UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

August 30, 2022

Mr. Kevin Cimorelli
Site Vice President
Susquehanna Nuclear, LLC
769 Salem Boulevard
NUCSB3
Berwick, PA 18603-0467

Subject: SUSQUEHANNA STEAM ELECTRIC STATION, UNITS 1 AND 2—ISSUANCE OF AMENDMENT NOS. 282 AND 265 REGARDING RISK-INFORMED COMPLETION TIMES IN TECHNICAL SPECIFICATIONS (EPID L-2021-LLA-0062)

Dear Mr. Cimorelli:

The U.S. Nuclear Regulatory Commission (NRC) has issued the enclosed Amendment No. 282 to Renewed Facility Operating License No. NPF-14 and Amendment No. 265 to Renewed Facility Operating License No. NPF-22 for the Susquehanna Steam Electric Station, Units 1 and 2, respectively.

These amendments revise the technical specifications in response to your application dated April 8, 2021, as supplemented by letters dated March 8, 2022, and June 27, 2022. The application is based on Technical Specifications Task Force traveler TSTF-505, Revision 2, “Provide Risk-Informed Extended Completion Times – RITSTF Initiative 4b,” dated July 2, 2018.

These amendments revise technical specification requirements in Renewed Facility Operating License Nos. NPF-14 and NPF-22 to allow risk-informed completion times for actions to be taken when limiting conditions for operation are not met.

The NRC staff's safety evaluation for these amendments is enclosed. The NRC will include a notice of issuance in the Commission's monthly *Federal Register* notice.

Sincerely,

/RA/

Audrey L. Klett, Senior Project Manager
Plant Licensing Branch I
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket Nos. 50-387 and 50-388

Enclosures:
1. Amendment No. 282 to
   License No. NPF-14
2. Amendment No. 265 to
   License No. NPF-22
3. Safety Evaluation

cc: Listserv

SUSQUEHANNA NUCLEAR, LLC

ALLEGHENY ELECTRIC COOPERATIVE, INC.

DOCKET NO. 50-387

SUSQUEHANNA STEAM ELECTRIC STATION, UNIT 1

AMENDMENT TO RENEWED FACILITY OPERATING LICENSE

Amendment No. 282
Renewed License No. NPF-14

1. The U.S. Nuclear Regulatory Commission has found that:

   A. The application for the amendment filed by Susquehanna Nuclear, LLC, dated April 8, 2021, as supplemented by letters dated March 8, 2022, and June 27, 2022, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the regulations of the Commission;

   C. There is reasonable assurance: (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, the license is amended by changes to the Renewed Facility Operating License and Technical Specifications, as indicated in the attachment to this license amendment, and paragraph 2.C.(2) of Renewed Facility Operating License No. NPF-14 is hereby amended to read as follows:

    2.C.(2) Technical Specifications and Environmental Protection Plan

    The Technical Specifications contained in Appendix A, as revised through Amendment No. 282, and the Environmental Protection Plan contained in Appendix B are hereby incorporated in the license. Susquehanna Nuclear, LLC shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

3. This license amendment is effective as of its date of issuance and shall be implemented within 180 days.

FOR THE NUCLEAR REGULATORY COMMISSION

Hipolito J. Gonzalez

Digitally signed by Hipolito J. Gonzalez
Date: 2022.08.30 14:19:31 -04'00'

Hipólito J. González, Chief, Chief
Plant Licensing Branch I
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Attachment:
Changes to the Renewed Facility Operating
License and Technical Specifications

Date of Issuance: August 30, 2022

ATTACHMENT TO LICENSE AMENDMENT NO. 282

SUSQUEHANNA STEAM ELECTRIC STATION, UNIT 1

RENEWED FACILITY OPERATING LICENSE NO. NPF-14

DOCKET NO. 50-387

Replace the following page of Renewed Facility Operating License No. NPF-14 with the attached revised page. The revised page is identified by amendment number and contains a marginal line indicating the area of change.

Remove	Insert
Page 3	Page 3

Replace the following pages of the appendix A technical specifications with the attached revised pages. The revised pages are identified by amendment number and contain marginal lines indicating the areas of change.

REMOVE	INSERT	REMOVE	INSERT	REMOVE	INSERT	REMOVE	INSERT
1.3-12	1.3-12	3.3-32	3.3-32	3.3-56	3.3-56	3.7-3	3.7-3
1.3-13	1.3-13	3.3-33	3.3-33	3.3-62	3.3-62	3.7-3a	3.7-3a
---------	1.3-14	3.3-34	3.3-34	3.3-72	3.3-72	3.7-3b	3.7-3b
3.1-20	3.1-20	3.3-35	3.3-35	3.3-73	3.3-73	3.7-3c	3.7-3c
3.3-1	3.3-1	3.3-37	3.3-37	3.3-74	3.3-74	3.7-3d	3.7-3d
3.3-2	3.3-2	3.3-38	3.3-38	---------	3.3-74a	---------	3.7-3e
3.3-3	3.3-3	3.3-39	3.3-39	3.5-1	3.5-1	3.7-4	3.7-4
3.3-4	3.3-4	3.3-40	3.3-40	3.5-2	3.5-2	3.7-5	3.7-5
3.3-5	3.3-5	3.3-41	3.3-41	3.5-3	3.5-3	---------	3.7-5a
3.3-6	3.3-6	3.3-42	3.3-42	3.5-4	3.5-4	---------	3.7-5b
3.3-6a	3.3-6a	3.3-43	3.3-43	3.5-5	3.5-5	3.8-1	3.8-1
---------	3.3-6b	3.3-44	3.3-44	3.5-6	3.5-6	3.8-2	3.8-2
---------	3.3-6c	3.3-45	3.3-45	3.5-7	3.5-7	3.8-3	3.8-3
3.3-16	3.3-16	3.3-46	3.3-46	3.5-12	3.5-12	3.8-4	3.8-4
3.3-17	3.3-17	3.3-47	3.3-47	3.6-6	3.6-6	3.8-5	3.8-5
3.3-18	3.3-18	3.3-48	3.3-48	3.6-8	3.6-8	3.8-6	3.8-6
3.3-19	3.3-19	3.3-49	3.3-49	3.6-9	3.6-9	3.8-7	3.8-7
3.3-20	3.3-20	3.3-50	3.3-50	3.6-10	3.6-10	3.8-8	3.8-8
---------	3.3-20a	3.3-51	3.3-51	3.6-11	3.6-11	3.8-23	3.8-23
3.3-21	3.3-21	---------	3.3-51a	3.6-19	3.6-19	3.8-23a	3.8-23a
3.3-22	3.3-22	3.3-52	3.3-52	3.6-26	3.6-26	3.8-37	3.8-37
3.3-29	3.3-29	3.3-53	3.3-53	3.6-28	3.6-28	3.8-38	3.8-38
3.3-30	3.3-30	3.3-54	3.3-54	3.7-1	3.7-1	5.0-18C	5.0-18c
3.3-31	3.3-31	3.3-55	3.3-55	3.7-2	3.7-2	---------	5.0-18d

(3) Susquehanna Nuclear, LLC, pursuant to the Act and 10 CFR Parts 30, 40, and 70, to receive, posses, and use at any time any byproduct, source and special nuclear material as sealed neutron sources for reactor startup, sealed neutron sources for reactor instrumentation and radiation monitoring equipment calibration, and as fission detectors in amounts as required;

(4) Susquehanna Nuclear, LLC, pursuant to the Act and 10 CFR Parts 30, 40, and 70 to receive, posses, and use in amounts as required any byproduct, source or special nuclear material without restriction to chemical or physical form, for sample analysis or instrument calibration or associated with radioactive apparatus or components; and

(5) Susquehanna Nuclear, LLC, pursuant to the Act and 10 CFR Parts 30, 40, and 70 to possess, but not separate, such byproduct and special nuclear materials as may be produced by the operation of the facility.

C. This license shall be deemed to contain and is subject to the conditions specified in the Commission’s regulations set forth in 10 CFR Chapter I and is subject to all applicable provisions of the Act and to the rules, regulations and orders of the Commission nor or hereafter in effect; and is subject to the additional conditions specified or incorporated below:

(1) <u>Maximum Power Level</u>

Susquehanna Nuclear, LLC is authorized to operate the facility at reactor core power levels not in excess of 3952 megawatts thermal in accordance with the conditions specified herein. The preoperational tests, startup tests and other items identified in License Conditions 2.C.(36), 2.C.(37), 2.C.(38), and 2.C.(39) to this license shall be completed as specified.

(2) <u>Technical Specifications and Environmental Protection Plan</u>

The Technical Specifications contained in Appendix A, as revised through Amendment No. 282, and the Environmental Protection Plan contained in Appendix B are hereby incorporated in the license. Susquehanna Nuclear, LLC shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

For Surveillance Requirements (SRs) that are new in Amendment 178 to Facility Operating License No. NPF-14, the first performance is due at the end of the first surveillance interval that begins at implementation of Amendment 178. For SRs that existed prior to Amendment 178, including SRs with modified acceptance criteria and SRs whose frequency of performance is being extended, the first performance is due at the end of the first surveillance interval that begins on the date the Surveillance was last performed prior to implementation of Amendment 178.

1.3 Completion Times

EXAMPLES (continued)

EXAMPLE 1.3-7

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One subsystem inoperable.	A.1 Verify affected subsystem isolated	1 hour AND Once per 8 hours thereafter
	AND	
	A.2 Restore subsystem to OPERABLE status.	72 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	12 hours
	AND	
	B.2 Be in MODE 4.	36 hours

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

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

1.3 Completion Times

EXAMPLES (continued)

EXAMPLE 1.3-8

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One subsystem inoperable.	A.1 Restore subsystem to OPERABLE status.	7 days OR In accordance with the Risk Informed Completion Time Program
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 4.	12 hours 36 hours

When a subsystem is declared inoperable, Condition A is entered. The 7 day Completion Time may be applied as discussed in Example 1.3-2. However, the licensee may elect to apply the Risk Informed Completion Time Program which permits calculation of a Risk Informed Completion Time (RICT) that may be used to complete the Required Action beyond the 7 day Completion Time. The RICT cannot exceed 30 days. After the 7 day Completion Time has expired, the subsystem must be restored to OPERABLE status within the RICT, or Condition B must also be entered.

The Risk Informed Completion Time Program requires recalculation of the RICT to reflect changing plant conditions. For planned changes, the revised RICT must be determined prior to implementation of the change in configuration. For emergent conditions, the revised RICT must be determined within the time limits of the Required Action Completion Time (i.e., not the RICT) or 12 hours after the plant configuration change, whichever is less.

1.3 Completion Times

EXAMPLES (continued)

EXAMPLE 1.3-8 (continued)

If the 7 day Completion Time clock of Condition A has expired and subsequent changes in plant condition result in exiting the applicability of the Risk Informed Completion Time Program without restoring the inoperable subsystem to OPERABLE status, Condition B is also entered and the Completion Time clocks for Required Actions B.1 and B.2 start.

If the RICT expires or is recalculated to be less than the time elapsed since the Condition was entered and the inoperable subsystem has not been restored to OPERABLE status, Condition B is also entered and the Completion Time clocks for Required Actions B.1 and B.2 start. If the inoperable subsystems are restored to OPERABLE status after Condition B is entered, Condition A is exited, and therefore, the Required Actions of Condition B may be terminated.

