURVEILLANCE REQUIREMENTS (continued)

This SR is modified by two Notes. Note 1 ensures that the test is performed with the diesel sufficiently hot. The requirement that the diesel has operated for at least 2 hours at approximately full load conditions prior to performance of this Surveillance is based on manufacturer recommendations for achieving hot conditions. The load band is provided to avoid routine overloading of the EDG. Routine overloads may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain EDG OPERABILITY. Momentary transients due to changing bus loads do not invalidate this test. Note 2 allows all EDG starts to be preceded by an engine prelube period to minimize wear and tear on the diesel during testing.

SR 3.8.1.11

Consistent with Regulatory Guide 1.9 (Ref. 3), paragraph c.2.2.11, this Surveillance ensures that the manual synchronization and load transfer from the EDG to the offsite source can be made and that the EDG can be returned to ready-to-load status when offsite power is restored. It also ensures that the auto-start logic is reset to allow the EDG to reload if a subsequent loss of offsite power occurs. The EDG is considered to be in ready-to-load status when the EDG is at rated speed and voltage, the output breaker is open and can receive an auto-close signal on bus undervoltage, and the associated individual time delay relays are reset.

The Frequency of 24 months is based on engineering judgment, taking into consideration plant conditions required to perform the Surveillance, and is intended to be consistent with the expected fuel cycle lengths. Operating experience has shown that these components usually pass the SR when performed at the 24 month Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. This restriction from normally performing the Surveillance in MODE 1, 2, or 3 is further amplified to allow the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed Surveillance, a successful Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the Surveillance; as well as the operator procedures available to cope with

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SURVEILLANCE REQUIREMENTS (continued)

these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when the Surveillance is performed in MODE 1, 2, or 3. Risk insights or deterministic methods may be used for this assessment. Credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.12

In the event of a DBA coincident with a loss of offsite power, the EDGs are required to supply the necessary power to ESF systems so that the fuel, RCS, and containment design limits are not exceeded.

This Surveillance verifies all actions encountered from a loss of offsite power actuation test signal in conjunction with an ECCS initiation signal, including de-energization of emergency buses, load shedding from emergency buses, and energization of the emergency buses and respective loads from the EDG. It further demonstrates the capability of the EDG to automatically achieve the required voltage and frequency within the specified time.

The EDG auto-start and energization of permanently connected loads time of 10 seconds is derived from requirements of the accident analysis for responding to a design basis large break LOCA (Ref. 12). The Surveillance should be continued for a minimum of 5 minutes in order to demonstrate that all starting transients have decayed and stability has been achieved.

The requirement to verify the connection and power supply of permanent and auto-connected loads is intended to satisfactorily show the relationship of these loads to the EDG loading logic. In certain circumstances, many of these loads cannot actually be connected or loaded without undue hardship or potential for undesired operation. For instance, Emergency Core Cooling Systems (ECCS) injection valves are not desired to be stroked open, or systems are not capable of being operated at full flow, or RHR systems performing a decay heat removal function are not desired to be realigned to the ECCS mode of operation. In lieu of actual demonstration of connection and loading of loads, testing that adequately shows the capability of the EDG system to perform these functions is acceptable. This testing may include any series of sequential, overlapping, or total steps so that the entire connection and loading sequence is verified.

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SURVEILLANCE REQUIREMENTS (continued)

The Frequency of 24 months is based on engineering judgment, taking into consideration plant conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths. Operating experience has shown that these components usually pass the SR when performed at the 24 month Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

This SR is modified by two Notes. The reason for Note 1 is to minimize wear and tear on the EDGs during testing. For the purpose of this testing, the EDGs must be started from standby conditions, that is, with the engine coolant and oil being continuously circulated and temperature maintained consistent with manufacturer recommendations. The reason for Note 2 is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. This restriction from normally performing the Surveillance in MODE 1, 2, or 3 is further amplified to allow portions of the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed partial Surveillance, a successful partial Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the partial Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when portions of the Surveillance are performed in MODE 1, 2, or 3. Risk insights or deterministic methods may be used for the assessment. Credit may be taken for unplanned events that satisfy this SR.

SR 3.8.1.13

Under accident conditions loads are sequentially connected to the bus by the individual time delay relays. The sequencing logic controls the permissive and starting signals to motor breakers to prevent overloading of the EDGs and offsite circuits due to high motor starting currents. The minimum load sequence time interval tolerance ensures that sufficient time exists for the EDGs and offsite circuits to restore frequency and voltage prior to applying the next load and that safety analysis assumptions regarding ESF equipment time delays are not violated.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The Frequency of 24 months is based on engineering judgment, taking into consideration plant conditions required to perform the Surveillance and is intended to be consistent with expected fuel cycle lengths. Operating experience has shown that these components usually pass the SR when performed at the 24 month Frequency. Therefore, the Frequency is acceptable from a reliability standpoint.

This SR is modified by a Note. The reason for the Note is that performing the Surveillance would remove a required offsite circuit from service, perturb the electrical distribution system, and challenge safety systems. This restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed Surveillance, a successful Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when the Surveillance is performed in MODE 1 or 2. Risk insights or deterministic methods may be used for this assessment. Credit may be taken for unplanned events that satisfy this SR.

REFERENCES

1. USAR, Section 1.2.6.
2. USAR, Section 8.2.
3. Regulatory Guide 1.9.
4. USAR, Chapter 5.
5. USAR, Chapter 14.
6. Regulatory Guide 1.93.
7. Generic Letter 84-15.
8. USAR, Chapter 8.
9. Regulatory Guide 1.108.

BASES

REFERENCES (continued)

10. Regulatory Guide 1.137.

11. ANSI C84.1, 1982.

12. USAR, Section 14.7.2.

13. IEEE Standard 387-1995.

14. EC 23085, EDG Fuel Oil Train Separation

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.2 AC Sources - Shutdown

BASES

BACKGROUND	A description of the AC sources is provided in the Bases for LCO 3.8.1, "AC Sources - Operating."

APPLICABLE SAFETY ANALYSES

The OPERABILITY of the minimum AC sources during MODES 4 and 5 and during movement of recently irradiated fuel assemblies in the secondary containment ensures that:

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

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

c. Adequate AC electrical power is provided to mitigate events postulated during shutdown, such as an inadvertent draindown of the vessel or a fuel handling accident involving handling recently irradiated fuel. Due to radioactive decay, AC electrical power is only required to be OPERABLE during fuel handling involving recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 24 hours).

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

During MODES 1, 2, and 3, various deviations from the analysis assumptions and design requirements are allowed within the ACTIONS. This allowance is in recognition that certain testing and maintenance activities must be conducted, provided an acceptable level of risk is not exceeded. During MODES 4 and 5, performance of a significant number of required testing and maintenance activities is also required. In

BASES

APPLICABLE SAFETY ANALYSES (continued)

MODES 4 and 5, the activities are generally planned and administratively controlled. Relaxations from typical MODES 1, 2, and 3 LCO requirements are acceptable during shutdown MODES, based on:

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

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

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

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

In the event of an accident during shutdown, this LCO ensures the capability of supporting systems necessary for avoiding immediate difficulty, assuming either a loss of all offsite power or a loss of all onsite (emergency diesel generator (EDG)) power.

AC Sources - Shutdown satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

One offsite circuit capable of supplying the onsite Class 1E power distribution subsystem(s) of LCO 3.8.8, "Distribution Systems - Shutdown," ensures that all required loads are powered from offsite power. An OPERABLE EDG, associated with a Distribution System 4.16 kV essential bus required OPERABLE by LCO 3.8.8, ensures that a diverse power source is available for providing electrical power support assuming a loss of the offsite circuit. Together, OPERABILITY of the required offsite circuit and EDG ensures the availability of sufficient AC sources to operate the plant in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents involving handling recently irradiated fuel and inadvertent reactor vessel draindown). Automatic initiation of the required EDG during shutdown conditions is specified in LCO 3.3.5.1, "ECCS Instrumentation," and LCO 3.3.8.1, "LOP Instrumentation."

The qualified offsite circuit(s) must be capable of maintaining rated frequency and voltage while connected to their respective 4.16 kV essential bus, and of accepting required loads during an accident. The primary AC electrical power distribution subsystem for each division

BASES

LCO (continued)

consists of a 4.16 kV essential bus (essential bus 15 for Division 1 and essential bus 16 for Division 2) having several offsite sources of power available. One offsite circuit consists of incoming disconnects to the 2R transformer, associated 2R transformer, and the respective circuit path including buses and feeder breakers to all 4.16 kV essential buses required by LCO 3.8.8. The second circuit consists of incoming disconnects to the 1R transformer, associated 1R transformer, and the respective circuit path including buses and feeder breakers to all 4.16 kV essential buses required by LCO 3.8.8. The third qualified offsite circuit consists of incoming disconnects to the 1AR transformer, associated 1AR transformer, and the respective circuit path including feeder breakers to all 4.16 kV essential buses required by LCO 3.8.8 (Ref. 1).

The required EDG must be capable of starting, accelerating to rated speed and voltage, connecting to its respective 4.16 kV essential bus on detection of bus undervoltage, and accepting required loads. This sequence must be accomplished within 10 seconds. Each EDG must also be capable of accepting required loads within the assumed loading sequence intervals, and must continue to operate until offsite power can be restored to the 4.16 kV essential buses. These capabilities are required to be met from a variety of initial conditions such as EDG in standby with engine hot and EDG in standby with engine at ambient conditions. Additional EDG capabilities must be demonstrated to meet required Surveillances, e.g., capability of the EDG to reject a load equivalent to its associated single largest post-accident load.

Proper sequencing of loads, including tripping of nonessential loads, is a required function for EDG OPERABILITY. In addition, proper sequence operation is an integral part of offsite circuit OPERABILITY since its inoperability impacts the ability to start and maintain energized loads required OPERABLE by LCO 3.8.8.

The necessary portions of the Emergency Diesel Generator - Emergency Service Water System capable of providing cooling to the required EDG are also required.

BASES

APPLICABILITY

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

a. Systems providing adequate coolant inventory makeup are available for the irradiated fuel assemblies in the core in case of an inadvertent draindown of the reactor vessel;

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

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

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

AC power requirements for MODES 1, 2, and 3 are covered in LCO 3.8.1.

ACTIONS

LCO 3.0.3 is not applicable while in MODE 4 or 5. However, since recently irradiated fuel assembly movement should be accounted for in MODE 1, 2, or 3, although not feasible, the ACTIONS 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, although not feasible, while in MODE 1, 2, or 3, the fuel movement is independent of reactor operations. Entering LCO 3.0.3, while in MODE 1, 2, or 3 would require the unit to be shutdown unnecessarily.

<u>A.1</u>

An offsite circuit is considered inoperable if it is not available to one required division. If two or more 4.16 kV essential buses are required per LCO 3.8.8, one division with offsite power available may be capable of supporting sufficient required features to allow continuation of CORE ALTERATIONS, recently irradiated fuel movement, and operations with a potential for draining the reactor vessel. By the allowance of the option to declare required features inoperable with no offsite power available, appropriate restrictions can be implemented in accordance with the affected required feature(s) LCOs' ACTIONS.

<u>A.2.1, A.2.2, A.2.3, A.2.4, B.1, B.2, B.3, and B.4</u>

With the offsite circuit not available to all required divisions, the option still exists to declare all required features inoperable. Since this option may

BASES

ACTIONS (continued)

involve undesired administrative efforts, the allowance for sufficiently conservative actions is made. With the required EDG inoperable, the minimum required diversity of AC power sources is not available. It is, therefore, required to suspend CORE ALTERATIONS, movement of recently irradiated fuel assemblies in the secondary containment, and activities that could result in inadvertent draining of the reactor vessel.

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

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

Pursuant to LCO 3.0.6, the Distribution System ACTIONS would not be entered even if all AC sources to it are inoperable, resulting in de-energization. Therefore, the Required Actions of Condition A have been modified by a Note to indicate that when Condition A is entered with no AC power to any required 4.16 kV essential bus, ACTIONS for LCO 3.8.8 must be immediately entered. This Note allows Condition A to provide requirements for the loss of the offsite circuit whether or not a division is de-energized. LCO 3.8.8 provides the appropriate restrictions for the situation involving a de-energized division.

SURVEILLANCE REQUIREMENTS

SR 3.8.2.1

SR 3.8.2.1 requires the SRs from LCO 3.8.1 that are necessary for ensuring the OPERABILITY of the AC sources in other than MODES 1, 2, and 3. SR 3.8.1.6 is not required to be met since only one offsite circuit is required to be OPERABLE. Refer to the corresponding Bases for LCO 3.8.1 for a discussion of each SR.

This SR is modified by two Notes. The reason for Note 1 is to preclude requiring the OPERABLE required EDG from being paralleled with the offsite power network or otherwise rendered inoperable during the performance of SRs, and to preclude deenergizing a required 4.16 kV essential bus or disconnecting a required offsite circuit during performance of SRs. With limited AC sources available, a single event could compromise both the required circuit and the EDG. It is the intent that these SRs must still be capable of being met, but actual performance

BASES

SURVEILLANCE REQUIREMENTS (continued)

is not required during periods when the EDG and offsite circuit is required to be OPERABLE. Note 2 states that SRs 3.8.1.8 and 3.8.1.12 are not required to be met when its associated ECCS subsystem(s) are not required to be OPERABLE. These SRs demonstrate the EDG response to an ECCS signal (either alone or in conjunction with a loss-of-power signal). This is consistent with the ECCS instrumentation requirements that do not require the ECCS signals when the ECCS System is not required to be OPERABLE per LCO 3.5.2, "ECCS - Shutdown."

REFERENCES

1. USAR, Section 8.2

B 3.8 ELECTRICAL POWER SYSTEMS

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

BASES

BACKGROUND

The emergency diesel generators (EDGs) are provided with a common fuel oil storage tank having a fuel oil capacity sufficient to operate one EDG for a period of 7 days while the EDG is supplying full load (2500 kW) as discussed in USAR, Section 8.4.1.1 (Ref. 1) and Regulatory Guide 1.137 (Ref. 2). This onsite fuel oil capacity is sufficient to operate the EDGs for longer than the time to replenish the onsite supply from outside sources.

The EDG fuel oil transfer system includes two separate fuel oil transfer subsystems. Fuel oil is transferred from the common fuel oil storage tank to the respective EDG day tank by the subsystem associated with that EDG. Redundancy of the fuel oil transfer pumps and piping precludes the failure of one fuel oil transfer pump, or the rupture of any pipe or valve to result in the loss of more than one EDG. The outside common fuel oil storage tank and piping are located underground. The Division 1 fuel oil transfer pumps are located in the fuel oil pump house. The Division 2 fuel oil transfer pumps are located in the 12 EDG day tank room.

For proper operation of the standby EDGs, it is necessary to ensure the proper quality of the fuel oil. Regulatory Guide 1.137 (Ref. 2) addresses the recommended fuel oil practices as supplemented by ANSI N195 (Ref. 3) and the ASTM standards provided in Reference 5. The fuel oil properties governed by these SRs are the water and sediment content, API gravity, and impurity level.

The EDG lubrication system is designed to provide sufficient lubrication to permit proper operation of its associated EDG under all loading conditions. The system is required to circulate the lube oil to the diesel engine working surfaces and to remove excess heat generated by friction during operation. Each engine oil sump contains an inventory capable of supporting a minimum of 7 days of operation. This supply is sufficient to allow the operator to replenish lube oil from outside sources.

Each EDG includes two independent air start subsystems. Each EDG air start subsystem has adequate capacity with air receiver pressure at $\geq$ 165 psig for two successive start attempts on the EDG without recharging the air start receivers. Each EDG air start subsystem includes three starting air receivers. The automatic start logic for each EDG will provide a cranking sequence to ensure two start attempts from each subsystem staggered such that there are a total of three start attempts on

BASES

BACKGROUND (continued)

the EDG. The first attempt will use the selected air start subsystem, the second attempt will use both air start subsystems, while the third attempt will use the air start subsystem that is not selected or not used on the first attempt. The third start attempt may not occur within enough time for the engine to be ready to accept load within 10 seconds of a demand requirement.

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in USAR, Chapter 14 (Ref. 4), assume Engineered Safety Feature (ESF) systems are OPERABLE. The EDGs are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that fuel, Reactor Coolant System, and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.5, Emergency Core Cooling Systems (ECCS) and Reactor Core Isolation Cooling (RCIC) System; and Section 3.6, Containment Systems.

Since Diesel Fuel Oil, Lube Oil, and Starting Air supports the operation of the standby AC power sources, it satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Stored diesel fuel oil is required to have sufficient supply for 7 days of full load operation for one EDG. It is also required to meet specific standards for quality. Additionally, sufficient lube oil supply must be available to ensure the capability to operate both EDGs at full load for 7 days. This requirement, in conjunction with an ability to obtain replacement supplies within 7 days, supports the availability of EDGs required to shut down the reactor and to maintain it in a safe condition for an anticipated operational occurrence (AOO) or a postulated DBA with loss of offsite power. EDG fuel oil transfer capability from the storage tank to the day tank and from the day tank to the base tank are addressed in LCO 3.8.1, "AC Sources - Operating," and LCO 3.8.2, "AC Sources - Shutdown."

Each starting air subsystem is required to have a minimum capacity for two successive EDG start attempts without recharging the air start receivers.

APPLICABILITY

The AC sources (LCO 3.8.1 and LCO 3.8.2) are required to ensure the availability of the required power to shut down the reactor and maintain it in a safe shutdown condition after an AOO or a postulated DBA. Because stored diesel fuel oil, lube oil, and starting air subsystem support LCO 3.8.1 and LCO 3.8.2, stored diesel fuel oil, lube oil, and starting air are required to be within limits when the associated EDG is required to be OPERABLE.

BASES

ACTIONS

The ACTIONS Table is modified by a Note indicating that separate Condition entry is allowed for each EDG. This is acceptable, since the Required Actions for each Condition provide appropriate compensatory actions for each inoperable EDG subsystem. Complying with the Required Actions for one inoperable EDG subsystem may allow for continued operation, and subsequent inoperable EDG subsystem(s) governed by separate Condition entry and application of associated Required Actions.

A.1

In this Condition, the 7 day fuel oil supply for an EDG is not available. The fuel oil equivalent to a 7-day supply is specified in SR 3.8.3.1. However, the Condition is restricted to fuel oil level reductions that maintain at least a 6 day supply. The fuel oil equivalent to a 6-day supply is 33,063 gallons for the 11 EDG and 47,282 gallons for the 12 EDG (Refs. 6 and 8). These circumstances may be caused by events such as either:

a. Full load operation required for an inadvertent start while at minimum required level; or

b. Feed and bleed operations that may be necessitated by increasing particulate levels or any number of other oil quality degradations.

This restriction allows sufficient time for obtaining the requisite replacement volume and performing the analyses required prior to addition of the fuel oil to the tank. A period of 48 hours is considered sufficient to complete restoration of the required level prior to declaring both EDGs inoperable. This period is acceptable based on the remaining capacity (> 6 days), the fact that procedures will be initiated to obtain replenishment, and the low probability of an event during this brief period.

B.1

In this condition the 7-day lube oil inventory i.e., sufficient lube oil to support 7 days of continuous EDG operation at full load conditions is not available. However, the Condition is restricted to lube oil volume reductions that maintain at least a 6 day supply. The lube oil equivalent volume to a 6-day supply is 142 gallons for each EDG. This restriction allows sufficient time for obtaining the requisite replacement volume. A period of 48 hours is considered sufficient to complete restoration of the required volume prior to declaring the EDG inoperable. This period is acceptable based on the remaining capacity (> 6 days), the low rate of usage, the fact that procedures will be initiated to obtain replenishment, and the low probability of an event during this brief period.

BASES

ACTIONS (continued)

C.1

This Condition is entered as a result of a failure to meet the acceptance criterion for particulates. Normally, trending of particulate levels allows sufficient time to correct high particulate levels prior to reaching the limit of acceptability. Poor sample procedures (bottom sampling), contaminated sampling equipment, and errors in laboratory analysis can produce failures that do not follow a trend. Since the presence of particulates does not mean failure of the fuel oil to burn properly in the diesel engine, since particulate concentration is unlikely to change significantly between Surveillance Frequency intervals, and since proper engine performance has been recently demonstrated (within 31 days), it is prudent to allow a brief period prior to declaring the associated EDG inoperable. The 7 day Completion Time allows for further evaluation, resampling, and re-analysis of the EDG fuel oil.

D.1

With the new fuel oil properties defined in the Bases for SR 3.8.3.3 not within the required limits, a period of 30 days is allowed for restoring the stored fuel oil properties. This period provides sufficient time to test the stored fuel oil to determine that the new fuel oil, when mixed with previously stored fuel oil, remains acceptable, or to restore the stored fuel oil properties. This restoration may involve feed and bleed procedures, filtering, or combination of these procedures. Even if a EDG start and load was required during this time interval and the fuel oil properties were outside limits, there is high likelihood that the EDG would still be capable of performing its intended function.

E.1

With starting air receiver pressure < 165 psig in one air starting subsystem, sufficient capacity for three successive EDG start attempts does not exist. However, as long as the other starting air receiver subsystem pressure is ≥ 165 psig, there is adequate capacity for two start attempts, and the EDG can be considered OPERABLE while the air receiver pressure is restored to the required limit. A period of 7 days is considered sufficient to complete restoration to the required pressure prior to declaring the EDG inoperable. This period is acceptable based on the remaining air start capacity in the other starting air subsystem, the fact that most EDG starts are accomplished on the first attempt, and the low probability of an event during the 7 day period.

BASES

ACTIONS (continued)

F.1

With starting air receiver pressure < 165 psig in both starting air subsystems, sufficient capacity for three successive EDG start attempts does not exist. However, as long as the receiver pressure is > 125 psig in at least one starting air subsystem, there is adequate capacity for at least one start attempt, and the EDG can be considered OPERABLE while the air receiver pressure is restored to the required limit. A period of 48 hours is considered sufficient to complete restoration to the required pressure prior to declaring the EDG inoperable. This period is acceptable based on the remaining air start capacity, the fact that most EDG starts are accomplished on the first attempt, and the low probability of an event during this brief period.

