Entergy

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Director
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GNRO-2012/00146

December 21, 2012

US Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, D.C. 20555-0001

SUBJECT: Technical Requirements Manual and Technical Specification Bases Update
Grand Gulf Nuclear Station, Unit 1
Docket No. 50-416
License No. NPF-29

Dear Sir or Madam:

Pursuant to Grand Gulf Nuclear Station (GGNS) Technical Requirements Manual Section 1.04, Entergy Operations, Inc. hereby submits an update of all changes made to the GGNS Technical Requirements Manual since the last submittal (GNRO 2011/00072 dated September 12, 2011). Additionally, Technical Specification Bases are submitted, for all changes made since the last submittal (GNRO 2011/00072 dated September 12, 2011), in accordance with GGNS Technical Specification 5.5.11. These updates are consistent with update frequency listed in 10CFR50.71(e).

This letter does not contain any commitments.

Should you have any questions, please contact Steven L. Ward at (601) 437-6566.

Sincerely,

CLP/slw

Attachment: GGNS Technical Requirements Manual and Technical Specification Bases Revised Pages

cc: (See Next Page)

A001
NRR

cc:

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

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Attachment to
GNRO 2012/00146

GGNS Technical Requirements Manual and
Technical Specification Bases Revised Pages

Grand Gulf Technical Requirements Manual (TRM) Revised Pages

LBDCR#	Affected TRM Pages	Topic of Change
10027	3.3-8-I, 3.3-8-II, 3.3-8-III, 3.3-13b-I, 3.3-18-IV, 3.3-18-V, 3.3-18-VI, 3.3-18-IX, 3.3-18-X, 3.3-18-XI, 3.3-18-XII, 3.3-18-XIII, 3.3-18-XIV, 7-8	Implemented Amendment 188 replacing an analog system with a digital Power Range Neutron Monitoring (PRNM) System
11018	6.3-23, 6.3-24	Abandoned the leading edge flow monitor (LEFM) 'LEFM Check Plus' System in place
12033	3.4-3-I	Implemented Amendment 188 which adds the new PRNM System
12035	3.3-8-I, 3.3-18-IVa, 3.3-18-VI, 3.3-18-IX, 3.3-58-II	Implemented Amendment 191 for the extended power uprate (EPU)
12037	3.1-25-I	Eliminated a duplicate surveillance requirement
12040	3.3-8-I, 3.3-8-II, 3.3-18-IX	Revised EPU allowable values and trip setpoints for certain functions
12042	6.7-6	Clarified which types of equipment a temperature allowance applies to

Grand Gulf Technical Specification Bases Revised Pages

LBDCR#	Affected Bases Pages	Topic of Change
10027	B 3.2-12, B 3.2-13, B 3.2-14, B 3.2-15, B 3.2-16, B 3.2-17, B 3.2-18, B 3.3-2, B 3.3-2a, B 3.3-2b, B 3.3-4, B 3.3-4a, B 3.3-6, B 3.3-6a, B 3.3-7, B 3.3-8, B 3.3-9, B 3.3-9a, B 3.3-9b, B 3.3-9c, B 3.3-9d, B 3.3-9e, B 3.3-9f, B 3.3-19, B 3.3-20, B 3.3-21, B 3.3-22, B 3.3-23, B 3.3-23a, B 3.3-23b, B 3.3-27a, B 3.3-27b, B 3.3-29a, B 3.3-29b, B 3.3-29c, B 3.3-29d, B 3.3-29e, B 3.3-30, B 3.3-39a, B 3.4-3, B 3.4-8, B 3.10-33	Implemented Amendment 188 replacing an analog system with a digital Power Range Neutron Monitoring (PRNM) System
10036	B 3.1-37, B 3.1-38a, B 3.1-39, B 3.1-40, B 3.1-41, B 3.1-42, B 3.1-43, B 3.1-44	Implemented Amendment 190 reflecting the use of enriched boron-10 isotope and increasing negative reactivity
11018	TRB-2, TRB-3	Abandoned the leading edge flow monitor (LEFM) 'LEFM Check Plus' System in place
11068	B 3.4-32, B 3.4-33, B 3.4-34, B 3.4-34a, B 3.4-35, B 3.4-36, B 3.4-36a, B 3.4-37	Implemented Amendment 187 to adopt TSTF-514, Rev. 3, Revise BWR Operability Requirements and Actions for RCS Leakage Instrumentation
12035	B 2.0-2, B 2.0-3, B 3.2-3, B 3.2-4, B 3.2-6, B 3.2-7, B 3.2-8, B 3.2-8a, B 3.2-10, B 3.2-11, B 3.3-7, B 3.3-9e, B 3.3-9f, B 3.3-12, B 3.3-15, B 3.3-16, B 3.3-17, B 3.3-24, B 3.3-28, B 3.3-46, B 3.3-48, B 3.3-68, B 3.3-69a, B 3.3-70, B 3.3-71, B 3.3-73, B 3.3-75, B 3.3-142, B 3.3-169, B 3.4-16, B 3.4-18, B 3.4-52, B 3.4-54, B 3.4-60, B 3.6-2, B 3.6-6, B 3.6-25, B 3.6-36, B 3.6-56, B 3.6-78, B 3.6-81, B 3.6-104, B 3.6-127, B 3.7-28, B 3.7-29, B 3.7-30	Implemented Amendment 191 for the extended power uprate
12044	B 3.4-3	Revised to include Linear Heat Generation Rate modification

SURVEILLANCE REQUIREMENTS

SURVEILLANCE	FREQUENCY
SR TR3.1.7.1 Deleted	

TABLE TR3.3.1.1-1

TECHNICAL SPECIFICATION REACTOR PROTECTION SYSTEM
TRIP SETPOINTS AND RESPONSE TIMES

FUNCTIONAL UNIT	TRIP SETPOINT	RESPONSE TIMES (SECONDS)
1. Intermediate Range Monitor		
a. Neutron Flux-High	<120/125 divisions of full scale	NA
b. Inoperative	NA	NA
2. Average Power Range Monitor: #		
a. Neutron Flux-High, Setdown	≤15% of RATED (d), (e) THERMAL POWER	NA
b. Fixed Neutron Flux-High	≤118% of RATED (d), (e) THERMAL POWER	NA
c. Inoperative	NA	NA
d. Flow-Biased Simulated Thermal Power - High	(c), (d), (e)	NA
e. 2-Out-Of-4 Voter	NA	≤0.05 (f)
f. OPRM Upscale	(d), (e), (g)	NA
3. Reactor Vessel Steam Dome Pressure - High	≤1064.7 psig	T_L ≤0.35(b)
4. Reactor Vessel Water Level - Low, Level 3	≥11.4 inches above instrument zero*	T_L ≤1.05(b)
5. Reactor Vessel Water Level - High, Level 8	≤53.5 inches above instrument zero*	T_L ≤1.05(b)
6. Main Steam Line Isolation Valve - Closure	≤6% closed	≤0.06
7. Drywell Pressure - High	≤1.23 psig	NA
8. Scram Discharge Volume Water Level - High		
a. Transmitter/Trip Unit	≤60% of full scale	NA
b. Float Switch	≤64"	NA
9. Turbine Stop Valve - Closure, ≤0.10	≥40 psig (a)	
10. Turbine Control Valve Fast Closure, Trip Oil Pressure - Low	≥46.0 psig (a)	≤0.10**

TABLE TR3.3.1.1-1

TECHNICAL SPECIFICATION REACTOR PROTECTION SYSTEM
TRIP SETPOINTS AND RESPONSE TIMES

FUNCTIONAL UNIT	TRIP SETPOINT	RESPONSE TIMES (SECONDS)
1. Intermediate Range Monitor		
a. Neutron Flux-High	<120/125 divisions of full scale	NA
b. Inoperative	NA	NA
2. Average Power Range Monitor: #		
a. Neutron Flux-High, Setdown	≤18% of RATED THERMAL POWER	NA
b. Neutron Flux-High	≤118% of RATED THERMAL POWER	≤0.09
c. Inoperative	NA	NA
d. Flow-Biased Simulated Thermal Power - High	(c)	≤0.09 (d)
3. Reactor Vessel Steam Dome Pressure - High	≤1064.7 psig	T_L ≤0.35(b)
4. Reactor Vessel Water Level - Low, Level 3	≥11.4 inches above instrument zero*	T_L ≤1.05(b)
5. Reactor Vessel Water Level - High, Level 8	≤53.5 inches above instrument zero*	T_L ≤1.05(b)
6. Main Steam Line Isolation Valve - Closure	≤6% closed	≤0.06
7. Drywell Pressure - High	≤1.23 psig	NA
8. Scram Discharge Volume Water Level - High		
a. Transmitter/Trip Unit	≤60% of full scale	NA
b. Float Switch	≤64"	NA
9. Turbine Stop Valve - Closure,	≥40 psig (a)	≤0.10
10. Turbine Control Valve Fast Closure, Trip Oil Pressure - Low	≥46.0 psig (a)	≤0.10**

TABLE TR3.3.1.1-1

TECHNICAL SPECIFICATION REACTOR PROTECTION SYSTEM
TRIP SETPOINTS AND RESPONSE TIMES

FUNCTIONAL UNIT	TRIP SETPOINT	RESPONSE TIMES (SECONDS)
1. Intermediate Range Monitor		
a. Neutron Flux-High	<120/125 divisions of full scale	NA
b. Inoperative	NA	NA
2. Average Power Range Monitor: #		
a. Neutron Flux-High, Setdown	≤18% of RATED THERMAL POWER	NA
b. Neutron Flux-High	≤117.3% of RATED THERMAL POWER	≤0.09
c. Inoperative	NA	NA
d. Flow-Biased Simulated Thermal Power - High	(c)	≤0.09 (d)
3. Reactor Vessel Steam Dome Pressure - High	≤1064.7 psig	T_L ≤0.35(b)
4. Reactor Vessel Water Level - Low, Level 3	≥11.4 inches above instrument zero*	T_L ≤1.05(b)
5. Reactor Vessel Water Level - High, Level 8	≤53.5 inches above instrument zero*	T_L ≤1.05(b)
6. Main Steam Line Isolation Valve - Closure	≤6% closed	≤0.06
7. Drywell Pressure - High	≤1.23 psig	NA
8. Scram Discharge Volume Water Level - High		
a. Transmitter/Trip Unit	≤60% of full scale	NA
b. Float Switch	≤64"	NA
9. Turbine Stop Valve - Closure,	≥40 psig (a)	≤0.10
10. Turbine Control Valve Fast Closure, Trip Oil Pressure - Low	≥46.0 psig (a)	≤0.10**

TABLE TR3.3.1.1-1

TECHNICAL SPECIFICATION REACTOR PROTECTION SYSTEM
TRIP SETPOINTS AND RESPONSE TIMES

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

NOTES

(a) This function is automatically bypassed at or below an Allowable Value of ≤36% RTP equivalent turbine first stage pressure.

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

The given numerical value is the acceptance criterion for T_L.

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

(c) Two-Loop Operation 0.65W + 60.9% RTP and ≤ 111.0% RTP
Single-Loop Operation: 0.65W + 38.8% RTP

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

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

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

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

* See Bases Figure B 3.3.1.1

** Measure from start of turbine control valve fast closure.

\# Response time shall be measured from detector output or from the input of the first electronic component in the channel.

TABLE TR3.3.1.1-1

TECHNICAL SPECIFICATION REACTOR PROTECTION SYSTEM
TRIP SETPOINTS AND RESPONSE TIMES

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

NOTES

(a) This function is automatically bypassed at or below an Allowable Value of ≤36% RTP equivalent turbine first stage pressure.

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

The given numerical value is the acceptance criterion for T_L.

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

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

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

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

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

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

* See Bases Figure B 3.3.1.1

** Measure from start of turbine control valve fast closure.

\# Response time shall be measured from detector output or from the input of the first electronic component in the channel.

TABLE TR3.3.1.1-2

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Page 3.3-13b-I has been deleted

ACTION (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. As required by Required Action A.1 and referenced in Table TR3.3.2.1-2.	D.1 Place the inoperable channel in the tripped condition.	12 hours
E. Deleted		

SURVEILLANCE REQUIREMENTS

-----NOTES-----

1. Refer to Table TR3.3.2.1-2 to determine which SRs apply for each Control Rod Block Function.

2. 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 control rod block capability.

SURVEILLANCE		FREQUENCY
SR TR3.3.2.1.3	-----NOTE----- Not required to be performed until 12 hours after entering MODE 2 from MODE 1. --- Perform a CHANNEL FUNCTIONAL TEST.	31 days AND Prior to each reactor startup.

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR TR3.3.2.1.4	---------------------NOTE---------------------- Not required to be performed until 12 hours after THERMAL POWER ≥ 21.8% RTP. --- Verify the absolute difference between the average power range monitor (APRM) channels and the heat balance calculated power ≤ 2% RTP while operating at ≥ 21.8% RTP.	7 days
SR TR3.3.2.1.5	Not Used	NA

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR TR3.3.2.1.6	Perform a CHANNEL FUNCTIONAL TEST.	366 days
SR TR3.3.2.1.7	Perform a CHANNEL FUNCTIONAL TEST.	184 days
SR TR3.3.2.1.8	Perform a CHANNEL FUNCTIONAL TEST.	Within 7 days prior to startup
SR TR3.3.2.1.9	---NOTE--- Neutron detectors may be excluded. --- Perform a CHANNEL CALIBRATION.	92 days
SR TR3.3.2.1.10	---NOTES--- 1. Neutron detectors are excluded. 2. APRM recirculation flow transmitters are excluded. 3. For Function 1.a, the digital components of the flow control trip reference cards are excluded. --- Perform a CHANNEL CALIBRATION.	24 months
SR TR3.3.2.1.11	Perform a CHANNEL CALIBRATION.	18 months
SR TR3.3.2.1.12	Perform APRM recirculation flow transmitter calibration.	18 months
SR TR3.3.2.1.13	Deleted	

TABLE TR3.3.2.1-2

CONTROL ROD BLOCK INSTRUMENTATION

FUNCTIONAL UNIT	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION A.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUES	TRIP SETPOINT
1. APRM						
a. Flow Biased Neutron Flux - Upscale	1	3	B	SR TR3.3.2.1.4 SR TR3.3.2.1.7 SR TR3.3.2.1.10 SR TR3.3.2.1.12 SR TR3.3.2.1.13	(e)	(e)
b. Inoperative	1, 2	3	B	SR TR3.3.2.1.7 SR TR3.3.2.1.8	NA	NA
c. Downscale	1	3	B	SR TR3.3.2.1.7 SR TR3.3.2.1.10	≥ 3% RTP	≥ 4% RTP +
d. Neutron Flux - Upscale, Startup	2	3	B	SR TR3.3.2.1.7 SR TR3.3.2.1.8 SR TR3.3.2.1.10	≤ 14% RTP	≤ 12% RTP

TABLE TR3.3.2.1-2

CONTROL ROD BLOCK INSTRUMENTATION

FUNCTIONAL UNIT	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION A.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUES	TRIP SETPOINT
1. APRM						
a. Flow Biased Neutron Flux - Upscale	1	6	B	SR TR3.3.2.1.4 SR TR3.3.2.1.7 SR TR3.3.2.1.10 SR TR3.3.2.1.12 SR TR3.3.2.1.13	(e),(f)	(e),(f)
b. Inoperative	1, 2	6	B	SR TR3.3.2.1.7 SR TR3.3.2.1.8	NA	NA
c. Downscale	1	6	B	SR TR3.3.2.1.7 SR TR3.3.2.1.10	≥ 3% RTP	≥ 5% RTP
d. Neutron Flux - Upscale, Startup	2	6	B	SR TR3.3.2.1.7 SR TR3.3.2.1.8 SR TR3.3.2.1.10	≤ 14% RTP	≤ 12% RTP
e. Restricted Region Entry Alarm (i)	1(j)	1	E	SR TR3.3.2.1.4 SR TR3.3.2.1.7 SR TR3.3.2.1.10 SR TR3.3.2.1.12 SR TR3.3.2.1.13	(g),(h)	(g),(h)

TABLE TR3.3.2.1-2 (Continued)

CONTROL ROD BLOCK INSTRUMENTATION

ACTION

NOTES

* With more than one control rod withdrawn during LCO 3.10.8 shutdown margin demonstrations.