IMMEDIATE COMPLETION TIME

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

3.1 REACTIVITY CONTROL SYSTEMS

3.1.7 Standby Liquid Control (SLC) System

LCO 3.1.7 Two SLC subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Concentration of sodium pentaborate in solution is not within limits of Figure 3.1.7-1.	A.1 Restore concentration of sodium pentaborate in solution to within limits of Figure 3.1.7-1.	8 hours
B. One SLC subsystem inoperable for reasons other than Condition A.	B.1 Restore SLC subsystem to OPERABLE status.	7 days OR In accordance with the Risk Informed Completion Time Program
C. Two SLC subsystems inoperable for reasons other than Condition A.	C.1 Restore one SLC subsystem to OPERABLE status.	8 hours
D. Required Action and associated Completion Time not met.	D.1 Be in MODE 3. AND D.2 Be in MODE 4.	12 hours 36 hours

3.3 INSTRUMENTATION

3.3.1.1 Reactor Protection System (RPS) Instrumentation

LCO 3.3.1.1 The RPS instrumentation for each Function in Table 3.3.1.1-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.1.1-1.

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required channels inoperable.	A.1 Place channel in trip. OR	12 hours OR -----------NOTE----------- Not applicable if there is a loss of function. ----------------------------- In accordance with the Risk Informed Completion Time Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.2 ---------------NOTE---------------- Not applicable for Functions 2.a, 2.b, 2.c, 2.d, or 2.f. -- Place associated trip system in trip.	12 hours OR -----------NOTE----------- Not applicable if there is a loss of function. ------------------------------ In accordance with the Risk Informed Completion Time Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. -----------NOTE--------------- Not applicable for Functions 2.a, 2.b, 2.c, 2.d, or 2.f. ---------------------------------- One or more Functions with one or more required channels inoperable in both trip systems.	B.1	Place channel in one trip system in trip.	6 hours OR -----------NOTE----------- Not applicable if there is a loss of function. ------------------------------ In accordance with the Risk Informed Completion Time Program
	OR		
	B.2	Place one trip system in trip.	6 hours OR -----------NOTE----------- Not applicable if there is a loss of function. ------------------------------ In accordance with the Risk Informed Completion Time Program
C. One or more Functions with RPS trip capability not maintained.	C.1	Restore RPS trip capability.	1 hour
D. Required Action and associated Completion Time of Condition A, B, or C not met.	D.1	Enter the Condition referenced in Table 3.3.1.1-1 for the channels.	Immediately

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
E. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	E.1	Reduce THERMAL POWER to < 26% RTP.	4 hours
F. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	F.1	Be in MODE 2.	6 hours
G. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	G.1	Be in MODE 3.	12 hours
H. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	H.1	Initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies.	Immediately
I. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	I.1	Initiate alternate method to detect and suppress thermal hydraulic instability oscillations.	12 hours
	AND		
	I.2	Restore required channels to OPERABLE.	120 days
J. Required Action and associated Completion Time of Condition I not met.	J.1	Reduce THERMAL POWER to < 23% RTP.	4 hours

SURVEILLANCE REQUIREMENTS

--NOTES--

1. Refer to Table 3.3.1.1-1 to determine which SRs apply for each RPS 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 RPS trip capability.

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.1	Perform CHANNEL CHECK.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.2	Perform CHANNEL CHECK.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.3	--------------------------------NOTE------------------------------- Not required to be performed until 12 hours after THERMAL POWER ≥ 23% RTP. --- Verify the absolute difference between the average power range monitor (APRM) channels and the calculated power is ≤ 2% RTP while operating at ≥ 23% RTP.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.4	-------------------------------NOTE-------------------------------- Not required to be performed when entering MODE 2 from MODE 1 until 12 hours after entering MODE 2. --- Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.5	Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.6	Verify the source range monitor (SRM) and intermediate range monitor (IRM) channels overlap.	Prior to fully withdrawing SRMs from the core
SR 3.3.1.1.7	-----------------------------NOTE------------------------------ Only required to be met during entry into MODE 2 from MODE 1. -- Verify the IRM and APRM channels overlap.	 In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.8	Calibrate the local power range monitors.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.9	--------------------------------NOTE-------------------------------- A test of all required contacts does not have to be performed. --- Perform CHANNEL FUNCTIONAL TEST.	 In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.10	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.11	-------------------------------NOTES------------------------------ 1. Neutron detectors are excluded. 2. For Function 1.a, not required to be performed when entering MODE 2 from MODE 1 until 12 hours after entering MODE 2. --- Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.12	-----------------------------NOTES----------------------------- 1. For Function 2.a, not required to be performed when entering MODE 2 from MODE 1 until 12 hours after entering MODE 2. 2. For Functions 2.b and 2.f, the CHANNEL FUNCTIONAL TEST includes the recirculation flow input processing, excluding the flow transmitters. --- Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.13	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.14	Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.15	Perform LOGIC SYSTEM FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.16	Verify Turbine Stop Valve-Closure and Turbine Control Valve Fast Closure, Trip Oil Pressure-Low Functions are not bypassed when THERMAL POWER is ≥ 26% RTP.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.17	--------------------------------NOTE-------------------------------- Neutron detectors are excluded. --- Verify the RPS RESPONSE TIME is within limits.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.18	------------------------------NOTES------------------------------- 1. Neutron detectors are excluded. 2. For Functions 2.b and 2.f, the recirculation flow transmitters that feed the APRMs are included. --- Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.19	Verify OPRM is not bypassed when APRM Simulated Thermal Power is ≥ 25% and recirculation drive flow is ≤ value equivalent to the core flow value defined in the COLR.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.20	Adjust recirculation drive flow to conform to reactor core flow.	In accordance with the Surveillance Frequency Control Program

3.3 INSTRUMENTATION

3.3.2.1 Control Rod Block Instrumentation

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

APPLICABILITY: According to Table 3.3.2.1-1.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One rod block monitor (RBM) channel inoperable.	A.1 Restore RBM channel to OPERABLE status.	24 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program
B. Required Action and associated Completion Time of Condition A not met. <u>OR</u> Two RBM channels inoperable.	B.1 Place one RBM channel in trip.	1 hour

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. Rod worth minimizer (RWM) inoperable during reactor startup.	C.1	Suspend control rod movement except by scram.	Immediately
	OR		
	C.2.1.1	Verify ≥ 12 rods withdrawn.	Immediately
		OR	
	C.2.1.2	Verify by administrative methods that startup with RWM inoperable has not been performed in the last calendar year.	Immediately
		AND	
	C.2.2	Verify movement of control rods is in compliance with banked position withdrawal sequence (BPWS) by a second licensed operator or other qualified member of the technical staff.	During control rod movement
D. RWM inoperable during reactor shutdown.	D.1	Verify movement of control rods is in accordance with BPWS by a second licensed operator or other qualified member of the technical staff.	During control rod movement
E. One or more Reactor Mode Switch-Shutdown Position channels inoperable.	E.1	Suspend control rod withdrawal.	Immediately
	AND		
	E.2	Initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies.	Immediately

SURVEILLANCE REQUIREMENTS

---NOTES---

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

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

SURVEILLANCE		FREQUENCY
SR 3.3.2.1.1	Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.2.1.2	-------------------------------NOTE------------------------------- Not required to be performed until 1 hour after any control rod is withdrawn at ≤ 10% RTP in MODE 2. --- Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.2.1.3	-------------------------------NOTE------------------------------- Not required to be performed until 1 hour after THERMAL POWER is ≤ 10% RTP in MODE 1. --- Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.2.1.4	Verify the RBM: a. Low Power Range – Upscale Function is not bypassed when APRM Simulated Thermal Power is ≥ 28% RTP and ≤ Intermediate Power Range Setpoint specified in the COLR. b. Intermediate Power Range – Upscale Function is not bypassed when APRM Simulated Thermal Power is > Intermediate Power Range Setpoint specified in the COLR and ≤ High Power Range Setpoint specified in the COLR. c. High Power Range – Upscale Function is not bypassed when APRM Simulated Thermal Power is > High Power Range Setpoint specified in the COLR.	In accordance with the Surveillance Frequency Control Program
SR 3.3.2.1.5	Verify the RWM is not bypassed when THERMAL POWER is ≤ 10% RTP.	In accordance with the Surveillance Frequency Control Program
SR 3.3.2.1.6	------------------------------NOTE------------------------------ Not required to be performed until 1 hour after reactor mode switch is in the shutdown position. -- Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.2.1.7	-------------------------------NOTE------------------------------- Neutron detectors are excluded. -- Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program
SR 3.3.2.1.8	Verify control rod sequences input to the RWM are in conformance with BPWS.	Prior to declaring RWM OPERABLE following loading of sequence into RWM

Table 3.3.2.1-1 (page 1 of 1)
Control Rod Block Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Rod Block Monitor				
a. Low Power Range – Upscale	(a)	2	SR 3.3.2.1.1 SR 3.3.2.1.4 SR 3.3.2.1.7(i)(j)	(f)
b. Intermediate Power Range – Upscale	(b)	2	SR 3.3.2.1.1 SR 3.3.2.1.4 SR 3.3.2.1.7(i)(j)	(f)
c. High Power Range – Upscale	(c), (d)	2	SR 3.3.2.1.1 SR 3.3.2.1.4 SR 3.3.2.1.7(i)(j)	(f)
d. Inop	(d), (e)	2	SR 3.3.2.1.1	NA
2. Rod Worth Minimizer	1(g), 2(g)	1	SR 3.3.2.1.2 SR 3.3.2.1.3 SR 3.3.2.1.5 SR 3.3.2.1.8	NA
3. Reactor Mode Switch – Shutdown Position	(h)	2	SR 3.3.2.1.6	NA

(a) THERMAL POWER is ≥ 28% RTP and ≤ Intermediate Power Range Setpoint specified in the COLR and MCPR is less than the limit specified in the COLR.

(b) THERMAL POWER is > Intermediate Power Range Setpoint specified in the COLR and ≤ High Power Range Setpoint specified in the COLR and MCPR is less than the limit specified in the COLR.

(c) THERMAL POWER is > High Power Range Setpoint specified in the COLR and < 90% RTP and MCPR is less than the limit specified in the COLR.

(d) THERMAL POWER is ≥ 90% RTP and MCPR is less than the limit specified in the COLR.

(e) THERMAL POWER is ≥ 28% RTP and < 90% RTP and MCPR is less than the limit specified in the COLR.

(f) Allowable value specified in the COLR.

(g) With THERMAL POWER ≤ 10% RTP.

(h) Reactor mode switch in the shutdown position.

(i) If the as-found channel setpoint is not the Nominal Trip Setpoint but is conservative with respect to the Allowable Value, then the channel shall be evaluated to verify that it is functioning as required before returning the channel to service.

(j) The instrument channel setpoint shall be reset to the Nominal Trip Setpoint at the completion of the surveillance; otherwise, the channel shall be declared inoperable. The NTSP and the methodology used to determine the NTSP is specified in the SSES Final Safety Analysis Report.

3.3 INSTRUMENTATION

3.3.2.2 Feedwater – Main Turbine High Water Level Trip Instrumentation

LCO 3.3.2.2 Three channels of feedwater- main turbine high water level trip instrumentation shall be OPERABLE.

APPLICABILITY: THERMAL POWER ≥ 23% RTP.

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One feedwater – main turbine high water level trip channel inoperable.	A.1 Place channel in trip.	7 days <u>OR</u> In accordance with the Risk Informed Completion Time Program
B. Two or more feedwater – main turbine high water level trip channels inoperable.	B.1 Restore feedwater – main turbine high water level trip capability.	2 hours
C. Required Action and associated Completion Time of Conditions A or B not met.	C.1 Reduce THERMAL POWER to < 23% RTP.	4 hours

SURVEILLANCE REQUIREMENTS

---NOTE---

When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided feedwater - main turbine high water level trip capability is maintained.