G.1

With a Required Action and associated Completion Time not met, or the stored diesel fuel oil, lube oil, or starting air subsystem not within limits for reasons other than addressed by Conditions A through F, the associated EDG may be incapable of performing its intended function and must be immediately declared inoperable.

SURVEILLANCE REQUIREMENTS

SR 3.8.3.1

This SR provides verification that there is an adequate inventory of fuel oil in the storage tank to support one EDG's operation for 7 days at full load. The fuel oil level equivalent to a 7 day supply is 37,837 gallons for the 11 EDG and 52,401 gallons for the 12 EDG (Refs. 6 and 7) when calculated in accordance with RG 1.137 (Ref. 2) and ANSI N195 (Ref. 3). The required fuel storage volume is determined using the most limiting energy content of the stored fuel that meets the plant design basis requirements. Using the most limiting energy content as verified by direct energy content measurement or the known correlation of diesel fuel oil absolute specific gravity or API gravity to energy content, the required diesel generator output, and the corresponding fuel consumption rate, the onsite fuel storage volume required for 7 days of operation can be determined. SR 3.8.3.3 requires that new and stored fuel oil properties are verified and maintained within the limits of the Diesel Fuel Oil Testing Program. The 7 day period is sufficient time to place the unit in a safe shutdown condition and to bring in replenishment fuel from an offsite location.

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

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.3.2

This Surveillance ensures that sufficient lubricating oil inventory is available to support at least 7 days of full load operation for each EDG. The lube oil volume equivalent to a 7-day supply is 165 gallons and is based on the EDG manufacturer's consumption values for the run time of the EDG. Implicit in this SR is the requirement to verify the capability to transfer the lube oil from its storage location to the EDG, if the EDG lube oil sump does not hold adequate inventory for 7 days of full load operation without the level reaching the manufacturer's recommended minimum level.

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

SR 3.8.3.3

The tests of new fuel oil prior to addition to the storage tank 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. 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 tank. These tests are to be conducted prior to adding the new fuel that is in the diesel oil receiving tank to the storage tank. The tests, limits, and applicable ASTM Standards are as follows:

a. Sample the new fuel oil:

    1) in accordance with ASTM D4057-88 (Ref. 5); or

    2) by recirculating fuel oil to avoid tank stratification and allowing a single point representative sample;

b. Verify that the new fuel oil sample has: (1) an API gravity at 60°F of ≥ 28 and ≤ 38 when tested in accordance with ASTM D287-92 (Ref. 5); (2) a saybolt viscosity at 100°F of ≥ 32.6 and ≤ 40.1 seconds universal when tested in accordance with ASTM D445-96 (Ref. 5); and (3) a flash point of ≥ 125°F when tested in accordance with ASTM D93-97 (Ref. 5); and

c. Verify water and sediment content within limits when tested in accordance with ASTM D1796-90 (Ref. 5).

BASES

SURVEILLANCE REQUIREMENTS (continued)

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

Following the initial analysis of the new fuel oil sample, further analysis is completed prior to or within 31 days following addition of the new fuel oil to the fuel oil storage tank to establish that the other properties specified in Table 1 of ASTM D975-91 (Ref. 5) are met for new fuel oil when tested in accordance with ASTM D975-91 (Ref. 5), except that the analysis for sulfur may be performed in accordance with ASTM D1552-95 (Ref. 5). The 31 day period is acceptable because the fuel oil properties of interest, even if they were not within stated limits, would not have an immediate effect on EDG operation. This Surveillance ensures the availability of high quality fuel oil for the EDGs.

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

Particulate concentrations should be determined in accordance with ASTM D6217-98 (Ref. 5). This method involves a gravimetric determination of total particulate concentration in the fuel oil and has a limit of 10 mg/l. It is acceptable to obtain a field sample for subsequent laboratory testing in lieu of field testing.

The Frequency of this test takes into consideration fuel oil degradation trends that indicate that particulate concentration is unlikely to change significantly between Frequency intervals.

SR 3.8.3.4

This Surveillance ensures that, without the aid of the refill compressor, sufficient air start capacity for each EDG is available. The system design requirements provide for a minimum of three engine start cycles without recharging. A start cycle is up to three seconds of cranking. The pressure specified in this SR is intended to reflect the lowest value at which the three starts can be accomplished.

The 31 day Frequency takes into account the capacity, capability, redundancy, and diversity of the AC sources and other indications available in the control room, including alarms, to alert the operator to below normal air start pressure.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.3.5

Microbiological fouling is a major cause of fuel oil degradation. There are numerous bacteria that can grow in fuel oil and cause fouling, but all must have a water environment in order to survive. Removal of water from the fuel storage tanks once every 31 days eliminates the necessary environment for bacterial survival. This is the most effective means of controlling microbiological fouling. In addition, it eliminates the potential for water entrainment in the fuel oil during EDG operation. Water may come from any of several sources, including condensation, ground water, rain water, contaminated fuel oil, and from breakdown of the fuel oil by bacteria. Frequent checking for and removal of accumulated water minimizes fouling and provides data regarding the watertight integrity of the fuel oil system. The Surveillance Frequencies are established by Regulatory Guide 1.137 (Ref. 2). This SR is for preventive maintenance. The presence of water does not necessarily represent failure of this SR, provided the accumulated water is removed during performance of the Surveillance.

REFERENCES

1. USAR, Section 8.4.1.1.
2. Regulatory Guide 1.137, Revision 1.
3. ANSI N195, 1976.
4. USAR, Chapter 14.
5. ASTM Standards: D4057-88; D287-92; D445-96; D93-97; D1796-90; D975-91; D1552-95; D6217-98.
6. Calculation 90-023, “Minimum Allowable Fuel Oil Storage Tank Level,” Revision 3.
7. EC 27297, “Fuel Oil Transfer Pumps Alternate High Flow Values” (AR 01527421, Calc assumption based on actual value changed).
8. EC 27470, “Diesel Fuel Oil Storage Tank 6 Day Alternate Level” (AR 01533921, Eval did not account for 6 day fuel oil supply).

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.4 DC Sources - Operating

BASES

BACKGROUND

The DC electrical power system provides the AC emergency power system with control power. It also provides both motive and control power to selected safety related equipment. Also, these DC subsystems provide DC electrical power to inverters, which in turn power the AC instrument loads. As required by USAR Section 1.2.6, USAR Section 1.2.10, and USAR Section 1.2.11 (Refs. 1, 2, and 3, respectively), the DC electrical power system is designed to have sufficient independence and redundancy to perform its safety functions, assuming a single failure.

The Division 1 and Division 2 250 VDC electrical power subsystems provide power to the associated uninterruptible AC power supply (UPS). The Division 1 electrical power subsystem also provides power to support the Reactor Core Isolation Cooling (RCIC) System motor operated valves, the RCIC turbine pumps, and other non-critical loads. The Division 2 electrical power subsystem supplies power for the High Pressure Coolant Injection (HPCI) System motor operated valves, the HPCI auxiliary oil pumps, and the Control Room Ventilation System control circuits. Each 250 VDC electrical power subsystem consists of two in series 125 VDC batteries, two normally inservice 125 VDC chargers, a spare 125 VDC charger, and all of the control equipment and interconnecting cabling to the associated distribution panel. Each battery is exclusively associated with a single division. Each set of battery chargers exclusively associated with a 250 VDC electrical power subsystem cannot be interconnected with the other 250 VDC electrical power subsystem. The inservice and spare chargers are supplied from the associated AC load group.

Division 1 and Division 2 125 VDC electrical power subsystems provide control power to the associated 4.16 kV essential bus and for each of the two 480 VAC essential load centers. Each 125 VDC electrical power subsystem consists of a battery, a charger, and all the control equipment and interconnecting cabling up to the associated distribution panels. The inservice chargers are supplied from the associated AC load group. The design includes a spare charger that can be used for either the Division 1 or Division 2 125 VDC electrical power subsystem. However, the spare charger is supplied from the Division 2 AC load group. The two battery buses can be connected to each other only by manually operating two disconnect switches in series; one switch is located at each battery bus. When two independent divisions of 125 VDC power are required, the two battery buses are not operated in a cross-connected configuration.

BASES

BACKGROUND (continued)

During normal operation, the DC loads are powered from the battery chargers with the batteries floating on the system. In case of loss of normal power to the battery charger, the DC loads are automatically powered from the station batteries.

The DC power distribution system is described in more detail in Bases for LCO 3.8.7, "Distribution System - Operating," and LCO 3.8.8, "Distribution System - Shutdown."

Each DC battery subsystem is separately housed in a ventilated room. The common standby 125 VDC battery charger is located in a room separate from the other 125 VDC battery chargers electrical power subsystems. Each subsystem is located in an area separated physically and electrically from the other subsystems to ensure that a single failure in one subsystem does not cause a failure in a redundant subsystem. There is no sharing between redundant Class 1E subsystems such as batteries, battery chargers, or distribution panels, except the common standby 125 VDC battery charger may be shared between the Division 1 and Division 2 125 VDC electrical power subsystems.

Each Division 1 and Division 2 250 VDC battery has adequate storage capacity to meet the duty cycle(s) discussed in USAR, Section 8.5.1.1 (Ref 4). Each Division 1 and Division 2 125 VDC battery has adequate storage capacity to meet the duty cycle(s) discussed in USAR, Section 8.5.2.1 (Ref. 5). The battery is designed with additional capacity above that required by the design duty cycle to allow for temperature variations and other factors.

The batteries for DC electrical power subsystems are sized to produce capacity greater than required for a design basis accident and monitored to ensure battery capacity will remain > 90% during the operating cycle. The minimum design voltage limit is 105/210 V.

The battery cells are of flooded lead acid construction with a nominal specific gravity of 1.215. The open circuit voltage is the voltage maintained when there is no charging or discharging. Once fully charged, the battery cell will maintain 98% capacity for 30 days without further charging per manufacturer's instructions. Optimal long term performance however, is obtained by maintaining a float voltage 2.20 to 2.25 Vpc. This provides adequate over-potential, which limits the formation of lead sulfate and self discharge.

Each battery charger of DC electrical power subsystem has ample power output capacity for the steady state operation of connected loads required during normal operation, while at the same time maintaining its battery

BASES

BACKGROUND (continued)

bank fully charged. Each station service battery charger has sufficient excess capacity to restore the battery from the design minimum charge to its fully charged state within 24 hours while supplying normal steady state loads.

The battery charger is normally in the float-charge mode. Float-charge is the condition in which the charger is supplying the connected loads and the battery cells are receiving adequate current to optimally charge the battery. This assures the internal losses of a battery are overcome and the battery is maintained in a fully charged state.

When desired, the charger can be placed in the equalize mode. The equalize mode is at a higher voltage than the float mode and charging current is correspondingly higher. The battery charger is operated in the equalize mode after a battery discharge or for routine maintenance. Following a battery discharge, the battery recharge characteristic accepts current at the current limit of the battery charger (if the discharge was significant, e.g., following a battery service test) until the battery terminal voltage approaches the charger voltage setpoint. Charging current then reduces exponentially during the remainder of the recharge cycle. Lead-calcium batteries have recharge efficiencies of greater than 95%, so once at least 105% of the ampere-hours discharged have been returned, the battery capacity would be restored to the same condition as it was prior to the discharge. This can be monitored by direct observation of the exponentially decaying charging current or by evaluating the amp-hours discharged from the battery and amp-hours returned to the battery.

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in USAR, Chapter 14 (Ref. 6), assume that Engineered Safety Feature (ESF) systems are OPERABLE. The DC electrical power system provides normal and emergency DC electrical power for the emergency diesel generators (EDGs), emergency auxiliaries, and control and switching during all MODES of operation. The OPERABILITY of the DC subsystems is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This includes maintaining DC sources OPERABLE during accident conditions in the event of:

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

b. A worst case single failure.

The DC Sources - Operating satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

The DC electrical power subsystems - with: 1) each Division 1 and Division 2 250 VDC subsystem consisting of two 125 V batteries in series, two battery chargers, and the corresponding control equipment and interconnecting cabling supplying power to the associated bus; and 2) each Division 1 and Division 2 125 VDC subsystem consisting of one battery, one battery charger, and the corresponding control equipment and interconnecting cabling supplying power to the associated bus are required to be OPERABLE to ensure the availability of the required power to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence (AOO) or a postulated DBA. Loss of any DC electrical power subsystem does not prevent the minimum safety function from being performed (Ref. 7). While the spare Division 2 125 VDC battery charger can be used to supply either the Division 1 or Division 2 125 VDC subsystem, it can be used to meet the LCO requirements only for the Division 2 125 VDC subsystem. If it is supplying the Division 1 125 VDC subsystem, the Division 1 125 VDC subsystem is inoperable.

APPLICABILITY

The DC electrical power sources are required to be OPERABLE in MODES 1, 2, and 3 to ensure safe unit operation and to ensure that:

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

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

The DC electrical power requirements for MODES 4 and 5 are addressed in the Bases for LCO 3.8.5, "DC Sources - Shutdown."

ACTIONS

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

Condition A represents one division with one or more required battery chargers inoperable (e.g., the voltage limit of SR 3.8.4.1 is not maintained). The ACTIONS provide a tiered response that focuses on returning the battery to the fully charged state and restoring a fully qualified charger to OPERABLE status in a reasonable time period. Required Action A.1 requires that the battery terminal voltage be restored to greater than or equal to the minimum established float voltage within 2 hours. This time provides for returning the inoperable charger to OPERABLE status or providing an alternate means of restoring battery terminal voltage to greater than or equal to the minimum established float voltage. Restoring the battery terminal voltage to greater than or equal to the minimum established float voltage provides good assurance that,

BASES

ACTIONS (continued)

within 12 hours, the battery will be restored to its fully charged condition (Required Action A.2) from any discharge that might have occurred due to the charger inoperability.

A discharged battery having terminal voltage of at least the minimum established float voltage indicates that the battery is on the exponential charging current portion (the second part) of its recharge cycle. The time to return a battery to its fully charged state under this condition is simply a function of the amount of the previous discharge and the recharge characteristic of the battery. Thus there is good assurance of fully recharging the battery within 12 hours, avoiding a premature shutdown with its own attendant risk.

If established battery terminal float voltage cannot be restored to greater than or equal to the minimum established float voltage within 2 hours, and the charger is not operating in the current-limiting mode, a faulty charger is indicated. A faulty charger that is incapable of maintaining established battery terminal float voltage does not provide assurance that it can revert to and operate properly in the current limit mode that is necessary during the recovery period following a battery discharge event that the DC system is designed for.

If the charger is operating in the current limit mode after 2 hours that is an indication that the battery is partially discharged and its capacity margins will be reduced. The time to return the battery to its fully charged condition in this case is a function of the battery charger capacity, the amount of loads on the associated DC system, the amount of the previous discharge, and the recharge characteristic of the battery. The charge time can be extensive, and there is not adequate assurance that it can be recharged within 12 hours (Required Action A.2).

Required Action A.2 requires that the battery float current be verified as less than or equal to 2 amps for 250 VDC batteries and less than or equal to 1 amp for 125 VDC batteries. This indicates that, if the battery had been discharged as the result of the inoperable battery charger, it has now been fully recharged. If at the expiration of the initial 12 hour period the battery float current is not less than or equal to 2 amps this indicates there may be additional battery problems and the battery must be declared inoperable.

Required Action A.3 limits the restoration time for the inoperable battery charger to 7 days. This action is applicable if an alternate means of restoring battery terminal voltage to greater than or equal to the minimum

BASES

ACTIONS (continued)

established float voltage has been used (e.g., balance of plant non-Class 1E battery charger). The 7 day Completion Time reflects a reasonable time to effect restoration of the qualified battery charger to OPERABLE status.

B.1

Condition B represents one division with a loss of ability to completely respond to an event, and a potential loss of ability to remain energized during normal operation. It is therefore imperative that the operator's attention focus on stabilizing the unit, minimizing the potential for complete loss of DC power to the affected division. The 2 hour limit is consistent with the allowed time for an inoperable DC Distribution System division.

If one of the required DC electrical power subsystems is inoperable for reasons other than Condition A (e.g., inoperable battery charger(s) and associated inoperable batteries), 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 to mitigate a worst case accident, continued power operation should not exceed 2 hours. The 2 hour Completion Time is based on Regulatory Guide 1.93 (Ref. 8) and reflects a reasonable time to assess unit status as a function of the inoperable DC electrical power subsystem and, if the DC electrical power subsystem is not restored to OPERABLE status, to prepare to effect an orderly and safe unit shutdown.

C.1 and C.2

If the inoperable 125 VDC or 250 VDC electrical power subsystem cannot be restored to OPERABLE status within the required Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems. The Completion Time to bring the unit to MODE 4 is consistent with the time required in Regulatory Guide 1.93 (Ref. 8).

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SURVEILLANCE REQUIREMENTS

SR 3.8.4.1

Verifying battery terminal voltage while on float charge helps to ensure the effectiveness of the battery chargers, which support the ability of the batteries to perform their intended function. Float charge is the condition in which the charger is supplying the continuous charge required to overcome the internal losses of a battery and maintain the battery in a fully charged state while supplying the continuous steady state loads of the associated DC subsystem. On float charge, battery cells will receive adequate current to optimally charge the battery. The voltage requirements are based on the nominal design voltage of the battery and are consistent with the minimum float voltage established by the battery manufacturer (2.20 Vpc or 132 V (for each 250 VDC subsystem battery) and 127.6 V (for each 125 VDC subsystem battery) at the battery terminals). This voltage maintains the battery plates in a condition that supports maintaining the grid life (expected to be approximately 20 years). The 7 day Frequency is conservative when compared with manufacturer recommendations and IEEE-450 (Ref. 9).

SR 3.8.4.2

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

This SR provides two options. One option requires that each Division 1 battery charger be capable of supplying ≥ 150 amps and each Division 2 battery charger be capable of supplying ≥ 110 amps for the 250 VDC subsystems and ≥ 50 amps for the 125 VDC subsystems at the minimum established float voltage for 4 hours. The ampere requirements are based on the output rating of the chargers for Division 1 and the rating of circuit breakers in the associated distribution cabinet for Division 2 (Ref. 11). The voltage requirements are based on the charger voltage level after a response to a loss of AC power. The time period is sufficient for the charger temperature to have stabilized and to have been maintained for at least 2 hours.

The other option requires that each battery charger be capable of recharging the battery after a service test coincident with supplying the largest coincident demands of the various continuous steady state loads (irrespective of the status of the plant during which these demands occur). This level of loading may not normally be available following the

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SURVEILLANCE REQUIREMENTS (continued)

battery service test and will need to be supplemented with additional loads. The duration for this test may be longer than the charger sizing criteria since the battery recharge is affected by float voltage, temperature, and the exponential decay in charging current. The battery is recharged when the measured charging current is ≤ 2 amps for 250 VDC batteries and ≤ 1 amp for 125 VDC batteries.

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

SR 3.8.4.3

A battery service test is a special test of the battery's capability, as found, to satisfy the design requirements (battery duty cycle) of the DC electrical power system. The discharge rate and test length corresponds to the design duty cycle requirements as specified in Reference 4 for the 250 VDC electrical power system and Reference 5 for the 125 VDC electrical power system.

The Frequency of 24 months is acceptable, given plant conditions required to perform the test and the other requirements existing to ensure adequate battery performance during the 24 months intervals. In addition, this Frequency is intended to be consistent with expected fuel cycle lengths.

This SR is modified by two Notes. Note 1 allows the performance of a modified performance discharge test in lieu of a service test.

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. This restriction from normally performing the Surveillance in MODE 1 or 2 is further amplified to allow portions of the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed partial Surveillance, a successful partial Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated

BASES

SURVEILLANCE REQUIREMENTS (continued)

independently for the partial Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when portions of the Surveillance are performed in MODE 1 or 2. Risk insights or deterministic methods may be used for the assessment. Credit may be taken for unplanned events that satisfy this SR.

REFERENCES

1. USAR, Section 1.2.6.
2. USAR, Section 1.2.10.
3. USAR, Section 1.2.11.
4. USAR, Section 8.5.1.1.
5. USAR, Section 8.5.2.1.
6. USAR, Chapter 14.
7. USAR, Section 14.7.2.3.2.
8. Regulatory Guide 1.93.
9. IEEE Standard 450, 1995.
10. Regulatory Guide 1.32, February 1977.
11. Amendment No. 153.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.5 DC Sources - Shutdown

BASES

BACKGROUND

A description of the DC sources is provided in the Bases for LCO 3.8.4, "DC Sources - Operating."

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident and transient analyses in USAR, Chapter 14 (Ref. 1), assume that Engineered Safety Feature systems are OPERABLE. The DC electrical power system provides normal and emergency DC electrical power for the emergency diesel generators (EDGs), emergency auxiliaries, and control and switching during all MODES of operation.

The OPERABILITY of the DC subsystems is consistent with the initial assumptions of the accident analyses and the requirements for the supported systems' OPERABILITY.

The OPERABILITY of the minimum DC electrical power sources during MODES 4 and 5 and during movement of recently irradiated fuel assemblies ensures that:

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

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

c. Adequate DC electrical power is provided to mitigate events postulated during shutdown, such as an inadvertent draindown of the vessel or a fuel handling accident involving handling recently irradiated fuel. Due to radioactive decay, DC electrical power sources are only required to be OPERABLE during fuel handling involving recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 24 hours).

In general, when the unit is shut down, the Technical Specifications requirements ensure that the unit has the capability to mitigate the consequences of postulated accidents. However, assuming a single failure and concurrent loss of all offsite or all onsite power is not required. The rationale for this is based on the fact that many Design Basis Accidents (DBAs) that are analyzed in MODES 1, 2, and 3 have no specific analyses in MODES 4 and 5. Worst case bounding events are deemed not credible in MODES 4 and 5 because the energy contained within the reactor pressure boundary, reactor coolant temperature and pressure, and the corresponding stresses result in the probabilities of occurrence being significantly reduced or eliminated, and in minimal

BASES

APPLICABLE SAFETY ANALYSES (continued)

consequences. These deviations from DBA analysis assumptions and design requirements during shutdown conditions are allowed by the LCO for required systems.