** OPERABLE channels must be associated with SRMs required OPERABLE per LCO 3.3.1.2.

*** With any control rod withdrawn from a core cell containing one or more fuel assemblies.

\+ The APRM downscale setpoint has been set to 5% in anticipation of operating at EPU conditions.

(a) This function is not required if detector count rate is > 100 cps or the IRM channels are on range 3 or higher.

(b) This function is not required when the associated IRM channels are on range 8 or higher.

(c) This function is not required when the IRM channels are on range 3 or higher.

(d) This function is not required when the IRM channels are on range 1.

(e) Two-Loop Operation: Allowable Value = 0.65W + 59.9% RTP and ≤ 110% RTP
Trip Setpoint = 0.65W + 57.9% and ≤ 108%

Single-Loop Operation: Allowable Value = 0.65W + 39.3% RTP
Trip Setpoint = 0.65W + 35.8% RTP

TABLE TR3.3.2.1-2 (Continued)

CONTROL ROD BLOCK INSTRUMENTATION

ACTION

NOTES

* With more than one control rod withdrawn during LCO 3.10.8 shutdown margin demonstrations.

** OPERABLE channels must be associated with SRMs required OPERABLE per LCO 3.3.1.2.

*** With any control rod withdrawn from a core cell containing one or more fuel assemblies.

(a) This function is not required if detector count rate is > 100 cps or the IRM channels are on range 3 or higher.

(b) This function is not required when the associated IRM channels are on range 8 or higher.

(c) This function is not required when the IRM channels are on range 3 or higher.

(d) This function is not required when the IRM channels are on range 1.

(e) Two-Loop Operation: Allowable Value = 0.58W + 59.1% RTP and ≤ 113% RTP
Trip Setpoint = 0.58W + 57.1% RTP and ≤ 111% RTP

Single-Loop Operation: Allowable Value = 0.58W + 37.4% RTP
Trip Setpoint = 0.58W + 34.3% RTP

TABLE TR3.3.2.1-2 (Continued)

CONTROL ROD BLOCK INSTRUMENTATION

ACTION

NOTES

* With more than one control rod withdrawn during LCO 3.10.8 shutdown margin demonstrations.

** OPERABLE channels must be associated with SRMs required OPERABLE per LCO 3.3.1.2.

*** With any control rod withdrawn from a core cell containing one or more fuel assemblies.

(a) This function is not required if detector count rate is > 100 cps or the IRM channels are on range 3 or higher.

(b) This function is not required when the associated IRM channels are on range 8 or higher.

(c) This function is not required when the IRM channels are on range 3 or higher.

(d) This function is not required when the IRM channels are on range 1.

(e) Two-Loop Operation: Allowable Value = 0.58W + 56.1% RTP and ≤ 110% RTP
Trip Setpoint = 0.58W + 54.1% RTP and ≤ 108% RTP

Single-Loop Operation: Allowable Value = 0.58W + 34.4% RTP
Trip Setpoint = 0.58W + 31.3% RTP

TABLE TR3.3.2.1-3

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FIGURE TR3.3.2.1-1

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FIGURE TR3.3.2.1-2

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FIGURE TR3.3.2.1-3

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FIGURE TR3.3.2.1-4

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TABLE TR3.3.6.1-1

TECHNICAL SPECIFICATION ISOLATION INSTRUMENTATION
TRIP SETPOINTS AND RESPONSE TIMES

	FUNCTION	TRIP SETPOINT	RESPONSE TIME (SECONDS)	Actuated Valve Groups
1.	MAIN STEAM LINE ISOLATION			
	a. Reactor Vessel Water Level - Low Low Low, Level 1	≥ -150.3 inches*	$T_L \leq 1.0$(f)	1
	b. Main Steam Line Pressure - Low	≥ 849 psig	$T_L \leq 1.0$(f)	1
	c. Main Steam Line Flow - High	≤ 253.2 psid	$T_L \leq 0.5$(f)	1
	d. Condenser Vacuum - Low	≥ 9 inches Hg. Vacuum	NA	1
	e. Main Steam Line Tunnel Temperature - High	≤ 185°F	NA	1
	f. Manual Initiation	NA	NA	1,10
2.	PRIMARY CONTAINMENT ISOLATION			
	a. Reactor Vessel Water Level - Low Low, Level 2	≥ -41.6 inches*	NA	6A,7,8,10
	b. Drywell Pressure - High	≤ 1.23 psig	NA	6A,7
	c. Reactor Vessel Water Level - Low Low Low, Level 1 (ECCS Division 1 and Division 2)	≥ -150.3 inches*	NA	5
	d. Drywell Pressure-High (ECCS - Division 1 and Division 2)	≤ 1.39 psig	NA	5(e)
	e. Reactor Vessel Water Level - Low Low, Level 2 (ECCS - Division 3)	≥ -41.6 inches*	NA	6B
	f. Drywell Pressure - High (ECCS - Division 3)	≤ 1.39 psig	NA	6B

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6.3 INSTRUMENTATION

6.3.12 Deleted

LCO 6.3.12 Deleted

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 6.3.12.1	Deleted	

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One or more areas exceeding the temperature limit(s) shown in Table 6.7.3-1 > 30 °F. The 30 °F allowance is for equipment in the room. This does not include the diesel generators.	C.1 Initiate action to provide a record of the amount by which and the cumulative time the temperature in the affected area exceeded its limit and an analysis to demonstrate the continued OPERABILITY of the affected equipment.	Immediately
	<u>AND</u>	
	C.2 Declare the equipment within the affected area inoperable.	4 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 6.7.3.1	Determine temperature to be within its limit in each of the areas shown in Table 6.7.3-1.	12 hours

b. a determination that the change will maintain the overall conformance of the solidified waste product to existing requirements of Federal, State, or other applicable regulations.

Shall become effective upon review and acceptance by the OSRC and the approval of the General Manager, Plant Operations.

7.6.3.9 OFFSITE DOSE CALCULATION MANUAL (ODCM)

Licensee initiated changes to the ODCM shall become effective upon review and acceptance by the OSRC.

7.6.3.10 SNUBBER PROGRAM

7.6.3.10.1 Snubber testing and visual examinations will be performed in accordance with the ASME OM Code Subsection ISTD and applicable addenda as required.

7.6.3.10.2 Deleted

7.6.3.10.3 Deleted

7.6.3.11 INSTRUMENT SETPOINTS AS-FOUND AND AS-LEFT TOLERANCES

Entergy Nuclear Management Manual (NMM) Procedure EN-DC-200, "I&C Uncertainties / Setpoint Calculations & Determinations," establishes direction for the performance of instrument uncertainty / setpoint calculations including determining the as-found tolerance (AFT) and as-left tolerance (ALT). NMM Procedure EN-IC-S-010-MULTI, "Instrument Uncertainty and Setpoint Calculation Methodology," provides examples using a standard methodology for determination of instrument uncertainties, loop uncertainties, instrument setpoints and instrument setpoint attributes (As-Left Tolerance, As-Found Tolerance, Allowable Value, etc.).

BASES

BACKGROUND (continued)

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 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.

APPLICABLE SAFETY ANALYSES

The fuel cladding must not sustain damage as a result of normal operation and AOOs. The reactor core SLs are established to preclude violation of the fuel design criterion that an MCPR SL 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 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 SL.

2.1.1.1 Fuel Cladding Integrity

The use of the fuel vendor's critical power correlations are valid for critical power calculations at pressures $\geq$ 685 psig and core flows $\geq$ 10% of rated (Ref. 3, 5, and 6). For operation at low pressures or low flows, the fuel cladding integrity SL is established by a limiting condition on core THERMAL POWER, with the following basis:

> Since the pressure drop in the bypass region is essentially all elevation head, the core pressure drop at low power and flow will always be > 4.5 psi. Analyses 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 4.5 psi driving head will be > 28 x 10^3 lb/hr. Full scale

(continued)

BASES

APPLICABLE SAFETY ANALYSES

2.1.1.1 Fuel Cladding Integrity (continued)

ATLAS test data taken at pressures from 14.7 psia to 800 psia 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 > 44.2% RTP. Thus a THERMAL POWER limit of 21.8% RTP [1.2 / (4408 MWt/800 bundles)] for reactor pressure < 685 psig is conservative. Because of the design thermal hydraulic compatibility of the reload fuel designs with the cycle 1 fuel, this justification and the associated low pressure and low flow limits remain applicable for future cycles of cores containing these fuel designs.

2.1.1.2 MCPR

The MCPR SL ensures sufficient conservatism in the operating MCPR limit that, in the event of an AOO from the limiting condition of operation, at least 99.9% of the fuel rods in the core would be expected to avoid boiling transition. The margin between calculated boiling transition (i.e., MCPR = 1.00) and the MCPR SL is based on a detailed statistical procedure that considers the uncertainties in monitoring the core operating state. One specific uncertainty included in the SL is the uncertainty inherent in the critical power correlation. Reference 6 describes the methodology used in determining the MCPR SL.

The calculated MCPR safety limit is reported to the customary three significant digits (i.e., X.XX); the MCPR operating limit is developed based on the calculated MCPR safety limit to ensure that at least 99.9% of the fuel rods in the core are expected to avoid boiling transition.

The fuel vendor's critical power correlations are based on a significant body of practical test data, providing a high degree of assurance that the critical power, as evaluated by the correlation, is within a small percentage of the actual critical power being estimated. As long as the core pressure and flow are within the range of validity of the correlations, the assumed reactor conditions used in defining the SL introduce conservatism into the limit because bounding high radial power factors and bounding flat local peaking distributions are used to estimate the number of rods in boiling transition. These conservatisms and the

(continued)

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 consists of a boron solution storage tank, two positive displacement pumps, two explosive valves, which 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 through the high pressure core spray system sparger.

APPLICABLE SAFETY ANALYSES

The SLC System is manually initiated from the main control room, as directed by the emergency operating procedures, if the operator believes the reactor cannot be shut down, or kept shut down, with the control rods. The SLC System is used in the event that not enough control rods can be inserted to accomplish shutdown and cooldown in the normal manner. A SLC injection is also credited in the LOCA dose analysis to buffer the post-accident suppression pool chemistry and prevent iodine re-evolution. The SLC System injects borated water into the reactor core to compensate for all of the various reactivity effects that could occur during plant operation. To meet this objective, it is necessary to inject a quantity of boron that produces a concentration of at least an equivalent of 780 ppm of natural boron in the reactor core at 68°F. To allow for potential leakage and imperfect mixing in the reactor system, an additional amount of boron equal to 25% of the amount cited above is added (Ref. 2). The concentration limits 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. This quantity of borated solution is the amount

(continued)

BASES

ACTIONS

A.1

In this condition, the concentration must be restored to within limits in 8 hours. It is not necessary under this condition to enter Condition E for both SLC subsystems inoperable, since they are capable of performing their original design basis function. Because of the low probability of an ATWS event and that the SLC System capability still exists for vessel injection under this condition, the allowed Completion Time of 8 hours is acceptable and provides adequate time to restore concentration to within limits.

(continued)

ACTIONS

B.1

If the volume of the sodium pentaborate solution is less than 4,200 gallons, the volume must be restored to greater than or equal to 4,200 gallons within 8 hours. When in Condition B.1, it is not necessary to enter Condition E for both SLC subsystems inoperable. The subsystems are capable of performing their original design basis function. Because of the low probability of an ATWS event and that the SLC System capability still exists for vessel injection under this condition, the allowed Completion Time of 8 hours is acceptable and provides adequate time to restore the volume to within limits.

C.1

If the temperature of the sodium pentaborate solution is less than 45oF or greater than 150°F, the temperature must be restored to within limits within 8 hours. When in Condition C.1, it is not necessary to enter Condition E for both SLC subsystems inoperable. The subsystems are capable of performing their original design basis function. Because of the low probability of an ATWS event and that the SLC System capability still exists for vessel injection under this condition, the allowed Completion Time of 8 hours is acceptable and provides adequate time to restore the temperature to within limits.

D.1

If one SLC subsystem is inoperable for reasons other than Conditions A, B or C, the inoperable subsystem must be restored to OPERABLE status within 7 days. In this condition, the remaining OPERABLE subsystem is adequate to perform the shutdown function. 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 System to shut down the plant.

E.1

If both SLC subsystems are inoperable for reasons other than Conditions A, B or C, 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

(continued)

BASES

ACTIONS

E.1 (continued)

concurrent with the failure of the controls rods to shut down the reactor.

F.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 3.1.7.1 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 the SLC System OPERABILITY without disturbing normal plant operation. These surveillances ensure the proper borated solution and temperature, including the temperature of the pump suction piping, are maintained. Maintaining a minimum specified borated solution temperature is important to ensuring that the boron remains in solution and does not precipitate out in the storage tank or in the pump suction piping. Maintaining the temperature less than 150°F ensures the pump net positive suction head requirements for two pump operation and SLC System piping qualifications. The 24-hour Frequency of these SRs is based on operating experience that has shown there are relatively slow variations in the measurement parameters of volume and temperature.