SURVEILLANCE		FREQUENCY
SR 3.3.2.2.1	Perform CHANNEL CHECK.	In accordance with the Surveillance Frequency Control Program
SR 3.3.2.2.2	-----------------------------NOTES------------------------------ 1. A test of all required contacts does not have to be performed. 2. For the Feedwater - Main Turbine High Water Level Function, a test of all required relays does not have to be performed. --- Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.2.2.3	Perform CHANNEL CALIBRATION. The Allowable Value shall be ≤ 55.5 inches.	In accordance with the Surveillance Frequency Control Program
SR 3.3.2.2.4	Perform LOGIC SYSTEM FUNCTIONAL TEST including valve actuation.	In accordance with the Surveillance Frequency Control Program

3.3 INSTRUMENTATION

3.3.4.1 End of Cycle Recirculation Pump Trip (EOC-RPT) Instrumentation

LCO 3.3.4.1

a. Two channels per trip system for each EOC-RPT instrumentation Function listed below shall be OPERABLE:

1. Turbine Stop Valve (TSV)-Closure; and

2. Turbine Control Valve (TCV) Fast Closure, Trip Oil Pressure Low.

<u>OR</u>

b. LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)," limits for inoperable EOC-RPT as specified in the COLR are made applicable.

APPLICABILITY: THERMAL POWER > 26% RTP.

ACTIONS

--NOTE--

Separate Condition entry is allowed for each channel.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more channels inoperable. <u>AND</u> MCPR limit for inoperable EOC-RPT not made applicable.	A.1 Restore channel to OPERABLE status. <u>OR</u>	72 hours <u>OR</u> -----------NOTE----------- Not applicable if there is a loss of function. ----------------------------- In accordance with the Risk Informed Completion Time Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. (continued)	A.2	---------------NOTE-------------- Not applicable if inoperable channel is the result of an inoperable breaker. ------------------------------------- Place channel in trip.	72 hours <u>OR</u> -----------NOTE----------- Not applicable if there is a loss of function. ------------------------------ In accordance with the Risk Informed Completion Time Program
	<u>OR</u>		
	A.3	Apply the MCPR limit for inoperable EOC-RPT as specified in the COLR.	72 hours
B. One or more Functions with EOC-RPT trip capability not maintained. <u>AND</u> MCPR limit for inoperable EOC-RPT not made applicable.	B.1	Restore EOC-RPT trip capability.	2 hours
	<u>OR</u>		
	B.2	Apply the MCPR limit for inoperable EOC-RPT as specified in the COLR.	2 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Required Action and associated Completion Time not met.	C.1 Remove the associated recirculation pump from service. <u>OR</u> C.2 Reduce THERMAL POWER to < 26% RTP.	4 hours 4 hours

SURVEILLANCE REQUIREMENTS

--NOTE--

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

SURVEILLANCE		FREQUENCY
SR 3.3.4.1.1	----------------------------NOTE---------------------------- A test of all required contacts does not have to be performed. --- Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.4.1.2	Perform CHANNEL CALIBRATION. The Allowable Values shall be: TSV-Closure: ≤ 7% closed; and TCV Fast Closure, Trip Oil Pressure – Low: ≥ 460 psig.	In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.4.1.3	Perform LOGIC SYSTEM FUNCTIONAL TEST including breaker actuation.	In accordance with the Surveillance Frequency Control Program
SR 3.3.4.1.4	Verify TSV-Closure and TCV Fast Closure, Trip Oil Pressure – Low Functions are not bypassed when THERMAL POWER is ≥ 26% RTP.	In accordance with the Surveillance Frequency Control Program
SR 3.3.4.1.5	-------------------------------NOTE------------------------------- Breaker arc suppression time may be assumed from the most recent performance of SR 3.3.4.1.6. --- Verify the EOC-RPT SYSTEM RESPONSE TIME is within limits.	In accordance with the Surveillance Frequency Control Program
SR 3.3.4.1.6	Determine RPT breaker arc suppression time.	In accordance with the Surveillance Frequency Control Program

3.3 INSTRUMENTATION

3.3.4.2 Anticipated Transient Without Scram Recirculation Pump Trip (ATWS-RPT) Instrumentation

LCO 3.3.4.2 Two channels per trip system for each ATWS-RPT instrumentation Function listed below shall be OPERABLE:

a. Reactor Vessel Water Level – Low Low, Level 2; and

b. Reactor Steam Dome Pressure – High.

APPLICABILITY: MODE 1.

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more channels inoperable.	A.1 Restore channel to OPERABLE status. OR	14 days OR -----------NOTE----------- Not applicable if there is a loss of function. ------------------------------ In accordance with the Risk Informed Completion Time Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. (continued)	A.2	---------------NOTE-------------- Not applicable if inoperable channel is the result of an inoperable breaker. ------------------------------------- Place channel in trip.	14 days <u>OR</u> -----------NOTE----------- Not applicable if there is a loss of function. ------------------------------ In accordance with the Risk Informed Completion Time Program
B. One Function with ATWS-RPT trip capability not maintained.	B.1	Restore ATWS-RPT trip capability.	72 hours
C. Both Functions with ATWS-RPT trip capability not maintained.	C.1	Restore ATWS-RPT trip capability for one Function.	1 hour
D. Required Action and associated Completion Time not met.	D.1 <u>OR</u> D.2	Remove the associated recirculation pump from service. Be in MODE 2.	6 hours 6 hours

SURVEILLANCE REQUIREMENTS

---NOTE---

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

SURVEILLANCE		FREQUENCY
SR 3.3.4.2.1	Perform CHANNEL CHECK of Reactor Vessel Water Level, Low Low, Level 2.	In accordance with the Surveillance Frequency Control Program
SR 3.3.4.2.2	------------------------------NOTE------------------------------ A test of all required contacts does not have to be performed. --- Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.4.2.3	Perform CHANNEL CALIBRATION of the Reactor Steam Dome Pressure – High. The Allowable Values shall be ≤ 1150 psig.	In accordance with the Surveillance Frequency Control Program
SR 3.3.4.2.4	Perform CHANNEL CALIBRATION of the Reactor Vessel Water Level Low Low, Level 2. The Allowable Values shall be ≥ -45 inches.	In accordance with the Surveillance Frequency Control Program
SR 3.3.4.2.5	Perform LOGIC SYSTEM FUNCTIONAL TEST including breaker actuation.	In accordance with the Surveillance Frequency Control Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. (continued)	B.2 -----------------NOTE-------------- Only applicable for Functions 3.a and 3.b. ---------------------------------------	
	Declare High Pressure Coolant Injection (HPCI) System inoperable.	1 hour from discovery of loss of HPCI initiation capability
	AND	
	B.3 Place channel in trip.	24 hours OR -----------NOTE----------- Not applicable if there is a loss of function. ------------------------------ In accordance with the Risk Informed Completion Time Program
C. As required by Required Action A.1 and referenced in Table 3.3.5.1-1.	C.1 ---------------NOTE---------------- Only applicable for Functions 1.d, 2.d, and 2.e. ---------------------------------------	
	Declare supported feature(s) inoperable when its redundant feature ECCS initiation capability is inoperable.	1 hour from discovery of loss of initiation capability for feature(s) in both divisions
	AND	

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. (continued)	C.2	Restore channel to OPERABLE status.	24 hours <u>OR</u> -----------NOTE----------- Not applicable if there is a loss of function. ----------------------------- In accordance with the Risk Informed Completion Time Program
D. As required by Required Action A.1 and referenced in Table 3.3.5.1-1.	D.1	----------------NOTE--------------- Only applicable if HPCI pump suction is not aligned to the suppression pool. -------------------------------------- Declare HPCI System inoperable.	1 hour from discovery of loss of HPCI initiation capability
	<u>AND</u>		
	D.2.1	Place channel in trip.	24 hours <u>OR</u> -----------NOTE----------- Not applicable if there is a loss of function. ----------------------------- In accordance with the Risk Informed Completion Time Program
		<u>OR</u>	

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
D. (continued)	D.2.2	Align the HPCI pump suction to the suppression pool.	24 hours
E. As required by Required Action A.1 and referenced in Table 3.3.5.1-1.	E.1	Declare Automatic Depressurization System (ADS) valves inoperable.	1 hour from discovery of loss of ADS initiation capability in both trip systems
	AND		
	E.2	Place channel in trip.	96 hours from discovery of inoperable channel concurrent with HPCI or reactor core isolation cooling (RCIC) inoperable OR -----------NOTE----------- Not applicable if there is a loss of function. ------------------------------ In accordance with the Risk Informed Completion Time Program AND

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. (continued)	E.2. (continued)	8 days <u>OR</u> -----------NOTE----------- Not applicable if there is a loss of function. ------------------------------ In accordance with the Risk Informed Completion Time Program
F. As required by Required Action A.1 and referenced in Table 3.3.5.1-1.	F.1 ---------------NOTE---------------- Only applicable for Functions 4.c, 4.e, 4.f, 4.g, 5.c, 5.e, 5.f, and 5.g. --------------------------------------- Declare ADS valves inoperable. <u>AND</u>	 1 hour from discovery of loss of ADS initiation capability in both trip systems

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
F. (continued)	F.2 Restore channel to OPERABLE status.	96 hours from discovery of inoperable channel concurrent with HPCI or RCIC inoperable OR -----------NOTE----------- Not applicable if there is a loss of function. ------------------------------ In accordance with the Risk Informed Completion Time Program AND 8 days OR -----------NOTE----------- Not applicable if there is a loss of function. ------------------------------ In accordance with the Risk Informed Completion Time Program
G. Required Action and associated Completion Time of Condition B, C, D, E, or F not met.	G.1 Declare associated supported feature(s) inoperable.	Immediately

SURVEILLANCE REQUIREMENTS

---NOTES---

1. Refer to Table 3.3.5.1-1 to determine which SRs apply for each ECCS 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 as follows: (a) for up to 6 hours for Functions 3.c and 3.e; and (b) for up to 6 hours for Functions other than 3.c and 3.e provided the associated Function or the redundant Function maintains ECCS initiation capability.

SURVEILLANCE		FREQUENCY
SR 3.3.5.1.1	Perform CHANNEL CHECK.	In accordance with the Surveillance Frequency Control Program
SR 3.3.5.1.2	-------------------------------NOTE------------------------------- A test of all required contacts does not have to be performed. --- Perform CHANNEL FUNCTIONAL TEST.	 In accordance with the Surveillance Frequency Control Program
SR 3.3.5.1.3	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program
SR 3.3.5.1.4	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program
SR 3.3.5.1.5	Perform LOGIC SYSTEM FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program

Table 3.3.5.1-1 (page 1 of 5)
Emergency Core Cooling System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER FUNCTION	CONDITIONS REFERENCED FROM REQUIRED ACTION A.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Core Spray System					
a. Reactor Vessel Water Level — Low Low Low, Level 1	1,2,3	4[(a)]	B	SR 3.3.5.1.1 SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.5	≥ -136 inches
b. Drywell Pressure — High	1,2,3	4[(a)]	B	SR 3.3.5.1.2 SR 3.3.5.1.3 SR 3.3.5.1.5	≤ 1.88 psig
c. Reactor Steam Dome Pressure — Low (initiation)	1,2,3	4	B	SR 3.3.5.1.2 SR 3.3.5.1.3 SR 3.3.5.1.5	≥ 407 psig (lower) ≤ 433 psig (upper)
d. Reactor Steam Dome Pressure — Low (injection permissive)	1,2,3	4	C	SR 3.3.5.1.2 SR 3.3.5.1.3 SR 3.3.5.1.5	≥ 407 psig (lower) ≤ 433 psig (upper)
e. Manual Initiation	1,2,3	2 1 per Subsystem	C	SR 3.3.5.1.5	NA

(a) Also required to initiate the associated diesel generator (DG), initiate Drywell Cooling Equipment Trip, and Emergency Service Water (ESW) Pump timer reset.