The shutdown Technical Specification requirements are designed to ensure that the unit has the capability to mitigate the consequences of certain postulated accidents. Worst case DBAs which are analyzed for operating MODES are generally viewed not to be a significant concern during shutdown MODES due to the lower energies involved. The Technical Specifications therefore require a lesser complement of electrical equipment to be available during shutdown than is required during operating MODES. More recent work completed on the potential risks associated with shutdown, however, have found significant risk associated with certain shutdown evolutions. As a result, in addition to the requirements established in the Technical Specifications, the industry has adopted NUMARC 91-06, "Guidelines for Industry Actions to Assess Shutdown Management," as an Industry initiative to manage shutdown tasks and associated electrical support to maintain risk at an acceptable low level. This may require the availability of additional equipment beyond that required by the shutdown Technical Specifications.

The DC Sources - Shutdown satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The Division 1 or Division 2 125 VDC electrical power subsystem consisting of one 125 V battery, one battery charger, and the corresponding control equipment and interconnecting cabling is required to be OPERABLE to support one division of the DC electrical power distribution subsystem(s) required OPERABLE by LCO 3.8.8, "Distribution Systems - Shutdown." This requirement ensures the availability of sufficient DC electrical power sources to operate the unit in a safe manner and to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents involving handling recently irradiated fuel and inadvertent reactor vessel draindown).

APPLICABILITY

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

a. Required features to provide adequate coolant inventory makeup are available for the irradiated fuel assemblies in the core in case of an inadvertent draindown of the reactor vessel;

b. Required features needed to mitigate a fuel handling accident involving handling recently irradiated fuel are available;

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APPLICABILITY (continued)

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

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

The DC electrical power requirements for MODES 1, 2, and 3 are covered in LCO 3.8.4.

ACTIONS

LCO 3.0.3 is not applicable while in MODE 4 or 5. However, since recently irradiated fuel assembly movement should be accounted for in MODE 1, 2, or 3, although not feasible, the ACTIONS 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, although not feasible, the fuel movement is independent of reactor operations. Entering LCO 3.0.3, while in MODE 1, 2, or 3 would require the unit to be shutdown unnecessarily.

<u>A.1, A.2, A.3, and A.4</u>

If the required Division 1 or Division 2 125 VDC electrical power subsystem is inoperable, the minimum required DC power sources are not available. Therefore, suspension of CORE ALTERATIONS, movement of recently irradiated fuel assemblies in the secondary containment, and any activities that could result in inadvertent draining of the reactor vessel is required.

Suspension of these activities shall not preclude completion of actions to establish a safe conservative condition. These actions minimize the probability of the occurrence of postulated events. It is further required to immediately initiate action to restore the required DC electrical power subsystem and to continue this action until restoration is accomplished in order to provide the necessary DC electrical power to the plant safety systems.

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

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SURVEILLANCE REQUIREMENTS

SR 3.8.5.1

SR 3.8.5.1 requires performance of all Surveillances required by SR 3.8.4.1 through SR 3.8.4.3. Therefore, see the corresponding Bases for LCO 3.8.4 for a discussion of each SR.

This SR is modified by a Note. The reason for the Note is to preclude requiring the OPERABLE DC sources from being discharged below their capability to provide the required power supply or otherwise rendered inoperable during the performance of SRs. It is the intent that these SRs must still be capable of being met, but actual performance is not required.

REFERENCES

1. USAR, Chapter 14.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.6 Battery Parameters

BASES

BACKGROUND

This LCO delineates the limits on battery float current as well as cell electrolyte temperature, level, and float voltage for the DC electrical power subsystems batteries. A discussion of these batteries and their OPERABILITY requirements is provided in the Bases for LCO 3.8.4, "DC Sources - Operating," and LCO 3.8.5, "DC Sources - Shutdown." In addition to the limitations of this Specification, the Battery Monitoring and Maintenance Program also implements a program specified in Specification 5.5.12 for monitoring various battery parameters that is based on the recommendations of IEEE Standard 450-1995, "IEEE Recommended Practice For Maintenance, Testing, And Replacement Of Vented Lead-Acid Batteries For Stationary Applications" (Ref. 1).

The battery cells are of flooded lead acid construction with a nominal specific gravity of 1.215. The open circuit voltage is the voltage maintained when there is no charging or discharging. Once fully charged, the battery cell will maintain 98% capacity for 30 days without further charging per manufacturer's instructions. Optimal long term performance however, is obtained by maintaining a float voltage 2.20 to 2.25 Vpc. This provides adequate over-potential which limits the formation of lead sulfate and self discharge.

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in USAR, Chapter 14 (Ref. 2), assume Engineered Safety Feature systems are OPERABLE. The DC electrical power subsystems provide normal and emergency DC electrical power for the emergency diesel generators (EDGs), emergency auxiliaries, and control and switching during all MODES of operation.

The specific Applicable Safety Analyses for the DC Electrical Power System are provided in the Bases of LCO 3.8.4 and LCO 3.8.5.

Since Battery Parameters support the operation of the DC electrical power subsystems, they satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Battery parameters must remain within acceptable limits to ensure availability of the required DC power to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence or a postulated DBA. Battery parameter limits are conservatively established, allowing continued DC electrical system function even with limits not met. Additional preventative maintenance, testing, and monitoring performed in accordance with the Battery Monitoring and Maintenance Program is conducted as specified in Specification 5.5.12.

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APPLICABILITY

The battery parameters are required solely for the support of the associated DC electrical power subsystem. Therefore, battery parameter limits are only required when the DC electrical power subsystem is required to be OPERABLE. Refer to the Applicability discussions in Bases for LCO 3.8.4 and LCO 3.8.5.

ACTIONS

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

With one or more cells in one or more batteries < 2.07 V, the battery cell is degraded. Within 2 hours verification of the required battery charger OPERABILITY is made by monitoring the battery terminal voltage (SR 3.8.4.1) and of the overall battery state of charge by monitoring the battery float charge current (SR 3.8.6.1). This assures that there is still sufficient battery capacity to perform the intended function. Therefore, the affected battery is not required to be considered inoperable solely as a result of one or more cells in one or more batteries < 2.07 V, and continued operation is permitted for a limited period up to 24 hours.

Since the Required Actions only specify "perform," a failure of SR 3.8.4.1 or SR 3.8.6.1 acceptance criteria does not result in this Required Action not met. However, if one of the SRs is failed the appropriate Condition(s), depending on the cause of the failures, is entered. If SR 3.8.6.1 is failed then there is not assurance that there is still sufficient battery capacity to perform the intended function and the battery must be declared inoperable immediately.

B.1 and B.2

One or more batteries with float current > 2 amps for the 250 VDC batteries or > 1 amp for 125 VDC batteries indicates that a partial discharge of the battery capacity has occurred. This may be due to a temporary loss of a battery charger or possibly due to one or more battery cells in a low voltage condition reflecting some loss of capacity. Within 2 hours verification of the required battery charger OPERABILITY is made by monitoring the battery terminal voltage. If the terminal voltage is found to be less than the minimum established float voltage there are two possibilities, the battery charger is inoperable or is operating in the current limit mode. If the charger is operating in the current limit mode after 2 hours that is an indication that the battery has been substantially discharged and likely cannot perform its required design functions. The time to return the battery to its fully charged condition in this case is a function of the battery charger capacity, the amount of loads on the associated DC system, the amount of the previous discharge, and the recharge characteristic of the battery. The charge time can be extensive, and there is not adequate assurance that it can be recharged within 12 hours (Required Action B.2). The battery must therefore be declared inoperable.

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ACTIONS (continued)

If the float voltage is found to be satisfactory there is good assurance that, within 12 hours, the battery will be restored to its fully charged condition (Required Action B.2) from any discharge that might have occurred due to a temporary loss of the battery charger.

A discharged battery with float voltage (the charger setpoint) across its terminals indicates that the battery is on the exponential charging current portion (the second part) of its recharge cycle. The time to return a battery to its fully charged state under this condition is simply a function of the amount of the previous discharge and the recharge characteristic of the battery. Thus there is good assurance of fully recharging the battery within 12 hours, avoiding a premature shutdown with its own attendant risk.

If the condition is due to one or more cells in a low voltage condition but still greater than 2.07 V and float voltage is found to be satisfactory, this is not indication of a substantially discharged battery and 12 hours is a reasonable time prior to declaring the battery inoperable.

Since Required Action B.1 only specifies "perform," a failure of SR 3.8.4.1 acceptance criteria does not result in the Required Action not met. However, if SR 3.8.4.1 is failed, the appropriate Condition(s), depending on the cause of the failure, is entered.

C.1, C.2, and C.3

With one or more batteries with one or more cells electrolyte level above the top of the plates, but below the minimum established design limits, the battery still retains sufficient capacity to perform the intended function. Therefore, the affected battery is not required to be considered inoperable solely as a result of electrolyte level not met. Within 31 days the minimum established design limits for electrolyte level must be re-established.

With electrolyte level below the top of the plates there is a potential for dryout and plate degradation. Required Actions C.1 and C.2 address this potential (as well as provisions in Specification 5.5.12, "Battery Monitoring and Maintenance Program." They are modified by a Note that indicates they are only applicable if electrolyte level is below the top of the plates. Within 8 hours level is required to be restored to above the top of the plates. The Required Action C.2 requirement to verify that there is no leakage by visual inspection and the Specification 5.5.12.b requirement to initiate action to equalize and test in accordance with manufacturer's

BASES

ACTIONS (continued)

recommendation are taken from Annex D of IEEE Standard 450-1995. They are performed following the restoration of the electrolyte level to above the top of the plates. Based on the results of the manufacturer's recommended testing the batteries may have to be declared inoperable and the affected cells replaced.

D.1

With one or more batteries with pilot cell temperature less than the minimum established design limits, 12 hours is allowed to restore the temperature to within limits. A low electrolyte temperature limits the current and power available. Since the battery is sized with margin, while battery capacity is degraded, sufficient capacity exists to perform the intended function and the affected battery is not required to be considered inoperable solely as a result of the pilot cell temperature not met.

E.1

With batteries in redundant divisions with battery parameters not within limits there is not sufficient assurance that battery capacity has not been affected to the degree that the batteries can still perform their required function, given that redundant batteries are involved. With redundant batteries involved this potential could result in a total loss of function on multiple systems that rely upon the batteries. The longer Completion Times specified for battery parameters on non-redundant batteries not within limits are therefore not appropriate, and the parameters must be restored to within limits on at least one division within 2 hours.

F.1

When any battery parameter is outside the allowances of the Required Actions for Condition A, B, C, D, or E, or failure of SR 3.8.6.6, sufficient capacity to supply the maximum expected load requirement is not ensured and the corresponding battery must be declared inoperable. Additionally, discovering one or more batteries in one division with one or more battery cells float voltage less than 2.07 V and float current greater than 2 amps for 250 VDC batteries or greater than 1 amp for 125 VDC batteries indicates that the battery capacity may not be sufficient to perform the intended functions. The battery must therefore be declared inoperable immediately.

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SURVEILLANCE REQUIREMENTS

SR 3.8.6.1

Verifying battery float current while on float charge is used to determine the state of charge of the battery. Float charge is the condition in which the charger is supplying the continuous charge required to overcome the internal losses of a battery and maintain the battery in a charged state. The float current requirements are based on the float current indicative of a charged battery. Use of float current to determine the state of charge of the battery is consistent with IEEE-450 (Ref. 1). The 7 day Frequency is more conservative than the recommendations of IEEE-450 (Ref. 1).

This SR is modified by a Note that states the float current requirement is not required to be met when battery terminal voltage is less than the minimum established float voltage of SR 3.8.4.1. When this float voltage is not maintained the Required Actions of LCO 3.8.4 ACTION A are being taken, which provide the necessary and appropriate verifications of the battery condition. Furthermore, the float current limit of 2 amps for 250 VDC batteries and 1 amp for 125 VDC batteries is established based on the nominal float voltage value and is not directly applicable when this voltage is not maintained.

SR 3.8.6.2 and SR 3.8.6.5

Optimal long term battery performance is obtained by maintaining a float voltage greater than or equal to the minimum established design limits provided by the battery manufacturer, which corresponds to 132 V for a 60 cell battery and 127.6 V for a 58 cell battery at the battery terminals, or 2.20 Vpc. This provides adequate over-potential, which limits the formation of lead sulfate and self discharge, which could eventually render the battery inoperable. Float voltages in this range or less, but greater than 2.07 Vpc, are addressed in Specification 5.5.12. SRs 3.8.6.2 and 3.8.6.5 require verification that the cell float voltages are equal to or greater than the short term absolute minimum voltage of 2.07 V, with cell voltage measured to the nearest 0.01 volt. The Frequencies for cell voltage verification every 31 days for pilot cell and 92 days for each connected cell are consistent with IEEE-450 (Ref. 1).

SR 3.8.6.3

The limit specified for electrolyte level ensures that the plates suffer no physical damage and maintains adequate electron transfer capability. The Frequency is consistent with IEEE-450 (Ref. 1).

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.6.4

This Surveillance verifies that the pilot cell temperature is greater than or equal to the minimum established design limit (i.e., 60°F). Pilot cell electrolyte temperature is maintained above this temperature to assure the battery can provided the required current and voltage to meet the design requirements. Temperatures lower than assumed in battery sizing calculations act to inhibit or reduce battery capacity. The Frequency is consistent with IEEE-450 (Ref. 1).

SR 3.8.6.6

A battery performance discharge test is a test of constant current capacity of a battery, normally done in the as found condition, after having been in service, to detect any change in the capacity determined by the acceptance test. The test is intended to determine overall battery degradation due to age and usage.

Either the battery performance discharge test or the modified performance discharge test is acceptable for satisfying SR 3.8.6.6; however, only the modified performance discharge test may be used to satisfy the battery service test requirements of SR 3.8.4.3.

A modified discharge test is a test of the battery capacity and its ability to provide a high rate, short duration load (usually the highest rate of the duty cycle). This will often confirm the battery's ability to meet the critical period of the load duty cycle, in addition to determining its percentage of rated capacity. Initial conditions for the modified performance discharge test should be identical to those specified for a performance discharge test as specified in IEEE-450 (Ref. 1).

It may consist of just two rates; for instance, the one minute rate for the battery or the largest current load of the duty cycle, followed by the test rate employed for the performance test, both of which envelope the duty cycle of the service test. Since the ampere-hours removed by a one minute discharge represents a very small portion of the battery capacity, the test rate can be changed to that for the modified performance discharge test without compromising the results of the performance discharge test. The battery terminal voltage for the modified performance discharge test must remain above the minimum battery terminal voltage specified in the battery service test for the duration of time equal to that of the service test.

BASES

SURVEILLANCE REQUIREMENTS (continued)

The acceptance criteria for this Surveillance are consistent with IEEE-450 (Ref. 1). This reference recommends that the battery be replaced if its capacity is below 80% of the manufacturer's rating if the battery was sized using a 1.25 aging factor. If a lesser aging factor was used, battery replacement will be required before 80% capacity is reached to ensure that the load can be served. The 250 VDC batteries were sized using a 1.11 aging factor, therefore a 90% capacity limit was chosen. While the 125 VDC batteries were sized using a 1.25 aging factor, a similar 90% capacity limit was chosen for conservatism. Furthermore, the 125 VDC and 250 VDC batteries are sized to meet the assumed duty cycle loads when the battery design capacity reaches this 90% limit.

The Frequency for this test is normally 60 months. If the battery shows degradation, or if the battery has reached 85% of its expected life and capacity is < 100% of the manufacturer's rating, the Surveillance Frequency is reduced to 12 months. However, if the battery shows no degradation but has reached 85% of its expected life, the Surveillance Frequency is only reduced to 24 months for batteries that retain capacity ≥ 100% of the manufacturer's rating. Degradation is indicated, according to IEEE-450 (Ref. 1), when the battery capacity drops by more than 10% relative to its capacity on the previous performance test or when it is below 90% of the manufacturer's rating. The 12 month and 60 month Frequencies are consistent with the recommendations in IEEE-450 (Ref. 1). The 24 month Frequency is derived from the recommendations of IEEE-450 (Ref. 1).

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. This restriction from normally performing the Surveillance in MODE 1, 2, or 3 is further amplified to allow portions of the Surveillance to be performed for the purpose of reestablishing OPERABILITY (e.g., post work testing following corrective maintenance, corrective modification, deficient or incomplete surveillance testing, and other unanticipated OPERABILITY concerns) provided an assessment determines plant safety is maintained or enhanced. This assessment shall, as a minimum, consider the potential outcomes and transients associated with a failed partial Surveillance, a successful partial Surveillance, and a perturbation of the offsite or onsite system when they are tied together or operated independently for the partial Surveillance; as well as the operator procedures available to cope with these outcomes. These shall be measured against the avoided risk of a plant shutdown and startup to determine that plant safety is maintained or enhanced when portions of the Surveillance are performed in MODE 1, 2, or 3. Risk insights or deterministic methods may be used for the assessment. Credit may be taken for unplanned events that satisfy this Surveillance.

BASES

REFERENCES

1. IEEE Standard 450, 1995.
2. USAR, Chapter 14.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.7 Distribution Systems - Operating

BASES

BACKGROUND

The onsite Class 1E AC and DC electrical power distribution system is divided into redundant and independent AC and DC electrical power distribution subsystems.

The primary AC electrical power distribution subsystem for each division consists of a 4.16 kV essential bus (essential bus 15 for Division 1 and essential bus 16 for Division 2) having several offsite sources of power available as well as a dedicated onsite emergency diesel generator (EDG) source. Each 4.16 kV essential bus is normally connected to the primary station auxiliary transformer, 2R, via its associated plant auxiliary 4.16 kV bus. During a loss of the 2R transformer to the 4.16 kV essential buses, the alternate supply breakers from the reserve transformer, 1R, attempt to close. In the event the 1R transformer is unable to accept the load, the essential buses are automatically transferred to the reserve auxiliary transformer, 1AR. The 1AR transformer supplies power directly to the essential buses. If all offsite sources are unavailable, the onsite EDGs supply power to the 4.16 kV essential buses.

Each AC distribution subsystem also includes 480 VAC load centers 103 and 104. Each load center is supplied from the associated 4.16 kV essential bus via a transformer.

There are two independent 125/250 VDC electrical power distribution subsystems that support the necessary power for Engineered Safety Feature (ESF) functions. Each 125/250 VDC electrical power distribution subsystem is supplied by a Division 1 or Division 2 250 VDC electrical power subsystem. Each subsystem consists of a distribution cabinet. There are two independent 125 VDC electrical power distribution subsystems that support the necessary power for safety functions. A Division 1 or Division 2 125 VDC electrical power subsystem supplies the associated 125 VDC electrical power distribution subsystem. Each subsystem consists of a 125 VDC distribution panel.

The list of all required distribution subsystem buses, load centers, distribution cabinets, and distribution panels is presented in Table B 3.8.7-1.

BASES

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident (DBA) and transient analyses in USAR, Chapter 14 (Ref. 1), assume ESF systems are OPERABLE. The AC and DC electrical power distribution systems are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Reactor Coolant System, and containment design limits are not exceeded. These limits are discussed in more detail in the Bases for Section 3.2, Power Distribution Limits; Section 3.5, Emergency Core Cooling Systems (ECCS) and Reactor Core Isolation Cooling (RCIC) System; and Section 3.6, Containment Systems.

The OPERABILITY of the AC and DC electrical power distribution subsystems is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the unit. This includes maintaining distribution systems OPERABLE during accident conditions in the event of:

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

b. A worst case active single failure.

The Distribution Systems - Operating satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The required electrical power distribution subsystems listed in Table B 3.8.7-1 ensure the availability of AC and DC electrical power for the systems required to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence (AOO) or a postulated DBA. The Division 1 and Division 2 AC and DC electrical power distribution subsystems are required to be OPERABLE. As noted in Table B 3.8.7-1, each division of the AC and DC Electrical Power Distribution Systems is a subsystem.

Maintaining the Division 1 and Division 2 AC and DC electrical power distribution subsystems OPERABLE ensures that the redundancy incorporated into the design of ESF is not defeated. Therefore, a single failure within any system or within the electrical power distribution subsystems will not prevent safe shutdown of the reactor.

The AC electrical power distribution subsystems require the associated buses and electrical circuits, including any load centers, to be energized to their proper voltages. OPERABLE DC electrical power distribution subsystems require the associated distribution panels to be energized to their proper voltage from either the associated battery or charger.

BASES

LCO (continued)

Based on the number of safety significant electrical loads associated with each bus listed in Table B 3.8.7-1, if one or more of the buses becomes inoperable, entry into the appropriate ACTIONS of LCO 3.8.7 is required. Some buses, such as motor control centers or panels, which help comprise the AC and DC distribution systems, are not listed in Table B 3.8.7-1. The loss of electrical loads associated with these buses may not result in a complete loss of a redundant safety function necessary to shut down the reactor and maintain it in a safe condition. Therefore, should one or more of these buses become inoperable due to a failure not affecting the OPERABILITY of a bus listed in Table B 3.8.7-1 (e.g., a breaker supplying a single distribution panel fails open), the individual loads on the bus would be declared inoperable, and the appropriate Conditions and Required Actions of the LCOs governing the individual loads would be entered. However, if one or more of these buses is inoperable due to a failure also affecting the OPERABILITY of a bus listed in Table B 3.8.7-1 (e.g., loss of 4.16 kV essential bus, which results in de-energization of all buses powered from the 4.16 kV essential bus), then although the individual loads are still considered inoperable, the Conditions and Required Actions of the LCO for the individual loads are not required to be entered, since LCO 3.0.6 allows this exception (i.e., the loads are inoperable due to the inoperability of a support system governed by a Technical Specification; the 4.16 kV essential bus)

In addition, tie breakers between redundant safety related AC and DC power distribution subsystems must be open. This prevents any electrical malfunction in any power distribution subsystem from propagating to the redundant subsystem, which could cause the failure of a redundant subsystem and a loss of essential safety function(s). If any tie breakers between redundant safety related AC or DC electrical power distribution subsystems are closed, the electrical power distribution subsystem that is not being powered from its normal source (i.e., it is being powered from its redundant electrical power distribution subsystem) is considered inoperable. This applies to the onsite, safety related, redundant electrical power distribution subsystems. It does not, however, preclude redundant Class 1E 4.16 kV essential buses from being powered from the same offsite circuit.