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.1.7.3 and SR 3.1.7.5

The requirements of 10 CFR 50.62 are met by the use of a sodium pentaborate solution enriched in the boron-10 (B-10) isotope. SR 3.1.7.3 determines whether the sodium pentaborate concentration, in conjunction with the boron enrichment, is within limits to meet the requirements of 10 CFR 50.62. SR 3.1.7.5 ensures that the parameters used in the determination of sodium pentaborate concentration are within limits. The available solution volume is the solution volume above the pump suction penetration. This surveillance requires an examination of the sodium pentaborate solution by using chemical analysis to ensure the proper weight of B-10 exists in the storage tank. SR 3.1.7.5 must be performed anytime boron or water is added to the storage tank solution to establish that the weight of B-10 is within the specified limits. This SR must be performed anytime the solution temperature is restored to > 45°F, to ensure no significant boron precipitation occurred.

The 31 day Frequency of these surveillances is appropriate because of the relatively slow variation of boron concentration between surveillances.

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 proper operation will occur if required.

(continued)

SURVEILLANCE REQUIREMENTS

SR 3.1.7.4 and SR 3.1.7.6 (continued)

The 31 day Frequency is based on operating experience that has demonstrated the reliability of the explosive charge continuity.

SR 3.1.7.6 verifies 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, power operated, and automatic valves in the SLC System flow path ensures 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 controls. This is acceptable since the SLC System is a manually initiated system. This Surveillance does not apply to valves that are locked, sealed, or otherwise secured in position, since they were verified to be in the correct position prior to locking, sealing, or securing. This verification of valve alignment does not apply to valves that cannot be inadvertently misaligned, such as check valves. This SR does not require any testing or valve manipulation; rather, it involves verification that those valves capable of being mispositioned are in the correct positions. The 31 day Frequency is based on engineering judgment and is consistent with the procedural controls governing valve operation that ensure correct valve positions.

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SR 3.1.7.7

Demonstrating each SLC System pump develops a flow rate ∃ 41.2 gpm at a discharge pressure ≥ 1340 psig without actuating the pump's relief valve 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 inspections 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

This Surveillance ensures 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. Other administrative controls, such as those that limit the shelf life of the explosive charges, must be followed. The pump and explosive valve tested should be alternated such that both complete flow paths are tested every 36 months, at alternating 18 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 SLC subsystem and into the RPV. The 18 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 test when performed at the 18 month Frequency; therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.1.7.9

Enriched sodium pentaborate solution is made by mixing granular, enriched sodium pentaborate with water. Isotopic tests on the sodium pentaborate solution to determine the actual B-10 enrichment must be performed once within 24 hours after boron is added to the solution in order to ensure that the B-10 enrichment is adequate. Enrichment testing is only required when boron addition is made since enrichment change cannot occur by any other processes.

REFERENCES

1. 10 CFR 50.62.
2. UFSAR, Section 9.3.5.3.
3. GNRI-91/00153, Issuance of Amendment No. 79 to Facility Operating License No. NPF-29 - Grand Gulf Nuclear Station, Unit 1, Regarding Standby Liquid Control System Technical Specifications, dated July 30, 1991.

BASES (continued)

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 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 (IRM) 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 < 21.8% RTP, the reactor operates with substantial margin to the APLHGR limits; thus, this LCO is not required.

ACTIONS

A.1

If any APLHGR exceeds the required limit, an assumption regarding an initial condition of the DBA and transient analyses may not be met. Therefore, prompt action is taken to restore the APLHGR(s) to within the required limit(s) such that the plant will be operating within analyzed conditions and within the design limits of the fuel rods. The 2 hour Completion Time is sufficient to restore the APLHGR(s) to within its limit 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 limit 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 < 21.8% RTP within 4 hours. The allowed Completion Time is reasonable, based on operating experience, to reduce THERMAL POWER to < 21.8% RTP in an orderly manner and without challenging plant systems.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.2.1.1

APLHGRs are required to be initially calculated within 12 hours after THERMAL POWER is ≥ 21.8% 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 under normal conditions. The 12 hour allowance after THERMAL POWER ≥ 21.8% RTP is achieved is acceptable given the large inherent margin to operating limits at low power levels.

REFERENCES

1. UFSAR, Chapter 4.
2. UFSAR, Chapter 15, Appendix 15C.
3. UFSAR, Chapter 15, Appendix 15D.
4. XN-NF-80-19(P)(A), "Exxon Nuclear Methodology for Boiling Water Reactors, Neutronics Methods for Design and Analysis," Volume 1 (as supplemented).
5. XN-NF-80-19(A), "Exxon Nuclear Methodology for Boiling Water Reactors, ECCS Evaluation Model," Volume 2 (as supplemented).
6. NEDE-24011-P-A, "General Electric Standard Application for Reactor Fuel (GESTAR)."

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. 3, 4, and 5). Flow dependent MCPR limits are determined by steady state thermal hydraulic methods using the three dimensional BWR simulator code (Ref. 6) and the steady state thermal hydraulic code (Ref. 2). $MCPR_f$ curves are provided based on the maximum credible flow runout transient for Loop Manual operation. The result of a single failure or single operator error during Loop Manual operation is the runout of only one loop because both recirculation loops are under independent control.

Power dependent MCPR limits ($MCPR_p$) are determined by the three dimensional BWR simulator code and the one dimensional transient code (Ref. 7). The $MCPR_p$ limits are established for a set of exposure intervals. The limiting transients are analyzed at the limiting exposure for each interval. 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 scram trips are bypassed, high and low flow $MCPR_p$ operating limits are provided for operating between 21.8% RTP and the previously mentioned bypass power level.

The MCPR satisfies Criterion 2 of the NRC Policy Statement.

LCO

The MCPR operating limits specified in the COLR are the result of the Design Basis Accident (DBA) and transient analysis. The MCPR operating limits are 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 21.8% RTP, the reactor is operating at a slow recirculation pump speed and the moderator void ratio is small. Surveillance of thermal limits below 21.8% RTP is unnecessary due to the large inherent margin that ensures that the MCPR SL is not exceeded even if a limiting transient occurs.

(continued)

BASES

APPLICABILITY (continued)

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 21.8% 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 monitor (IRM) provides rapid scram initiation for any significant power increase transient, which effectively eliminates any MCPR compliance concern. Therefore, at THERMAL POWER levels < 21.8% RTP, the reactor is operating with substantial margin to the MCPR limits and this LCO is not required.

ACTIONS

A.1

If any MCPR is outside the required limit, 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 limit(s) 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 limit 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 the required limit 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 < 21.8% RTP within 4 hours. The allowed Completion Time is reasonable, based on operating experience, to reduce THERMAL POWER to < 21.8% RTP in an orderly manner and without challenging plant systems.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.2.2.1

The MCPR is required to be initially calculated within 12 hours after THERMAL POWER is ≥ 21.8% 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 reaches ≥ 21.8% RTP is acceptable given the large inherent margin to operating limits at low power levels.

SR 3.2.2.2

Because the transient analyses may take credit for conservatism in the control rod scram speed performance, it must be demonstrated that the specific scram speed distribution is consistent with that used in the transient analyses. SR 3.2.2.2 determines the actual scram speed distribution and compares it with the assumed distribution. The MCPR operating limit is then determined based either on the applicable limit associated with scram times of LCO 3.1.4, "Control Rod Scram Times," or the realistic scram times. The scram time dependent MCPR limits are contained in the COLR. This determination must be performed and any necessary changes must be implemented within 72 hours after each set of control rod 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 the actual control rod scram speed distribution expected during the fuel cycle.

REFERENCES

1. NUREG-0562, "Fuel Failures As A Consequence of Nucleate Boiling or Dry Out," June 1979.
2. NEDE-24011-P-A General Electric Standard Application for Reactor Fuel (GESTAR II).
3. UFSAR, Chapter 15, Appendix 15B.
4. UFSAR, Chapter 15, Appendix 15C.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

REFERENCES (continued)

5. UFSAR, Chapter 15, Appendix 15D.

6. NEDE-30130-P-A, Steady-State Nuclear Methods.

7. NEDO-24154, Qualification of the One-Dimensional Core Transient Model for Boiling Water Reactors.

BASES

APPLICABLE SAFETY ANALYSES (continued)	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 limits are multiplied by the smaller of either the flow dependent LHGR factor ($LHGRFAC_f$) or the power dependent LHGR factor ($LHGRFAC_p$) corresponding to the existing core flow and power state to ensure adherence to the fuel mechanical design bases during the limiting transient. $LHGRFAC_f$'s are generated to protect the core from slow flow runout transients. A curve is provided based on the maximum credible flow runout transient for Loop Manual operation. The result of a single failure or single operator error during operation in Loop Manual is the runout of only one loop because both recirculation loops are under independent control. $LHGRFAC_p$'s are generated to protect the core from plant transients other than core flow increases. For GE fuel, the power- and flow-dependent LHGR factors are identical to the power- and flow-dependent MAPLHGR factors. The LHGR satisfies Criterion 2 of the NRC Policy Statement.
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 < 21.8% 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 ≥ 21.8% RTP.
ACTIONS	<u>A.1</u> 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

(continued)

BASES

ACTIONS

A.1 (continued)

restore the LHGR(s) to within its required limit(s) such that the plant is operating within analyzed conditions and within the design limits of the fuel rods. The 2 hour Completion Time is normally sufficient to restore the LHGR(s) to within its limit 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 limit 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 < 21.8% RTP within 4 hours. The allowed Completion Time is reasonable, based on operating experience, to reduce THERMAL POWER to < 21.8% 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 ≥ 21.8% RTP and then every 24 hours thereafter. They are compared with 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 under normal conditions. The 12 hour allowance after THERMAL POWER ≥ 21.8% RTP is achieved is acceptable given the large inherent margin to operating limits at lower power levels.

REFERENCES

1. UFSAR, Chapter 15.
2. UFSAR, Chapter 4.
3. NUREG-0800, "Standard Review Plan," Section 4.2, II.A.2(g), Revision 2, July 1981.

B 3.2 POWER DISTRIBUTION LIMITS

B 3.2.4 Deleted

Pages B 3.2-12 through B 32.-18 have been deleted

BASES (continued)

Pages B 3.2-12 through B 3.2-18 have been deleted.

BASES (continued)

Pages B 3.2-12 through B 3.2-18 have been deleted.

BASES

BASES

Pages B 3.2-12 through B 3.2-18 have been deleted.

BASES

Pages B 3.2-12 through B 3.2-18 have been deleted.

Pages B 3.2-12 through B 3.2-18 have been deleted.

Pages B 3.2-12 through B 3.2-18 have been deleted.

BASES

BACKGROUND (continued)

The RPS is comprised of two independent trip systems (A and B), with two logic channels in each trip system (logic channels A1 and A2, B1 and B2), as shown in Reference 1. The outputs of the logic channels in a trip system are combined in a one-out-of-two logic so 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 one-out-of-two taken twice logic. 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 10 seconds after the full scram signal is received. This 10 second delay on reset ensures that the scram function will be completed.

Two scram pilot valves are located in the hydraulic control unit (HCU) 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.

<u>Application of TSTF-493, Rev. 4 (Ref. 17) to APRM Functions 2.a, 2.b, 2.d, and 2.f</u>

10 CFR 50.36(c)(1)(ii)(A) requires that Technical Specifications include Limited Safety System Settings (LSSSs) for variables that have significant safety functions. LSSSs are 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 is exceeded." The Analytical Limit is the limit of the process variable at

(continued)

BASES

BACKGROUND (continued)

which a protective action is initiated, as established by the safety analysis, to ensure that a safety limit (SL) is not exceeded. Any automatic protection action that occurs on reaching the Analytical Limit, therefore, ensures that the SL is not exceeded. However, in practice, the actual settings for automatic protective channels must be chosen to be more conservative than the Analytical Limit to account for instrument loop uncertainties related to the setting at which the automatic protective action would actually occur.

The trip setpoint is a predetermined setting for a protection channel chosen to ensure automatic actuation prior to the process variable reaching the Analytical Limit, thus ensuring that the SL would not be exceeded. As such, the trip setpoint accounts for uncertainties in setting the channel (e.g., calibration) and uncertainties in how the channel might actually perform (e.g., repeatability), changes in the point of action of the channel over time (e.g., drift during surveillance intervals), and any other factors that may influence its actual performance (e.g., harsh accident environments). In this manner, the trip setpoint ensures that SLs are not exceeded.

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)." Relying solely on the trip setpoint to define OPERABILITY in Technical Specifications would be an overly restrictive requirement if it were applied as an OPERABILITY limit for the "as found" value of a protection channel 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 protection channel 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 because 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 protection channel. Therefore, the channel would remain OPERABLE because it would have performed its safety function and the only corrective action required would be to reset the

(continued)

BASES

BACKGROUND (continued)

Channel within the established as-left tolerance around the trip setpoint to account for further drift during the next surveillance interval.

Although the channel is OPERABLE under these circumstances. the trip setpoint must be adjusted to a value within the as left tolerance, 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 (as-found criteria).

However, there is also some point beyond which the channel may not be able to perform its function due to, for example, greater-than-expected drift. This value is specified in the Technical Specifications in order to define OPERABILITY of the channels and is designated as the Allowable Value.

If the actual setting (as-found setpoint) of the channel is found to be conservative with respect to the Allowable Value but is beyond the as-found tolerance, the channel is OPERABLE but degraded. The degraded condition will be further evaluated during performance of the Surveillance Requirement. This evaluation will consist of resetting the channel setpoint to the trip setpoint (within the allowed tolerance), and evaluating the channel response. If the channel is functioning as required and expected to pass the next surveillance, then the channel is OPERABLE and can be restored to service at the completion of the surveillance After the surveillance is completed, the channel as-found condition will be entered into the Corrective Action Program for further evaluation.

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

The actions of the RPS are assumed in the safety analyses of References 2, 3, and 4. 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

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

environment errors (for channels that must function in harsh environments as defined by 10 CFR 50.49) are accounted for.

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 specified in the Table that 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 is required in each MODE to provide primary and diverse initiation signals.

RPS is required to be OPERABLE in MODE 5 with any control rod withdrawn from a core cell containing one or more fuel assemblies. 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 (SDM)") and refuel position one-rod-out interlock (LCO 3.9.2, "Refuel Position One-Rod-Out Interlock") ensure that no event requiring RPS will occur. During normal operation in MODES 3 and 4, all control rods are fully inserted and the Reactor Mode SwitchcShutdown Position control rod withdrawal block (LCO 3.3.2.1, "Control Rod Block Instrumentation") does not allow any control rod to be withdrawn. 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>Application of TSTF-493, Rev. 4 (Ref. 17) to APRM Functions2.a, 2.b, 2.d, and 2.f</u>

Permissive and interlock setpoints allow blocking trips during plant startups, and restoring trips when the permissive conditions are not satisfied; however, they are not explicitly modeled in the safety analyses. These permissives and interlocks ensure that the starting conditions are consistent with the safety analysis before preventive or mitigating actions occur. Because these permissives or interlocks are only one of multiple conservative starting assumptions for the accident analysis, they are generally considered as nominal values without regard to measurement accuracy.