Table 3.3.5.1-1 (page 2 of 5)
Emergency Core Cooling System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER FUNCTION	CONDITIONS REFERENCED FROM REQUIRED ACTION A.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
2. Low Pressure Coolant Injection (LPCI) System					
a. Reactor Vessel Water Level — Low Low Low, Level 1	1,2,3	4[(b)]	B	SR 3.3.5.1.1 SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.5	≥ -136 inches
b. Drywell Pressure — High	1,2,3	4[(b)]	B	SR 3.3.5.1.2 SR 3.3.5.1.3 SR 3.3.5.1.5	≤ 1.88 psig
c. Reactor Steam Dome Pressure — Low (initiation)	1,2,3	4	B	SR 3.3.5.1.2 SR 3.3.5.1.3 SR 3.3.5.1.5	≥ 407 psig (lower) ≤ 433 psig (upper)
d. Reactor Steam Dome Pressure — Low (injection permissive)	1,2,3	4	C	SR 3.3.5.1.2 SR 3.3.5.1.3 SR 3.3.5.1.5	≥ 407 psig (lower) ≤ 433 psig (upper)
e. Reactor Steam Dome Pressure — Low (Recirculation Discharge Valve Permissive)	1[(c)], 2[(c)], 3[(c)]	4	C	SR 3.3.5.1.2 SR 3.3.5.1.3 SR 3.3.5.1.5	≥ 216 psig
f. Manual Initiation	1,2,3	2 1 per subsystem	C	SR 3.3.5.1.5	NA

(b) Also required to initiate the associated DGs, ESW pump timer reset and Turbine Building and Reactor Building Chiller trip.

(c) With either associated recirculation pump discharge or bypass valves open.

Table 3.3.5.1-1 (page 3 of 5)
Emergency Core Cooling System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER FUNCTION	CONDITIONS REFERENCED FROM REQUIRED ACTION A.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
3. High Pressure Coolant Injection (HPCI) System					
a. Reactor Vessel Water Level — Low Low, Level 2	1, $2^{(d)}$, $3^{(d)}$	4	B	SR 3.3.5.1.1 SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.5	≥ -45 inches
b. Drywell Pressure — High	1, $2^{(d)}$,$3^{(d)}$	4	B	SR 3.3.5.1.2 SR 3.3.5.1.3 SR 3.3.5.1.5	≤ 1.88 psig
c. Reactor Vessel Water Level — High, Level 8	1, $2^{(d)}$, $3^{(d)}$	2	C	SR 3.3.5.1.2 SR 3.3.5.1.3 SR 3.3.5.1.5	≤ 55.5 inches
d. Condensate Storage Tank Level — Low	1, $2^{(d)}$, $3^{(d)}$	2	D	SR 3.3.5.1.2 SR 3.3.5.1.3 SR 3.3.5.1.5	≥ 40.5 inches above tank bottom
e. Manual Initiation	1, $2^{(d)}$, $3^{(d)}$	1	C	SR 3.3.5.1.5	NA

(d) With reactor steam dome pressure > 150 psig.

Table 3.3.5.1-1 (page 4 of 5)
Emergency Core Cooling System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER FUNCTION	CONDITIONS REFERENCED FROM REQUIRED ACTION A.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
4. Automatic Depressurization System (ADS) Trip System A					
a. Reactor Vessel Water Level — Low Low Low, Level 1	1, $2^{(d)}$, $3^{(d)}$	2	E	SR 3.3.5.1.1 SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.5	≥ -136 inches
b. Drywell Pressure — High	1, $2^{(d)}$, $3^{(d)}$	2	E	SR 3.3.5.1.2 SR 3.3.5.1.3 SR 3.3.5.1.5	≤ 1.88 psig
c. Automatic Depressurization System Initiation Timer	1, $2^{(d)}$, $3^{(d)}$	1	F	SR 3.3.5.1.2 SR 3.3.5.1.3 SR 3.3.5.1.5	≤ 114 seconds
d. Reactor Vessel Water Level — Low, Level 3 (Confirmatory)	1, $2^{(d)}$, $3^{(d)}$	1	E	SR 3.3.5.1.1 SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.5	≥ 11.5 inches
e. Core Spray Pump Discharge Pressure — High	1, $2^{(d)}$, $3^{(d)}$	2	F	SR 3.3.5.1.2 SR 3.3.5.1.3 SR 3.3.5.1.5	≥ 125 psig and ≤ 165 psig
f. Low Pressure Coolant Injection Pump Discharge Pressure — High	1, $2^{(d)}$, $3^{(d)}$	4	F	SR 3.3.5.1.2 SR 3.3.5.1.3 SR 3.3.5.1.5	≥ 115 psig and ≤ 135 psig
g. Automatic Depressurization System Drywell Pressure Bypass Actuation Timer	1, $2^{(d)}$, $3^{(d)}$	2	F	SR 3.3.5.1.2 SR 3.3.5.1.3 SR 3.3.5.1.5	≤ 450 sec
h. Manual Initiation	1, $2^{(d)}$, $3^{(d)}$	2	F	SR 3.3.5.1.5	NA

(d) With reactor steam dome pressure > 150 psig.

Table 3.3.5.1-1 (page 5 of 5)
Emergency Core Cooling System Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER FUNCTION	CONDITIONS REFERENCED FROM REQUIRED ACTION A.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
5. ADS Trip System B					
a. Reactor Vessel Water Level — Low Low Low, Level 1	1, $2^{(d)}$, $3^{(d)}$	2	E	SR 3.3.5.1.1 SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.5	≥ -136 inches
b. Drywell Pressure — High	1, $2^{(d)}$, $3^{(d)}$	2	E	SR 3.3.5.1.2 SR 3.3.5.1.3 SR 3.3.5.1.5	≤ 1.88 psig
c. Automatic Depressurization System Initiation Timer	1, $2^{(d)}$, $3^{(d)}$	1	F	SR 3.3.5.1.2 SR 3.3.5.1.3 SR 3.3.5.1.5	≤ 114 sec
d. Reactor Vessel Water Level — Low, Level 3 (Confirmatory)	1, $2^{(d)}$, $3^{(d)}$	1	E	SR 3.3.5.1.1 SR 3.3.5.1.2 SR 3.3.5.1.4 SR 3.3.5.1.5	≥ 11.5 inches
e. Core Spray Pump Discharge Pressure — High	1, $2^{(d)}$, $3^{(d)}$	2	F	SR 3.3.5.1.2 SR 3.3.5.1.3 SR 3.3.5.1.5	≥ 125 psig and ≤ 165 psig
f. Low Pressure Coolant Injection Pump Discharge Pressure — High	1, $2^{(d)}$, $3^{(d)}$	4	F	SR 3.3.5.1.2 SR 3.3.5.1.3 SR 3.3.5.1.5	≥ 115 psig and ≤ 135 psig
g. Automatic Depressurization System Drywell Pressure Bypass Actuation Timer	1, $2^{(d)}$, $3^{(d)}$	2	F	SR 3.3.5.1.2 SR 3.3.5.1.3 SR 3.3.5.1.5	≤ 450 sec
h. Manual Initiation	1, $2^{(d)}$, $3^{(d)}$	2	F	SR 3.3.5.1.5	NA

(d) With reactor steam dome pressure > 150 psig.

3.3 INSTRUMENTATION

3.3.5.3 Reactor Core Isolation Cooling (RCIC) System Instrumentation

LCO 3.3.5.3 The RCIC System instrumentation for each Function in Table 3.3.5.3-1 shall be OPERABLE.

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

ACTIONS

--NOTE--

Separate Condition entry is allowed for each channel.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more channels inoperable.	A.1 Enter the Condition referenced in Table 3.3.5.3-1 for the channel.	Immediately

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. As required by Required Action A.1 and referenced in Table 3.3.5.3-1.	B.1	Declare RCIC System inoperable.	1 hour from discovery of loss of RCIC initiation capability
	AND		
	B.2	Place channel in trip.	24 hours OR -----------NOTE----------- Not applicable if there is a loss of function. ------------------------------ In accordance with the Risk Informed Completion Time Program
C. As required by Required Action A.1 and referenced in Table 3.3.5.3-1.	C.1	Restore channel to OPERABLE status.	24 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
D. As required by Required Action A.1 and referenced in Table 3.3.5.3-1.	D.1	---------------NOTE-------------- Only applicable if RCIC pump suction is not aligned to the suppression pool. -------------------------------------	
		Declare RCIC System inoperable.	1 hour from discovery of loss of RCIC initiation capability
	<u>AND</u>		
	D.2.1	Place channel in trip.	24 hours <u>OR</u> -----------NOTE----------- Not applicable if there is a loss of function. ----------------------------- In accordance with the Risk Informed Completion Time Program
		<u>OR</u>	
	D.2.2	Align RCIC pump suction to the suppression pool.	24 hours
E. Required Action and associated Completion Time of Condition B, C, or D not met.	E.1	Declare RCIC System inoperable.	Immediately

SURVEILLANCE REQUIREMENTS

---NOTES---

1. Refer to Table 3.3.5.3-1 to determine which SRs apply for each RCIC 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 as follows: (a) for up to 6 hours for Functions 2 and 4 and (b) for up to 6 hours for Functions other than Functions 2 and 4 provided the associated Function maintains RCIC initiation capability.

SURVEILLANCE		FREQUENCY
SR 3.3.5.3.1	Perform CHANNEL CHECK.	In accordance with the Surveillance Frequency Control Program
SR 3.3.5.3.2	-------------------------------NOTE------------------------------- A test of all required contacts does not have to be performed. --- Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.5.3.3	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program
SR 3.3.5.3.4	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program
SR 3.3.5.3.5	Perform LOGIC SYSTEM FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program

Table 3.3.5.3-1 (page 1 of 1)
Reactor Core Isolation System Instrumentation

FUNCTION	REQUIRED CHANNELS PER FUNCTION	CONDITIONS REFERENCED FROM REQUIRED ACTION A.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Reactor Vessel Water Level – Low Low, Level 2	4	B	SR 3.3.5.3.1 SR 3.3.5.3.2 SR 3.3.5.3.4 SR 3.3.5.3.5	≥ -45 inches
2. Reactor Vessel Water Level – High Level 8	2	C	SR 3.3.5.3.1 SR 3.3.5.3.2 SR 3.3.5.3.3 SR 3.3.5.3.5	≤ 55.5 inches
3. Condensate Storage Tank Level – Low	2	D	SR 3.3.5.3.2 SR 3.3.5.3.3 SR 3.3.5.3.5	≥ 36.0 inches above the tank bottom
4. Manual Initiation	1	C	SR 3.3.5.3.5	NA

3.3 INSTRUMENTATION

3.3.6.1 Primary Containment Isolation Instrumentation

LCO 3.3.6.1 The primary containment isolation instrumentation for each Function in Table 3.3.6.1-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.6.1-1.