APPLICABILITY

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

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

BASES

APPLICABILITY (continued)

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

Electrical power distribution subsystem requirements for MODES 4 and 5 and other conditions in which AC and DC electrical power distribution subsystems are required are covered in the Bases for LCO 3.8.8, "Distribution Systems - Shutdown."

ACTIONS

A.1

With one or more Division 1 and Division 2 required AC buses or load centers inoperable and a loss of function has not occurred, the remaining AC electrical power distribution subsystems are capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure. The overall reliability is reduced, however, because a single failure in the remaining electrical power distribution subsystems could result in the minimum required ESF functions not being supported. Therefore, the required AC buses and load centers must be restored to OPERABLE status within 8 hours.

The Condition A worst scenario is one division without AC power (i.e., no offsite power to the division and the associated EDG inoperable). In this situation, the unit is more vulnerable to a complete loss of AC power. It is, therefore, imperative that the unit operators' attention be focused on minimizing the potential for loss of power to the remaining division by stabilizing the unit and restoring power to the affected division. The 8 hour time limit before requiring a unit shutdown in this Condition is acceptable because of:

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

b. The low potential for an event in conjunction with a single failure of a redundant component in the division with AC power. (The redundant component is verified OPERABLE in accordance with Specification 5.5.10, "Safety Function Determination Program (SFDP).")

Required Action A.1 is modified by a Note that requires the applicable Conditions and Required Actions of LCO 3.8.4, "DC Sources - Operating," to be entered for DC divisions made inoperable by inoperable power

BASES

ACTIONS (continued)

distribution subsystems. This is an exception to LCO 3.0.6 and ensures the proper actions are taken for these components. Inoperability of a distribution system can result in loss of charging power to batteries and eventual loss of DC power. This Note ensures that the appropriate attention is given to restoring charging power to batteries, if necessary, after loss of distribution systems.

B.1

With one or more DC distribution panel(s) inoperable, and a loss of function has not yet occurred, the remaining DC electrical power distribution subsystem is capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure. The overall reliability is reduced, however, because a single failure in the remaining DC electrical power distribution subsystem could result in the minimum required ESF functions not being supported. Therefore, the required DC electrical power distribution subsystem(s) must be restored to OPERABLE status within 2 hours by powering the bus from the associated battery or charger.

Condition B worst scenario is one division without adequate DC power, potentially with both the battery significantly degraded and the associated charger nonfunctioning. In this situation the plant is significantly more vulnerable to a complete loss of all DC power. It is, therefore, imperative that the operator's attention focus on stabilizing the plant, minimizing the potential for loss of power to the remaining divisions, and restoring power to the affected division.

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

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

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

BASES

ACTIONS (continued)

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

The 2 hour Completion Time for DC electrical power distribution subsystems is consistent with Regulatory Guide 1.93 (Ref. 2).

C.1 and C.2

If the inoperable distribution subsystem cannot be restored to OPERABLE status within the associated Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

D.1

Condition D corresponds to a level of degradation in the electrical power distribution system that causes a required safety function to be lost. When the inoperability of two or more AC or DC electrical power distribution subsystems, in combination, 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. The term "combination" means that the loss of function must result from the inoperability of two or more AC and DC electrical power distribution subsystems; a loss of function solely due to a single AC or DC electrical power distribution subsystem inoperability even with another AC or DC electrical power distribution subsystem concurrently inoperable does not require entry in Condition D.

SURVEILLANCE REQUIREMENTS

SR 3.8.7.1

This Surveillance verifies that the AC and DC electrical power distribution subsystems are functioning properly, with the correct circuit breaker alignment. The correct breaker alignment ensures the appropriate separation and independence of the electrical divisions are maintained, and the appropriate voltage is available to each required bus, load center, or distribution panel. The verification of proper voltage availability on the

BASES

SURVEILLANCE REQUIREMENTS (continued)

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. USAR, Chapter 14.

2. Regulatory Guide 1.93, December 1974.

Table B 3.8.7-1 (page 1 of 1)
AC and DC Electrical Power Distribution Systems

TYPE	VOLTAGE	DIVISION 1[(a)]	DIVISION 2[(a)]
AC Buses	4.16 kV	Essential Bus 15	Essential Bus 16
	480 V	Load Center 103	Load Center 104
DC Buses	125/250 V	Distribution Panel D31	Distribution Panel D100
	125 V	Distribution Panel D11	Distribution Panel D21

(a) Each division of the AC and DC Electrical Power Distribution Systems is a subsystem.

B 3.8 ELECTRICAL POWER SYSTEMS

B 3.8.8 Distribution Systems - Shutdown

BASES

BACKGROUND

A description of the AC and DC electrical power distribution system is provided in the Bases for LCO 3.8.7, "Distribution Systems - Operating."

APPLICABLE SAFETY ANALYSES

The initial conditions of Design Basis Accident and transient analyses in USAR, Chapter 14 (Ref. 1), assume Engineered Safety Feature (ESF) systems are OPERABLE. The AC and DC electrical power distribution systems are designed to provide sufficient capacity, capability, redundancy, and reliability to ensure the availability of necessary power to ESF systems so that the fuel, Emergency Core Cooling Systems and Reactor Core Isolation Cooling System, and containment design limits are not exceeded.

The OPERABILITY of the AC and DC electrical power distribution system is consistent with the initial assumptions of the accident analyses and the requirements for the supported systems' OPERABILITY.

The OPERABILITY of the minimum AC and DC electrical power sources and associated power distribution subsystems during MODES 4 and 5, and during movement of recently irradiated fuel assemblies in the secondary containment ensures that:

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

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

c. Adequate power is provided to mitigate events postulated during shutdown, such as an inadvertent draindown of the vessel or a fuel handling accident involving handling recently irradiated fuel. Due to radioactive decay, AC and DC electrical power distribution subsystems are only required to be OPERABLE during fuel handling involving recently irradiated fuel (i.e., fuel that has occupied part of a critical reactor core within the previous 24 hours).

The Distribution Systems - Shutdown satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

Various combinations of subsystems, equipment, and components are required OPERABLE by other LCOs, depending on the specific plant condition. Implicit in those requirements is the required OPERABILITY of necessary support required features. This LCO explicitly requires energization of the portions of the electrical distribution system necessary to support OPERABILITY of Technical Specifications required systems,

LCO (continued)

equipment, and components - both specifically addressed by their own LCO, and implicitly required by the definition of OPERABILITY.

Maintaining these portions of the distribution system energized ensures the availability of sufficient power to operate the plant in a safe manner to mitigate the consequences of postulated events during shutdown (e.g., fuel handling accidents involving handling recently irradiated fuel and inadvertent reactor vessel draindown).

APPLICABILITY

The AC and DC electrical power distribution subsystems required to be OPERABLE in MODES 4 and 5 and during movement of recently irradiated fuel assemblies in the secondary containment provide assurance that:

a. Systems to provide adequate coolant inventory makeup are available for the irradiated fuel in the core in case of an inadvertent draindown of the reactor vessel;

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

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

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

The AC and DC electrical power distribution subsystem requirements for MODES 1, 2, and 3 are covered in LCO 3.8.7.

ACTIONS

LCO 3.0.3 is not applicable while in MODE 4 or 5. However, since recently irradiated fuel assembly movement should be accounted for in MODE 1, 2, or 3, although not feasible, the ACTIONS 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, although not feasible, the fuel movement is independent of reactor operations. Entering LCO 3.0.3, while in MODE 1, 2, or 3 would require the unit to be shutdown unnecessarily.

<u>A.1, A.2.1, A.2.2, A.2.3, A.2.4, and A.2.5</u>

Although redundant required features may require redundant divisions of electrical power distribution subsystems to be OPERABLE, one OPERABLE distribution subsystem division may be capable of supporting

ACTIONS (continued)

sufficient required features to allow continuation of CORE ALTERATIONS, recently irradiated fuel movement, and operations with a potential for draining the reactor vessel. By allowing the option to declare required features associated with an inoperable distribution subsystem inoperable, appropriate restrictions are implemented in accordance with the affected distribution subsystem LCO's Required Actions. In many instances this option may involve undesired administrative efforts. Therefore, the allowance for sufficiently conservative actions is made, (i.e., to suspend CORE ALTERATIONS, movement of recently irradiated fuel assemblies in the secondary containment, and any activities that could result in inadvertent draining of the reactor vessel).

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

Notwithstanding performance of the above conservative Required Actions, a required residual heat removal-shutdown cooling (RHR-SDC) subsystem may be inoperable. In this case, Required Actions A.2.1 through A.2.4 do not adequately address the concerns relating to coolant circulation and heat removal. Pursuant to LCO 3.0.6, the RHR-SDC ACTIONS would not be entered. Therefore, Required Action A.2.5 is provided to direct declaring RHR-SDC inoperable, which results in taking the appropriate RHR-SDC ACTIONS.

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

SURVEILLANCE REQUIREMENTS

SR 3.8.8.1

This Surveillance verifies that the AC and DC electrical power distribution subsystems are functioning properly, with the buses energized. The verification of proper voltage availability on the buses ensures that the required power is readily available for motive as well as control functions for critical system loads connected to these buses. The 7 day Frequency takes into account the redundant capability of the electrical power distribution subsystems, as well as other indications available in the control room that alert the operator to subsystem malfunctions.

REFERENCES

1. USAR, Chapter 14.

B 3.9 REFUELING OPERATIONS

B 3.9.1 Refueling Equipment Interlocks

BASES

BACKGROUND

Refueling equipment interlocks restrict the operation of the refueling equipment or the withdrawal of control rods to reinforce unit procedures that prevent the reactor from achieving criticality during refueling. The refueling interlock circuitry senses the conditions of the refueling equipment and the control rods. Depending on the sensed conditions, interlocks are actuated to prevent the operation of the refueling equipment or the withdrawal of control rods.

USAR, Section 1.2.2 (Ref. 1), requires the reactor core to be designed so that control rod action, with the maximum worth control rod fully withdrawn and unavailable for use, is capable of bringing the reactor core subcritical and maintaining it so from any power level in the operating cycle. The control rods, when fully inserted, serve as the system capable of maintaining the reactor subcritical in cold conditions during all fuel movement activities and accidents.

Two channels of instrumentation are provided to sense the position of the refueling platform and the full insertion of all control rods. Additionally, inputs are provided for the loading of the refueling platform fuel grapple, the loading of the refueling platform frame mounted hoist, the loading of the refueling platform monorail mounted hoist, the full retraction of the fuel grapple, and the loading of the service platform hoist. With the reactor mode switch in the refuel position, the indicated conditions are combined in logic circuits to determine if all restrictions on refueling equipment operations and control rod insertion are satisfied.

A control rod not at its full-in position interrupts power to the refueling equipment and prevents operating the equipment over the reactor core when loaded with a fuel assembly or if the grapple is not fully retracted. Conversely, the refueling equipment located over the core and loaded with fuel inserts a control rod withdrawal block in the Reactor Manual Control System to prevent withdrawing a control rod.

The refueling platform has two mechanical switches that open before the platform or any of its hoists are physically located over the reactor vessel. All refueling hoists have switches that open when the hoists are loaded with fuel.

The refueling interlocks use these indications to prevent operation of the refueling equipment with fuel loaded over the core whenever any control rod is withdrawn, or to prevent control rod withdrawal whenever fuel loaded refueling equipment is over the core (Ref. 2).

BASES

BACKGROUND (continued)

The hoist switches open at a load lighter than the weight of a single fuel assembly in water.

APPLICABLE SAFETY ANALYSES

Proper operation of the refueling interlocks are relied upon for the control rod removal error during refueling and the fuel assembly insertion error during refueling events. Criticality will not result with adequate SDM and OPERABLE refueling interlocks. A prompt reactivity excursion during refueling could potentially result in fuel failure with subsequent release of radioactive material to the environment.

Criticality and, therefore, subsequent prompt reactivity excursions are prevented during the insertion of fuel, provided all control rods are fully inserted during the fuel insertion. The refueling interlocks accomplish this by preventing loading of fuel into the core with any control rod withdrawn or by preventing withdrawal of a rod from the core during fuel loading.

The refueling platform location switches activate at a point outside of the reactor core such that, with a fuel assembly loaded and a control rod withdrawn, the fuel is not over the core.

Refueling equipment interlocks satisfy Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

To prevent criticality during refueling, the refueling interlocks associated with the reactor mode switch refuel position ensure that fuel assemblies are not loaded into the core with any control rod withdrawn.

To prevent these conditions from developing, the all-rods-in, the refueling platform position, the refueling platform fuel grapple fuel loaded, the refueling platform trolley frame mounted hoist fuel loaded, the refueling platform monorail mounted hoist fuel loaded, the refueling platform fuel grapple fully retracted position, and the service platform hoist fuel loaded inputs are required to be OPERABLE when the reactor mode switch is in the refuel position. These inputs are combined in logic circuits, which provide refueling equipment or control rod blocks to prevent operations that could result in criticality during refueling operations.

APPLICABILITY

In MODE 5, a prompt reactivity excursion could cause fuel damage and subsequent release of radioactive material to the environment. The refueling equipment interlocks protect against prompt reactivity excursions during MODE 5. The interlocks are required to be OPERABLE during in-vessel fuel movement with refueling equipment associated with the interlocks when the reactor mode switch is in the refuel position. The interlocks are not required when the reactor mode

BASES

APPLICABILITY (continued)

switch is in the shutdown position since a control rod block (LCO 3.3.2.1, "Control Rod Block Instrumentation") ensures control rod withdrawal cannot occur simultaneously with in-vessel fuel movements.

In MODES 1, 2, 3, and 4, the reactor pressure vessel head is on, and CORE ALTERATIONS are not possible. Therefore, the refueling interlocks are not required to be OPERABLE in these MODES.

ACTIONS

A.1, A.2.1, and A.2.2

With one or more of the required refueling equipment interlocks inoperable, the unit must be placed in a condition in which the LCO does not apply or is not necessary. This can be performed by ensuring fuel assemblies are not moved in the reactor vessel or by ensuring that the control rods are inserted and cannot be withdrawn. Therefore, Required Action A.1 requires that in-vessel fuel movement with the affected refueling equipment be immediately suspended. This action ensures that operations are not performed with equipment that would potentially not be blocked from unacceptable operations (e.g., loading fuel into a cell with a control rod withdrawn). Suspension of in-vessel fuel movement shall not preclude completion of movement of a component to a safe position.

Alternatively, Required Actions A.2.1 and A.2.2 require a control rod withdrawal block to be inserted and all control rods to be subsequently verified to be fully inserted. Required Action A.2.1 ensures no control rods can be withdrawn, because a block to control rod withdrawal is in place. The withdrawal block utilized must ensure that if rod withdrawal is requested, the rod will not respond (i.e., it will remain inserted). This action can be accomplished by inserting an electrical or hydraulic block to control rod withdrawal. Required Action A.2.2 is normally performed after placing the rod withdrawal block in effect, and provides a verification that all control rods are fully inserted. This verification that all control rods are fully inserted is in addition to the periodic verifications required by SR 3.9.3.1. Like Required Action A.1, Required Actions A.2.1 and A.2.2 ensure unacceptable operations are prohibited (e.g., loading fuel into a cell with the control rod withdrawn).

SURVEILLANCE REQUIREMENTS

SR 3.9.1.1

Performance of a CHANNEL FUNCTIONAL TEST demonstrates each required refueling equipment interlock will function properly when a simulated or actual signal indicative of a required condition is injected into the logic. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single

BASES

SURVEILLANCE REQUIREMENTS (continued)

contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. The CHANNEL FUNCTIONAL TEST may be performed by any series of sequential, overlapping, or total channel steps so that the entire channel is tested.

The 7 day Frequency is based on engineering judgment and is considered adequate in view of other indications of refueling interlocks and their associated input status that are available to unit operations personnel.

REFERENCES

1. USAR, Section 1.2.2.
2. USAR, Section 7.2.1.2.2.1.

B 3.9 REFUELING OPERATIONS

B 3.9.2 Refuel Position One-Rod-Out Interlock

BASES

BACKGROUND	The refuel position one-rod-out interlock restricts the movement of control rods to reinforce unit procedures that prevent the reactor from becoming critical during refueling operations. During refueling operations, no more than one control rod is permitted to be withdrawn. USAR, Section 1.2.2 (Ref. 1), requires the reactor core to be designed so that control rod action, with the maximum worth control rod fully withdrawn and unavailable for use, is capable of bringing the reactor core subcritical and maintaining it so from any power level in the operating cycle. The control rods serve as the system capable of maintaining the reactor subcritical in cold conditions. The refuel position one-rod-out interlock prevents the selection of a second control rod for movement when any other control rod is not fully inserted (Ref. 2). It is a logic circuit that has redundant channels. It uses the all- rods-in signal (from the control rod full-in position indicators discussed in LCO 3.9.4, "Control Rod Position Indication") and a rod selection signal (from the Reactor Manual Control System). This Specification ensures that the performance of the refuel position one-rod-out interlock in the event of a control rod withdrawal error during refueling.
APPLICABLE SAFETY ANALYSES	Proper operation of the refuel position one-rod-out interlock is relied upon for the control rod withdrawal error during refueling event. One control rod withdrawn during refueling will not result in criticality. A prompt reactivity excursion during refueling could potentially result in fuel failure with subsequent release of radioactive material to the environment. The refuel position one-rod-out interlock and adequate SDM (LCO 3.1.1, "SHUTDOWN MARGIN (SDM)") prevent criticality by preventing withdrawal of more than one control rod. With one control rod withdrawn, the core will remain subcritical, thereby preventing any prompt critical excursion. The refuel position one-rod-out interlock satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO	To prevent criticality during MODE 5, the refuel position one-rod-out interlock ensures no more than one control rod may be withdrawn. Both channels of the refuel position one-rod-out interlock are required to be OPERABLE and the reactor mode switch must be locked in the refuel position to support the OPERABILITY of these channels.
APPLICABILITY	In MODE 5, with the reactor mode switch in the refuel position, the OPERABLE refuel position one-rod-out interlock provides protection against prompt reactivity excursions. In MODES 1, 2, 3, and 4, the refuel position one-rod-out interlock is not required to be OPERABLE and is bypassed. In MODES 1 and 2, the Reactor Protection System (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation") and the control rods (LCO 3.1.3, "Control Rod OPERABILITY") provide mitigation of potential reactivity excursions. In MODES 3, 4, and 5 with the reactor mode switch in the shutdown position, a control rod block (LCO 3.3.2.1, "Control Rod Block Instrumentation") ensures all control rods are inserted, thereby preventing criticality during shutdown conditions.
ACTIONS	<u>A.1 and A.2</u> With the refuel position one-rod-out interlock inoperable, the refueling interlocks may not be capable of preventing more than one control rod from being withdrawn. This condition may lead to criticality. Control rod withdrawal must be immediately suspended, and action must be immediately initiated to fully insert all insertable control rods in core cells containing one or more fuel assemblies. Action must continue until all such control rods are fully inserted. Control rods in core cells containing no fuel assemblies do not affect the reactivity of the core and, therefore, do not have to be inserted.
SURVEILLANCE REQUIREMENTS	<u>SR 3.9.2.1</u> Proper functioning of the refuel position one-rod-out interlock requires the reactor mode switch to be in refuel. During control rod withdrawal in MODE 5, improper positioning of the reactor mode switch could, in some instances, allow improper bypassing of required interlocks. Therefore, this Surveillance imposes an additional level of assurance that the refuel position one-rod-out interlock will be OPERABLE when required. By "locking" the reactor mode switch in the proper position (i.e., removing the reactor mode switch key from the console while the reactor mode switch is positioned in refuel), an additional administrative control is in place to preclude operator errors from resulting in unanalyzed operation. The Frequency of 12 hours is sufficient in view of other administrative controls utilized during refueling operations to ensure safe operation.

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.9.2.2

Performance of a CHANNEL FUNCTIONAL TEST on each channel demonstrates the associated refuel position one-rod-out interlock will function properly when a simulated or actual signal indicative of a required condition is injected into the logic. A successful test of the required contact(s) of a channel relay may be performed by the verification of the change of state of a single contact of the relay. This clarifies what is an acceptable CHANNEL FUNCTIONAL TEST of a relay. This is acceptable because all of the other required contacts of the relay are verified by other Technical Specifications and non-Technical Specifications tests at least once per refueling interval with applicable extensions. The CHANNEL FUNCTIONAL TEST may be performed by any series of sequential, overlapping, or total channel steps so that the entire channel is tested. The 7 day Frequency is considered adequate because of demonstrated circuit reliability, procedural controls on control rod withdrawals, and visual and audible indications available in the control room to alert the operator to control rods not fully inserted. To perform the required testing, the applicable condition must be entered (i.e., a control rod must be withdrawn from its full-in position). Therefore, SR 3.9.2.2 has been modified by a Note that states the CHANNEL FUNCTIONAL TEST is not required to be performed until 1 hour after any control rod is withdrawn.