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

Allowable Values for RPS instrumentation functions are specified for each RPS function specified in Table 3.3.1.1-1. Trip setpoints and the methodologies for calculating the as-left and as-found tolerances are described in the Technical Requirements Manual. The nominal setpoints are selected to ensure the actual setpoints remain conservative with respect to the as-found tolerance between successive CHANNEL CALIBRATIONS. After each calibration, the trip setpoint shall be left within the as-left band around the setpoint.

1.a. Intermediate Range Monitor (IRM) Neutron Flux - High

The IRMs monitor neutron flux levels from the upper range of the source range monitors (SRMs) 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

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1.a. Intermediate Range Monitor (IRM) Neutron Flux-High (continued)

unexpected reactivity excursions. In MODE 1, the APRM System, the rod withdrawal limiter (RWL), and the RPC provide protection against control rod withdrawal error events and the IRMs are not required.

1.b. Intermediate Range Monitor-Inop

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 a module is not plugged in, an inoperative trip signal will be 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 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 Function is required.

Average Power Range Monitor (APRM

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

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The APRM subsystem is divided into four APRM/OPRM channels and four 2-Out-Of-4 Voter channels. Each APRM/OPRM 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/OPRM channel, but no voter channels, to be bypassed. A trip from any one un-bypassed APRM/OPRM channel will result in a "half-trip" in all four of the voter channels, but no trip inputs to either RPS trip system. Since APRM Functions 2.a, 2.b, 2.d, and 2.f are implemented in the same hardware, these functions are combined with APRM Inop Function 2.c. Any Function 2.a, 2.b, 2.c, or 2.d trip from any two un-bypassed APRM/OPRM channels will result in a full trip in each of the four 2-Out-Of-4 Voter channels, which in turn results in two trip inputs to 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/OPRM channels will result in a full trip from each Voter channel. Three of the four APRM/OPRM 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 APRM Functions 2.a, 2.b, and 2.d, at least 20 LPRM inputs, with at least three LPRM inputs from each of the four axial levels at which the LPRMs are located, must be operable for each APRM/OPRM channel. For the OPRM Upscale, Function 2.f, LPRMs are assigned to "cells" of four detectors. A minimum of 30 cells, each with a minimum of two LPRMs, must be OPERABLE for the OPRM Upscale Function 2.f to be OPERABLE.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2.a. Average Power Range Monitor Neutron Flux-High, Setdown (continued)

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 that prevents fuel damage resulting from abnormal operating transients in this power range. For 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 Neutron FluxcHigh Function because of the relative setpoints.

With the IRMs at 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 corewide increase in power.

No specific safety analyses take direct 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% RTP (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.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2.a. Average Power Range Monitor Neutron Flux-High, Setdown (continued)

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 that prevents fuel damage resulting from abnormal operating transients in this power range. For 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 Neutron Flux—High Function because of the relative setpoints.

With the IRMs at 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 corewide increase in power.

No specific safety analyses take direct 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 21.8% RTP (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 < 21.8% RTP.

The Allowable Value is based on preventing significant increases in power when THERMAL POWER is < 25% RTP.

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2.a. Average Power Range Monitor Neutron Flux-High, Setdown (continued)

The Average Power Range Monitor Neutron Flux-High, Setdown Function must be OPERABLE during MODE 2 when control rods may be withdrawn since the potential for criticality exits. In MODE 1, the Average Power Range Monitor Neutron Flux-High Function provides protection against reactivity transients and the RWL and RPC protect against control rod withdrawal error events.

2.b. Average Power Range Monitor Fixed Neutron Flux-High

The Average Power Range Monitor Fixed 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 2, the Average Power Range Monitor Fixed Neutron Flux-High Function is assumed to terminate the main steam isolation valve (MSIV) closure event and, along with the safety/relief valves (S/RVs), limits the peak reactor pressure vessel (RPV) pressure to less than the ASME Code limits. The control rod drop accident (CRDA) analysis (Ref. 7) takes credit for the Average Power Range Monitor Fixed Neutron Flux-High Function to terminate the CRDA.

The Allowable Value is based on the Analytical Limit assumed in the CRDA analyses.

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

2.b. Average Power Range Monitor Fixed Neutron Flux-High (continued)

The Average Power Range Monitor Fixed 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 Fixed Neutron Flux-High Function is assumed in the CRDA analysis that is applicable 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 Monitor Fixed Neutron FluxcHigh Function is not required in MODE 2.

Three of the four APRM/OPRM channels are required to be OPERABLE for each of the APRM Functions. This function (Inop) provides assurance that the minimum number of channels is OPERABLE.

For any APRM/OPRM channel, any time its keylock switch is in any position other than "OPER," a module is unplugged, or the automatic self-test system detects a critical fault with the APRM/OPRM channel, an Inop trip is sent to all four 2-out-of-4 voter channels. Inop trips from two or more un-bypassed APRM/OPRM channels result in a trip output from all four 2-out-of-4 voter channels to their associated trip system.

2.c. Average Power Range Monitor-Inop

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

There is no Allowable Value for this Function.

This Function is required to be OPERABLE in the MODES where the APRM Functions are required.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

2.d. Average Power Range Monitor Flow Biased Simulated Thermal Power - High

The Average Power Range Monitor Flow Biased 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 Fixed Neutron Flux - High Function Allowable Value.

The APRM Flow Biased Simulated Thermal Power - High Function provides protection against transients where THERMAL POWER increases slowly (such as the Loss of Feedwater Heating event) and protects the fuel cladding integrity by ensuring that the MCPR SL is not exceeded. 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 APRM Neutron Flux - High Function will provide a scram signal before the APRM Flow Biased Simulated Thermal Power - High Function setpoint is exceeded

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BASES

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BASES

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

2.d. Average Power Range Monitor Flow Biased Simulated Thermal Power - High (continued)

Each APRM channel uses one total drive flow signal representative of total core flow. The total drive flow processing logic, part of the APRM/OPRM channel, but 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/OPRM channel OPERABILITY requirements for this Function.

The clamped Allowable Value is based on analyses that take credit for the APRM Simulated Thermal Power - High Function for mitigating 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 Flow Biased Simulated Thermal Power - High Function is required to be OPERABLE in MODE 1 when there is the possibility of generating excessive THERMAL POWER and potentially exceeding the SL applicable to high pressure and core flow conditions (MCPR SL). During MODES 2 and 5, OTHER IRM and APRM Functions provide protection for fuel cladding integrity.

2.e. and 2.f Average Power Range Monitor Flow Biased Simulated

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 when 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 must be OPERABLE in MODES 1 and 2.

All four voter channels are required to be OPERABLE. Each voter channel includes self-diagnostic function. 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.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The 2-Out-Of-4 Voter Function votes APRM Functions 2.a, 2.b, and 2.d independently of Function 2.f. The voter also includes separate outputs to RPS for the two independently voted sets of functions, each of which is redundant (four total outputs). 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 Voter Function 2.e.

There is no Allowable Value for this Function.

2.f. Oscillation Power Range Monitor (OPRM) Upscale

The OPRM Upscale Function, which implements the BWR Owners' Group Option III stability solution, complies with GDC 10 and GDC 12, thereby providing protection from exceeding the fuel MCPR SL due to anticipated thermal-hydraulic power oscillations.

References 13 and 14 describe three algorithms for detecting thermal-hydraulic instability related neutron flux oscillations: (1) the Period-Based Detection Algorithm; (2) the Amplitude-Based Algorithm; and (3) the Growth-Rate Algorithm. All three are implemented via the OPRM Upscale Function, but the safety analysis takes credit only for the Period-Based Detection Algorithm. The remaining algorithms provide defense-in-depth and additional protection against unanticipated oscillations. OPRM Upscale Function OPERABILITY for Technical Specification purposes is based only on the Period-Based Detection algorithm.

The OPRM Upscale Function receives input signals from the LPRMs, which are combined into "cells" for evaluation by the OPRM algorithms

The OPRM Upscale Function is required to be OPERABLE when the plant is at > 24% RTP, the region of power-flow operation where anticipated events could lead to thermal-hydraulic instability and related neutron flux oscillations. Within this region, the automatic trip is enabled when THERMAL POWER, as indicated by the APRM Simulated Thermal Power, is > 29% RTP and reactor core flow, as indicated by recirculation drive flow, is < 60% of rated flow, the

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)

The 2-Out-Of-4 Voter Function votes APRM Functions 2.a, 2.b, and 2.d independently of Function 2.f. The voter also includes separate outputs to RPS for the two independently voted sets of functions, each of which is redundant (four total outputs). 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 Voter Function 2.e.

There is no Allowable Value for this Function.

2.f. Oscillation Power Range Monitor (OPRM) Upscale

The OPRM Upscale Function, which implements the BWR Owners' Group Option III stability solution, complies with GDC 10 and GDC 12, thereby providing protection from exceeding the fuel MCPR SL due to anticipated thermal-hydraulic power oscillations.

References 13 and 14 describe three algorithms for detecting thermal-hydraulic instability related neutron flux oscillations: (1) the Period-Based Detection Algorithm; (2) the Amplitude-Based Algorithm; and (3) the Growth-Rate Algorithm. All three are implemented via the OPRM Upscale Function, but the safety analysis takes credit only for the Period-Based Detection Algorithm. The remaining algorithms provide defense-in-depth and additional protection against unanticipated oscillations. OPRM Upscale Function OPERABILITY for Technical Specification purposes is based only on the Period-Based Detection algorithm.

The OPRM Upscale Function receives input signals from the LPRMs, which are combined into "cells" for evaluation by the OPRM algorithms

The OPRM Upscale Function is required to be OPERABLE when the plant is at > 21% RTP, the region of power-flow operation where anticipated events could lead to thermal-hydraulic instability and related neutron flux oscillations. Within this region, the automatic trip is enabled when THERMAL POWER, as indicated by the APRM Simulated Thermal Power, is > 26% RTP and reactor recirculation drive flow is < 60% of rated drive flow, the

(continued)

BASES

APPLICABLE SAFETY ANALYSES LCO, and APPLICABILITY (continued)

operating region where actual thermal-hydraulic oscillations may occur. The lower bound, 24% RTP, provides margin in the unlikely event of loss of feedwater heating while the plant is operating below the 29% automatic OPRM Upscale trip enable point. Loss of feedwater heating is the only identified event that could cause reactor power to increase into the region of concern without operator action. An OPRM Upscale trip is issued from an APRM/OPRM channel when the Period-Based Detection algorithm in that channel detects oscillatory changes in the neutron flux indicated by the combined signals of the LPRM detectors in a cell, with period confirmations and relative cell amplitude exceeding specified setpoints. One or more cells in a channel exceeding the trip conditions will result in a channel trip. An OPRM Upscale trip is also issued from the channel if either the Growth-Rate or Amplitude-Based algorithms detect growing oscillatory changes is the neutron flux 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 setpoint for the OPRM Upscale Period-Based Detection algorithm is specified in the COLR.

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BASES

APPLICABLE SAFETY ANALYSES LCO, and APPLICABILITY (continued)

operating region where actual thermal-hydraulic oscillations may occur. The lower bound, 21% RTP, provides margin in the unlikely event of loss of feedwater heating while the plant is operating below the 26% automatic OPRM Upscale trip enable point. Loss of feedwater heating is the only identified event that could cause reactor power to increase into the region of concern without operator action. An OPRM Upscale trip is issued from an APRM/OPRM channel when the Period-Based Detection algorithm in that channel detects oscillatory changes in the neutron flux indicated by the combined signals of the LPRM detectors in a cell, with period confirmations and relative cell amplitude exceeding specified setpoints. One or more cells in a channel exceeding the trip conditions will result in a channel trip. An OPRM Upscale trip is also issued from the channel if either the Growth-Rate or Amplitude-Based algorithms detect growing oscillatory changes is the neutron flux 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 setpoint for the OPRM Upscale Period-Based Detection algorithm is specified in the COLR.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

5. Reactor Vessel Water Level—High, Level 8 (continued)

Reactor Vessel Water Level—High, Level 8 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—High, Level 8 Allowable Value is specified to ensure that the MCPR SL is not violated during the assumed transient. The Function is bypassed when the reactor mode switch is not in the run position.

Four channels of the Reactor Vessel Water Level—High, Level 8 Function, with two channels in each trip system arranged in a one-out-of-two logic, are available and are required to be OPERABLE when THERMAL POWER is ≥ 21.8% RTP to ensure that no single instrument failure will preclude a scram from this Function on a valid signal. With THERMAL POWER < 21.8% RTP, this Function is not required since MCPR is not a concern below 21.8% RTP

6. 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 2, the Average Power Range Monitor Fixed 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 transients analyzed in Reference 4 (e.g., low steam line pressure, manual closure of MSIVs, high steam line flow). 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.

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BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

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

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

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

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

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

This Function must be enabled at THERMAL POWER ≥ 35.4% RTP, which is the Analytical Limit. This is normally accomplished automatically by pressure transmitters sensing turbine first stage pressure; therefore, to consider this Function OPERABLE, the turbine bypass valves must remain shut at THERMAL POWER ≥ 35.4% RTP The setpoint is feedwater temperature dependent as a result of the subcooling changes that affect the turbine first stage pressure/reactor power relationship.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

9. Turbine Stop Valve Closure, Trip Oil Pressure—Low (continued)

The Turbine Stop Valve Closure, Trip Oil Pressure—Low 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, Trip Oil Pressure—Low 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 if any three TSVs should close. This Function is required, consistent with analysis assumptions, whenever THERMAL POWER is ≥ 35.4% RTP. This Function is not required when THERMAL POWER is < 35.4% RTP since the Reactor Vessel Steam Dome Pressure—High and the Average Power Range Monitor Fixed Neutron Flux—High Functions are adequate to maintain the necessary safety margins.

10. Turbine Control Valve Fast Closure, Trip 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, Trip Oil Pressure—Low Function is the primary scram signal for the generator load rejection event analyzed in Reference 4. For this event, the reactor scram reduces the amount of energy required to be absorbed and, along with the actions of the EOC-RPT System, ensures that the MCPR SL is not exceeded.

Turbine Control Valve Fast Closure, Trip Oil Pressure—Low signals are initiated by the EHC fluid pressure at each control valve. There is one pressure transmitter associated

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

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

with each control valve, the signal from each transmitter being assigned to a separate RPS logic channel. This Function must be enabled at THERMAL POWER ≥ 35.4% RTP. This is normally accomplished automatically by pressure transmitters sensing turbine first stage pressure; therefore, to consider this Function OPERABLE, the turbine bypass valves must remain shut at THERMAL POWER ≥ 35.4% RTP. The basis for the setpoint of this automatic bypass is identical to that described for the Turbine Stop Valve Closure, Trip Oil Pressure—Low Function.

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

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

11. Reactor Mode Switch—Shutdown Position

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

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

(continued)

BASES

ACTIONS (continued)

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, a Note has been provided that allows separate Condition entry for each inoperable RPS instrumentation channel.