ACTIONS

---NOTES---

1. Penetration flow paths may be unisolated intermittently under administrative controls.

2. Separate Condition entry is allowed for each channel.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required channels inoperable.	A.1 Place channel in trip.	12 hours for Functions 2.a, 2.d, 6.b, 7.a, and 7.b <u>OR</u> -----------NOTE----------- Not applicable if there is a loss of function. ----------------------------- In accordance with the Risk Informed Completion Time Program <u>AND</u>

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. (continued)	A.1.	(continued)	24 hours for Functions other than Functions 2.a, 2.d, 6.b, 7.a, and 7.b <u>OR</u> -----------NOTE----------- Not applicable if there is a loss of function. ------------------------------ In accordance with the Risk Informed Completion Time Program
B. One or more automatic Functions with isolation capability not maintained.	B.1	Restore isolation capability.	1 hour
C. Required Action and associated Completion Time of Condition A or B not met.	C.1	Enter the Condition referenced in Table 3.3.6.1-1 for the channel.	Immediately
D. As required by Required Action C.1 and referenced in Table 3.3.6.1-1.	D.1	Isolate associated main steam line (MSL).	12 hours
	<u>OR</u>		
	D.2.1	Be in MODE 3.	12 hours
		<u>AND</u>	
	D.2.2	Be in MODE 4.	36 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. As required by Required Action C.1 and referenced in Table 3.3.6.1-1.	E.1 Be in MODE 2.	6 hours
F. As required by Required Action C.1 and referenced in Table 3.3.6.1-1.	F.1 Isolate the affected penetration flow path(s).	1 hour
G. As required by Required Action C.1 and referenced in Table 3.3.6.1-1.	G.1 Isolate the affected penetration flow path(s).	24 hours
H. As required by Required Action C.1 and referenced in Table 3.3.6.1-1. <u>OR</u> Required Action and associated Completion Time for Condition F or G not met.	H.1 Be in MODE 3. <u>AND</u> H.2 Be in MODE 4.	12 hours 36 hours
I. As required by Required Action C.1 and referenced in Table 3.3.6.1-1.	I.1 Declare associated standby liquid control subsystem (SLC) inoperable. <u>OR</u> I.2 Isolate the Reactor Water Cleanup System.	1 hour 1 hour

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
J. As required by Required Action C.1 and referenced in Table 3.3.6.1-1.	J.1 Initiate action to restore channel to OPERABLE status.	Immediately

SURVEILLANCE REQUIREMENTS

---NOTES---

1. Refer to Table 3.3.6.1-1 to determine which SRs apply for each Primary Containment Isolation 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 isolation capability.

SURVEILLANCE		FREQUENCY
SR 3.3.6.1.1	Perform CHANNEL CHECK.	In accordance with the Surveillance Frequency Control Program
SR 3.3.6.1.2	-------------------------------NOTES------------------------------ 1. A test of all required contacts does not have to be performed. 2. For Functions 2.e, 3.a, and 4.a, a test of all required relays does not have to be performed. --- Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.6.1.3	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program
SR 3.3.6.1.4	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program
SR 3.3.6.1.5	Perform LOGIC SYSTEM FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.6.1.6	------------------------------NOTES------------------------------ 1. For Function 1.b, channel sensors are excluded. 2. Response time testing of isolating relays is not required for Function 5.a. --- Verify the ISOLATION SYSTEM RESPONSE TIME is within limits.	In accordance with the Surveillance Frequency Control Program

Table 3.3.6.1-1 (page 6 of 6)
Primary Containment Isolation Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION C.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
6. Shutdown Cooling System Isolation					
a. Reactor Steam Dome Pressure – High	1,2,3	1	F	SR 3.3.6.1.2 SR 3.3.6.1.3 SR 3.3.6.1.5	≤ 108 psig
b. Reactor Vessel Water Level – Low, Level 3	3	2	J	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.3 SR 3.3.6.1.5	≥ 11.5 inches
c. Manual Initiation	3	1	G	SR 3.3.6.1.5	NA
7. Traversing Incore Probe Isolation					
a. Reactor Vessel Water Level – Low, Level 3	1,2,3	2	G	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.3 SR 3.3.6.1.5	≥ 11.5 inches
b. Drywell Pressure – High	1,2,3	2	G	SR 3.3.6.1.2 SR 3.3.6.1.4 SR 3.3.6.1.5	≤ 1.88 psig

3.3 INSTRUMENTATION

3.3.8.1 Loss of Power (LOP) Instrumentation

LCO 3.3.8.1 The LOP instrumentation for each Function in Table 3.3.8.1-1 shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

--NOTE--

Separate Condition entry is allowed for each channel.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required channels inoperable.	A.1 Enter the Condition referenced in Table 3.3.8.1-1 for the channel.	Immediately
B. As required by Required Action A.1 and referenced in Table 3.3.8.1-1.	B.1 Place channel in trip.	1 hour <u>OR</u> -----------NOTE----------- Not applicable if there is a loss of function. ------------------------------ In accordance with the Risk Informed Completion Time Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. As required by Required Action A.1 and referenced in Table 3.3.8.1-1.	C.1	Restore the inoperable Channel.	1 hour <u>OR</u> -----------NOTE----------- Not applicable if there is a loss of function. ------------------------------ In accordance with the Risk Informed Completion Time Program
D. Required Action and associated Completion Time of Condition B or C not met.	D.1	Declare associated diesel generator (DG) inoperable.	Immediately

SURVEILLANCE REQUIREMENTS

-----NOTES-----

1. Refer to Table 3.3.8.1-1 to determine which SRs apply for each LOP 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 DG initiation capability.

SURVEILLANCE		FREQUENCY
SR 3.3.8.1.1	Perform CHANNEL CHECK.	In accordance with the Surveillance Frequency Control Program
SR 3.3.8.1.2	Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.8.1.3	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program
SR 3.3.8.1.4	Perform LOGIC SYSTEM FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program

Table 3.3.8.1-1 (page 1 of 1)
Loss of Power Instrumentation

FUNCTION	REQUIRED CHANNELS PER BUS	CONDITIONS REFERENCED FROM REQUIRED ACTION A.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. 4.16 kV Emergency Bus Undervoltage (Loss of Voltage < 20%)				
a. Bus Undervoltage	1	C	SR 3.3.8.1.3 SR 3.3.8.1.4	≥ 780.4 V and ≤ 899.6 V
b. Time Delay	1	C	SR 3.3.8.1.3 SR 3.3.8.1.4	≥ 0.4 sec and ≤ 0.6 sec
2. 4.16 kV Emergency Bus Undervoltage Low Setting (Degraded Voltage 65%)				
a. Bus Undervoltage	2	B	SR 3.3.8.1.1 SR 3.3.8.1.2 SR 3.3.8.1.3 SR 3.3.8.1.4	≥ 2503 V and ≤ 2886 V
b. Time Delay	1	C	SR 3.3.8.1.2 SR 3.3.8.1.3 SR 3.3.8.1.4	≥ 2.7 sec and ≤ 3.3 sec
3. 4.16 kV Emergency Bus Undervoltage LOCA (Degraded Voltage 93%)				
a. Bus Undervoltage	2	B	SR 3.3.8.1.1 SR 3.3.8.1.2 SR 3.3.8.1.3 SR 3.3.8.1.4	≥ 3801 V and ≤ 3935 V
b. Time Delay (LOCA)	1	C	SR 3.3.8.1.3 SR 3.3.8.1.4	≥ 9 sec and ≤ 11 sec
c. Time Delay (Non-LOCA)	1	C	SR 3.3.8.1.2 SR 3.3.8.1.3 SR 3.3.8.1.4	≥ 4 min 30 sec and ≤ 5 min 30 sec

3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS), REACTOR PRESSURE VESSEL (RPV) WATER INVENTORY CONTROL, AND REACTOR CORE ISOLATION COOLING (RCIC) SYSTEM

3.5.1 ECCS – Operating

LCO 3.5.1 Each ECCS injection/spray subsystem and the Automatic Depressurization System (ADS) function of six safety/relief valves shall be OPERABLE.

APPLICABILITY: MODE 1,
MODES 2 and 3, except high pressure coolant injection (HPCI) and ADS valves are not required to be OPERABLE with reactor steam dome pressure ≤ 150 psig.

ACTIONS

--NOTE--

LCO 3.0.4.b is not applicable to HPCI.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One low pressure ECCS injection/spray subsystem inoperable for reasons other than Condition B.	A.1 Restore low pressure ECCS injection/spray subsystem to OPERABLE status.	7 days <u>OR</u> In accordance with the Risk Informed Completion Time Program
B. One LPCI pump in one or both LPCI subsystems inoperable.	B.1 Restore LPCI pump(s) to OPERABLE status.	7 days <u>OR</u> In accordance with the Risk Informed Completion Time Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. Required Action and associated Completion Time of Condition A or Condition B not met.	C.1	Be in MODE 3.	12 hours
	AND		
	C.2	Be in MODE 4.	36 hours
D. HPCI System inoperable.	D.1	Verify by administrative means RCIC System is OPERABLE.	Immediately
	AND		
	D.2	Restore HPCI System to OPERABLE status.	14 days OR In accordance with the Risk Informed Completion Time Program
E. HPCI System inoperable. AND Condition A or Condition B entered.	E.1	Restore HPCI System to OPERABLE status.	72 hours OR In accordance with the Risk Informed Completion Time Program
	OR		
	E.2	Restore low pressure ECCS injection/spray subsystem to OPERABLE status.	72 hours OR In accordance with the Risk Informed Completion Time Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
F. One ADS valve inoperable.	F.1	Restore ADS valve to OPERABLE status.	14 days OR In accordance with the Risk Informed Completion Time Program
G. One ADS valve inoperable. AND Condition A or Condition B entered.	G.1	Restore ADS valve to OPERABLE status.	72 hours OR In accordance with the Risk Informed Completion Time Program
	OR		
	G.2	Restore low pressure ECCS injection/spray subsystem to OPERABLE status.	72 hours OR In accordance with the Risk Informed Completion Time Program
H. Two or more ADS valves inoperable. OR Required Action and associated Completion Time of Condition D, E, F, or G not met.	H.1	Be in MODE 3.	12 hours
	AND		
	H.2	Reduce reactor steam dome pressure to ≤ 150 psig.	36 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
I. Two Core Spray subsystems inoperable. <u>OR</u> One LPCI subsystem inoperable for reasons other than Condition B and One Core Spray subsystem inoperable. <u>OR</u> Two LPCI subsystems inoperable for reasons other than Condition B. <u>OR</u> HPCI System and one or more ADS valves inoperable.	I.1 Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.1.1	Verify, for each ECCS injection/spray subsystem, the piping is filled with water from the pump discharge valve to the injection valve.	In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.5.1.2	-------------------------------NOTE------------------------------- Low pressure coolant injection (LPCI) subsystems may be considered OPERABLE during alignment and operation for decay heat removal with reactor steam dome pressure less than the Residual Heat Removal (RHR) cut in permissive pressure in MODE 3, if capable of being manually realigned and not otherwise inoperable. -- Verify each ECCS injection/spray subsystem manual, power operated, and automatic valve in the flow path, that is not locked, sealed, or otherwise secured in position, and the HPCI flow controller are in the correct position.	In accordance with the Surveillance Frequency Control Program
SR 3.5.1.3	Verify ADS gas supply header pressure is ≥ 135 psig.	In accordance with the Surveillance Frequency Control Program
SR 3.5.1.4	Verify at least one RHR System cross tie valve is closed and power is removed from the valve operator.	In accordance with the Surveillance Frequency Control Program
SR 3.5.1.5	Verify each 480 volt AC swing bus transfers automatically from the normal source to the alternate source on loss of power.	In accordance with the Surveillance Frequency Control Program
SR 3.5.1.6	-------------------------------NOTE------------------------------- Not required to be performed if performed within the previous 31 days. -- Verify each recirculation pump discharge valve and bypass valve cycles through one complete cycle of full travel or is de-energized in the closed position.	Once each startup prior to exceeding 25% RTP

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.5.1.7	Verify the following ECCS pumps develop the specified flow rate against a system head corresponding to the specified reactor pressure. SYSTEM / FLOW RATE / NO. OF PUMPS / SYSTEM HEAD CORRESPONDING TO A REACTOR PRESSURE OF Core Spray / ≥ 6350 gpm / 2 / ≥ 105 psig LPCI / ≥ 12,200 gpm / 1 / ≥ 20 psig	In accordance with the Inservice Testing Program
SR 3.5.1.8	------------------------------NOTE------------------------------ Not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. --- Verify, with reactor pressure ≤ 1060 and ≥ 920 psig, the HPCI pump can develop a flow rate ≥ 5000 gpm against a system head corresponding to reactor pressure.	In accordance with the Inservice Testing Program
SR 3.5.1.9	------------------------------NOTE------------------------------ Not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. --- Verify, with reactor pressure ≤ 165 psig, the HPCI pump can develop a flow rate ≥ 5000 gpm against a system head corresponding to reactor pressure.	In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.5.1.10	------------------------------NOTE------------------------------ Vessel injection/spray may be excluded. -- Verify each ECCS injection/spray subsystem actuates on an actual or simulated automatic initiation signal.	In accordance with the Surveillance Frequency Control Program
SR 3.5.1.11	------------------------------NOTE------------------------------ Valve actuation may be excluded. -- Verify the ADS actuates on an actual or simulated automatic initiation signal.	In accordance with the Surveillance Frequency Control Program
SR 3.5.1.12	Verify each ADS valve actuator strokes when manually actuated.	In accordance with the Surveillance Frequency Control Program
SR 3.5.1.13	------------------------------NOTE------------------------------ Instrumentation response time is based on historical response time data. -- Verify the ECCS RESPONSE TIME for each ECCS injection/spray subsystem is within limit.	In accordance with the Surveillance Frequency Control Program

3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS), REACTOR PRESSURE VESSEL (RPV) WATER INVENTORY CONTROL, AND REACTOR CORE ISOLATION COOLING (RCIC) SYSTEM

3.5.3 RCIC System

LCO 3.5.3 The RCIC System shall be OPERABLE.