REFERENCES

1. USAR, Section 1.2.2.
2. USAR, Section 7.2.1.2.2.1.

B 3.9 REFUELING OPERATIONS

B 3.9.3 Control Rod Position

BASES

BACKGROUND	Control rods provide the capability to maintain the reactor subcritical under all conditions and to limit the potential amount and rate of reactivity increase caused by a malfunction in the Control Rod Drive System. During refueling, movement of control rods is limited by the refueling interlocks (LCO 3.9.1, "Refueling Equipment Interlocks" and LCO 3.9.2, "Refuel Position One-Rod-Out Interlock") or the control rod block with the reactor mode switch in the shutdown position (LCO 3.3.2.1, "Control Rod Block Instrumentation"). USAR, Section 1.2.2 (Ref. 1), requires the reactor core to be designed so that control rod action, with the maximum worth control rod fully withdrawn and unavailable for use, is capable of bringing the reactor core subcritical and maintaining it so from any power level in the operating cycle. The control rods serve as the system capable of maintaining the reactor subcritical in cold conditions. The refueling interlocks allow a single control rod to be withdrawn at any time unless fuel is being loaded into the core. To preclude loading fuel assemblies into the core with a control rod withdrawn, all control rods must be fully inserted. This prevents the reactor from achieving criticality during refueling operations.
APPLICABLE SAFETY ANALYSES	Prevention and mitigation of prompt reactivity excursions during refueling are provided by the refueling interlocks (LCO 3.9.1 and LCO 3.9.2), the SDM (LCO 3.1.1, "SHUTDOWN MARGIN (SDM)"), the intermediate range monitor neutron flux scram (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation"), and the control rod block instrumentation (LCO 3.3.2.1). A control rod withdrawal error during refueling event relies on the proper operation of the refueling interlocks and adequate SDM. A fuel assembly insertion error event relies on all control rods being fully inserted. Thus, prior to fuel reload, all control rods must be fully inserted to minimize the probability of an inadvertent criticality. Control rod position satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	All control rods must be fully inserted during applicable refueling conditions to minimize the probability of an inadvertent criticality during refueling.

BASES

APPLICABILITY	During MODE 5, loading fuel into core cells with control rods withdrawn may result in inadvertent criticality. Therefore, the control rods must be inserted before loading fuel into a core cell. All control rods must be inserted before loading fuel to ensure that a fuel loading error does not result in loading fuel into a core cell with the control rod withdrawn. In MODES 1, 2, 3, and 4, the reactor pressure vessel head is on, and no fuel loading activities are possible. Therefore, this Specification is not applicable in these MODES.
ACTIONS	A.1 With all control rods not fully inserted during the applicable conditions, an inadvertent criticality could occur that is not analyzed in the USAR. All fuel loading operations must be immediately suspended. Suspension of these activities shall not preclude completion of movement of a component to a safe position.
SURVEILLANCE REQUIREMENTS	SR 3.9.3.1 During refueling, to ensure that the reactor remains subcritical, all control rods must be fully inserted prior to and during fuel loading. Periodic checks of the control rod position ensure this condition is maintained. The 12 hour Frequency takes into consideration the procedural controls on control rod movement during refueling as well as the redundant functions of the refueling interlocks.
REFERENCES	1. USAR, Section 1.2.2.

B 3.9 REFUELING OPERATIONS

B 3.9.4 Control Rod Position Indication

BASES

BACKGROUND

The full-in position indication channel for each control rod provides necessary information to the refueling interlocks to prevent inadvertent criticalities during refueling operations. During refueling, the refueling interlocks (LCO 3.9.1, "Refueling Equipment Interlocks" and LCO 3.9.2, "Refuel Position One-Rod-Out Interlock") use the full-in position indication channel to limit the operation of the refueling equipment and the movement of the control rods. Two full-in position indication switches (S51 and S52) provide input to the all-rods-in logic for each control rod. Switch S51 provides full core display beyond full-in (scram) position indication (double dashes - no number) and switch S52 provides full core display normal green full-in position indication. Switch S52 is set slightly beyond switch S00, which provides the digital "00" full-in position readout (switch S00 does not provide input to the all-rods-in logic and is not considered a full-in channel). When switch S52 is actuated, the color of the full core display "00" readout is changed from amber to green, indicating the control rod is full-in and latched. Switches S51 and S52 are wired in parallel, such that, if either switch indicates full-in, the all-rods-in logic will receive a full-in signal for that control rod. Therefore, each control rod is considered to have only one "full-in" position indication channel. The absence of the full-in position indication channel signal for any control rod removes the all-rods-in permissive for the refueling equipment interlocks and prevents fuel loading. Also, this condition causes the refuel position one-rod-out interlock to not allow the withdrawal of any other control rod.

USAR, Section 1.2.2 (Ref. 1), requires the reactor core to be designed so that control rod action, with the maximum worth control rod fully withdrawn and unavailable for use, is capable of bringing the reactor core subcritical and maintaining it so from any power level in the operating cycle. The control rods serve as the system capable of maintaining the reactor subcritical in cold conditions.

APPLICABLE SAFETY ANALYSES

Prevention and mitigation of prompt reactivity excursions during refueling are provided by the refueling interlocks (LCO 3.9.1 and LCO 3.9.2), the SDM (LCO 3.1.1, "SHUTDOWN MARGIN (SDM)"), the intermediate range monitor neutron flux scram (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation"), and the control rod block instrumentation (LCO 3.3.2.1, "Control Rod Block Instrumentation").

A control rod withdrawal error during refueling event relies on the proper operation of the refueling interlocks and adequate SDM. For the fuel assembly insertion error event, maintaining all control rods fully inserted

BASES

APPLICABLE SAFETY ANALYSES (continued)

will not result in criticality. The full-in position indication channel is required to be OPERABLE so that the refueling interlocks can ensure that fuel cannot be loaded with any control rod withdrawn and that no more than one control rod can be withdrawn at a time.

Control rod position indication satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).

LCO

The control rod full-in position indication channel for each control rod must be OPERABLE to provide the required input to the refueling interlocks. A channel is OPERABLE if it provides correct position indication to the refueling interlock logic.

APPLICABILITY

During MODE 5, the control rods must have OPERABLE full-in position indication channels to ensure the applicable refueling interlocks will be OPERABLE.

In MODES 1 and 2, requirements for control rod position are specified in LCO 3.1.3, "Control Rod OPERABILITY." In MODES 3 and 4, with the reactor mode switch in the shutdown position, a control rod block (LCO 3.3.2.1) ensures all control rods are inserted, thereby preventing criticality during shutdown conditions.

ACTIONS

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

<u>A.1.1, A.1.2, A.1.3, A.2.1, and A.2.2</u>

With one or more full-in position indication channels inoperable, compensating actions must be taken to protect against potential reactivity excursions from fuel assembly insertions or control rod withdrawals. This may be accomplished by immediately suspending in-vessel fuel movement and control rod withdrawal, and immediately initiating action to fully insert all insertable control rods in core cells containing one or more

BASES

ACTIONS (continued)

fuel assemblies. Actions must continue until all insertable control rods in core cells containing one or more fuel assemblies are fully inserted. Suspension of in-vessel fuel movements and control rod withdrawal shall not preclude moving a component to a safe position.

Alternatively, actions must be immediately initiated to fully insert the control rod(s) associated with the inoperable full-in position indicator(s) and disarm the drive(s) to ensure that the control rod is not withdrawn. Actions must continue until all associated control rods are fully inserted and drives are disarmed electrically or hydraulically. The control rods can be electrically disarmed by disconnecting power from all four directional control valve solenoids. The control rods can be hydraulically disarmed by closing the drive water and exhaust water isolation valves. Under these conditions (control rod fully inserted and disarmed), an inoperable full-in channel may be bypassed to allow refueling operations to proceed. An alternate method must be used to ensure the control rod is fully inserted (e.g., use the "00" notch position indication).

SURVEILLANCE REQUIREMENTS

SR 3.9.4.1

The full-in position indication channels provide input to the one-rod-out interlock and other refueling interlocks that require an all-rods-in permissive. The interlocks are actuated when the full-in position indication for any control rod is not present, since this indicates that all rods are not fully inserted. Therefore, testing of the full-in position indication channels is performed to ensure that when a control rod is withdrawn, the full-in position indication is not present. Note that failure to indicate full-in when the control rod is not withdrawn results in conservative actuation of the one-rod-out interlock, and therefore, is not explicitly required to be verified by this SR. The full-in position indication channel is considered inoperable even with the control rod fully inserted, if it would continue to indicate full-in with the control rod withdrawn. Performing the SR each time a control rod is withdrawn is considered adequate because of the procedural controls on control rod withdrawals and the visual and audible indications available in the control room to alert the operator to control rods not fully inserted.

REFERENCES

1. USAR, Section 1.2.2.

B 3.9 REFUELING OPERATIONS

B 3.9.5 Control Rod OPERABILITY - Refueling

BASES

BACKGROUND	Control rods are components of the Control Rod Drive (CRD) System, the primary reactivity control system for the reactor. In conjunction with the Reactor Protection System, the CRD System provides the means for the reliable control of reactivity changes during refueling operation. In addition, the control rods provide the capability to maintain the reactor subcritical under all conditions and to limit the potential amount and rate of reactivity increase caused by a malfunction in the CRD System. USAR, Section 1.2.2 (Ref. 1), requires the reactor core to be designed so that control rod action, with the maximum worth control rod fully withdrawn and unavailable for use, is capable of bringing the reactor core subcritical and maintaining it so from any power level in the operating cycle. The CRD System is the system capable of maintaining the reactor subcritical in cold conditions.
APPLICABLE SAFETY ANALYSES	Prevention and mitigation of prompt reactivity excursions during refueling are provided by refueling interlocks (LCO 3.9.1, "Refueling Equipment Interlocks" and LCO 3.9.2, "Refuel Position One-Rod-Out Interlock"), the SDM (LCO 3.1.1, SHUTDOWN MARGIN (SDM)"), the intermediate range monitor neutron flux scram (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation"), and the control rod block instrumentation (LCO 3.3.2.1, "Control Rod Block Instrumentation"). A prompt reactivity excursion during refueling could potentially result in fuel failure with subsequent release of radioactive material to the environment. Control rod scram provides protection should a prompt reactivity excursion occur. Control rod OPERABILITY during refueling satisfies Criterion 3 of 10 CFR 50.36(c)(2)(ii).
LCO	Each withdrawn control rod must be OPERABLE. The withdrawn control rod is considered OPERABLE if the scram accumulator pressure is ≥ 940 psig and the control rod is capable of being automatically inserted upon receipt of a scram signal. Inserted control rods have already completed their reactivity control function, and therefore are not required to be OPERABLE.
APPLICABILITY	During MODE 5, withdrawn control rods must be OPERABLE to ensure that in a scram the control rods will insert and provide the required negative reactivity to maintain the reactor subcritical.

BASES

APPLICABILITY (continued

For MODES 1 and 2, control rod requirements are found in LCO 3.1.2, "Reactivity Anomalies," LCO 3.1.3, "Control Rod OPERABILITY," LCO 3.1.4, "Control Rod Scram Times," and LCO 3.1.5, "Control Rod Scram Accumulators." During MODES 3 and 4, control rods are not able to be withdrawn since the reactor mode switch is in shutdown and a control rod block is applied. This provides adequate requirements for control rod OPERABILITY during these conditions.

ACTIONS

A.1

With one or more withdrawn control rods inoperable, action must be immediately initiated to fully insert the inoperable control rod(s). Inserting the control rod(s) ensures the shutdown and scram capabilities are not adversely affected. Actions must continue until the inoperable control rod(s) is fully inserted.

SURVEILLANCE REQUIREMENTS

SR 3.9.5.1 and SR 3.9.5.2

During MODE 5, the OPERABILITY of control rods is primarily required to ensure a withdrawn control rod will automatically insert if a signal requiring a reactor shutdown occurs. Because no explicit analysis exists for automatic shutdown during refueling, the shutdown function is satisfied if the withdrawn control rod is capable of automatic insertion and the associated CRD scram accumulator pressure is ≥ 940 psig.

The 7 day Frequency takes into consideration equipment reliability, procedural controls over the scram accumulators, and control room alarms and indicating lights that indicate low accumulator charge pressures.

SR 3.9.5.1 is modified by a Note that allows 7 days after withdrawal of the control rod to perform the Surveillance. This acknowledges that the control rod must first be withdrawn before performance of the Surveillance, and therefore avoids potential conflicts with SR 3.0.1.

REFERENCES

1. USAR, Section 1.2.2.

B 3.9 REFUELING OPERATIONS

B 3.9.6 Reactor Pressure Vessel (RPV) Water Level

BASES

BACKGROUND

The movement of fuel assemblies or handling of control rods within the RPV requires a minimum water level of 21 ft 11 inches above the top of the RPV flange. During refueling, this maintains a sufficient water level in the reactor vessel cavity and spent fuel pool. Sufficient water is necessary to retain iodine fission product activity in the water in the event of a fuel handling accident (Refs. 1, 2, and 3). Sufficient iodine activity would be retained to limit offsite doses from the accident to within 10 CFR 50.67 (Ref. 4) limits.

APPLICABLE SAFETY ANALYSES

During movement of fuel assemblies or handling of control rods, the water level in the RPV is an initial condition design parameter in the analysis of a fuel handling accident postulated by Regulatory Guide 1.25 (Ref. 1) and NUREG-0800 (Ref. 5). A minimum water level of 23 ft (Ref. 3) allows a decontamination factor of 200 to be used in the accident analysis for iodine. This relates to the assumption that 99.5% of the total iodine released from the pellet to cladding gap of all the dropped fuel assembly rods is retained by the water. The fuel pellet to cladding gap is assumed to contain the release fractions specified in Reference 3.

Analysis of the fuel handling accident is described in Reference 2. With a minimum water level of 23 ft and a minimum decay time of 24 hours prior to fuel handling, the analysis and test programs demonstrate that the iodine release due to a postulated fuel handling accident is adequately captured by the water and that offsite doses are maintained within allowable limits (Ref. 4).

While the worst case assumptions include the dropping of the irradiated fuel assembly being handled onto the reactor core, the possibility exists of the dropped assembly striking the RPV flange and releasing fission products. Therefore, the minimum depth for water coverage to ensure acceptable radiological consequences is specified from the RPV flange. Since the worst case event results in failed fuel assemblies seated in the core, as well as the dropped assembly, dropping an assembly on the RPV flange will result in reduced releases of fission gases. Based on this judgment, and the physical dimensions which preclude normal operation with water level 23 feet above the flange, a slight reduction in this water level is acceptable (Ref. 3).

RPV water level satisfies Criterion 2 of 10 CFR 50.36(c)(2)(ii).

BASES

LCO

A minimum water level of 21 ft 11 inches above the top of the RPV flange is required to ensure that the radiological consequences of a postulated fuel handling accident are within acceptable limits, as provided by the guidance of Reference 2.

APPLICABILITY

LCO 3.9.6 is applicable when moving fuel assemblies or handling control rods (i.e., movement with other than the normal control rod drive) within the RPV. The LCO minimizes the possibility of a fuel handling accident that is beyond the assumptions of the safety analysis. Requirements for fuel handling accidents in the spent fuel storage pool are covered by LCO 3.7.8, "Spent Fuel Storage Pool Water Level."

ACTIONS

A.1

If the water level is < 21 ft 11 inches above the top of the RPV flange, all operations involving movement of fuel assemblies and handling of control rods within the RPV shall be suspended immediately to ensure that a fuel handling accident cannot occur. The suspension of fuel movement and control rod handling shall not preclude completion of movement of a component to a safe position.

SURVEILLANCE REQUIREMENTS

SR 3.9.6.1

Verification of a minimum water level of 21 ft 11 inches above the top of the RPV flange ensures that the design basis for the postulated fuel handling accident analysis during refueling operations is met. Water at the required level limits the consequences of damaged fuel rods, which are postulated to result from a fuel handling accident (Ref. 2).

The Frequency of 24 hours is based on engineering judgment and is considered adequate in view of the large volume of water and the normal procedural controls on valve positions, which make significant unplanned level changes unlikely.

REFERENCES

1. Regulatory Guide 1.25, March 23, 1972.
2. USAR, Section 14.7.6.
3. Regulatory Guide 1.183, July 2000.
4. 10 CFR 50.67.
5. NUREG-0800, Section 15.7.4.

B 3.9 REFUELING OPERATIONS

B 3.9.7 Residual Heat Removal (RHR) - High Water Level

BASES

BACKGROUND

The purpose of the RHR System in MODE 5 is to remove decay heat and sensible heat from the reactor coolant, as described by USAR, Section 10.2.4.2 (Ref. 1). Each of the two shutdown cooling loops of the RHR System can provide the required decay heat removal. Each loop consists of two motor driven pumps, a heat exchanger, and associated piping and valves. Both loops have a common suction from the same recirculation loop. Each pump discharges the reactor coolant, after it has been cooled by circulation through the respective heat exchangers, to the reactor via either recirculation loop. The RHR heat exchangers transfer heat to the RHR Service Water (SW) System. The RHR shutdown cooling mode is manually controlled.

In addition to the RHR subsystems, the volume of water above the reactor pressure vessel (RPV) flange provides a heat sink for decay heat removal.

APPLICABLE SAFETY ANALYSES

With the unit in MODE 5, the RHR Shutdown Cooling System is not required to mitigate any events or accidents evaluated in the safety analyses. The RHR Shutdown Cooling System is required for removing decay heat to maintain the temperature of the reactor coolant.

The RHR Shutdown Cooling System satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

LCO

Only one RHR shutdown cooling subsystem is required to be OPERABLE and in operation in MODE 5 with irradiated fuel in the RPV and the water level ≥ 21 ft 11 inches above the RPV flange. Only one subsystem is required to be OPERABLE because the volume of water above the RPV flange provides backup decay heat removal capability.

An OPERABLE RHR shutdown cooling subsystem consists of an RHR pump, a heat exchanger, valves, piping, instruments, and controls to ensure an OPERABLE flow path. In addition, the necessary portions of the RHRSW System must be capable of providing cooling water to the RHR heat exchanger.

Additionally, the RHR shutdown cooling subsystem is considered OPERABLE if it can be manually aligned (remote or local) in the shutdown cooling mode for removal of decay heat. Operation (either continuous or intermittent) of one subsystem can maintain and reduce the reactor coolant temperature as required. However, to ensure adequate

BASES

LCO (continued)

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 be removed from operation every 8 hours.

APPLICABILITY

One RHR shutdown cooling subsystem must be OPERABLE and in operation in MODE 5, with irradiated fuel in the RPV and with the water level ≥ 21 feet 11 inches above the top of the RPV flange, to provide decay heat removal. RHR shutdown cooling subsystem requirements in other MODES are covered by LCOs in Section 3.4, Reactor Coolant System (RCS). RHR shutdown cooling subsystem requirements in MODE 5 with irradiated fuel in the reactor pressure vessel and with the water level < 21 ft 11 inches above the RPV flange are given in LCO 3.9.8, "Residual Heat Removal (RHR) - Low Water Level."

ACTIONS

A.1

With the required RHR shutdown cooling subsystem inoperable, an alternate method of decay heat removal must be provided within 1 hour. In this condition, the volume of water above the RPV flange provides adequate capability to remove decay heat from the reactor core. However, the overall reliability is reduced because loss of water level could result in reduced decay heat removal capability. The 1 hour Completion Time is based on decay heat removal function and the probability of a loss of the available decay heat removal capabilities. Furthermore, verification of the functional availability of the alternate method must be reconfirmed every 24 hours thereafter. This will ensure continued heat removal capability.

Alternate decay heat removal methods are available to the operators for review and preplanning in the unit operating procedures. The required cooling capability of the alternate method should be ensured by verification (by calculation or demonstration) of its capability to maintain or reduce temperature. For example, this may include the use of the Fuel Pool Cooling System or the Reactor Water Cleanup System operating with the regenerative heat exchanger bypassed (heat reject mode). Either or both systems may be used to reject hot water while using a cooler source of water for makeup. The method used to remove the decay heat should be the most prudent choice based on unit conditions.

B.1, B.2, B.3, and B.4

If no RHR shutdown cooling subsystem is OPERABLE and an alternate method of decay heat removal is not available in accordance with Required Action A.1, actions shall be taken immediately to suspend

BASES

ACTIONS (continued)

operations involving an increase in reactor decay heat load by suspending loading of irradiated fuel assemblies into the RPV.

Additional actions are required to minimize any potential fission product release to the environment. This includes ensuring secondary containment is OPERABLE; one standby gas treatment subsystem is OPERABLE; and secondary containment isolation capability is available in each associated penetration flow path not isolated that is assumed to be isolated to mitigate radioactive releases (i.e., one secondary containment isolation valve and associated instrumentation are OPERABLE or other acceptable administrative controls to assure isolation capability). These administrative controls consist of stationing a dedicated qualified individual, who is in continuous communication with the control room, at the controls of the isolation device. In this way, the penetration can be rapidly isolated when a need for secondary containment isolation is indicated. This (ensuring components are OPERABLE) may be performed as an administrative check, by examining logs or other information to determine whether the components are out of service for maintenance or other reasons. It is not necessary to perform the Surveillances needed to demonstrate the OPERABILITY of the components. If, however, any required component is inoperable, then it must be restored to OPERABLE status. In this case, a surveillance may need to be performed to restore the component to OPERABLE status. Actions must continue until all required components are OPERABLE.

<u>C.1 and C.2</u>

If no RHR shutdown cooling subsystem is in operation, an alternate method of coolant circulation is required to be established within 1 hour. The Completion Time is modified such that the 1 hour is applicable separately for each occurrence involving a loss of coolant circulation.

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

BASES

SURVEILLANCE REQUIREMENTS	SR 3.9.7.1 This Surveillance demonstrates that the RHR shutdown cooling subsystem is in operation and circulating reactor coolant. The required flow rate is determined by the flow rate necessary to provide sufficient decay heat removal capability. The Frequency of 12 hours is sufficient in view of other visual and audible indications available to the operator for monitoring the RHR shutdown cooling subsystem in the control room.
REFERENCES	1. USAR, Section 10.2.4.2.

B 3.9 REFUELING OPERATIONS

B 3.9.8 Residual Heat Removal (RHR) - Low Water Level

BASES

BACKGROUND

The purpose of the RHR System in MODE 5 is to remove decay heat and sensible heat from the reactor coolant, as described by USAR, Section 10.2.4.2 (Ref. 1). Each of the two shutdown cooling loops of the RHR System can provide the required decay heat removal. Each loop consists of two motor driven pumps, a heat exchanger, and associated piping and valves. Both loops have a common suction from the same recirculation loop. Each pump discharges the reactor coolant, after it has been cooled by circulation through the respective heat exchangers, to the reactor via either recirculation loop. The RHR heat exchangers transfer heat to the RHR Service Water (SW) System. The RHR shutdown cooling mode is manually controlled.