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. 9 and 15) 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. Alternately, 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.

As noted, Action A.2 is not applicable to APRM Functions 2.a, 2.b, 2.c, 2.d, or 2.f. Inoperability of one required APRM/OPRM 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.

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

Inoperability of more than one required APRM/OPRM 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.

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 both trip systems (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 9 or 15 for the 12 hour Completion Time. Within the 6 hour allowance, the associated Function will have all required channels either OPERABLE or in trip (or in any combination) in one trip system.

Completing one of these Required Actions restores RPS to an equivalent reliability level as that evaluated in Reference 9 or 15, 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 as to which trip system is in the more degraded state should be based on prudent judgment and current plant conditions (i.e., what MODE the plant is in). If this action would result in a scram or recirculation pump trip, 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

(continued)

ACTIONS

B.1 and B.2 (continued)

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 or RPT), Condition D must be entered and its Required Action taken.

As noted, Condition B is not applicable to APRM Functions2.a, 2.b, 2.c, 2.d, or 2.f. Inoperability of one require APRM/OPRM 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/OPRM channels for which Condition B applies. For an inoperable APRM/OPRM 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 more than required APRM/OPRM 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. 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, and 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, Conditions B does not apply.

C.1

Required Action C.1 is intended to ensure that appropriate actions are taken if multiple, 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 and APRM Functions, this would require both trip systems to have one channel OPERABLE or in trip (or the associated trip system

(continued)

BASES

ACTIONS

C.1 (continued)

in trip). For Function 6 (Main Steam Isolation Valve Closure), this would require both trip systems to have each channel associated with the MSIVs in three MSLs (not necessarily the same MSLs for both trip systems), OPERABLE or in trip (or the associated trip system in trip). For Function 9 (Turbine Stop Valve Closure, Trip Oil Pressure Low), this would require both trip systems to have three channels, each 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.

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, H.1, and K.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 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 Times of Required Actions E.1 and K.1 are consistent with the Completion Time provided in LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)."

(continued)

BASES

ACTIONS (continued)

I.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. Subsequently, if the manual scram channels are inoperable, the reactor mode switch is locked in the shutdown position to prevent inadvertent control rod withdrawals.

J.1

If OPRM Upscale trip capability is not maintained, Condition J exists. Reference 15 justified use of alternate methods to detect and suppress oscillations for a limited period of time. The alternate methods are procedurally established consistent with the guidelines identified in Reference 6 requiring manual operator action to scram the plant if certain predefined events occur. The 12-hour allowed action time is based on engineering judgment to allow orderly transition to the alternate methods while limiting the period of time during which no automatic or alternate detect and suppress trip capability is formally in place. Based on the small probability of an instability event occurring at all, the 12 hours is judged to be reasonable.

J. 2

The alternate method to detect and suppress oscillations implemented in accordance with J.1 was evaluated (Reference 15) based on use up to 120 days only. The evaluation, based on engineering judgment, concluded that the likelihood of an instability event that could not be adequately handled by the alternate methods during this 120-day period was negligibly small. The 120-day period is intended to be an outside limit to allow for the case where design changes or extensive analysis might be required to understand or

(continued

BASES

ACTIONS

J.2 (continued)

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.

LCO 3.0.4 is not applicable to J.2 to allow unit restart in the event of a shutdown during the 120-day completion time.

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 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 RPS 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 the RPS will trip when necessary.

SR 3.3.1.1.1 and SR 3.3.1.1.19

Performance of the CHANNEL CHECK ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a similar parameter on other channels. It is based on the assumption that instrument channels monitoring the same parameter should read approximately the same value. Significant deviations between the instrument channels could be an indication of excessive instrument drift on 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.

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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 agreement criteria include an expectation of overlap when transitioning between neutron flux instrumentation. The overlap between SRMs and IRMs must be demonstrated prior to withdrawing SRMs from the fully inserted position since indication is being transitioned from SRMs to the IRMs. This will ensure that reactor power will not be increased into a neutron flux region without adequate indication. The overlap between IRMs and APRMs is of concern when reducing power into the IRM range. On power increases, the system design will prevent further increases (by initiating a rod block) if adequate overlap is not maintained.

Overlap between IRMs and APRMs exists when sufficient IRMs and APRMs concurrently have on-scale readings such that the transition between MODE 1 and MODE 2 can be made without either APRM downscale rod block, or IRM upscale rod block. Overlap between SRMs and IRMs similarly exists when, prior to withdrawing the SRMs from the fully inserted position, IRMs are above 2/40 on range 1 before SRMs have reached the upscale rod block.

If overlap for a group of channels is not demonstrated (e.g., IRM/APRM overlap), the reason for the failure of the Surveillance should be determined and the appropriate channel(s) that are required in the current MODE or condition should be declared inoperable.

The Frequency is of once every 12 hours for SR 3.3.1.1.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.

The Frequency of once every 24 hours for SR 3.3.1.1.19 is based on improved processing and reduced drift of the digital equipment in combination with four fully redundant flow transmitter channels and improved failure detection (Reference 15).

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

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 3.3.1.1.7.

A restriction to satisfying this SR when < 21.8% RTP is provided that requires the SR to be met only at ≥ 21.8% RTP because it is difficult to accurately maintain APRM indication of core THERMAL POWER consistent with a heat balance when < 21.8% 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 ≥ 21.8% 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 21.8% 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 21.8% 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 entire channel will perform the intended function.

Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

As noted, 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 and APRM 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1.10, SR 3.3.1.1.12 and SR 3.3.1.1.17 (continued)

Note 3 to SR 3.3.1.1.10 states that the APRM recirculation flow transmitters are excluded from CHANNEL CALIBRATION of Function 2.d, Average Power Range Monitor Flow Biased Simulated Thermal Power - High. Calibration of the flow transmitters is performed on an 18-month frequency (SR 3.3.1.1.17).

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

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

The Frequency of 18 months for SR 3.3.1.1.12 and SR 3.3.1.1.17 is based upon the assumption of the magnitude of equipment drift in the setpoint analysis.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.1.10

The Frequency of 24 months for SR 3.3.1.1.10 is based upon justification provided in Reference 15. The only analog components involved with main signal processing are input isolation amplifiers (one per LPRM and one per flow input), a sample-and-hold circuit, and an analog-to-digital (A/D) converter. These analog components are highly reliable and very stable with virtually no drift. In addition, the sample-and-hold circuit and A/D converters are tested as part of the automatic self-test.

The processing hardware for the APRM Functions is digital and has no drift. One of the most sensitive signals, the flow processing, is automatically compared between channels. Any digital failures will be identified by the automatic self-test, CHANNEL CHECK, or in very rare cases by the CHANNEL FUNCTIONAL TEST.

The automatic self-test includes steps that check the performance and accuracy of the sample and hold circuits and the A/D converters, and the related processing. Self-test logic also periodically tests the input amplifiers and processing for accuracy. In addition, CHANNEL FUNCTIONAL TESTS include an automated "cal check" which will check the performance of all of the analog amplifiers and the entire processing loop.

The combined improvement justifies the factor-of-four increase in calibration interval, particularly in that the calibration will actually be checked at the CHANNEL FUNCTIONAL TEST and self-test frequencies.

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BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.1.1.13

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

The 18 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 18 month Frequency.

SR 3.3.1.1.14

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

If any bypass channel setpoint is nonconservative (i.e., the Functions are bypassed at ≥ 35.4% RTP, either due to open main turbine bypass valve(s) or other reasons), then the affected Turbine Stop Valve, Trip Oil Pressure—Low and Turbine Control Valve Fast Closure, Trip Oil Pressure—Low Functions are considered inoperable. Alternatively, the bypass channel can be placed in the conservative condition (nonbypass). If placed in the nonbypass condition, this SR is met and the channel is considered OPERABLE.

The Frequency of 18 months is based on engineering judgment and reliability of the components.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1.15 (continued)

RPS RESPONSE TIME tests are conducted on an 18 month STAGGERED TEST BASIS. Note 3 requires STAGGERED TEST BASIS Frequency to be determined based on 4 channels per trip system, in lieu of the 8 channels specified in Table 3.3.1.1-1 for the MSIV Closure Function. This Frequency is based on the logic interrelationships of the various channels required to produce an RPS scram signal.

Therefore, staggered testing results in response time verification of these devices every 18 months. This Frequency is consistent with the typical industry refueling cycle and is based upon plant operating experience, which shows that random failures of instrumentation components causing serious time degradation, but not channel failure, are infrequent.

SR 3.3.1.1.16 and SR 3.3.1.1.18

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BASES

SURVEILLANCE REQUIREMENTS — SR 3.3.1.1.20, 3.3.1.1.21, 3.3.1.1.22, and 3.3.1.1.23 (continued)

SR 3.3.1.1.20

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/OPRM and voter channels. The CHANNEL FUNCTIONAL TEST covers the APRM/OPRM channels (including recirculation flow processing -- applicable to Function 2.b 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 3.3.1.1.20 is based on the reliability analysis of Reference 15. (NOTE: Actual voting logic of the 2-Out-Of-4 Voter Function is tested as part of SR 3.3.1.1.21.)

Note 1 is provided for APRM Function 2.a that requires this SR to be performed within 12 hours of entering MODE 2 from MODE 1. Testing the MODE 2 APRM Function cannot be performed in MODE 1 without utilizing jumpers or lifted leads This note allows entry into MODE 2 from MODE 1 if the associated Frequency is not met per SR 3.0.2.

Note 2 is provided for APRM Functions 2.a, 2.b, and 2.c to clarify the APRM/OPRM channels and 2-Out-Of-4 Voter channels are included in the CHANNEL FUNCTIONAL TEST

Note 3 is provided for APRM Functions 2.d and 2.f to clarify the APRM/OPRM channels and the 2-Out-Of-4 Voter channels plus the flow input function, excluding the flow transmitters, are included in the CHANNEL FUNCTIONAL TEST.

SR 3.3.1.1.21

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 APR-related redundant RPS relays. The test is only required to include the voting logic of the 2-Out-Of-4 Voter channels and RPS relays not tested as part of the CHANNEL FUNCIONAL TEST.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1.21 (continued)

The 24-month Frequency is based on the justification that virtually all of the equipment is tested by the CHANNEL FUNCTIONAL TESTS. The periodic LPRM calibrations (every 2000 full power hours) provide an indirect test of LPRM interfaces including detectors. The design of the equipment allows virtually all testing and routine adjustments to be performed with no changes to the configuration (e.g., no disconnecting wires), so the risk of problems caused by the normal operation of the system is greatly reduced.

SR 3.3.1.1.22

This SR ensures that the individual channel response times for Function 2.e are less than or equal to the maximum values assumed in the accident analysis. This test may be performed in one measurement or in overlapping segments, with verification that all associated components are tested. The RPS RESPONSE TIME acceptance criteria are included in the applicable plant procedures.

RPS RESPONSE TIME for the APRM 2-Out-Of-4 Voter 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.)

APRM and OPRM RESPONSE TIME tests are conducted on a 24-month STAGGERED TEST BASIS. The Note requires the STAGGERED TEST BASIS to be determined based on four channels of APRM outputs and four 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 four actual 2-Out-Of-4 Voter channels.

The redundant outputs from the 2-Out-Of-4 Voter channel (two for APRM trips and two 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 3.3.1.1.22, so "n" = 8. The note further requires that testing OPRM and APRM outputs from a 2-Out-Of-4 Voter be alternated.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1.22 (continued)

In addition to these commitments, Reference 15 require that testing inputs to each RPS Trip System alternate.

Combining these frequency requirements, an acceptable test sequence is one that:

a. Tests each RPS trip system interface every other cycle,

b. Alternates testing APRM and OPRM outputs from any specific 2-Out-Of-4 Voter channel, and

c. Alternates between divisions at least every other test cycle.

Each test of an APRM or OPRM 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 RPS. Consequently, each of the RPS relays is tested every fourth cycle. The RPS relay testing frequency is twice the frequency justified by Reference 15.

SR 3.3.1.1.23

This SR ensures that scrams initiated from OPRM Upscale Function 2.f will not be inadvertently bypassed when TERMAL POWER, as indicated by the APRM Simulated Thermal Power is greater than or equal to 29% RTP and core flow as indicated by recirculation drive flow is less than 60% rated flow. This normally involves confirming the bypass setpoints. Adequate margins for the instrument setpoint methodologies are incorporated into the actual setpoint. The actual surveillance ensures that the OPRM Upscale Function is enabled (not bypassed) for the correct values of APRM Simulated Thermal Power and recirculation drive flow. Other surveillances ensure that the APRM Simulated Thermal Power and recirculation flow properly correlate with THERMAL POWER and core flow, respectively.

If any bypass setpoint is non-conservative (i.e., the OPRM Upscale function is bypassed when APRM Simulated Thermal Power is greater than or equal 29% RTP and recirculation drive flow is less than 60% of rated flow), then the affected channel is considered inoperable for the OPRM Upscale function. Alternatively, the bypass setpoint may be adjusted to place the channel in a conservative condition (non-bypassed). If placed in "non-bypassed," this SR is met and the channel is considered OPERABLE.

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BASES

SURVEILLANCE REQUIREMENTS

SR 3.3.1.1.23 (continued)

The Frequency of once every 24 months is based on engineering judgment recognizing that the actual values are stored digitally, so there is no drift, and any hardware failures that affect these setpoints will most likely be detected by the automatic self-test function.

REFERENCES

1. UFSAR, Figure 7.2-1.
2. UFSAR, Section 5.2.2.
3. UFSAR, Section 6.3.3.
4. UFSAR, Chapter 15.
5. UFSAR, Section 15.4.1.
6. NEDO-23842, "Continuous Control Rod Withdrawal in the Startup Range," April 18, 1978.
7. UFSAR, Section 15.4.9.

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BASES

REFERENCES (continued)

8. Letter, P. Check (NRC) to G. Lainas (NRC), "BWR Scram Discharge System Safety Evaluation," December 1, 1980, as attached to NRC Generic Letter dated December 9, 1980.

9. NEDO-30851-P-A, "Technical Specification Improvement Analyses for BWR Reactor Protection System," March 1988.

10. NEDO-32291-A, "System Analyses for Elimination of Selected Response Time Testing Requirements," October 1995.

11. GNRI-97/00181, Amendment 133 to the Operating License.

12. NEDO-32339-A, ALong Term Stability Solution: Enhanced Option I-A.@

13. NEDO-31960-P-A, "BWR Owners' Group Long-Term Stability Solution Licensing Methodology," and Supplement 1.

14. NEDO-32465-P-a, "BWR Owners' Group Reactor Stability Detect and Suppress Solutions Licensing Basis Methodology for Reload Applications"

15. NEDC-32410-P-A, "Nuclear Measurement Analysis and Control - Power Range Neutron Monitor (NUMAC PRNM) Retrofit Plus Opiton III Stability trip Function," Vols 1 and 2, and Supplement 1

16. BWR Owners' Group Letter, L.A. England to the NRC, M.J. Virgilio, "BWR Owners' Group Guidelines for Stability Interim Corrective Action," June 6, 1994

17. TSTF-493, "Clarify Application of Setpoint Methodology for LSSS Functions"

B 3.3 INSTRUMENTATION

B 3.3.1.3 Deleted

Pages B 3.3-39a through B 3.3-39i have been deleted.