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

ACTIONS

---NOTE---

LCO 3.0.4.b is not applicable to RCIC.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. RCIC System inoperable.	A.1 Verify by administrative means High Pressure Coolant Injection System is OPERABLE.	Immediately
	<u>AND</u>	
	A.2 Restore RCIC System to OPERABLE status.	14 days <u>OR</u> In accordance with the Risk Informed Completion Time Program
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	12 hours
	<u>AND</u>	
	B.2 Reduce reactor steam dome pressure to ≤ 150 psig.	36 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. (continued)	B.2	Lock an OPERABLE door closed.	24 hours
	AND		
	B.3	---------------NOTE---------------- Air lock doors in high radiation areas or areas with limited access due to inerting may be verified locked closed by administrative means. --------------------------------------	
		Verify an OPERABLE door is locked closed.	Once per 31 days
C. Primary containment air lock inoperable for reasons other than Condition A or B.	C.1	Initiate action to evaluate primary containment overall leakage rate per LCO 3.6.1.1, using current air lock test results.	Immediately
	AND		
	C.2	Verify a door is closed.	1 hour
	AND		
	C.3	Restore air lock to OPERABLE status.	24 hours OR In accordance with the Risk Informed Completion Time Program

3.6 CONTAINMENT SYSTEMS

3.6.1.3 Primary Containment Isolation Valves (PCIVs)

LCO 3.6.1.3 Each PCIV shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

---NOTES---

1. Penetration flow paths may be unisolated intermittently under administrative controls.

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

3. Enter applicable Conditions and Required Actions for systems made inoperable by PCIVs.

4. Enter applicable Conditions and Required Actions of LCO 3.6.1.1, "Primary Containment," when PCIV leakage results in exceeding overall containment leakage rate acceptance criteria in MODES 1, 2, and 3.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. ------------NOTE-------------- Only applicable to penetration flow paths with two PCIVs except for the H_2O_2 Analyzer penetrations. ---------------------------------- One or more penetration flow paths with one PCIV inoperable except for purge valve leakage not within limit.	A.1 Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, blind flange, or check valve with flow through the valve secured.	4 hours except for main steam line <u>OR</u> In accordance with the Risk Informed Completion Time Program <u>AND</u>

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.1 (continued)	8 hours for main steam line OR In accordance with the Risk Informed Completion Time Program
	AND	
	A.2 ---------------NOTE--------------- Isolation devices in high radiation areas may be verified by use of administrative means. ------------------------------------- Verify the affected penetration flow path is isolated.	Once per 31 days following isolation for isolation devices outside primary containment AND Prior to entering MODE 2 or 3 from MODE 4, if primary containment was de-inerted while in MODE 4, if not performed within the previous 92 days, for isolation devices inside primary containment

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. ------------NOTE-------------- Only applicable to penetration flow paths with two PCIVs except for the H_2O_2 Analyzer penetrations. --------------------------------- One or more penetration flow paths with two PCIVs inoperable except for purge valve leakage not within limit.	B.1	Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, or blind flange.	1 hour
C. -------------NOTE------------- Only applicable to penetration flow paths with only one PCIV. --------------------------------- One or more penetration flow paths with one PCIV inoperable.	C.1	Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, or blind flange.	72 hours except for excess flow check valves (EFCVs) AND 12 hours for EFCVs
	AND		
	C.2	---------------NOTE--------------- Isolation devices in high radiation areas may be verified by use of administrative means. ------------------------------------- Verify the affected penetration flow path is isolated.	Once per 31 days following isolation

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
D. -------------NOTE------------- Only applicable to the H_2O_2 Analyzer penetrations. ---------------------------------- One or more H_2O_2 Analyzer penetrations with one or two PCIVs inoperable.	D.1	Isolate the affected penetration flow path by the use of at least one closed and de-activated automatic valve, closed manual valve, or blind flange.	72 hours
	<u>AND</u>		
	D.2	Verify the affected penetration flow path is isolated.	Once per 31 days following isolation
E. Secondary containment bypass leakage rate not within limit.	E.1	Restore leakage rate to within limit.	4 hours
F. One or more penetration flow paths with one or more containment purge valves not within purge valve leakage limit.	F.1	Restore the valve leakage to within valve leakage limit.	24 hours
G. Required Action and associated Completion Time of Condition A, B, C, D, E, or F not met.	G.1	Be in MODE 3.	12 hours
	<u>AND</u>		
	G.2	Be in MODE 4.	36 hours

3.6 CONTAINMENT SYSTEMS

3.6.1.6 Suppression Chamber-to-Drywell Vacuum Breakers

LCO 3.6.1.6 Five suppression chamber-to-drywell vacuum breaker pairs shall be OPERABLE and closed, except when performing their intended function.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One suppression chamber-to-drywell vacuum breaker pair inoperable for opening.	A.1 Restore the vacuum breaker pair to OPERABLE status.	72 hours OR In accordance with the Risk Informed Completion Time Program
B. One suppression chamber-to-drywell vacuum breaker not closed.	B.1 Verify the other vacuum breaker in the pair is closed. AND B.2 Close the open vacuum breaker.	2 hours 72 hours
C. Both Suppression Chamber-to-Drywell vacuum breakers in one vacuum breaker pair not closed.	C.1 Close one open vacuum breaker in the affected vacuum breaker pair.	2 hours

3.6 CONTAINMENT SYSTEMS

3.6.2.3 Residual Heat Removal (RHR) Suppression Pool Cooling

LCO 3.6.2.3 Two RHR suppression pool cooling subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One RHR suppression pool cooling subsystem inoperable.	A.1 Restore RHR suppression pool cooling subsystem to OPERABLE status.	7 days <u>OR</u> In accordance with the Risk Informed Completion Time Program
B. Two RHR suppression pool cooling subsystems inoperable.	B.1 Restore one RHR suppression pool cooling subsystem to OPERABLE status.	8 hours
C. Required Action and associated Completion Time not met.	C.1 Be in MODE 3. <u>AND</u> C.2 Be in MODE 4.	12 hours 36 hours

3.6 CONTAINMENT SYSTEMS

3.6.2.4 Residual Heat Removal (RHR) Suppression Pool Spray

LCO 3.6.2.4 Two RHR suppression pool spray subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One RHR suppression pool spray subsystem inoperable.	A.1 Restore RHR suppression pool spray subsystem to OPERABLE status.	7 days OR In accordance with the Risk Informed Completion Time Program
B. Two RHR suppression pool spray subsystems inoperable.	B.1 Restore one RHR suppression pool spray subsystem to OPERABLE status.	8 hours
C. Required Action and associated Completion Time not met.	C.1 Be in MODE 3. AND C.2 Be in MODE 4.	12 hours 36 hours

3.7 PLANT SYSTEMS

3.7.1 Residual Heat Removal Service Water (RHRSW) System and the Ultimate Heat Sink (UHS)

LCO 3.7.1 Two RHRSW subsystems and the UHS shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

---NOTE---

Enter applicable Conditions and Required Actions of LCO 3.4.8, "Residual Heat Removal (RHR) Shutdown Cooling System-Hot Shutdown," for RHR shutdown cooling made inoperable by RHRSW System.

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. --------------NOTE------------ Separate Condition entry is allowed for each valve. --------------------------------- One valve in Table 3.7.1-1 inoperable. <u>OR</u> One valve in Table 3.7.1-2 inoperable. <u>OR</u> One valve in Table 3.7.1-3 inoperable. <u>OR</u>	A.1	Declare the associated RHRSW subsystems inoperable	Immediately
	<u>AND</u>		
	A.2	Establish an open flow path to the UHS.	8 hours
	<u>AND</u>		
	A.3	Restore the inoperable valve(s) to OPERABLE status.	8 hours from the discovery of an inoperable RHRSW subsystem in the opposite loop from the inoperable valve(s) <u>AND</u>

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
Any combination of valves in Table 3.7.1-1, Table 3.7.1-2, or Table 3.7.1-3 in the same return loop inoperable.	A.3	(continued)	72 hours OR In accordance with the Risk Informed Completion Time Program
B. One Unit 1 RHRSW subsystem inoperable.	B.1 OR	Restore the Unit 1 RHRSW subsystem to OPERABLE status.	72 hours from discovery of the associated Unit 2 RHRSW subsystem inoperable OR In accordance with the Risk Informed Completion Time Program AND 7 days OR In accordance with the Risk Informed Completion Time Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. (continued)	--------------------NOTE-------------------- The Risk Informed Completion Time Program cannot be applied if the temporary 14-day Completion Time is in effect. --	
	B.2 Restore the Unit 1 RHRSW subsystem to OPERABLE status.	14 days during the replacement of the Unit 2 ESW piping[1]
C. Both Unit 1 RHRSW subsystems inoperable.	C.1 Restore one Unit 1 RHRSW subsystem to OPERABLE status.	8 hours from discovery of one Unit 2 RHRSW subsystem not capable of supporting associated Unit 1 RHRSW subsystem <u>AND</u> 72 hours
D. Required Action and associated Completion Time not met. <u>OR</u> UHS inoperable.	D.1 Be in MODE 3. <u>AND</u> D.2 Be in MODE 4.	12 hours 36 hours

[1]This Completion Time is only applicable during the Unit 2 'A' and 'B' ESW piping replacement while the compensatory measures identified in Enclosure 2 to letter PLA-7830 are in place. Upon completion of pipe replacement activities, this temporary extension is no longer applicable and will expire on June 25, 2027.