APPLICABLE SAFETY ANALYSES

With the unit in MODE 5, the RHR Shutdown Cooling System is not required to mitigate any events or accidents evaluated in the safety analyses. The RHR Shutdown Cooling System is required for removing decay heat to maintain the temperature of the reactor coolant.

The RHR Shutdown Cooling System satisfies Criterion 4 of 10 CFR 50.36(c)(2)(ii).

LCO

In MODE 5 with irradiated fuel in the reactor pressure vessel (RPV) and the water level < 21 ft 11 inches above the RPV flange both RHR shutdown cooling subsystems must be OPERABLE and one RHR shutdown cooling subsystem must be in operation.

An OPERABLE RHR shutdown cooling subsystem consists of an RHR pump, a heat exchanger, valves, piping, instruments, and controls to ensure an OPERABLE flow path. To meet the LCO, both pumps in one loop or one pump in each of the two loops must be OPERABLE. In addition, the necessary portions of the RHRSW System must be capable of providing cooling water to the RHR heat exchanger.

Additionally, each RHR shutdown cooling subsystem is considered OPERABLE if it can be manually aligned (remote or local) in the shutdown cooling mode for removal of decay heat. Operation (either continuous or intermittent) of one subsystem can maintain and reduce the reactor coolant temperature as required. However, to ensure adequate core flow to allow for accurate average reactor coolant temperature monitoring, nearly continuous operation is required. A Note is provided to allow a 2 hour exception for the operating subsystem to be removed from operation every 8 hours.

BASES

APPLICABILITY

Two RHR shutdown cooling subsystems are required to be OPERABLE, and one must be in operation in MODE 5, with irradiated fuel in the RPV and with the water level < 21 ft 11 inches above the top of the RPV flange, to provide decay heat removal. RHR shutdown cooling subsystem requirements in other MODES are covered by LCOs in Section 3.4, Reactor Coolant System (RCS). RHR shutdown cooling subsystem requirements in MODE 5 with irradiated fuel in the RPV and with the water level ≥ 21 ft 11 inches above the RPV flange are given in LCO 3.9.7, "Residual Heat Removal (RHR) - High Water Level."

ACTIONS

A.1

With one of the two required RHR shutdown cooling subsystems inoperable, the remaining subsystem is capable of providing the required decay heat removal. However, the overall reliability is reduced. Therefore, an alternate method of decay heat removal must be provided. With both required RHR shutdown cooling subsystems inoperable, an alternate method of decay heat removal must be provided in addition to that provided for the initial RHR shutdown cooling subsystem inoperability. This re-establishes backup decay heat removal capabilities, similar to the requirements of the LCO. The 1 hour Completion Time is based on the decay heat removal function and the probability of a loss of the available decay heat removal capabilities. Furthermore, verification of the functional availability of this alternate method(s) must be reconfirmed every 24 hours thereafter. This will ensure continued heat removal capability.

Alternate decay heat removal methods are available to the operators for review and preplanning in the unit operating procedures. The required cooling capacity of the alternate method should be ensured by verification (by calculation or demonstration) of its capability to maintain or reduce temperature. For example, this may include the use of the Fuel Pool Cooling System or the Reactor Water Cleanup System operating with the regenerative heat exchanger bypassed (heat reject mode). Either or both systems may be used to reject hot water while using a cooler source of water for makeup. The method used to remove decay heat should be the most prudent choice based on unit conditions.

Condition A is modified by a Note allowing separate Condition entry for each required RHR shutdown cooling subsystem. This is acceptable since the Required Actions for this Condition provide appropriate compensatory actions for each inoperable required RHR shutdown cooling subsystem. Complying with the Required Actions allow for continued operation. A subsequent inoperable required RHR shutdown cooling subsystem is governed by subsequent entry into the Condition and application of the Required Actions.

BASES

ACTIONS (continued)

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

With the required decay heat removal subsystem(s) inoperable and the required alternate method(s) of decay heat removal not available in accordance with Required Action A.1, additional actions are required to minimize any potential fission product release to the environment. This includes ensuring secondary containment is OPERABLE; one standby gas treatment subsystem is OPERABLE; and secondary containment isolation capability is available in each associated penetration flow path not isolated that is assumed to be isolated to mitigate radioactive releases (i.e., one secondary containment isolation valve and associated instrumentation are OPERABLE or other acceptable administrative controls to assure isolation capability). These administrative controls consist of stationing a dedicated qualified individual, who is in continuous communication with the control room, at the controls of the isolation device. In this way, the penetration can be rapidly isolated when a need for secondary containment isolation is indicated. This (ensuring components are OPERABLE) may be performed as an administrative check, by examining logs or other information to determine whether the components are out of service for maintenance or other reasons. It is not necessary to perform the Surveillances needed to demonstrate the OPERABILITY of the components. If, however, any required component is inoperable, then it must be restored to OPERABLE status. In this case, the surveillance may need to be performed to restore the component to OPERABLE status. Actions must continue until all required components are OPERABLE.

C.1 and C.2

If no RHR shutdown cooling subsystem is in operation, an alternate method of coolant circulation is required to be established within 1 hour. The Completion Time is modified such that the 1 hour is applicable separately for each occurrence involving a loss of coolant circulation.

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

BASES

SURVEILLANCE REQUIREMENTS	SR 3.9.8.1 This Surveillance demonstrates that one RHR shutdown cooling subsystem is in operation and circulating reactor coolant. The required flow rate is determined by the flow rate necessary to provide sufficient decay heat removal capability. The Frequency of 12 hours is sufficient in view of other visual and audible indications available to the operator for monitoring the RHR shutdown cooling subsystems in the control room.
REFERENCES	1. USAR, Section 10.2.4.2.

B 3.10 SPECIAL OPERATIONS

B 3.10.1 Inservice Leak and Hydrostatic Testing Operation

BASES

BACKGROUND

The purpose of this Special Operations LCO is to allow certain reactor coolant pressure tests to be performed in MODE 4 when the metallurgical characteristics of the reactor pressure vessel (RPV) require the pressure testing at temperatures > 212°F (normally corresponding to MODE 3) or to allow completing these reactor coolant pressure tests when the initial conditions do not required temperatures > 212°F. Furthermore, as approved by Reference 3, the purpose is to allow continued performance of control rod scram time testing required by SR 3.1.4.1 or SR 3.1.4.4 if reactor coolant temperatures exceed 212°F when the control rod scram time testing is initiated in conjunction with an inservice leak or hydrostatic test. These control rod scram time tests would be performed in accordance with LCO 3.10.4, “Single Control Rod Withdrawl – Cold Shutdown,” during MODE 4 operation.

Inservice hydrostatic testing and system leakage pressure tests required by Section XI of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code (Ref. 1) are performed prior to the reactor going critical after a refueling outage. Recirculation pump operation and a water solid RPV are used to achieve the necessary temperatures and pressures required for these tests. The minimum temperatures (at the required pressures) allowed for these tests are determined from the RPV pressure and temperature (P/T) limits required by LCO 3.4.9, "Reactor Coolant System (RCS) Pressure and Temperature (P/T) Limits." These limits are conservatively based on the fracture toughness of the reactor vessel, taking into account anticipated vessel neutron fluence.

With increased reactor vessel fluence over time, the minimum allowable vessel temperature increases at a given pressure. Periodic updates to the RPV P/T limit curves are performed as necessary, based upon the results of analyses of irradiated surveillance specimens removed from the vessel. Hydrostatic and leak testing may eventually be required with minimum reactor coolant temperatures > 212°F. However, even with the required minimum reactor coolant temperatures < 212°F, maintaining RCS temperatures within a small band during the test can be impractical. Removal of the heat addition from reactor recirculation pump operation and reactor core decay heat is coarsely controlled by the control rod drive hydraulic system flow and reactor water cleanup system non-regenerative heat exchanger operation. Test conditions are focused on maintaining a steady state pressure, and tightly limited temperature control poses an unnecessary burden on the operator and may not be achievable in certain instances.

BASES

BACKGROUND (continued)

The hydrostatic and/or RCS system leakage tests require increasing pressure to approximately 1000 psig. Since scram time testing required by SR 3.1.4.1 and SR 3.1.4.4 requires reactor steam dome pressure ≥ 800 psig.

Other testing may be performed in conjunction with the allowances for inservice leak or hydrostatic tests and control rod scram time tests.

APPLICABLE SAFETY ANALYSES

Allowing the reactor to be considered in MODE 4, when the reactor coolant temperature is > 212°F, during, or as a consequence of, hydrostatic or leak testing, or as a consequence of control rod scram time testing initiated in conjunction with an inservice leak or hydrostatic test, effectively provides an exception to MODE 3 requirements, including OPERABILITY of primary containment and the full complement of redundant Emergency Core Cooling Systems. Since the tests are performed nearly water solid, at low decay heat values, and near MODE 4 conditions, the stored energy in the reactor core will be very low. Under these conditions, the potential for failed fuel and a subsequent increase in coolant activity above the LCO 3.4.6, "RCS Specific Activity," limits are minimized. In addition, the secondary containment will be OPERABLE, in accordance with this Special Operations LCO, and will be capable of handling any airborne radioactivity or steam leaks that could occur during the performance of hydrostatic or leak testing. Furthermore, the specific activity of the reactor coolant is assumed to be ≤ 0.02 μCi/gm DOSE EQUIVALENT I-131. The required pressure testing conditions provide adequate assurance that the consequences of a steam leak will be conservatively bounded by the consequences of the postulated main steam line break outside of primary containment described in Reference 2. Therefore, these requirements will conservatively limit radiation releases to the environment.

In the event of a large primary system leak, the reactor vessel would rapidly depressurize, allowing the low pressure core cooling systems to operate. The capability of the low pressure coolant injection and core spray subsystems, as required in MODE 4 by LCO 3.5.2, "ECCS - Shutdown," would be more than adequate to keep the core flooded under this low decay heat load condition. Small system leaks would be detected by leakage inspections before significant inventory loss occurred.

For the purposes of this test, the protection provided by normally required MODE 4 applicable LCOs, in addition to the reactor coolant specific activity limit and secondary containment requirements required to be met by this Special Operations LCO, will ensure acceptable consequences during normal hydrostatic test conditions and during postulated accident conditions.

BASES

APPLICABLE SAFETY ANALYSES (continued)

As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of 10 CFR 50.36(c)(2)(ii) apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.

LCO

As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. Operation at reactor coolant temperatures > 212°F can be in accordance with Table 1.1-1 for MODE 3 operation without meeting this Special Operations LCO or its ACTIONS. This option may be required due to P/T limits, however, which require testing at temperatures > 212°F, performance of inservice leak and hydrostatic testing would also necessitate the inoperability of some subsystems normally required to be OPERABLE when > 212°F. Additionally, even with the required minimum reactor coolant temperatures < 212°F, RCS temperatures may drift above 212°F during the performance of inservice leak and hydrostatic testing or during subsequent control rod scram time testing, which is typically performed in conjunction with inservice leak and hydrostatic testing. While this Special Operations LCO is provided for inservice leak and hydrostatic testing, and for scram time testing initiated in conjunction with an inservice leak or hydrostatic test, parallel performance of other tests and inspections is not precluded.

If it is desired to perform these tests while complying with this Special Operations LCO, then the MODE 4 applicable LCOs, the reactor coolant specific activity limit, and the specified MODE 3 LCOs must be met. This Special Operations LCO allows changing Table 1.1-1 temperature limits for MODE 4 to "NA" and suspending the requirements of LCO 3.4.8, "Residual Heat Removal (RHR) Shutdown Cooling System - Cold Shutdown." The additional requirements for the reactor coolant specific activity limit and the secondary containment LCOs to be met will provide sufficient protection for operations at reactor coolant temperatures > 212°F for the purpose of performing an inservice leak or hydrostatic test, and for control rod scram testing initiated in conjunction with an inservice leak or hydrostatic test.

This LCO allows primary containment to be open for frequent unobstructed access to perform inspections, and for outage activities on various systems to continue consistent with the MODE 4 applicable requirements.

BASES

APPLICABILITY

The MODE 4 requirements may only be modified for the performance of inservice leak or hydrostatic tests, or as a consequence of, hydrostatic or leak testing, or as a consequence of control rod scram time testing initiated in conjunction with an inservice leak or hydrostatic test, so that these operations can be considered as in MODE 4, even though the reactor coolant temperature is > 212°F. The additional requirements for the reactor coolant specific activity limit as well as the secondary containment LCOs to be met according to the imposed MODE 3 requirements provides conservatism in the response of the unit to any event that may occur. Operations in all other MODES are unaffected by this LCO.

ACTIONS

A Note has been provided to modify the ACTIONS related to inservice leak and hydrostatic testing operation. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for each requirement of the LCO not met provide appropriate compensatory measures for separate requirements that are not met. As such, a Note has been provided that allows separate Condition entry for each requirement of the LCO.

<u>A.1</u>

If an LCO specified in LCO 3.10.1 is not met, the ACTIONS applicable to the stated requirements are entered immediately and complied with. Required Action A.1 has been modified by a Note that clarifies the intent of another LCO's Required Action to be in MODE 4 includes reducing the average reactor coolant temperature to ≤ 212°F.

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

Required Action A.2.1 and Required Action A.2.2 are alternate Required Actions that can be taken instead of Required Action A.1 to restore compliance with the normal MODE 4 requirements, and thereby exit this Special Operation LCO's Applicability. Activities that could further increase reactor coolant temperature or pressure are suspended immediately, in accordance with Required Action A.2.1, and the reactor coolant temperature is reduced to establish normal MODE 4 requirements. The allowed Completion Time of 24 hours for Required Action A.2.2 is based on engineering judgment and provides sufficient

BASES

ACTIONS (continued)

time to reduce the average reactor coolant temperature from the highest expected value to ≤ 212°F with normal cooldown procedures. The Completion Time is also consistent with the time provided in LCO 3.0.3 to reach MODE 4 from MODE 3.

SURVEILLANCE REQUIREMENTS

SR 3.10.1.1

The LCOs made applicable are required to have their Surveillances met to establish that this LCO is being met. A discussion of the applicable SRs is provided in their respective Bases.

SR 3.10.1.2

This Surveillance is performed to ensure the reactor coolant specific activity is within limit. The Frequency is based on ensuring the reactor coolant specific activity is within the limit prior to increasing average reactor coolant temperature above the MODE 3 limit (i.e., 212°F).

REFERENCES

1. American Society of Mechanical Engineers, Boiler and Pressure Vessel Code, Section XI.
2. USAR, Section 14.7.3.
3. Amendment No. 174, “Monticello Nuclear Generating Plant – Issuance of Amendment No. 174 to Adopt Technical Specifications Task Force (TSTF) Traveler TSTF-484, Revision 0, Use of TS 3.10.1 for Scram Time Testing Activities (TAC No. MF0362),” dated August 9, 2013. (ADAMS Accession No. ML13168A219)

B 3.10 SPECIAL OPERATIONS

B 3.10.2 Reactor Mode Switch Interlock Testing

BASES

BACKGROUND

The purpose of this Special Operations LCO is to permit operation of the reactor mode switch from one position to another to confirm certain aspects of associated interlocks during periodic tests and calibrations in MODES 3, 4, and 5.

The reactor mode switch is a conveniently located, multiposition, keylock switch provided to select the necessary scram functions for various plant conditions (Ref. 1). The reactor mode switch selects the appropriate trip relays for scram functions and provides appropriate bypasses. The mode switch positions and related scram interlock functions are summarized as follows:

a. Shutdown - Initiates a reactor scram; bypasses main steam isolation valve closure and condenser low vacuum scrams;

b. Refuel - Selects Neutron Monitoring System (NMS) scram function for low neutron flux level operation (intermediate range monitors); bypasses main steam isolation valve closure and condenser low vacuum scrams;

c. Startup/Hot Standby - Selects NMS scram function for low neutron flux level operation (intermediate range monitors); bypasses main steam isolation valve closure and condenser low vacuum scrams; and

d. Run - Selects NMS scram function for power range operation (average power range monitors).

The reactor mode switch also provides interlocks for such functions as control rod blocks, scram discharge volume trip bypass, refueling interlocks, and main steam isolation valve isolations.

APPLICABLE SAFETY ANALYSES

The purpose for reactor mode switch interlock testing is to prevent fuel failure by precluding reactivity excursions or core criticality. The interlock functions of the shutdown and refuel positions normally maintained for the reactor mode switch in MODES 3, 4, and 5 are provided to preclude reactivity excursions that could potentially result in fuel failure. Interlock testing that requires moving the reactor mode switch to other positions (run, startup/hot standby, or refuel) while in MODE 3, 4, or 5, requires administratively maintaining all control rods inserted and no CORE

BASES

APPLICABLE SAFETY ANALYSES (continued)

ALTERATIONS in progress. With all control rods inserted in core cells containing one or more fuel assemblies, and no CORE ALTERATIONS in progress, there are no credible mechanisms for unacceptable reactivity excursions during the planned interlock testing.

For postulated events, such as control rod removal error during refueling or loading of fuel with a control rod withdrawn, fuel failure will not occur. The withdrawal of a single control rod will not result in criticality when adequate SDM is maintained. Also, loading fuel assemblies into the core with a single control rod withdrawn will not result in criticality, thereby preventing fuel failure.

As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of 10 CFR 50.36(c)(2)(ii) apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.

LCO

As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. MODES 3, 4, and 5 operations not specified in Table 1.1-1 can be performed in accordance with other Special Operations LCOs (i.e., LCO 3.10.1, "Inservice Leak and Hydrostatic Testing Operation," LCO 3.10.3, "Single Control Rod Withdrawal - Hot Shutdown," LCO 3.10.4, "Single Control Rod Withdrawal - Cold Shutdown," and LCO 3.10.8, "SDM Test - Refueling") without meeting this LCO or its ACTIONS. If any testing is performed that involves the reactor mode switch interlocks and requires repositioning beyond that specified in Table 1.1-1 for the current MODE of operation, the testing can be performed, provided all interlock functions potentially defeated are administratively controlled. In MODES 3, 4, and 5 with the reactor mode switch in shutdown as specified in Table 1.1-1, all control rods are fully inserted and a control rod block is initiated. Therefore, all control rods in core cells that contain one or more fuel assemblies must be verified fully inserted while in MODES 3, 4, and 5, with the reactor mode switch in other than the shutdown position. The additional LCO requirement to preclude CORE ALTERATIONS is appropriate for MODE 5 operations, as discussed below, and is inherently met in MODES 3 and 4 by the definition of CORE ALTERATIONS, which cannot be performed with the vessel head in place.

BASES

LCO (continued)

In MODE 5, with the reactor mode switch in the refuel position, only one control rod can be withdrawn under the refuel position one-rod-out interlock (LCO 3.9.2, "Refuel Position One-Rod-Out Interlock"). The refueling equipment interlocks (LCO 3.9.1, "Refueling Equipment Interlocks") appropriately control other CORE ALTERATIONS. Due to the increased potential for error in controlling these multiple interlocks, and the limited duration of tests involving the reactor mode switch position, conservative controls are required, consistent with MODES 3 and 4. The additional controls of administratively not permitting other CORE ALTERATIONS will adequately ensure that the reactor does not become critical during these tests.

APPLICABILITY

Any required periodic interlock testing involving the reactor mode switch, while in MODES 1 and 2, can be performed without the need for Special Operations exceptions. Mode switch manipulations in these MODES would likely result in unit trips. In MODES 3, 4, and 5, this Special Operations LCO is only permitted to be used to allow reactor mode switch interlock testing that cannot conveniently be performed without this allowance or testing that must be performed prior to entering another MODE. Such interlock testing may consist of required Surveillances, or may be the result of maintenance, repair, or troubleshooting activities. In MODES 3, 4, and 5, the interlock functions provided by the reactor mode switch in shutdown (i.e., all control rods inserted and incapable of withdrawal) and refueling (i.e., refueling interlocks to prevent inadvertent criticality during CORE ALTERATIONS) positions can be administratively controlled adequately during the performance of certain tests.

ACTIONS

A.1, A.2, A.3.1, and A.3.2

These Required Actions are provided to restore compliance with the Technical Specifications overridden by this Special Operations LCO. Restoring compliance will also result in exiting the Applicability of this Special Operations LCO.

All CORE ALTERATIONS, except control rod insertion, if in progress, are immediately suspended in accordance with Required Action A.1, and all insertable control rods in core cells that contain one or more fuel assemblies are fully inserted within 1 hour, in accordance with Required Action A.2. This will preclude potential mechanisms that could lead to criticality. Control rods in core cells containing no fuel assemblies do not affect the reactivity of the core and therefore, do not have to be inserted. Suspension of CORE ALTERATIONS shall not preclude the completion of movement of a component to a safe condition. Placing the reactor mode switch in the shutdown position will ensure that all inserted control

BASES

ACTIONS (continued)

rods remain inserted and result in operating in accordance with Table 1.1-1. Alternatively, if in MODE 5, the reactor mode switch may be placed in the refuel position, which will also result in operating in accordance with Table 1.1-1. A Note is added to Required Action A.3.2 to indicate that this Required Action is not applicable in MODES 3 and 4, since only the shutdown position is allowed in these MODES. The allowed Completion Time of 1 hour for Required Action A.2, Required Action A.3.1, and Required Action A.3.2 provides sufficient time to normally insert the control rods and place the reactor mode switch in the required position, based on operating experience, and is acceptable given that all operations that could increase core reactivity have been suspended.

SURVEILLANCE REQUIREMENTS

SR 3.10.2.1 and SR 3.10.2.2

Meeting the requirements of this Special Operations LCO maintains operation consistent with or conservative to operating with the reactor mode switch in the shutdown position (or the refuel position for MODE 5). The functions of the reactor mode switch interlocks that are not in effect, due to the testing in progress, are adequately compensated for by the Special Operations LCO requirements. The administrative controls are to be periodically verified to ensure that the operational requirements continue to be met. The Surveillances performed at the 12 hour and 24 hour Frequencies are intended to provide appropriate assurance that each operating shift is aware of and verifies compliance with these Special Operations LCO requirements.