BASES

SURVEILLANCE REQUIREMENTS

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

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

SR 3.3.2.1.5

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

SR 3.3.2.1.6

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.2.1.9

LCO 3.1.3 and LCO 3.1.6 may require individual control rods to be bypassed in RACS to allow insertion of an inoperable control rod or correction of a control rod pattern not in compliance with BPWS. With the control rods bypassed in the RACS, the RPC will not control the movement of these bypassed control rods. Individual control rods may also be required to be bypassed to allow continuous withdrawal for determining the location of leaking fuel assemblies, adjustment of control rod speed, or control rod scram time testing. To ensure the proper bypassing and movement of those affected control rods, a second licensed operator or other qualified member of the technical staff must verify the bypassing and movement of these control rods is in conformance with applicable analyses. As noted, only one bypassed control rod may be moved at a time. This restriction minimizes the potential rate of change of reactivity. Compliance with this SR allows the RPC and RWL to be OPERABLE with these control rods bypassed.

REFERENCES

1. UFSAR, Section 7.6.1.7.3.
2. UFSAR, Section 15.4.2.
3. NEDE-24011-P-A, "General Electric Standard Application for Reactor Fuel" (latest approved revision).
4. "Modifications to the Requirements for Control Rod Drop Accident Mitigating Systems," BWR Owners Group, July 1986.
5. NEDO-21231, "Banked Position Withdrawal Sequence," January 1977.
6. 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.
7. NEDC-30851-P-A, "Technical Specification Improvement Analysis for BWR Control Rod Block Instrumentation," October 1988.
8. NEDC-330040-A, "Licensing Topical Report Constant Pressure Power Uprate," Revision 4, July 2003.

BASES

BACKGROUND (continued)

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

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

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

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

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

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

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY (continued)	transmitter associated with each stop valve, and the signal from each transmitter is assigned to a separate trip channel. The logic for the TSV Closure, Trip Oil Pressure—Low Function is such that two or more TSVs must be closed to produce an EOC-PT. This Function must be enabled at THERMAL POWER ≥ 35.4% RTP. This is normally accomplished automatically by pressure transmitters sensing turbine

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

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

first stage pressure; therefore to consider this Function OPERABLE, the turbine bypass valves must remain shut at ≥ 35.4% RTP. Four channels of TSV Closure, with two channels in each trip system, are available and required to be OPERABLE to ensure that no single instrument failure will preclude an EOC-RPT from this Function on a valid signal. The TSV Closure, Trip Oil Pressure—Low Allowable Value is selected high enough to detect imminent TSV closure.

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

The automatic enable setpoint is feedwater temperature dependent as a result of the subcooling changes that affect the turbine first stage pressure/reactor power relationship.

TCV Fast Closure, Trip Oil Pressure - Low

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

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

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

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

This protection is required consistent with the analysis, whenever the THERMAL POWER is ≥ 35.4% RTP with any recirculating pump in fast speed. Below 35.4% RTP or with recirculation pumps in slow speed, the Reactor Vessel Steam Dome Pressure—High and the APRM Fixed Neutron Flux—High Functions of the RPS are adequate to maintain the necessary safety margins. The turbine first stage pressure/reactor power relationship for the setpoint of the automatic enable is identical to that described for TSV closure.

ACTIONS

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

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

sufficient channels are OPERABLE or in trip, such that the EOC-RPT System will generate a trip signal from the given Function on a valid signal and both recirculation pumps can be tripped from fast speed operation. This requires two channels of the Function, in the same trip system, to be OPERABLE or in trip, and the associated EOC-RPT fast speed breakers to be OPERABLE or in trip. Alternatively, Required Action B.2 requires the MCPR limit for inoperable EOC-RPT, as specified in the COLR, to be applied. This also restores the margin to MCPR assumed in the safety analysis.

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 the EOC-RPT instrumentation during this period. It is also consistent with the 2 hour Completion Time provided in LCO 3.2.2, Required Action A.1, since this instrumentation's purpose is to preclude a MCPR violation.

C.1 and C.2

With any Required Action and associated Completion Time not met, THERMAL POWER must be reduced to < 35.4% RTP within 4 hours. Alternately, the associated recirculation pump fast speed breaker may be removed from service since this performs the intended function of the instrumentation. The allowed Completion Time of 4 hours is reasonable, based on operating experience, to reduce THERMAL POWER to < 35.4% RTP from full power conditions in an orderly manner and without challenging plant systems.

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 EOC-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. 5) assumption of the average time required to perform channel surveillance. That analysis demonstrated that the 6 hour testing allowance does

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.4.1.4

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 a part of this test, overlapping the LOGIC SYSTEM FUNCTIONAL TEST, to provide complete testing of the associated safety function. Therefore, if a breaker is incapable of operating, the associated instrument channel would also be inoperable.

The 18 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 test when performed at the 18 month Frequency.

SR 3.3.4.1.5

This SR ensures that an EOC-RPT initiated from the TSV Closure, Trip Oil Pressure—Low and TCV Fast Closure, Trip Oil Pressure—Low Functions will not be inadvertently bypassed when THERMAL POWER is ≥ 35.4% RTP. This involves calibration of the bypass channels. Adequate margins for the instrument setpoint methodologies are incorporated into the actual setpoint. Because main turbine bypass flow can affect this setpoint nonconservatively (THERMAL POWER is derived from first stage pressure), the main turbine bypass valves must remain closed at THERMAL POWER ≥ 35.4% RTP to ensure that the calibration remains valid. If any bypass channel's setpoint is nonconservative (i.e., the Functions are bypassed at ≥ 35.4% RTP either due to open main turbine bypass valves or other reasons), the affected TSV Closure, Trip Oil Pressure—Low and TCV Fast Closure, Trip Oil Pressure—Low Functions are considered inoperable. Alternatively, the bypass channel can be placed in the conservative condition (nonbypass). If placed in the nonbypass condition, this SR is met and the channel considered OPERABLE.

The Frequency of 18 months has shown that channel bypass failures between successive tests are rare.

(continued)

BASES

APPLICABLE SAFETY ANALYSES, LCO, and APPLICABILITY

1.b. Main Steam Line Pressure—Low (continued)

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 685 psig, which results in a scram due to MSIV closure, thus reducing reactor power to < 21.8% RTP.)

The MSL low pressure signals are initiated from four transmitters that are connected to the MSL header. The transmitters are arranged such that, even though physically separated from each other, each transmitter 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. 2).

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 directly assumed in the analysis of the main steam line break (MSLB) accident (Ref. 1). 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 and offsite doses do not exceed the 10 CFR 50.67 limits.

The MSL flow signals are initiated from 16 transmitters that are connected to the four MSLs. The transmitters are arranged such that, even though physically separated from

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.3.6.1.2

A CHANNEL FUNCTIONAL TEST is performed on each required channel to ensure that the entire channel will perform the intended function.

Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology.

The Frequency is based on reliability analysis described in References 5 and 6.

SR 3.3.6.1.3

The calibration of trip units consists of a test to provide 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 3.3.6.1-1. For Function 1.c, Main Steam Line Flow - High, there is a plant specific program which verifies that the instrument channel functions as required by verifying the as-left and as-found settings are consistent with those established by the setpoint methodology. 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 References 5 and 6.

SR 3.3.6.1.4, SR 3.3.6.1.5, and SR 3.3.6.1.6

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, SR 3.3.6.1.5, and SR 3.3.6.1.6 is based on the assumption of the magnitude of equipment drift in the setpoint analysis.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	margins during abnormal operational transients (Ref. 2), which are analyzed in Chapter 15 of the UFSAR. A plant specific LOCA analysis has been performed assuming only 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 (Ref. 3). The transient analyses of Chapter 15 of the UFSAR have also been performed for single recirculation loop operation (Ref. 3) and demonstrate sufficient flow coastdown characteristics to maintain fuel thermal margins during the abnormal operational transients analyzed provided the MCPR requirements are modified. The APLHGR and MCPR limits for single loop operation are specified in the COLR. Recirculation loops operating satisfies Criterion 2 of the NRC Policy Statement.
LCO	Two recirculation loops are normally required to be 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. Alternatively, 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 POWERRATIO (MCPR)", and LCO 3.3.1.1, "RPS Instrumentation", must be applied to allow continued operation consistent with the assumptions of References 3 The LCO is modified by a Note which allows up to 12 hours before having to put in effect the required modifications to required limits after a change in the reactor operating conditions from two recirculation loops operating to single recirculation loop operation. If the required limits are

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BASES

APPLICABLE SAFETY ANALYSES (continued)	margins during abnormal operational transients (Ref. 2), which are analyzed in Chapter 15 of the UFSAR. A plant specific LOCA analysis has been performed assuming only 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 (Ref. 3). The transient analyses of Chapter 15 of the UFSAR have also been performed for single recirculation loop operation (Ref. 3) and demonstrate sufficient flow coastdown characteristics to maintain fuel thermal margins during the abnormal operational transients analyzed provided the MCPR requirements are modified. The APLHGR and MCPR limits for single loop operation are specified in the COLR. Recirculation loops operating satisfies Criterion 2 of the NRC Policy Statement.
LCO	Two recirculation loops are normally required to be 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. Alternatively, 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)"), LCO 3.2.3 "Linear Heat Generation Rate" (LHGR), and LCO 3.3.1.1, "RPS Instrumentation", must be applied to allow continued operation consistent with the assumptions of References 3. The LCO is modified by a Note which allows up to 12 hours before having to put in effect the required modifications to required limits after a change in the reactor operating conditions from two recirculation loops operating to single recirculation loop operation. If the required limits are

(continued)

BASES (continued)

REFERENCES

1. UFSAR, Section 6.3.3.7.
2. UFSAR, Section 5.4.1.1.
3. UFSAR, Chapter 15, Appendix 15C.
4. Deleted
5. Deleted

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.3.1 (continued)

Individual jet pumps in a recirculation loop typically do not have the same flow. The unequal flow is due to the drive flow manifold, which does not distribute flow equally to all risers. The flow (or jet pump diffuser to lower plenum differential pressure) pattern or relationship of one jet pump to the loop average is repeatable. An appreciable change in this relationship is an indication that increased (or reduced) resistance has occurred in one of the jet pumps. This may be indicated by an increase in the relative flow for a jet pump that has experienced beam cracks.

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

The 24 hour Frequency has been shown by operating experience to be adequate to verify jet pump OPERABILITY and is consistent with the 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 when THERMAL POWER is ≤ 21.8% 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.

REFERENCES

1. UFSAR, Section 6.3.
2. GE Service Information Letter No. 330, "Jet Pump Beam Cracks," June 9, 1990.
3. NUREG/CR-3052, "Closeout of IE Bulletin 80-07: BWR Jet Pump Assembly Failure," November 1984.

BASES (continued)

APPLICABLE SAFETY ANALYSES

The overpressure protection system must accommodate the most severe pressure 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. 2). For the purpose of the analyses, six of the S/RVs are assumed to operate in the relief mode, and nine 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.

Reference 3 discusses additional events that are expected to actuate the S/RVs. From an overpressure standpoint, the design basis events are bounded by the MSIV closure with flux scram event described above.

S/RVs satisfy Criterion 3 of the NRC Policy Statement.

LCO

The safety function of nine S/RVs is required to be OPERABLE in the safety mode, and an additional six S/RVs (other than the nine S/RVs that satisfy the safety function) must be OPERABLE in the relief mode. The requirements of this LCO are applicable only to the capability of the S/RVs to mechanically open to relieve excess pressure. In Reference 2, an evaluation was performed to establish the parametric relationship between the peak vessel pressure and the number of OPERABLE S/RVs. The results show that with a minimum of nine S/RVs in the safety mode and six S/RVs in the relief mode OPERABLE, the ASME Code limit of 1375 psig is not exceeded.

The S/RV setpoints are established to ensure the ASME Code limit on peak reactor pressure is satisfied. The ASME Code specifications require the lowest safety valve be set at or below vessel design pressure (1250 psig) and the highest safety valve be set so the total accumulated pressure does not exceed 110% of the design pressure for conditions. The transient evaluations in Reference 3 are based on these setpoints, but also include the additional uncertainties of ± 3% of the nominal setpoint to account for potential setpoint drift to provide an added degree of conservatism.

(continued)

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.7 RCS Leakage Detection Instrumentation

BASES

BACKGROUND

GDC 30 of 10 CFR 50, Appendix A (Ref. 1), requires means for detecting and, to the extent practical, identifying the location of the source of RCS LEAKAGE. Regulatory Guide 1.45, Revision 0, (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 rates. In addition to meeting the OPERABILITY requirements, the monitors are typically set to provide the most sensitive response without causing an excessive number of spurious alarms. The Bases for LCO 3.4.5, "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 three independently monitored variables, such as sump level changes and drywell gaseous and particulate radioactivity levels. The primary means of quantifying LEAKAGE in the drywell is the drywell floor drain sump monitoring system.

The drywell floor drain sump monitoring system monitors the LEAKAGE collected in the floor drain sump. This unidentified LEAKAGE consists of LEAKAGE from control rod drives, valve flanges or packings, floor drains, the Closed Cooling Water System, and drywell air cooling unit condensate drains, and any LEAKAGE not collected in the drywell equipment drain sump.

(continued)

BASES

BACKGROUND (continued)	The drywell atmospheric monitoring systems continuously monitor the drywell atmosphere for airborne particulate and gaseous radioactivity. A sudden increase of radioactivity, which may be attributed to RCPB steam or reactor water LEAKAGE, is annunciated in the control room. Condensate from four of the six drywell coolers is routed to the drywell floor drain sump and is monitored by a flow transmitter that provides indication and alarms in the control room. This drywell air cooler condensate flow rate monitoring system serves as an added indicator, but not quantifier, of RCS unidentified LEAKAGE.
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). Identification of the LEAKAGE 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.

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	RCS leakage detection instrumentation satisfies Criterion 1 of the NRC Policy Statement.

LCO

The LCO requires instruments of diverse monitoring principles to be OPERABLE to provide confidence that small amounts of unidentified LEAKAGE are detected in time to allow actions to place the plant in a safe condition, when RCS LEAKAGE indicates possible RCPB degradation.

The LCO requires three instruments to be OPERABLE.