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.1.1	Verify the water level is greater than or equal to 678 feet 1 inch above Mean Sea Level.	In accordance with the Surveillance Frequency Control Program
SR 3.7.1.2	Verify the average water temperature of the UHS is: a. -----------------------------NOTE----------------------------- Only applicable with both units in MODE 1 or 2, or with either unit in MODE 3 for less than twelve (12) hours. -- ≤ 85°F; or b. -----------------------------NOTE----------------------------- Only applicable when either unit has been in MODE 3 for at least twelve (12) hours but not more than twenty-four (24) hours. -- ≤ 87°F; or c. -----------------------------NOTE----------------------------- Only applicable when either unit has been in MODE 3 for at least twenty-four (24) hours. -- ≤ 88°F.	In accordance with the Surveillance Frequency Control Program
SR 3.7.1.3	Verify each RHRSW manual, power operated, and automatic valve in the flow path, that is not locked, sealed, or otherwise secured in position, is in the correct position or can be aligned to the correct position.	In accordance with the Surveillance Frequency Control Program
SR 3.7.1.4	Verify that valves HV-01222A and B (the spray array bypass valves) close upon receipt of a closing signal and open upon receipt of an opening signal.	In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.7.1.5	Verify that valves HV-01224A1 and B1 (the large spray array valves) close upon receipt of a closing signal and open upon receipt of an opening signal.	In accordance with the Surveillance Frequency Control Program
SR 3.7.1.6	Verify that valves HV-01224A2 and B2 (the small spray array valves) close upon receipt of a closing signal and open upon receipt of an opening signal.	In accordance with the Surveillance Frequency Control Program
SR 3.7.1.7	Verify that valves 012287A and 012287B (the spray array bypass manual valves) are capable of being opened and closed.	In accordance with the Surveillance Frequency Control Program

TABLE 3.7.1-1

Ultimate Heat Sink Spray Array Valves

VALVE NUMBER	VALVE DESCRIPTION
HV-01224A1	Loop A large spray array valve
HV-01224B1	Loop B large spray array valve
HV-01224A2	Loop A small spray array valve
HV-01224B2	Loop B small spray array valve

TABLE 3.7.1-2

Ultimate Heat Sink Spray Array Bypass Valves

VALVE NUMBER	VALVE DESCRIPTION
HV-01222A	Loop A spray array bypass valve
HV-01222B	Loop B spray array bypass valve

TABLE 3.7.1-3

Ultimate Heat Sink Spray Array Bypass Manual Valves

VALVE NUMBER	VALVE DESCRIPTION
012287A	Loop A spray array bypass manual valve
012287B	Loop B spray array bypass manual valve

3.7 PLANT SYSTEMS

3.7.2 Emergency Service Water (ESW) System

LCO 3.7.2 Two ESW subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

---NOTE---

Enter applicable Conditions and Required Actions of LCO 3.8.1, “AC Sources – Operating,” for DGs made inoperable by ESW.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One ESW pump in each subsystem inoperable.	A.1 Restore both ESW pumps to OPERABLE status.	7 days <u>OR</u> In accordance with the Risk Informed Completion Time Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One or two ESW subsystems not capable of supplying ESW flow to at least three required DGs.	B.1 Restore ESW flow to the required DGs to ensure that each ESW subsystem is supplying at least three DGs.	7 days OR -----------NOTE----------- Not applicable if there is a loss of function. ------------------------------ In accordance with the Risk Informed Completion Time Program
	OR --------------------NOTE-------------------- The Risk Informed Completion Time Program cannot be applied if the temporary 14-day Completion Time is in effect. --	
	B.2 Restore ESW flow to the required DGs to ensure that each ESW subsystem is supplying at least three DGs.	14 days during the replacement of the Unit 2 ESW piping[(1)]

[(1)] This Completion Time is only applicable during the Unit 2 ‘A’ and ‘B’ ESW piping replacement while the compensatory measures identified in Enclosure 2 to letter PLA-7830 are in place. Upon completion of pipe replacement activities, this temporary extension is no longer applicable and will expire on June 25, 2027.

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One ESW subsystem inoperable for reasons other than Condition B.	C.1 Restore the ESW subsystem to OPERABLE status.	7 days OR In accordance with the Risk Informed Completion Time Program
	OR --------------------NOTE-------------------- The Risk Informed Completion Time Program cannot be applied if the temporary 14-day Completion Time is in effect. ---	
	C.2 Restore the ESW subsystem to OPERABLE status.	14 days during the replacement of the Unit 2 ESW piping[1]
D. Required Action and associated Completion Time of Condition A, B, or C not met. OR Both ESW subsystems inoperable for reasons other than Conditions A and B.	D.1 Be in MODE 3. AND D.2 Be in MODE 4.	12 hours 36 hours

[1] This Completion Time is only applicable during the Unit 2 ‘A’ and ‘B’ ESW piping replacement while the compensatory measures identified in Enclosure 2 to letter PLA-7830 are in place. Upon completion of pipe replacement activities, this temporary extension is no longer applicable and will expire on June 25, 2027.

SURVEILLANCE REQUIREMENTS

	SURVEILLANCE	FREQUENCY
SR 3.7.2.1	-------------------------------NOTE------------------------------- Isolation of flow to individual components does not render ESW System inoperable. --- Verify each ESW subsystem manual, power operated, and automatic valve in the flow paths servicing safety related systems or components, that is not locked, sealed, or otherwise secured in position, is in the correct position.	In accordance with the Surveillance Frequency Control Program
SR 3.7.2.2	Verify each ESW subsystem actuates on an actual or simulated initiation signal.	In accordance with the Surveillance Frequency Control Program

3.8 ELECTRICAL POWER SYSTEMS

3.8.1 AC Sources - Operating

LCO 3.8.1 The following AC electrical power sources shall be OPERABLE:

a. Two qualified circuits between the offsite transmission network and the onsite Class 1E AC Electrical Power Distribution System; and

b. Four diesel generators (DGs).

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

--NOTES--

1. LCO 3.0.4.b is not applicable to DGs.

2. When an OPERABLE diesel generator is placed in an inoperable status solely for the purpose of alignment of DG E to or from the Class 1E distribution system, entry into associated Conditions and Required Actions may be delayed for up to 8 hours, provided both offsite circuits are OPERABLE and capable of supplying the affected 4.16 kV ESS Bus.

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One offsite circuit inoperable.	A.1	Perform SR 3.8.1.1 for OPERABLE offsite circuit.	1 hour <u>AND</u> Once per 8 hours thereafter
	<u>AND</u>		
	A.2	Declare required feature(s) with no offsite power available inoperable when the redundant required feature(s) are inoperable.	24 hours from discovery of no offsite power to one 4.16 kV ESS bus concurrent with inoperability of redundant required feature(s)
	<u>AND</u>		
	A.3	Restore offsite circuit to OPERABLE status.	72 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. One required DG inoperable.	B.1	Perform SR 3.8.1.1 for OPERABLE offsite circuits.	1 hour <u>AND</u> Once per 8 hours thereafter
	<u>AND</u>		
	B.2	Declare required feature(s), supported by the inoperable DG, inoperable when the redundant required feature(s) are inoperable.	4 hours from discovery of Condition B concurrent with inoperability of redundant required feature(s)
	<u>AND</u>		
	B.3.1	Determine OPERABLE DGs are not inoperable due to common cause failure. <u>OR</u>	24 hours
	B.3.2	Perform SR 3.8.1.7 for OPERABLE DGs.	24 hours <u>OR</u> 24 hours prior to entering Condition B
	<u>AND</u>		
	B.4	Restore required DG to OPERABLE status.	72 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Two offsite circuits inoperable.	C.1 Restore one offsite circuit to OPERABLE status.	24 hours OR In accordance with the Risk Informed Completion Time Program
D. One offsite circuit inoperable. AND One required DG inoperable.	----------------------NOTE----------------- Enter applicable Conditions and Required Actions of LCO 3.8.7, "Distribution Systems-Operating," when Condition D is entered with no AC power source to any 4.16 kV ESS bus. --	
	D.1 Restore offsite circuit to OPERABLE status.	12 hours OR In accordance with the Risk Informed Completion Time Program
	OR	
	D.2 Restore required DG to OPERABLE status.	12 hours OR In accordance with the Risk Informed Completion Time Program
E. Two or more required DGs inoperable.	E.1 Restore at least three required DGs to OPERABLE status.	2 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
F. Required Action and Associated Completion Time of Condition A, B, C, D, or E not met.	F.1 Be in MODE 3. AND F.2 Be in MODE 4.	12 hours 36 hours
G. One or more offsite circuits and two or more required DGs inoperable. OR One required DG and two offsite circuits inoperable.	G.1 Enter LCO 3.0.3.	Immediately
H. Manual synchronization circuit inoperable.	H.1 Restore manual synchronization circuit to OPERABLE status.	14 days

SURVEILLANCE REQUIREMENTS

---NOTE---

Four DGs are required and a DG is only considered OPERABLE when the DG is aligned to the Class 1E distribution system. DG Surveillance Requirements have been modified to integrate the necessary testing to demonstrate the availability of DG E and ensure its OPERABILITY when substituted for any other DG. If the DG Surveillance Requirements, as modified by the associated Notes, are met and performed, DG E can be considered available and OPERABLE when substituted for any other DG after performance of SR 3.8.1.3 and SR 3.8.1.7.

SURVEILLANCE		FREQUENCY
SR 3.8.1.1	Verify correct breaker alignment and indicated power availability for each offsite circuit.	In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.2	Not Used.	
SR 3.8.1.3	-----------------------------NOTES-------------------------------- 1. DG loading may include gradual loading as recommended by the manufacturer. 2. Momentary transients outside the load range do not invalidate this test. 3. This Surveillance shall be conducted on only one DG at a time. 4. This SR shall be preceded by and immediately follow, without shutdown, a successful performance of SR 3.8.1.7. 5. DG E, when not aligned to the Class 1E distribution system, may satisfy this SR using the test facility. 6. A single test will satisfy this Surveillance for both units if synchronization is to the 4.16 kV ESS bus for Unit 1 for one periodic test and synchronization is to the 4.16 kV ESS bus for Unit 2 for the next periodic test. However, if it is not possible to perform the test on Unit 2 or test performance is not required per SR 3.8.2.1, then the test shall be performed synchronized to the 4.16 kV ESS bus for Unit 1. --	
	Verify each DG is synchronized and loaded and operates for ≥ 60 minutes at a load ≥ 3600 kW and ≤ 4000 kW.	In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.8.1.4	Verify each engine mounted day tank fuel oil level is ≥ 420 gallons for DG A-D and ≥ 425 gallons for DG E.	In accordance with the Surveillance Frequency Control Program
SR 3.8.1.5	Check for and remove accumulated water from each engine mounted day tank.	In accordance with the Surveillance Frequency Control Program
SR 3.8.1.6	Verify the fuel oil transfer system operates to automatically transfer fuel oil from the storage tanks to each engine mounted tank.	In accordance with the Surveillance Frequency Control Program
SR 3.8.1.7	---------------------------NOTES------------------------------ 1. All DG starts may be preceded by an engine prelube period. 2. A single test at the specified Frequency will satisfy this Surveillance for both units. --- Verify each DG starts from standby condition and achieves, in ≤ 10 seconds, voltage ≥ 3793 V and frequency ≥ 58.8, and after steady state conditions are reached, maintains voltage ≥ 4000 V and ≤ 4400 V and frequency ≥ 59.3 Hz and ≤ 60.5 Hz.	In accordance with the Surveillance Frequency Control Program
SR 3.8.1.8	---------------------------NOTE-------------------------------- The automatic transfer of the unit power supply shall not be performed in MODE 1 or 2. --- Verify automatic and manual transfer of unit power supply from the normal offsite circuit to the alternate offsite circuit.	In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.9	------------------------------NOTE------------------------------ A single test at the specified Frequency will satisfy this Surveillance for both units. -- Verify each DG rejects a load greater than or equal to its associated single largest post-accident load, and: a. Following load rejection, the frequency is ≤ 64.5 Hz; b. Within 4.5 seconds following load rejection, the voltage is ≥ 3760 V and ≤ 4560 V, and after steady state conditions are reached, maintains voltage ≥ 4000 V and ≤ 4400 V; and c. Within 6 seconds following load rejection, the frequency is ≥ 59.3 Hz and ≤ 60.5 Hz.	In accordance with the Surveillance Frequency Control Program
SR 3.8.1.10	------------------------------NOTE------------------------------ A single test at the specified Frequency will satisfy this Surveillance for both units. -- Verify each DG does not trip and voltage is maintained ≤ 4560 V during and following a load rejection of ≥ 4000 kW.	In accordance with the Surveillance Frequency Control Program