REFERENCES

1. USAR, Section 7.6.1.2.7.

B 3.10 SPECIAL OPERATIONS

B 3.10.3 Single Control Rod Withdrawal - Hot Shutdown

BASES

BACKGROUND

The purpose of this MODE 3 Special Operations LCO is to permit the withdrawal of a single control rod for testing while in hot shutdown, by imposing certain restrictions. In MODE 3, the reactor mode switch is in the shutdown position, and all control rods are inserted and blocked from withdrawal. Many systems and functions are not required in these conditions, due to the other installed interlocks that are actuated when the reactor mode switch is in the shutdown position. However, circumstances may arise while in MODE 3 that present the need to withdraw a single control rod for various tests (e.g., friction tests, scram timing, and coupling integrity checks). These single control rod withdrawals are normally accomplished by selecting the refuel position for the reactor mode switch. This Special Operations LCO provides the appropriate additional controls to allow a single control rod withdrawal in MODE 3.

APPLICABLE SAFETY ANALYSES

With the reactor mode switch in the refuel position, proper operation of the refueling interlocks and adequate SDM will preclude unacceptable reactivity excursions.

Refueling interlocks restrict the movement of control rods to reinforce operational procedures that prevent the reactor from becoming critical. These interlocks prevent the withdrawal of more than one control rod. Under these conditions, since only one control rod can be withdrawn, the core will always be shut down even with the highest worth control rod withdrawn if adequate SDM exists.

The control rod scram function provides backup protection to normal refueling procedures and the refueling interlocks, which prevent inadvertent criticalities during refueling.

Alternate backup protection can be obtained by ensuring that a five by five array of control rods, centered on the withdrawn control rod, are inserted and incapable of withdrawal.

As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of 10 CFR 50.36(c)(2)(ii) apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.

BASES

LCO	As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. Operation in MODE 3 with the reactor mode switch in the refuel position can be performed in accordance with other Special Operations LCOs (i.e., LCO 3.10.2, "Reactor Mode Switch Interlock Testing," without meeting this Special Operations LCO or its ACTIONS. However, if a single control rod withdrawal is desired in MODE 3, controls consistent with those required during refueling must be implemented and this Special Operations LCO applied. "Withdrawal" in this application includes the actual withdrawal of the control rod as well as maintaining the control rod in a position other than the full-in position, and reinserting the control rod. The refueling interlocks of LCO 3.9.2, "Refuel Position One-Rod-Out Interlock," required by this Special Operations LCO, will ensure that only one control rod can be withdrawn. To back up the refueling interlocks (LCO 3.9.2), the ability to scram the withdrawn control rod in the event of an inadvertent criticality is provided by this Special Operations LCO's requirements in Item d.1. Alternately, provided a sufficient number of control rods in the vicinity of the withdrawn control rod are known to be inserted and incapable of withdrawal (by electrically or hydraulically disarming the CRD) (Item d.2), the possibility of criticality on withdrawal of this control rod is sufficiently precluded, so as not to require the scram capability of the withdrawn control rod. Also, once this alternate (Item d.2) is completed, the SDM requirement to account for both the withdrawn-untrippable control rod and the highest worth control rod may be changed to allow the withdrawn-untrippable control rod to be the single highest worth control rod.
APPLICABILITY	Control rod withdrawals are adequately controlled in MODES 1, 2, and 5 by existing LCOs. In MODES 3 and 4, control rod withdrawal is only allowed if performed in accordance with this Special Operations LCO or Special Operations LCO 3.10.4, "Single Control Rod Withdrawal - Cold Shutdown," and is limited to one control rod. This allowance is only provided with the reactor mode switch in the refuel position. For these conditions, the one-rod-out interlock (LCO 3.9.2), control rod position indication (LCO 3.9.4, "Control Rod Position Indication"), full insertion requirements for all other control rods and scram functions (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation," and LCO 3.9.5," Control Rod OPERABILITY - Refueling"), or the added administrative controls in Item d.2 of this Special Operations LCO, minimize potential reactivity excursions.
ACTIONS	A Note has been provided to modify the ACTIONS related to a single control rod withdrawal while in MODE 3. Section 1.3, Completion Times, specifies once a Condition has been entered, subsequent divisions, subsystems, components or variables expressed in the Condition discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies Required Actions of

BASES

ACTIONS (continued)

the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for each requirement of the LCO not met provide appropriate compensatory measures for separate requirements that are not met. As such, a Note has been provided that allows separate Condition entry for each requirement of the LCO.

A.1

If one or more of the requirements specified in this Special Operations LCO are not met, the ACTIONS applicable to the stated requirements of the affected LCOs are immediately entered as directed by Required Action A.1. Required Action A.1 has been modified by a Note that clarifies the intent of any other LCO's Required Action, to insert all control rods. This Required Action includes exiting this Special Operations Applicability by returning the reactor mode switch to the shutdown position. A second Note has been added, which clarifies that this Required Action is only applicable if the requirements not met are for an affected LCO.

A.2.1 and A.2.2

Required Actions A.2.1 and A.2.2 are alternate Required Actions that can be taken instead of Required Action A.1 to restore compliance with the normal MODE 3 requirements, thereby exiting this Special Operations LCO's Applicability. Actions must be initiated immediately to insert all insertable control rods. Actions must continue until all such control rods are fully inserted. Placing the reactor mode switch in the shutdown position will ensure all inserted rods remain inserted and restore operation in accordance with Table 1.1-1. The allowed Completion Time of 1 hour to place the reactor mode switch in the shutdown position provides sufficient time to normally insert the control rods.

SURVEILLANCE REQUIREMENTS

SR 3.10.3.1, SR 3.10.3.2, and SR 3.10.3.3

The other LCOs made applicable in this Special Operations LCO are required to have their Surveillances met to establish that this Special Operations LCO is being met. If the local array of control rods is inserted and disarmed while the scram function for the withdrawn rod is not available, periodic verification in accordance with SR 3.10.3.2 is required to preclude the possibility of criticality. The control rods can be hydraulically disarmed by closing the drive water and exhaust water isolation valves. Electrically, the control rods can be disarmed by

BASES

SURVEILLANCE REQUIREMENTS (continued)

disconnecting power to all four directional control valve solenoids. SR 3.10.3.2 has been modified by a Note, which clarifies that this SR is not required to be met if SR 3.10.3.1 is satisfied for LCO 3.10.3.d.1 requirements, since SR 3.10.3.2 demonstrates that the alternative LCO 3.10.3.d.2 requirements are satisfied. Also, SR 3.10.3.3 verifies that all control rods other than the control rod being withdrawn are fully inserted. The 24 hour Frequency is acceptable because of the administrative controls on control rod withdrawal, the protection afforded by the LCOs involved, and hardwire interlocks that preclude additional control rod withdrawals.

REFERENCES None.

B 3.10 SPECIAL OPERATIONS

B 3.10.4 Single Control Rod Withdrawal - Cold Shutdown

BASES

BACKGROUND

The purpose of this MODE 4 Special Operations LCO is to permit the withdrawal of a single control rod for testing or maintenance, while in cold shutdown, by imposing certain restrictions. In MODE 4, the reactor mode switch is in the shutdown position, and all control rods are inserted and blocked from withdrawal. Many systems and functions are not required in these conditions, due to the installed interlocks associated with the reactor mode switch in the shutdown position. Circumstances may arise while in MODE 4, however, that present the need to withdraw a single control rod for various tests (e.g., friction tests, scram time testing, and coupling integrity checks). Certain situations may also require the removal of the associated control rod drive (CRD). These single control rod withdrawals and possible subsequent removals are normally accomplished by selecting the refuel position for the reactor mode switch.

APPLICABLE SAFETY ANALYSES

With the reactor mode switch in the refuel position, proper operation of the refueling interlocks and adequate SDM will preclude unacceptable reactivity excursions.

Refueling interlocks restrict the movement of control rods to reinforce operational procedures that prevent the reactor from becoming critical. These interlocks prevent the withdrawal of more than one control rod. Under these conditions, since only one control rod can be withdrawn, the core will always be shut down even with the highest worth control rod withdrawn if adequate SDM exists.

The control rod scram function provides backup protection in the event normal refueling procedures and the refueling interlocks fail to prevent inadvertent criticalities during refueling. Alternate backup protection can be obtained by ensuring that a five by five array of control rods, centered on the withdrawn control rod, are inserted and incapable of withdrawal. This alternate backup protection is required when removing a CRD because this removal renders the withdrawn control rod incapable of being scrammed.

As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of 10 CFR 50.36(c)(2)(ii) apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.

BASES

LCO

As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. Operation in MODE 4 with the reactor mode switch in the refuel position can be performed in accordance with other LCOs (i.e., Special Operations LCO 3.10.2, "Reactor Mode Switch Interlock Testing") without meeting this Special Operations LCO or its ACTIONS. If a single control rod withdrawal is desired in MODE 4, controls consistent with those required during refueling must be implemented and this Special Operations LCO applied. "Withdrawal" in this application includes the actual withdrawal of the control rod as well as maintaining the control rod in a position other than the full-in position, and reinserting the control rod.

The refueling interlocks of LCO 3.9.2, "Refuel Position One-Rod-Out Interlock," required by this Special Operations LCO will ensure that only one control rod can be withdrawn. At the time CRD removal begins, the disconnection of the position indication probe will cause LCO 3.9.4, "Control Rod Position Indication," and therefore, LCO 3.9.2 to fail to be met. Therefore, prior to commencing CRD removal, a control rod withdrawal block is required to be inserted to ensure that no additional control rods can be withdrawn and that compliance with this Special Operations LCO is maintained.

To back up the refueling interlocks (LCO 3.9.2) or the control rod withdrawal block, the ability to scram the withdrawn control rod in the event of an inadvertent criticality is provided by the Special Operations LCO requirements in Item c.1. Alternatively, when the scram function is not OPERABLE, or when the CRD is to be removed, a sufficient number of rods in the vicinity of the withdrawn control rod are required to be inserted and made incapable of withdrawal (by electrically or hydraulically disarming the CRD) (Item c.2). This precludes the possibility of criticality upon withdrawal of this control rod. Also, once this alternate (Item c.2) is completed, the SDM requirement to account for both the withdrawn-untrippable control rod and the highest worth control rod may be changed to allow the withdrawn-untrippable control rod to be the single highest worth control rod.

APPLICABILITY

Control rod withdrawals are adequately controlled in MODES 1, 2, and 5 by existing LCOs. In MODES 3 and 4, control rod withdrawal is only allowed if performed in accordance with Special Operations LCO 3.10.3, "Single Control Rod Withdrawal - Hot Shutdown," or this Special Operations LCO, and if limited to one control rod. This allowance is only provided with the reactor mode switch in the refuel position.

During these conditions, the full insertion requirements for all other control rods, the one-rod-out interlock (LCO 3.9.2), control rod position indication (LCO 3.9.4), and scram functions (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation," LCO 3.3.8.2, "Reactor Protection System

BASES

APPLICABILITY (continued)

(RPS) Electric Power Monitoring," MODE 5 requirements, and LCO 3.9.5, "Control Rod OPERABILITY - Refueling"), or the added administrative controls in Item b.2 and Item c.2 of this Special Operations LCO, provide mitigation of potential reactivity excursions.

ACTIONS

A Note has been provided to modify the ACTIONS related to a single control rod withdrawal while in MODE 4. Section 1.3, Completion Times, specifies that once a Condition has been entered, subsequent divisions, subsystems, components, or variables expressed in the Condition discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for each requirement of the LCO not met provide appropriate compensatory measures for separate requirements that are not met. As such, a Note has been provided that allows separate Condition entry for each requirement of the LCO.

A.1, A.2.1, and A.2.2

If one or more of the requirements of this Special Operations LCO are not met with the affected control rod insertable, these Required Actions restore operation consistent with normal MODE 4 conditions (i.e., all rods inserted) or with the exceptions allowed in this Special Operations LCO. Required Action A.1 has been modified by a Note that clarifies that the intent of any other LCO's Required Action to insert all control rods. This Required Action includes exiting this Special Operations LCO Applicability by returning the reactor mode switch to the shutdown position. A second Note has been added to Required Action A.1 to clarify that this Required Action is only applicable if the requirements not met are for an affected LCO.

Required Actions A.2.1 and A.2.2 are specified, based on the assumption that the control rod is being withdrawn. If the control rod is still insertable, actions must be immediately initiated to fully insert all insertable control rods and within 1 hour place the reactor mode switch in the shutdown position. Actions must continue until all such control rods are fully inserted. The allowed Completion Time of 1 hour for placing the reactor mode switch in the shutdown position provides sufficient time to normally insert the control rods.

BASES

ACTIONS (continued)

B.1, B.2.1, and B.2.2

If one or more of the requirements of this Special Operations LCO are not met with the affected control rod not insertable, withdrawal of the control rod and removal of the associated CRD must be immediately suspended. If the CRD has been removed, such that the control rod is not insertable, the Required Actions require the most expeditious action be taken to either initiate action to restore the CRD and insert its control rod, or initiate action to restore compliance with this Special Operations LCO.

SURVEILLANCE REQUIREMENTS

SR 3.10.4.1, SR 3.10.4.2, SR 3.10.4.3, and SR 3.10.4.4

The other LCOs made applicable by this Special Operations LCO are required to have their associated surveillances met to establish that this Special Operations LCO is being met. If the local array of control rods is inserted and disarmed while the scram function for the withdrawn rod is not available, periodic verification is required to ensure that the possibility of criticality remains precluded. The control rods can be hydraulically disarmed by closing the drive water and exhaust water isolation valves. Electrically, the control rods can be disarmed by disconnecting power to all four directional control valve solenoids. Verification that all the other control rods are fully inserted is required to meet the SDM requirements. Verification that a control rod withdrawal block has been inserted ensures that no other control rods can be inadvertently withdrawn under conditions when position indication instrumentation is inoperable for the affected control rod. The 24 hour Frequency is acceptable because of the administrative controls on control rod withdrawals, the protection afforded by the LCOs involved, and hardwire interlocks to preclude an additional control rod withdrawal.

SR 3.10.4.2 and SR 3.10.4.4 have been modified by Notes, which clarify that these SRs are not required to be met if the alternative requirements demonstrated by SR 3.10.4.1 are satisfied.

REFERENCES

None.

B 3.10 SPECIAL OPERATIONS

B 3.10.5 Single Control Rod Drive (CRD) Removal - Refueling

BASES

BACKGROUND

The purpose of this MODE 5 Special Operations LCO is to permit the removal of a single CRD during refueling operations by imposing certain administrative controls. Refueling interlocks restrict the movement of control rods and the operation of the refueling equipment to reinforce operational procedures that prevent the reactor from becoming critical during refueling operations. During refueling operations, no more than one control rod in a core cell containing one or more fuel assemblies is permitted to be withdrawn. The refueling interlocks use the "full-in" position indicators to determine the position of all control rods. If the "full-in" position signal is not present for every control rod, then the all rods in permissive for the refueling equipment interlocks is not present and fuel loading is prevented. Also, the refuel position one-rod-out interlock will not allow the withdrawal of a second control rod.

The control rod scram function provides backup protection in the event normal refueling procedures, and the refueling interlocks described above fail to prevent inadvertent criticalities during refueling. The requirement for the refueling interlocks to be OPERABLE precludes the possibility of removing the CRD once a control rod is withdrawn from a core cell containing one or more fuel assemblies. This Special Operations LCO provides controls sufficient to ensure the possibility of an inadvertent criticality is precluded, while allowing a single CRD to be removed from a core cell containing one or more fuel assemblies. The removal of the CRD involves disconnecting the position indication probe, which causes noncompliance with LCO 3.9.4, "Control Rod Position Indication," and, therefore, LCO 3.9.1, "Refueling Equipment Interlocks," and LCO 3.9.2, "Refueling Position One-Rod-Out Interlock." The CRD removal also requires isolation of the CRD from the CRD Hydraulic System, thereby causing inoperability of the control rod (LCO 3.9.5, "Control Rod OPERABILITY - Refueling").

APPLICABLE SAFETY ANALYSES

With the reactor mode switch in the refuel position, proper operation of the refueling interlocks and adequate SDM will preclude unacceptable reactivity excursions.

Refueling interlocks restrict the movement of control rods and the operation of the refueling equipment to reinforce operational procedures that prevent the reactor from becoming critical. These interlocks prevent the withdrawal of more than one control rod. Under these conditions, since only one control rod can be withdrawn, the core will always be shut down even with the highest worth control rod withdrawn if adequate SDM

BASES

APPLICABLE SAFETY ANALYSES (continued)

exists. By requiring all other control rods to be inserted and a control rod withdrawal block initiated, the function of the inoperable one-rod-out interlock (LCO 3.9.2) is adequately maintained. This Special Operations LCO requirement that no other CORE ALTERATIONS are in progress adequately compensates for the inoperable all-rods-in permissive for the refueling equipment interlocks (LCO 3.9.1).

The control rod scram function provides backup protection to normal refueling procedures and the refueling interlocks, which prevent inadvertent criticalities during refueling. Since the scram function and refueling interlocks may be suspended, alternate backup protection required by this Special Operations LCO is obtained by ensuring that a five by five array of control rods, centered on the withdrawn control rod, are inserted and are incapable of being withdrawn, and all other control rods are inserted and incapable of being withdrawn by insertion of a control rod block.

As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of 10 CFR 50.36(c)(2)(ii) apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.

LCO

As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. Operation in MODE 5 with any of the following LCOs, LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation," LCO 3.3.8.2, "Reactor Protection System (RPS) Electric Power Monitoring," LCO 3.9.1, LCO 3.9.2, LCO 3.9.4, or LCO 3.9.5 not met, can be performed in accordance with the Required Actions of these LCOs without meeting this Special Operations LCO or its ACTIONS. However, if a single CRD removal from a core cell containing one or more fuel assemblies is desired in MODE 5, controls consistent with those required by LCO 3.3.1.1, LCO 3.3.8.2, LCO 3.9.1, LCO 3.9.2, LCO 3.9.4, and LCO 3.9.5 must be implemented, and this Special Operations LCO applied.

By requiring all other control rods to be inserted and a control rod withdrawal block initiated, the function of the inoperable one-rod-out interlock (LCO 3.9.2) is adequately maintained. This Special Operations LCO requirement that no other CORE ALTERATIONS are in progress adequately compensates for the inoperable all-rods-in permissive for the refueling equipment interlocks (LCO 3.9.1). Ensuring that the five by five array of control rods, centered on the withdrawn control rod, are inserted

BASES

LCO (continued)

and incapable of withdrawal (by electrically or hydraulically disarming the CRD) adequately satisfies the backup protection that LCO 3.3.1.1 and LCO 3.9.2 would have otherwise provided. Also, once these requirements (Items a, b, and c) are completed, the SDM requirement to account for both the withdrawn-untrippable control rod and the highest worth control rod may be changed to allow the withdrawn-untrippable control rod to be the single highest worth control rod.

APPLICABILITY

Operation in MODE 5 is controlled by existing LCOs. The allowance to comply with this Special Operations LCO in lieu of the ACTIONS of LCO 3.3.1.1, LCO 3.3.8.2, LCO 3.9.1, LCO 3.9.2, LCO 3.9.4, and LCO 3.9.5 is appropriately controlled with the additional administrative controls required by this Special Operations LCO, which reduce the potential for reactivity excursions.

ACTIONS

A.1, A.2.1, and A.2.2

If one or more of the requirements of this Special Operations LCO are not met, the immediate implementation of these Required Actions restores operation consistent with the normal requirements for failure to meet LCO 3.3.1.1, LCO 3.9.1, LCO 3.9.2, LCO 3.9.4, and LCO 3.9.5 (i.e., all control rods inserted) or with the allowances of this Special Operations LCO. The Completion Times for Required Action A.1, Required Action A.2.1, and Required Action A.2.2 are intended to require that these Required Actions be implemented in a very short time and carried through in an expeditious manner to either initiate action to restore the CRD and insert its control rod, or initiate action to restore compliance with this Special Operations LCO. Actions must continue until either Required Action A.2.1 or Required Action A.2.2 is satisfied.

SURVEILLANCE REQUIREMENTS

SR 3.10.5.1, SR 3.10.5.2, SR 3.10.5.3, SR 3.10.5.4, and SR 3.10.5.5

Verification that all the control rods, other than the control rod withdrawn for the removal of the associated CRD, are fully inserted is required to ensure the SDM is within limits. Verification that the local five by five array of control rods, other than the control rod withdrawn for removal of the associated CRD, is inserted and disarmed, while the scram function for the withdrawn rod is not available, is required to ensure that the possibility of criticality remains precluded. The control rods can be hydraulically disarmed by closing the drive water and exhaust water isolation valves. Electrically, the control rods can be disarmed by disconnecting power to all four directional control valve solenoids. Verification that a control rod withdrawal block has been inserted ensures

BASES

SURVEILLANCE REQUIREMENTS (continued)

that no other control rods can be inadvertently withdrawn under conditions when position indication instrumentation is inoperable for the withdrawn control rod. The Surveillance for LCO 3.1.1, which is made applicable by this Special Operations LCO, is required in order to establish that this Special Operations LCO is being met. Verification that no other CORE ALTERATIONS are being made is required to ensure the assumptions of the safety analysis are satisfied.

Periodic verification of the administrative controls established by this Special Operations LCO is prudent to preclude the possibility of an inadvertent criticality. The 24 hour Frequency is acceptable, given the administrative controls on control rod removal and hardwire interlock to block an additional control rod withdrawal.

REFERENCES None.

B 3.10 SPECIAL OPERATIONS

B 3.10.6 Multiple Control Rod Withdrawal - Refueling

BASES

BACKGROUND

The purpose of this MODE 5 Special Operations LCO is to permit multiple control rod withdrawal during refueling by imposing certain administrative controls.