The drywell floor drain sump monitoring system is required to quantify the unidentified LEAKAGE rate from the RCS. Thus, for the system to be considered OPERABLE, the sump level monitoring portion of the system must be OPERABLE and capable of determining the leakage rate. The identification of an increase in unidentified LEAKAGE will be delayed by the time required for the unidentified LEAKAGE to travel to the drywell floor drain sump and it may take longer than one hour to detect a 1 gpm increase in unidentified LEAKAGE, depending on the origin and magnitude of the LEAKAGE. This sensitivity is acceptable for containment sump monitor OPERABILITY.

The reactor coolant contains radioactivity that, when released to the drywell, can be detected by the gaseous or particulate drywell atmospheric radioactivity monitor. Only one of the two detectors is required to be OPERABLE. Radioactivity detection systems are included for monitoring both particulate and gaseous activities because of their sensitivities and rapid response to RCS LEAKAGE, but have recognized limitations. Reactor coolant radioactivity levels will be low during initial reactor startup and for a few weeks thereafter, until activated corrosion products have been formed and fission products appear from fuel element cladding contamination or cladding defects. If there are few fuel element cladding defects and low levels of activation products, it may not be possible for the gaseous or particulate drywell atmospheric radioactivity monitors to detect a 1 gpm increase within 1 hour during normal operation. However, the gaseous or particulate drywell atmospheric radioactivity monitor is OPERABLE when it is capable of detecting a 1 gpm increase in unidentified LEAKAGE within 1 hour given an RCS activity equivalent to that assumed in the design calculations for the monitors (Reference 6).

This LCO is satisfied when monitors of diverse measurement means are available. Thus, the drywell floor drain sump monitoring system, in combination with a gaseous or

(continued)

BASES

LCO (continued)	particulate drywell atmospheric radioactivity monitor and a drywell air cooler condensate flow rate monitoring system, provides an acceptable minimum.
APPLICABILITY	In MODES 1, 2, and 3, leakage detection systems are required to be OPERABLE to support LCO 3.4.5. This Applicability is consistent with that for LCO 3.4.5.

ACTIONS

A.1

With the drywell floor drain sump monitoring system inoperable, no other form of sampling can provide the equivalent information to quantify leakage. However, the drywell atmospheric activity monitor and the drywell air cooler condensate flow rate monitor will provide indications of changes in leakage.

With the drywell floor drain sump monitoring system inoperable, but with RCS unidentified and total LEAKAGE being determined every 12 hours (SR 3.4.5.1), operation may continue for 30 days. Manual methods, using approved M&TE, can be used to monitor sump fill times and leakage and change in leakage during the 30 day allowed outage time for the drywell floor drain sump monitoring system to ensure compliance with SR 3.4.5.1. The 30 day Completion Time of Required Action A.1 is acceptable, based on operating experience, considering the multiple forms of leakage detection that are still available.

(continued)

BASES

ACTIONS (continued)

B.1

With both gaseous and particulate drywell atmospheric monitoring channels inoperable, grab samples of the drywell atmosphere shall 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., air cooler condensate flow rate monitor) is available. The 12 hour interval provides periodic information that is adequate to detect LEAKAGE.

C.1

With the required drywell air cooler condensate flow rate monitoring system inoperable, SR 3.4.7.1 is performed every 8 hours to provide periodic information of activity in the drywell at a more frequent interval than the routine Frequency of SR 3.4.7.1. The 8 hour interval provides periodic information that is adequate to detect LEAKAGE and recognizes that other forms of leakage detection are available. However, this Required Action is modified by a Note that allows this action to be not applicable if the required drywell atmospheric monitoring system is inoperable. Consistent with SR 3.0.1, Surveillances are not required to be performed on inoperable equipment.

D.1, D.2, D.3.1 and D.3.2

With the drywell floor drain sump monitoring system and the drywell air cooler condensate flow rate monitoring system inoperable, the only means of detecting LEAKAGE is the drywell atmospheric gaseous radiation monitor. A Note clarifies this applicability of the Condition. The drywell atmospheric gaseous radiation monitor typically cannot detect a 1 gpm leak within one hour when RCS activity is low. In addition, this configuration does not provide the required diverse means of leakage detection. Indirect methods of monitoring RCS leakage must be implemented. Grab samples of the drywell atmosphere must be performed every 12 hours to provide alternate periodic information.

Administrative means of monitoring RCS leakage include monitoring and trending parameters that may indicate an increase in RCS leakage. There are diverse alternative mechanisms from which appropriate indicators may be selected based on plant conditions. It is not necessary to utilize all of these methods, but a method or methods should be selected considering the current plant conditions and historical or expected sources of unidentified leakage. The administrative methods are drywell pressure and temperature, Component Cooling Water System outlet temperatures and makeup, Reactor Recirculation System pump seal motor cooler temperature indication, Drywell cooling fan outlet temperatures, Control Rod Drive System flange temperatures, and Safety Relief Valves tailpipe temperature. These indications, coupled with the atmospheric grab

(continued)

BASES

ACTIONS (continued)

samples, are sufficient to alert the operating staff to an unexpected increase in unidentified LEAKAGE.

The 12 hour interval is sufficient to detect increasing RCS leakage. The Required Action provides 7 days to restore another RCS leakage monitor to OPERABLE status to regain the intended leakage detection diversity. The 7 day Completion Time ensures that the plant will not be operated in a degraded configuration for a lengthy time period.

E.1 and E.2

With both the gaseous and particulate drywell atmospheric monitor channels and the drywell air cooler condensate flow rate monitor inoperable, the only means of detecting LEAKAGE is the drywell floor drain sump monitoring system. This Condition does not provide the required diverse means of leakage detection. The Required Action is to restore either of the inoperable monitoring systems to OPERABLE status within 30 days to regain the intended leakage detection diversity. The 30 day Completion Time ensures that the plant will not be operated in a degraded configuration for a lengthy time period.

F.1 and F.2

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

G.1

With all required monitors inoperable, no required automatic means of monitoring LEAKAGE are available, and immediate plant shutdown in accordance with LCO 3.0.3 is required.

SURVEILLANCE REQUIREMENTS

SR 3.4.7.1

This SR requires the performance of a CHANNEL CHECK of the required drywell atmospheric 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.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.7.2

This SR requires the performance of a CHANNEL FUNCTIONAL TEST of the required RCS leakage detection instrumentation. The test ensures that the monitors can perform their function in the desired manner. The test also verifies the relative accuracy of the instrumentation. The Frequency of 31 days considers instrument reliability, and operating experience has shown it proper for detecting degradation.

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.4.7.3

This SR requires the performance of a CHANNEL CALIBRATION of the required RCS leakage detection instrumentation channels. The calibration verifies the accuracy of the instrumentation, including the instruments located inside the drywell. The Frequency of 18 months is a typical refueling cycle and considers channel reliability. Operating experience has proven this Frequency is acceptable.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 30.
2. Regulatory Guide 1.45, Revision 0, "Reactor Coolant Pressure Boundary Leakage Detection System." 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.
5. UFSAR, Section 5.2.5.5.3.
6. UFSAR, Section 5.2.5.2.

B 3.4 REACTOR COOLANT SYSTEM (RCS)

B 3.4.11 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 Pressure Temperature Limits Report (PTLR) (Ref. 13) contains P/T limit curves for normal operation (including heatup and cooldown), and inservice leak and hydrostatic testing.

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 (i.e., to the right of the applicable curve).

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 American Society of Mechanical Engineers (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), 10 CFR 50, Appendix H (Ref. 4) and the UFSAR Reactor Materials Surveillance Program (Ref. 9, 10, 11). The operating P/T limit curves will be adjusted, as

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	are acceptance limits themselves since they preclude operation in an unanalyzed condition. RCS P/T limits satisfy Criterion 2 of the NRC Policy Statement.
LCO	The elements of this LCO are:

LCO

The elements of this LCO are:

a. RCS pressure and temperature are within the limits specified in the PLTR and heatup or cooldown rate is within the limits specified in the PTLR.

b. The temperature difference between the reactor vessel bottom head coolant and the reactor pressure vessel (RPV) coolant is within the limits specified in the PTLR during recirculation pump startup and during increases in THERMAL POWER or loop flow while operating at low THERMAL POWER or loop flow.

c. The temperature difference between the reactor coolant in the respective recirculation loop and in the reactor vessel is within the limits specified in the PTLR during pump startup and during increases in THERMAL POWER or loop flow while operating at low THERMAL POWER or loop flow.

d. RCS pressure and temperature are within the criticality limits specified in the PTLR based on the current Effective Fuel Power Year (EFPY) prior to achieving criticality.

e. The reactor vessel flange and the head flange temperatures is within the limits specified in the PTLR when tensioning the reactor vessel head bolting studs.

These limits define allowable operating regions and permit a large number of operating cycles while also providing a wide margin to nonductile failure.

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

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.4.11.8 and SR 3.4.11.9 (continued)

Plant specific test data has determined that the bottom head is not subject to temperature stratification with natural circulation at power levels as low as 36% of RTP with any single loop flow rate when the recirculation pump is on high speed operation. Therefore, SR 3.4.11.8 and SR 3.4.11.9 have been modified by a Note that requires the Surveillance to be met only when THERMAL POWER or loop flow is being increased when the above conditions are not met. The Note for SR 3.4.11.9 further limits the requirement for this Surveillance to exclude comparison of the idle loop temperature if the idle loop is isolated from the RPV since the water in the loop cannot be introduced into the remainder of the reactor coolant system.

REFERENCES

1. 10 CFR 50, Appendix G.
2. ASME, Boiler and Pressure Vessel Code, Section III, Appendix G.
3. ASTM E 185-82, "Standard Practice for Conducting Surveillance Tests For Light-Water Cooled Nuclear Power Reactor Vessels," July 1982.
4. 10 CFR 50, Appendix H.
5. Regulatory Guide 1.99, Revision 2, May 1988.
6. ASME, Boiler and Pressure Vessel Code, Section XI, Appendix E.
7. NEDO-21778-A, "Transient Pressure Rises Affecting Fracture Toughness Requirements For BWRs," December 1978.
8. UFSAR, Section 15.4.4.
9. GNRI-96/00176, Amendment 127 Safety Evaluation
10. GNRI-96/00186, Amendment 127 Safety Evaluation, Correction
11. UFSAR, Section 5.3.1.6.1
12. GNRI-97/00139, Amendment 132 to the Operating License.
13. GGNS Pressure Temperature Limits Report, Revision 0

BACKGROUND (continued)	This Specification ensures that the performance of the primary containment, in the event of a DBA, meets the assumptions used in the safety analyses of References 1 and 2. SR 3.6.1.1.1 leakage rate requirements are in conformance with 10 CFR 50, Appendix J (Ref. 3), as modified by approved exemptions.
APPLICABLE SAFETY ANALYSES	The safety design basis for the primary containment is that it must withstand the pressures and temperatures of the limiting DBA without exceeding the design leakage rate. The DBA that postulates the maximum release of radioactive material within primary containment is a LOCA. In the analysis of this accident, it is assumed that primary containment is OPERABLE such that release of fission products to the environment is controlled by the rate of primary containment leakage. Analytical methods and assumptions involving the primary containment are presented in References 1 and 2. The safety analyses assume a nonmechanistic fission product release following a DBA, which forms the basis for determination of offsite doses. The fission product release is, in turn, based on an assumed leakage rate from the primary containment. OPERABILITY of the primary containment ensures that the leakage rate assumed in the safety analyses is not exceeded. The maximum allowable leakage rate for the primary containment (L_a) is 0.682% by weight of the containment and drywell air per 24 hours at the maximum peak containment pressure (P_a) of 11.9 psig (Ref. 4). Primary containment satisfies Criterion 3 of the NRC Policy Statement.
LCO	Primary containment OPERABILITY is maintained by limiting leakage to $\leq 1.0\ L_a$, except prior to the first unit startup after performing a required 10 CFR 50, Appendix J leakage test. At this time, the combined Type B and Type C leakage must be $< 0.6\ L_a$, and the overall Type A leakage must be $< 0.75\ L_a$. Compliance with this LCO will ensure a primary containment configuration, including equipment hatches, that is structurally sound and that will limit leakage to those

(continued)

BASES

BACKGROUND (continued)	DBA. Not maintaining air lock integrity or leak tightness may result in a leakage rate in excess of that assumed in the unit safety analysis.
APPLICABLE SAFETY ANALYSES	The DBA that postulates the maximum release of radioactive material within primary containment is a LOCA. In the analysis of this accident, it is assumed that primary containment is OPERABLE, such that release of fission products to the environment is controlled by the rate of primary containment leakage. The primary containment is designed with a maximum allowable leakage rate (L_a) of 0.682% by weight of the containment and drywell air per 24 hours at the calculated maximum peak containment pressure (P_a) of 11.9 psig. This allowable leakage rate forms the basis for the acceptance criteria imposed on the SRs associated with the air locks. Primary containment air lock OPERABILITY is also required to minimize the amount of fission product gases that may escape primary containment through the air lock and contaminate and pressurize the secondary containment. Primary containment air locks satisfy Criterion 3 of the NRC Policy Statement.
LCO	As part of the primary containment, the air lock's safety function is related to control of containment leakage rates following a DBA. Thus, the air lock's structural integrity and leak tightness are essential to the successful mitigation of such an event. The primary containment air locks are required to be OPERABLE. For each air lock to be considered OPERABLE, the air lock interlock mechanism must be OPERABLE, the air lock must be in compliance with the Type B air lock leakage test, both air lock doors must be OPERABLE, and the test connection valves must be OPERABLE in accordance with LCO 3.6.1.3. These normally closed manual isolation valves are considered OPERABLE when closed or when intermittently opened under administrative controls. The interlock allows only one air lock door to be open at a time. This provision ensures that a gross breach of primary containment does not exist when primary containment is required to be OPERABLE.

(continued)

BASES

SURVEILLANCE REQUIREMENTS

SR 3.6.1.3.7 (continued)

each automatic PCIV will actuate to its isolation position on a primary containment isolation signal. The LOGIC SYSTEM FUNCTIONAL TEST in SR 3.3.6.1.7 overlaps this SR to provide complete testing of the safety function. The 18 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 18 month Frequency. Therefore, the Frequency was concluded to be acceptable from a reliability standpoint.

SR 3.6.1.3.8

The analyses in Reference 2 is based on leakage that is less than the specified leakage rate. Leakage through any single main steam line must be ≤ 100 scfh when tested at a pressure of 11.9 psig. Leakage through all four steam lines must be ≤ 250 scfh when tested at P_a (11.9 psig). The MSIV leakage rate must be verified to be in accordance with the leakage test requirements of Reference 3, as modified by approved exemptions. A Note is added to this SR which states that these valves are only required to meet this leakage limit in MODES 1, 2 and 3. In the other conditions, the Reactor Coolant System is not pressurized and specific primary containment leakage limits are not required.

SR 3.6.1.3.9

Surveillance of hydrostatically tested lines provides assurance that the calculation assumptions of Reference 2 is met.