Refueling interlocks restrict the movement of control rods and the operation of the refueling equipment to reinforce operational procedures that prevent the reactor from becoming critical during refueling operations. During refueling operations, no more than one control rod in a core cell containing one or more fuel assemblies is permitted to be withdrawn. When all four fuel assemblies are removed from a cell, the control rod may be withdrawn with no restrictions. Any number of control rods may be withdrawn and removed from the reactor vessel if their cells contain no fuel.

The refueling interlocks use the "full-in" position indicators to determine the position of all control rods. If the "full-in" position signal is not present for every control rod, then the all rods in permissive for the refueling equipment interlocks is not present and fuel loading is prevented. Also, the refuel position one-rod-out interlock will not allow the withdrawal of a second control rod.

To allow more than one control rod to be withdrawn during refueling, these interlocks must be defeated. This Special Operations LCO establishes the necessary administrative controls to allow bypassing the "full-in" position indicators.

APPLICABLE SAFETY ANALYSES

Proper operation of the refueling interlocks and adequate SDM will prevent unacceptable reactivity excursions during refueling. To allow multiple control rod withdrawals, control rod removals, associated control rod drive (CRD) removal, or any combination of these, the "full-in" position indication is allowed to be bypassed for each withdrawn control rod if all fuel has been removed from the cell. With no fuel assemblies in the core cell, the associated control rod has no reactivity control function and is not required to remain inserted. Prior to reloading fuel into the cell, however, the associated control rod must be inserted to ensure that an inadvertent criticality does not occur.

As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of 10 CFR 50.36(c)(2)(ii) apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.

BASES

LCO

As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. Operation in MODE 5 with either LCO 3.9.3, "Control Rod Position," LCO 3.9.4, "Control Rod Position Indication," or LCO 3.9.5, "Control Rod OPERABILITY - Refueling," not met, can be performed in accordance with the Required Actions of these LCOs without meeting this Special Operations LCO or its ACTIONS. If multiple control rod withdrawal or removal, or CRD removal is desired, all four fuel assemblies are required to be removed from the associated cells. Prior to entering this LCO, any fuel remaining in a cell whose CRD was previously removed under the provisions of another LCO must be removed. "Withdrawal" in this application includes the actual withdrawal of the control rod as well as maintaining the control rod in a position other than the full-in position, and reinserting the control rod.

When fuel is loaded into the core with multiple control rods withdrawn, approved reload sequences are used to ensure that no fuel assembly is loaded into the core without the associated control rod fully inserted. The approved reload sequence must meet the following criteria: a) after removing all four fuel assemblies from a core cell, no fuel can be loaded into the core with a blade guide in the core cell and the associated control rod not fully inserted; and b) prior to loading the first fuel assembly into a cell that previously contained no fuel assemblies, the associated control rod must be verified to be fully inserted by refueling floor personnel. Therefore, these two criteria ensure that no fuel assembly is loaded into the core without the associated control rod fully inserted. Otherwise, all control rods must be fully inserted before loading fuel.

APPLICABILITY

Operation in MODE 5 is controlled by existing LCOs. The exceptions from other LCO requirements (e.g., the ACTIONS of LCO 3.9.3, LCO 3.9.4, or LCO 3.9.5) allowed by this Special Operations LCO are appropriately controlled by requiring all fuel to be removed from cells whose "full-in" indicators are allowed to be bypassed.

ACTIONS

A.1, A.2, A.3.1, and A.3.2

If one or more of the requirements of this Special Operations LCO are not met, the immediate implementation of these Required Actions restores operation consistent with the normal requirements for refueling (i.e., all control rods inserted in core cells containing one or more fuel assemblies) or with the exceptions granted by this Special Operations LCO. The Completion Times for Required Action A.1, Required Action A.2, Required Action A.3.1, and Required Action A.3.2 are intended to require that these Required Actions be implemented in a very short time and carried through in an expeditious manner to either initiate action to restore the affected CRDs and insert their control rods, or initiate action to restore compliance with this Special Operations LCO.

BASES

SURVEILLANCE REQUIREMENTS	SR 3.10.6.1, SR 3.10.6.2, and SR 3.10.6.3 Periodic verification of the administrative controls established by this Special Operations LCO is prudent to preclude the possibility of an inadvertent criticality. The 24 hour Frequency is acceptable, given the administrative controls on fuel assembly and control rod removal, and takes into account other indications of control rod status available in the control room.
REFERENCES	None.

B 3.10 SPECIAL OPERATIONS

B 3.10.7 Control Rod Testing - Operating

BASES

BACKGROUND	The purpose of this Special Operations LCO is to permit control rod testing, while in MODES 1 and 2, by imposing certain administrative controls. Control rod patterns during startup conditions are controlled by the operator and the rod worth minimizer (RWM) (LCO 3.3.2.1, "Control Rod Block Instrumentation"), such that only the specified control rod sequences and relative positions required by LCO 3.1.6, "Rod Pattern Control," are allowed over the operating range from all control rods inserted to the low power setpoint (LPSP) of the RWM. The sequences effectively limit the potential amount and rate of reactivity increase that could occur during a control rod drop accident (CRDA). During these conditions, control rod testing is sometimes required that may result in control rod patterns not in compliance with the prescribed sequences of LCO 3.1.6. These tests include SDM demonstrations, control rod scram time testing, and control rod friction testing. This Special Operations LCO provides the necessary exemption to the requirements of LCO 3.1.6 and provides additional administrative controls to allow the deviations in such tests from the prescribed sequences in LCO 3.1.6.
APPLICABLE SAFETY ANALYSES	NOTE: Certain AREVA safety analysis methods have been approved for use (Amendment 188); however, those methods may not be invoked in the analysis-of-record until AREVA fuel is loaded in the core. Until that time, General Electric – Hitachi (GEH) safety analysis methods will continue to support core operation and the description of the GEH methods in the TS Bases shall prevail. To the extent that approved AREVA methods may be described and referenced without conflicting with the GEH analysis-of-record, the TS Bases reflect both GEH and AREVA methods. Refer to CORE OPERATING LIMIT REPORT (COLR) Section 1.0 to determine whether GEH or AREVA methods were used for the current operating cycle. The analytical methods and assumptions used in evaluating the CRDA are summarized in References 1, 2, 3, 4, and 5. CRDA analyses assume the reactor operator follows prescribed withdrawal sequences. These sequences define the potential initial conditions for the CRDA analyses. The RWM provides backup to operator control of the withdrawal sequences to ensure the initial conditions of the CRDA analyses are not violated. For special sequences developed for control rod testing, the initial control rod patterns assumed in the safety analysis of References 1, 2, 3, 4, and 5 may not be preserved. Therefore special CRDA analyses are required to demonstrate that these special sequences will not result in unacceptable consequences, should a CRDA occur during the testing. These analyses, performed in accordance with an NRC approved methodology, are dependent on the specific test being performed.

BASES

APPLICABLE SAFETY ANALYSES (continued)

As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of 10 CFR 50.36(c)(2)(ii) apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.

LCO

As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. Control rod testing may be performed in compliance with the prescribed sequences of LCO 3.1.6, and during these tests, no exceptions to the requirements of LCO 3.1.6 are necessary. For testing performed with a sequence not in compliance with LCO 3.1.6, the requirements of LCO 3.1.6 may be suspended, provided additional administrative controls are placed on the test to ensure that the assumptions of the special safety analysis for the test sequence are satisfied. Assurances that the test sequence is followed can be provided by either programming the test sequence into the RWM, with conformance verified as specified in SR 3.3.2.1.8 and allowing the RWM to monitor control rod withdrawal and provide appropriate control rod blocks if necessary, or by verifying conformance to the approved test sequence by a second licensed operator (Operator or Senior Operator) or other qualified member of the technical staff (i.e., engineer). These controls are consistent with those normally applied to operation in the startup range as defined in the SRs and ACTIONS of LCO 3.3.2.1, "Control Rod Block Instrumentation."

APPLICABILITY

Control rod testing, while in MODES 1 and 2, with THERMAL POWER greater than 10% RTP, is adequately controlled by the existing LCOs on power distribution limits and control rod block instrumentation. Control rod movement during these conditions is not restricted to prescribed sequences and can be performed within the constraints of LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)," LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)," LCO 3.2.3, "LINEAR HEAT GENERATION RATE (LHGR)," and LCO 3.3.2.1. With THERMAL POWER less than or equal to 10% RTP, the provisions of this Special Operations LCO are necessary to perform special tests that are not in conformance with the prescribed sequences of LCO 3.1.6. While in MODES 3 and 4, control rod withdrawal is only allowed if performed in accordance with Special Operations LCO 3.10.3, "Single Control Rod Withdrawal - Hot Shutdown," or Special Operations LCO 3.10.4, "Single Control Rod Withdrawal - Cold Shutdown," which provide adequate controls to ensure that the assumptions of the safety analyses of References 1, 2, 3, 4, and 5 are satisfied. During these Special

BASES

APPLICABILITY (continued)

Operations and while in MODE 5, the one-rod-out interlock (LCO 3.9.2, "Refuel Position One-Rod-Out Interlock,") and scram functions (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation," and LCO 3.9.5, "Control Rod OPERABILITY - Refueling"), or the added administrative controls prescribed in the applicable Special Operations LCOs, provide mitigation of potential reactivity excursions.

ACTIONS

A.1

With the requirements of the LCO not met (e.g., the control rod pattern is not in compliance with the special test sequence, the sequence is improperly loaded in the RWM) the testing is required to be immediately suspended. Upon suspension of the special test, the provisions of LCO 3.1.6 are no longer excepted, and appropriate actions are to be taken to restore the control rod sequence to the prescribed sequence of LCO 3.1.6, or to shut down the reactor, if required by LCO 3.1.6.

SURVEILLANCE REQUIREMENTS

SR 3.10.7.1

With the special test sequence not programmed into the RWM, a second licensed operator (Operator or Senior Operator) or other qualified member of the technical staff (i.e., engineer) is required to verify conformance with the approved sequence for the test. This verification must be performed during control rod movement to prevent deviations from the specified sequence. A Note is added to indicate that this Surveillance does not need to be met if SR 3.10.7.2 is satisfied.

SR 3.10.7.2

When the RWM provides conformance to the special test sequence, the test sequence must be verified to be correctly loaded into the RWM prior to control rod movement. This Surveillance demonstrates compliance with SR 3.3.2.1.8, thereby demonstrating that the RWM is OPERABLE. A Note has been added to indicate that this Surveillance does not need to be met if SR 3.10.7.1 is satisfied.

BASES

REFERENCES

1. NEDE-24011-P-A-US, General Electric Standard Application for Reactor Fuel, (revision specified in Specification 5.6.3).

2. Letter from T. Pickens (BWROG) to G.C. Lainas (NRC) "Amendment 17 to General Electric Licensing Topical Report NEDE-24011-P-A," BWROG-8644, August 15, 1986.

3. USAR, Section 14.7.1.

4. XN-NF-80-19(P)(A) Volume 1 and Supplements 1 and 2, “Exxon Nuclear Methodology for Boiling Water Reactors – Neutronic Methods for Design and Analysis”, Exxon Nuclear Company, March 1983.

5. EMF-2158(P)(A) Revision 0, “Siemens Power Corporation Methodology for Boiling Water Reactors: Evaluation and Validation for CASMO-4/MICROBURN-B2”, Siemens Power Corporation, October 1999.

B 3.10 SPECIAL OPERATIONS

B 3.10.8 SHUTDOWN MARGIN (SDM) Test - Refueling

BASES

BACKGROUND

The purpose of this MODE 5 Special Operations LCO is to permit SDM testing to be performed for those plant configurations in which the reactor pressure vessel (RPV) head is either not in place or the head bolts are not fully tensioned.

LCO 3.1.1, "SHUTDOWN MARGIN (SDM)," requires that adequate SDM be demonstrated following fuel movements or control rod replacement within the RPV. The demonstration must be performed prior to or within 4 hours after criticality is reached. This SDM test may be performed prior to or during the first startup following the refueling. Performing the SDM test prior to startup requires the test to be performed while in MODE 5, with the vessel head bolts less than fully tensioned (and possibly with the vessel head removed). While in MODE 5, the reactor mode switch is required to be in the shutdown or refuel position, where the applicable control rod blocks ensure that the reactor will not become critical. The SDM test requires the reactor mode switch to be in the startup/hot standby position, since more than one control rod will be withdrawn for the purpose of demonstrating adequate SDM. This Special Operations LCO provides the appropriate additional controls to allow withdrawing more than one control rod from a core cell containing one or more fuel assemblies when the reactor vessel head bolts are less than fully tensioned.

APPLICABLE SAFETY ANALYSES

NOTE: Certain AREVA safety analysis methods have been approved for use (Amendment 188); however, those methods may not be invoked in the analysis-of-record until AREVA fuel is loaded in the core. Until that time, General Electric – Hitachi (GEH) safety analysis methods will continue to support core operation and the description of the GEH methods in the TS Bases shall prevail. To the extent that approved AREVA methods may be described and referenced without conflicting with the GEH analysis-of-record, the TS Bases reflect both GEH and AREVA methods. Refer to CORE OPERATING LIMIT REPORT (COLR) Section 1.0 to determine whether GEH or AREVA methods were used for the current operating cycle.

Prevention and mitigation of unacceptable reactivity excursions during control rod withdrawal, with the reactor mode switch in the startup/hot standby position while in MODE 5, is provided by the intermediate range monitor (IRM) neutron flux scram (LCO 3.3.1.1, "Reactor Protection System (RPS) Instrumentation"), and control rod block instrumentation (LCO 3.3.2.1, "Control Rod Block Instrumentation"). The limiting reactivity excursion during startup conditions while in MODE 5 is the control rod drop accident (CRDA).

BASES

APPLICABLE SAFETY ANALYSES (continued)

CRDA analyses assume that the reactor operator follows prescribed withdrawal sequences. For SDM tests performed within these defined sequences, the analyses of References 1, 2, 3, 4, and 5 are applicable. However, for some sequences developed for the SDM testing, the control rod patterns assumed in the safety analyses of References 1, 2, 3, 4, and 5 may not be met. Therefore, special CRDA analyses, performed in accordance with an NRC approved methodology, are required to demonstrate the SDM test sequence will not result in unacceptable consequences should a CRDA occur during the testing. For the purpose of this test, the protection provided by the normally required MODE 5 applicable LCOs, in addition to the requirements of this LCO, will maintain normal test operations as well as postulated accidents within the bounds of the appropriate safety analyses (Refs. 1, 2, 3, 4, and 5). In addition to the added requirements for the RWM, RPS shorting links, and control rod coupling, the single notch withdrawal mode is specified for out of sequence withdrawals. Requiring the single notch withdrawal mode limits withdrawal steps to a single notch, which limits inserted reactivity, and allows adequate monitoring of changes in neutron flux, which may occur during the test.

As described in LCO 3.0.7, compliance with Special Operations LCOs is optional, and therefore, no criteria of 10 CFR 50.36(c)(2)(ii) apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.

LCO

As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. SDM tests may be performed while in MODE 2, in accordance with Table 1.1-1, without meeting this Special Operations LCO or its ACTIONS. For SDM tests performed while in MODE 5, additional requirements must be met to ensure that adequate protection against potential reactivity excursions is available. To provide additional scram protection, beyond the normally required IRMs, SRMs are also required to be OPERABLE so that when any SRM reaches its trip setpoint, a reactor scram will be initiated. This is known as the RPS non-coincident scram mode and is accomplished by removing the shorting links associated with the RPS. Because multiple control rods will be withdrawn and the reactor will potentially become critical, the RPS non-coincident scram mode associated with the SRMs must be enforced and the approved control rod withdrawal sequence must be enforced by the RWM (LCO 3.3.2.1, Function 2, MODE 2), or must be verified by a second licensed operator (Operator or Senior Operator) or other qualified member of the technical staff (i.e., engineer). To provide additional protection against an inadvertent criticality, control rod withdrawals that do not conform to the banked position withdrawal sequence specified in

BASES

LCO (continued)

LCO 3.1.6, "Rod Pattern Control," (i.e., out of sequence control rod withdrawals) must be made in the individual notched withdrawal mode to minimize the potential reactivity insertion associated with each movement. Coupling integrity of withdrawn control rods is required to minimize the probability of a CRDA and ensure proper functioning of the withdrawn control rods, if they are required to scram. Because the reactor vessel head may be removed during these tests, no other CORE ALTERATIONS may be in progress. Furthermore, since the control rod scram function with the RCS at atmospheric pressure relies solely on the CRD accumulator, it is essential that the CRD charging water header remain pressurized. This Special Operations LCO then allows changing the Table 1.1-1 reactor mode switch position requirements to include the startup/hot standby position, such that the SDM tests may be performed while in MODE 5.

APPLICABILITY

These SDM test Special Operations requirements are only applicable if the SDM tests are to be performed while in MODE 5 with the reactor mode switch in the startup/hot standby position. Additional requirements during these tests to enforce control rod withdrawal sequences and restrict other CORE ALTERATIONS provide protection against potential reactivity excursions. Operations in all other MODES are unaffected by this LCO.

ACTIONS

A.1 and A.2

With one or more control rods discovered uncoupled during this Special Operation, a controlled insertion of each uncoupled control rod is required; either to attempt recoupling, or to preclude a control rod drop. This controlled insertion is preferred since, if the control rod fails to follow the drive as it is withdrawn (i.e., is "stuck" in an inserted position), placing the reactor mode switch in the shutdown position per Required Action B.1 could cause substantial secondary damage. If recoupling is not accomplished, operation may continue, provided the control rods are fully inserted within 3 hours and disarmed (electrically or hydraulically) within 4 hours. Inserting a control rod ensures the shutdown and scram capabilities are not adversely affected. The control rod is disarmed to prevent inadvertent withdrawal during subsequent operations. The control rods can be hydraulically disarmed by closing the drive water and exhaust water isolation valves. Electrically the control rods can be disarmed by disconnecting power from all four directional control valve solenoids. Required Action A.1 is modified by a Note that allows the RWM to be bypassed if required to allow insertion of the inoperable control rods and continued operation. LCO 3.3.2.1, "Control Rod Block Instrumentation," Actions provide additional requirements when the RWM is bypassed to ensure compliance with the CRDA analysis.

BASES

ACTIONS (continued)

The allowed Completion Times are reasonable, considering the small number of allowed inoperable control rods, and provide time to insert and disarm the control rods in an orderly manner and without challenging plant systems.

Condition A is modified by a Note allowing separate Condition entry for each uncoupled control rod. This is acceptable since the Required Actions for this Condition provide appropriate compensatory actions for each uncoupled control rod. Complying with the Required Actions may allow for continued operation. Subsequent uncoupled control rods are governed by subsequent entry into the Condition and application of the Required Actions.

B.1

With one or more of the requirements of this LCO not met for reasons other than an uncoupled control rod, the testing should be immediately stopped by placing the reactor mode switch in the shutdown or refuel position. This results in a condition that is consistent with the requirements for MODE 5 where the provisions of this Special Operations LCO are no longer required.

SURVEILLANCE REQUIREMENTS

SR 3.10.8.1

Periodic verification that the RPS shorting links are removed will help ensure the IRM trips are in non-coincidence mode and that when any SRM reaches its trip setpoint, a reactor scram will be initiated. This will ensure that the reactor is operated within the bounds of the safety analysis. The 12 hour Frequency is intended to provide appropriate assurance that each operating shift is aware of and verifies compliance with these Special Operations LCO requirements.

SR 3.10.8.2 and SR 3.10.8.3

The control rod withdrawal sequences during the SDM tests may be enforced by the RWM (LCO 3.3.2.1, Function 2, MODE 2 requirements) or by a second licensed operator (Operator or Senior Operator) or other qualified member of the technical staff (i.e., engineer). As noted, either the applicable SRs for the RWM (LCO 3.3.2.1) must be satisfied according to the applicable Frequencies (SR 3.10.8.2), or the proper movement of control rods must be verified (SR 3.10.8.3). This latter verification (i.e., SR 3.10.8.3) must be performed during control rod

BASES

SURVEILLANCE REQUIREMENTS (continued)

movement to prevent deviations from the specified sequence. These surveillances provide adequate assurance that the specified test sequence is being followed.

SR 3.10.8.4

Periodic verification of the administrative controls established by this LCO will ensure that the reactor is operated within the bounds of the safety analysis. The 12 hour Frequency is intended to provide appropriate assurance that each operating shift is aware of and verifies compliance with these Special Operations LCO requirements.

SR 3.10.8.5

Coupling verification is performed to ensure the control rod is connected to the control rod drive mechanism and will perform its intended function when necessary. The verification is required to be performed any time a control rod is withdrawn to the "full-out" notch position, or prior to declaring the control rod OPERABLE after work on the control rod or CRD System that could affect coupling. This Frequency is acceptable, considering the low probability that a control rod will become uncoupled when it is not being moved as well as operating experience related to uncoupling events.

SR 3.10.8.6

CRD charging water header pressure verification is performed to ensure the motive force is available to scram the control rods in the event of a scram signal. Since the reactor is depressurized in MODE 5, there is insufficient reactor pressure to scram the control rods. Verification of charging water header pressure ensures that if a scram were required, capability for rapid control rod insertion would exist. The minimum pressure of 940 psig is well below the expected pressure of approximately 1500 psig while still ensuring sufficient pressure for rapid control rod insertion. The 7 day Frequency has been shown to be acceptable through operating experience and takes into account indications available in the control room.

BASES

REFERENCES

1. NEDE-24011-P-A-US, General Electric Standard Application for Reactor Fuel, (revision specified in Specification 5.6.3).

2. Letter from T. Pickens (BWROG) to G.C. Lainas, NRC, "Amendment 17 to General Electric Licensing Topical Report NEDE-24011-P-A," BWROG-8644, August 15, 1986.

3. USAR, Section 14.7.1.

4. XN-NF-80-19(P)(A) Volume 1 and Supplements 1 and 2, “Exxon Nuclear Methodology for Boiling Water Reactors – Neutronic Methods for Design and Analysis”, Exxon Nuclear Company, March 1983.

5. EMF-2158(P)(A) Revision 0, “Siemens Power Corporation Methodology for Boiling Water Reactors: Evaluation and Validation for CASMO-4/MICROBURN-B2”, Siemens Power Corporation, October 1999.