This SR is modified by a Note that states these valves are only required to meet the combined leakage rate in MODES 1, 2, and 3 since this is when the Reactor Coolant System is

(continued)

B 3.6 CONTAINMENT SYSTEMS

B 3.6.1.7 Residual Heat Removal (RHR) Containment Spray System

BASES

BACKGROUND

The primary containment is designed with a suppression pool so that, in the event of a loss of coolant accident (LOCA), steam released from the primary system is channeled through the suppression pool water and condensed without producing significant pressurization of the primary containment. The primary containment is designed so that with the pool initially at the minimum water volume and the worst single failure of the primary containment heat removal systems, suppression pool energy absorption combined with subsequent operator controlled pool cooling will prevent the primary containment pressure from exceeding its design value. However, the primary containment must also withstand a postulated bypass leakage pathway that allows the passage of steam from the drywell directly into the primary containment airspace, bypassing the suppression pool. The primary containment also must withstand a low energy steam release into the primary containment airspace. The RHR Containment Spray System is designed to mitigate the effects of bypass leakage and low energy line breaks.

There are two redundant, 100% capacity RHR containment spray subsystems. Each subsystem consists of a suction line from the suppression pool, an RHR pump, a heat exchanger, and three spray spargers inside the primary containment (outside of the drywell) above the refueling floor. Dispersion of the spray water is accomplished by 350 nozzles in each subsystem.

The RHR containment spray mode will be automatically initiated, if required, following a LOCA.

APPLICABLE SAFETY ANALYSES

Reference 1 contains the results of analyses that predict the primary containment pressure response for a LOCA with the maximum allowable bypass leakage area.

The equivalent flow path area for bypass leakage has been specified to be 0.8 ft^2. The analysis demonstrates that with containment spray operation the primary containment pressure remains within design limits.

(continued)

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 a pump and two heat exchangers in series and is manually initiated and independently controlled. The two RHR 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 external heat sink.

The heat removal capability of one RHR subsystem is sufficient to meet the overall DBA pool cooling requirement to limit peak temperature to 210°F for loss of coolant accidents (LOCAs) and transient events such as a turbine trip without bypass or a stuck open safety/relief valve (S/RV). S/RV leakage 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 analyses 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.

(continued)

B 3.6 CONTAINMENT SYSTEMS

B 3.6.3.3 Drywell Purge System

BASES

BACKGROUND

The Drywell Purge System ensures a uniformly mixed post accident containment atmosphere, thereby minimizing the potential for local hydrogen burns due to a pocket of hydrogen above the flammable concentration.

The drywell purge compressor also performs the function diluting the drywell source term with the containment and suppression pool environment by pressurizing the drywell and discharging the drywell source term through the drywell suppression pool vents with the implementation of the Extended Power Uprate this dilution of drywell source term is no longer credited in the Equipment Qualification analysis.

The Drywell Purge System is an Engineered Safety Feature and is designed to operate in post accident environments without loss of function. The system has two independent subsystems, each consisting of a compressor and associated valves, controls, and piping. Each subsystem is sized to pump 1000 scfm. Each subsystem is powered from a separate emergency power supply. Since each subsystem can provide 100% of the mixing requirements, the system will provide its design function with a worst case single active failure.

Following an accident, the drywell is immediately pressurized due to the release of steam into the drywell environment. This pressure is relieved by the lowering of the water level within the weir wall, clearing the drywell vents and allowing the mixture of steam and noncondensibles to flow into the primary containment through the suppression pool, removing much of the heat from the steam. The remaining steam in the drywell begins to condense. As steam flow from the reactor pressure vessel ceases, the drywell pressure falls rapidly. Both drywell purge compressors start automatically 30 seconds after asignal is received from the Emergency Core Cooling System instrumentation, but only when drywell pressure has decreased to within approximately 0.87 psi above primary containment pressure.

(continued)

ACTIONS

B.1 and B.2 (continued)

provided by one division of the hydrogen igniters. The 1 hour Completion Time allows a reasonable period of time to verify that a loss of hydrogen control function does not exist. The verification may be performed as an administrative check by examining logs or other information to determine the availability of the alternate hydrogen control system. It does not mean to perform the surveillances needed to demonstrate OPERABILITY of the alternate hydrogen control system. If the ability to perform the hydrogen control function is maintained, continued operation is permitted with two drywell purge subsystems inoperable for up to 7 days. Seven days is a reasonable time to allow two drywell purge subsystems to be inoperable because the hydrogen control function is maintained and because of the low probability of the occurrence of an accident.

C.1

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. The allowed Completion Time of 12 hours is reasonable, based on operating experience, to reach MODE 3 from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.3.3.1

Performance of a CHANNEL FUNCTIONAL TEST demonstrates the associated channel will function properly. Any setpoint adjustment shall be consistent with the assumptions of the current plant specific setpoint methodology. The 31 day Frequency is reasonable, based on operating experience.

SR 3.6.3.3.2

Operating each drywell purge subsystem from the control room for ≥ 15 minutes ensures that each subsystem is OPERABLE and

(continued)

BASES

ACTIONS

A.1

In the event the drywell is inoperable, it 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 the drywell OPERABLE during MODES 1, 2, and 3. This time period also ensures that the probability of an accident (requiring drywell OPERABILITY) occurring during periods when the drywell is inoperable is minimal. Also, the Completion Time is the same as that applied to inoperability of the primary containment in LCO 3.6.1.1, "Primary Containment."

B.1 and B.2

If the drywell 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 3.6.5.1.1

The analyses in Reference 2 are based on a maximum drywell bypass leakage. This Surveillance ensures that the actual drywell bypass leakage is less than or equal to the acceptable $A/\sqrt{k}$ design value of 0.8 ft^2 assumed in the safety analysis. The testing is performed with one airlock door open (the airlock door remaining open is changed for the performance of each required test). As left drywell bypass leakage, prior to the first startup after performing a required drywell bypass leakage test, is required to be $\leq$ 10% of the drywell bypass leakage limit. At all other times between required drywell leakage rate tests, the acceptance criteria is based on design $A/\sqrt{k}$. At the design $A/\sqrt{k}$ the containment temperature and pressurization response are bounded by the assumptions of

(continued)

BASES (continued)

APPLICABLEE SAFETY ANALYSES

The Drywell Vacuum Relief System must function in the event of a large break LOCA to control rapid weir wall overflow that could cause drag and impact loadings on essential equipment and systems in the drywell above the weir wall. The Drywell Vacuum Relief System is not required to assist in hydrogen dilution or to protect the structural integrity of the drywell following a large break LOCA. Furthermore, their passive operation (remaining closed and not leaking during drywell pressurization) is implicit in all of the LOCA analyses (Ref. 1).

The Drywell Vacuum Relief System satisfies Criterion 3 of the NRC Policy Statement.

LCO

The LCO ensures that in the event of a LOCA, two drywell post-LOCA and two drywell purge vacuum relief subsystems are available to mitigate the potential subsequent drywell depressurization. Each vacuum relief subsystem is OPERABLE when capable of opening at the required setpoint but is maintained in the closed position during normal operation.

APPLICABILITY

In MODES 1, 2, and 3, a Design Basis Accident could cause pressurization of primary containment. Therefore, Drywell Vacuum Relief 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 Drywell Vacuum Relief System OPERABLE is not required in MODE 4 or 5.

ACTIONS

The ACTIONS are modified by a NOTE, which ensures appropriate remedial actions are taken, if necessary, if the drywell is rendered inoperable by inoperable drywell vacuum relief subsystems.

A.1

With one or more vacuum relief subsystems open, the subsystem must be closed within 4 hours. This assures that drywell leakage would not result if a postulated LOCA were to occur. The 4 hour Completion Time is acceptable, since the drywell design bypass leakage ($A/\sqrt{k}$) of 0.8 ft^2 is

(continued)

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 30.4% 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 Turbine Bypass System consists of three hydraulically operated combined stop and control valves. The bypass valves are controlled by the turbine-generator and Pressure Control System, as discussed in FSAR Section 7.7.1.5. Normally, the bypass control valves are held closed and the pressure regulator controls the turbine control valves, directing all steam flow to the turbine. If the speed control load restricts steam flow to the turbine, the pressure regulator controls system pressure by opening the bypass control valves. If the capacity of the bypass valves is exceeded while the turbine cannot accept an increase in steam flow, the system pressure will rise and the reactor protection system action will cause shutdown of the reactor.

APPLICABLE SAFETY ANALYSES

The Main Turbine Bypass System is assumed to function during the rod withdrawal error (RWE) at power event, as discussed in FSAR Section 15.4.2, loss of feedwater heating event (LOFWH), as discussed in FSAR Section 15.1.1 and the slow opening of the recirculation control valve events as described in FSAR Section 15.4.5. Opening the bypass valves during these events mitigates the increase in reactor vessel pressure, which affects the MCPR and LHGR during the event. Only the RWE and LOFWH events initiating from near RTP will open the bypass valves. The basis for the applicable power range of the Main Turbine Bypass System is the slow opening of the recirculation control valve. Two or more inoperable Main Turbine Bypass valves may result in LHGR and MCPR penalties.

BASES (continued)

LCO

Two of the three Main Turbine Bypass valves are required to be OPERABLE to limit peak pressure in the main steam lines and maintain reactor pressure within acceptable limits during events that cause slow pressurization, such that the Safety Limit MCPR is not exceeded. With two or more Main Turbine Bypass valves inoperable, modifications to the LHGR limits (LCO 3.2.3) and the MCPR limits (LCO 3.2.2) may be applied to allow continued operation.

Main Turbine Bypass valves are considered OPERABLE when they are capable of opening in response to increasing main steam line pressure. This response is within the assumption of the applicable analysis. The LHGR and MCPR limits for two or more inoperable Main Turbine Bypass valves are specified in the COLR.

APPLICABILITY

The Main Turbine Bypass System is required to be OPERABLE at ≥ 70% RTP to ensure that the fuel cladding integrity safety limit and the cladding 1% plastic strain limit are not violated during the slow opening of the recirculation control valve event. As discussed in the Bases for LCO 3.2.2 and LCO 3.2.3, sufficient margin to these limits exists below 70% RTP. Additionally, the Main Turbine Bypass valves are not expected to open when the event initiates from below 70% RTP. Therefore, these requirements are only necessary when operating at or above this power.

ACTIONS

A.1

If the Main Turbine Bypass system is inoperable, or the LHGR and MCPR limits for two or more inoperable Main Turbine Bypass valves, as specified in the COLR, are not applied, the assumptions of the design basis transient analysis may not be met. Under such circumstances, prompt action should be taken to restore the Main Turbine Bypass System to OPERABLE status or adjust the LHGR and MCPR limits accordingly. The 2 hour Completion Time is reasonable, based on the time to complete the Required Action and the low probability of an event occurring during this period requiring two of the three Main Turbine Bypass valves.

(continued)

BASES (continued)

B.1

If the Main Turbine Bypass System cannot be restored to OPERABLE status or the LHGR and MCPR limits for two or more inoperable Main Turbine Bypass valves are not applied, THERMAL POWER must be reduced to < 70% RTP. As discussed in the Applicability section, operation at <70% RTP results in sufficient margin to the required limits, and the Main Turbine Bypass system is not required to protect fuel integrity during the feedwater controller failure, maximum demand event. The 4 hour Completion Time is reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging unit systems.

SURVEILLANCE REQUIREMENTS

SR 3.7.7.1

Cycling each Main Turbine Bypass valve through one complete cycle of full travel demonstrates that the valves are mechanically OPERABLE and will function when required. The 31 day Frequency is based on engineering judgment, is consistent with the procedural controls governing valve operation, and ensures correct valve positions. Therefore, the Frequency is acceptable from a reliability standpoint.

SR 3.7.7.2

The Main Turbine Bypass System is required to actuate automatically to perform its design function. This SR demonstrates that, with the required system initiation signals, the valves will actuate to their required position. The 18 month Frequency is based on the need to perform this Surveillance under the conditions that apply during a unit outage and because of the potential for an unplanned transient if the Surveillance were performed with the reactor at power. Operating experience has shown the 18 month Frequency, which is based on the refueling cycle, is acceptable from a reliability standpoint.

REFERENCES

None

BASES

APPLICABLE SAFETY ANALYSES (continued)

CRDA analyses assume that the reactor operator follows prescribed withdrawal sequences. For SDM tests performed within these defined sequences, the analyses of References 1 and 2 are applicable. However, for some sequences developed for the SDM testing, the control rod patterns assumed in the safety analyses of References 1 and 2 may not be met. Therefore, special CRDA analyses, performed in accordance with an NRC approved methodology, are required to demonstrate that the SDM test sequence will not result in unacceptable consequences should a CRDA occur during the testing. For the purpose of this test, protection provided by the normally required MODE 5 applicable LCOs, in addition to the requirements of this LCO, will maintain normal test operations as well as postulated accidents within the bounds of the appropriate safety analyses (Refs. 1 and 2). In addition to the added requirements for the Rod Pattern Controller (RPC), APRM, 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 the NRC Policy Statement apply. Special Operations LCOs provide flexibility to perform certain operations by appropriately modifying requirements of other LCOs. A discussion of the criteria satisfied for the other LCOs is provided in their respective Bases.

LCO

As described in LCO 3.0.7, compliance with this Special Operations LCO is optional. SDM tests may be performed while in MODE 2, in accordance with Table 1.1-1, without meeting this Special Operations LCO or its ACTIONS. For SDM tests performed while in MODE 5, additional requirements must be met to ensure that adequate protection against potential reactivity excursions is available. To provide additional scram protection, beyond the normally required IRMs, the APRMs are also required to be OPERABLE (LCO 3.3.1.1, Functions 2.a, 2.c, and 2.e) as though the reactor were in MODE 2. Because multiple control rods will be withdrawn and the reactor will potentially become critical, the approved control rod withdrawal sequence must be enforced by the RPC (LCO 3.3.2.1, Function 1b, MODE 2), or

(continued)

B 6.3.5 LOOSE PART DETECTION SYSTEM --Deleted

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

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

B 6.3.8 TURBINE OVERSPEED PROTECTION

This specification is provided to ensure that the turbine overspeed protection instrumentation and the turbine speed control valves are OPERABLE and will protect the turbine from excessive overspeed. Protection from turbine excessive overspeed is required since excessive overspeed of the turbine could generate potentially damaging missiles which could impact and damage safety-related components, equipment or structures. For any valves which become INOPERABLE UFSAR section 3.5.1.3 shall be reviewed for affect on the probability analysis to ensure risk is appropriately addressed.

B 6.3.12 Ultrasonic Flowmeter --Deleted

B 6.3.12 Deleted

B 6.4.1 CHEMISTRY

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

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

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

B 6.7.2 SEALED SOURCE CONTAMINATION

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

B 6.7.3 AREA TEMPERATURE MONITORING

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

B 6.7.4 SPENT FUEL STORAGE POOL TEMPERATURE

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