3.8 ELECTRICAL POWER SYSTEMS

3.8.4 DC Sources-Operating

LCO 3.8.4 The DC electrical power subsystems in Table 3.8.4-1 shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. -------------NOTE------------- Not applicable to DG E DC electrical power system. --------------------------------- One Unit 1 battery charger on one 125 VDC electrical power subsystem inoperable. <u>OR</u> One Unit 1 battery charger on 250 VDC Division II electrical power subsystem inoperable. <u>OR</u> Two Unit 1 battery chargers on 250 VDC Division 1 electrical power subsystem inoperable.	A.1 Restore battery terminal voltage to greater than or equal to the minimum established float voltage. <u>AND</u> A.2 Verify battery float current ≤ 2 amps. <u>AND</u> A.3 Restore battery charger(s) to OPERABLE status.	2 hours Once per 12 hours 72 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. -------------NOTE------------- Not applicable to DG E DC electrical power system. --------------------------------- One Unit 1 125 VDC battery bank inoperable. <u>OR</u> One Unit 1 250 VDC battery bank inoperable.	B.1 Restore battery bank to OPERABLE status.	2 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program
C ------------NOTE------------ Not applicable to DG E DC electrical power subsystem. --------------------------------- One Unit 1 DC electrical power subsystem inoperable for reasons other than Condition A or B.	C.1 Restore Unit 1 DC electrical power subsystem to OPERABLE status.	2 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program
D. Two or more Unit 1 subsystems inoperable. <u>OR</u> Required Action and associated Completion Time of Conditions A, B, or C not met.	D.1 Be in MODE 3. <u>AND</u> D.2 Be in MODE 4.	12 hours 36 hours

3.8 ELECTRICAL POWER SYSTEMS

3.8.7 Distribution Systems - Operating

LCO 3.8.7 The electrical power distribution subsystems in Table 3.8.7-1 shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. ------------NOTE-------------- Not applicable to DG E DC electrical power subsystem. --------------------------------- One or more Unit 1 AC electrical power distribution subsystems inoperable.	---------------------NOTE------------------- Enter applicable Conditions and Required Actions of LCO 3.8.4, "DC Sources - Operating," for DC source(s) made inoperable by inoperable power distribution subsystem(s). --	
	A.1 Restore Unit 1 AC electrical power distribution subsystem(s) to OPERABLE status.	8 hours <u>OR</u> ----------NOTES---------- 1. Not applicable if there is a loss of function. 2. Only applicable to AC electrical power sources included in the PRA model. ------------------------------ In accordance with the Risk Informed Completion Time Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. ------------NOTE------------ Not applicable to DG E DC electrical power subsystem. ------------------------------- One or more Unit 1 DC electrical power distribution subsystems inoperable.	B.1 Restore Unit 1 DC electrical power distribution subsystem(s) to OPERABLE status.	2 hours OR -----------NOTE----------- Not applicable if there is a loss of function. ----------------------------- In accordance with the Risk Informed Completion Time Program
C. Required Action and Associated Completion Time of Condition A or Condition B not met.	C.1 Be in MODE 3. AND C.2 Be in MODE 4.	12 hours 36 hours
D. Diesel Generator E DC electrical power subsystem inoperable while not aligned to the Class 1E distribution system.	D.1 Verify that all ESW valves associated with Diesel Generator E are closed.	2 hours
E. Diesel Generator E DC electrical power subsystem inoperable, while aligned to the Class 1E distribution system.	E.1 Declare Diesel Generator E inoperable.	2 hours
F. Two or more Unit 1 electrical power distribution subsystems inoperable that result in a loss of safety function.	F.1 Enter LCO 3.0.3.	Immediately

5.5 Programs and Manuals

5.5.14 Control Room Envelope Habitability Program (continued)

e. The quantitative limits on unfiltered air inleakage into the CRE. These limits shall be stated in a manner to allow direct comparison to the unfiltered air inleakage measured by the testing described in paragraph c. The unfiltered air inleakage limit for radiological challenges is the inleakage flow rate assumed in the licensing basis analyses of DBA consequences. Unfiltered air inleakage limits for hazardous chemicals must ensure that exposure of CRE occupants to these hazards will be within the assumptions in the licensing basis.

f. The provisions of SR 3.0.2 are applicable to the Frequencies for assessing CRE habitability, determining CRE unfiltered inleakage, and measuring CRE pressure and assessing the CRE boundary as required by paragraphs c and d, respectively.

5.5.15 Surveillance Frequency Control Program

This program provides controls for Surveillance Frequencies. The program shall ensure that Surveillance Requirements specified in the Technical Specifications are performed at intervals sufficient to assure the associated Limiting Conditions for Operation are met.

a. The Surveillance Frequency Control Program shall contain a list of Frequencies of those Surveillance Requirements for which the Frequency is controlled by the program.

b. Changes to the Frequencies listed in the Surveillance Frequency Control Program shall be made in accordance with NEI 04-10, “Risk-Informed Method for Control of Surveillance Frequencies,” Revision 1.

c. The provisions of Surveillance Requirements 3.0.2 and 3.0.3 are applicable to the Frequencies established in the Surveillance Frequency Control Program.

5.5.16 Risk Informed Completion Time Program

This program provides controls to calculate a Risk Informed Completion Time (RICT) and must be implemented in accordance with NEI 06-09-A, Revision 0, “Risk-Managed Technical Specifications (RMTS) Guidelines.” The program shall include the following:

a. The RICT may not exceed 30 days;

5.5 Programs and Manuals

5.5.16 Risk Informed Completion Time Program (continued)

b. A RICT may only be utilized in MODE 1 and 2;

c. When a RICT is being used, any change to the plant configuration, as defined in NEI 06-09-A, Appendix A, must be considered for the effect on the RICT.

1. For planned changes, the revised RICT must be determined prior to implementation of the change in configuration.

2. For emergent conditions, the revised RICT must be determined within the time limits of the Required Action Completion Time (i.e., not the RICT) or 12 hours after the plant configuration change, whichever is less.

3. Revising the RICT is not required if the plant configuration change would lower plant risk and would result in a longer RICT.

d. For emergent conditions, if the extent of condition evaluation for inoperable structures, systems, or components (SSCs) is not complete prior to exceeding the Completion Time, the RICT shall account for the increased possibility of common cause failure (CCF) by either:

1. Numerically accounting for the increased possibility of CCF in the RICT calculation; or

2. Risk Management Actions (RMAs) not already credited in the RICT calculation shall be implemented that support redundant or diverse SSCs that perform the function(s) of the inoperable SSCs, and, if practicable, reduce the frequency of initiating events that challenge the functions(s) performed by the inoperable SSCs.

e. The risk assessment approaches and methods shall be acceptable to the NRC. The plant PRA shall be based on the as-built, as-operated, and maintained plant; and reflect the operating experience at the plant, as specified in Regulatory Guide 1.200, Revision 2. Methods to assess the risk from extending the Completion Times must be PRA methods approved for use with this program, or other methods approved by the NRC for generic use; and any change in the PRA methods to assess risk that are outside these approval boundaries require prior NRC approval.

SUSQUEHANNA NUCLEAR, LLC

ALLEGHENY ELECTRIC COOPERATIVE, INC.

DOCKET NO. 50-388

SUSQUEHANNA STEAM ELECTRIC STATION, UNIT 2

AMENDMENT TO RENEWED FACILITY OPERATING LICENSE

Amendment No. 265
Renewed License No. NPF-22

1. The U.S. Nuclear Regulatory Commission has found that:

   A. The application for the amendment filed by Susquehanna Nuclear, LLC, dated April 8, 2021, as supplemented by letter dated March 8, 2022, and June 27, 2022, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's regulations set forth in 10 CFR Chapter I;

   B. The facility will operate in conformity with the application, the provisions of the Act, and the regulations of the Commission;

   C. There is reasonable assurance: (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations;

   D. The issuance of this amendment will not be inimical to the common defense and security or to the health and safety of the public; and

   E. The issuance of this amendment is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied.

2. Accordingly, the license is amended by changes to the Renewed Facility Operating License and Technical Specifications, as indicated in the attachment to this license amendment, and paragraph 2.C.(2) of Renewed Facility Operating License No. NPF-22 is hereby amended to read as follows:

    2.C.(2) Technical Specifications and Environmental Protection Plan

    The Technical Specifications contained in Appendix A, as revised through Amendment No. 265, and the Environmental Protection Plan contained in Appendix B are hereby incorporated in the license. Susquehanna Nuclear, LLC shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

3. This license amendment is effective as of its date of issuance and shall be implemented within 180 days.

FOR THE NUCLEAR REGULATORY COMMISSION

Hipolito J. Gonzalez

Digitally signed by Hipolito J. Gonzalez
Date: 2022.08.30 14:16:51 -04'00'

Hipólito J. González, Chief
Plant Licensing Branch I
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Attachment:
Changes to the Renewed Facility Operating License and Technical Specifications

Date of Issuance: August 30, 2022

ATTACHMENT TO LICENSE AMENDMENT NO. 265

SUSQUEHANNA STEAM ELECTRIC STATION, UNIT 2

RENEWED FACILITY OPERATING LICENSE NO. NPF-22

DOCKET NO. 50-388

Replace the following page of Renewed Facility Operating License No. NPF-22 with the attached revised page. The revised page is identified by amendment number and contains a marginal line indicating the area of change.

Remove	Insert
Page 3	Page 3

Replace the following pages of the appendix A technical specifications with the attached revised pages. The revised pages are identified by amendment number and contain marginal lines indicating the areas of change.

REMOVE	INSERT	REMOVE	INSERT	REMOVE	INSERT	REMOVE	INSERT
1.3-12	1.3-12	3.3-32	3.3-32	3.3-73	3.3-73	3.7-3b	3.7-3b
1.3-13	1.3-13	3.3-33	3.3-33	3.3-74	3.3-74	3.7-4	3.7-4
---------	1.3-14	3.3-34	3.3-34	---------	3.3-74a	3.7-5	3.7-5
3.1-20	3.1-20	3.3-35	3.3-35	3.5-1	3.5-1	---------	3.7-5a
3.3-1	3.3-1	3.3-36	3.3-36	3.5-2	3.5-2	---------	3.7-5b
3.3-2	3.3-2	3.3-38	3.3-38	3.5-3	3.5-3	3.8-1	3.8-1
3.3-3	3.3-3	3.3-39	3.3-39	3.5-4	3.5-4	3.8-2	3.8-2
3.3-4	3.3-4	3.3-40	3.3-40	3.5-5	3.5-5	3.8-3	3.8-3
3.3-5	3.3-5	3.3-41	3.3-41	3.5-6	3.5-6	3.8-4	3.8-4
3.3-6	3.3-6	3.3-42	3.3-42	3.5-7	3.5-7	3.8-5	3.8-5
3.3-6a	3.3-6a	---------	3.3-42a	3.5-12	3.5-12	3.8-26	3.8-26
3.3-6b	3.3-6b	3.3-48	3.3-48	3.6-6	3.6-6	3.8-26a	3.8-26a
---------	3.3-6c	3.3-49	3.3-49	3.6-8	3.6-8	3.8-44	3.8-44
3.3-16	3.3-16	3.3-50	3.3-50	3.6-9	3.6-9	3.8-45	3.8-45
3.3-17	3.3-17	3.3-51	3.3-51	3.6-10	3.6-10	3.8-46	3.8-46
3.3-18	3.3-18	---------	3.3-51a	3.6-11	3.6-11	3.8-47	3.8-47
3.3-19	3.3-19	3.3-52	3.3-52	3.6-19	3.6-19	3.8-48	3.8-48
3.3-20	3.3-20	3.3-53	3.3-53	3.6-26	3.6-26	3.8-49	3.8-49
---------	3.3-20a	3.3-54	3.3-54	3.6-28	3.6-28	---------	3.8-49a
3.3-21	3.3-21	3.3-55	3.3-55	3.7-1	3.7-1	5.0-18C	5.0-18c
3.3-22	3.3-22	3.3-56	3.3-56	3.7-2	3.7-2	---------	5.0-18d
3.3-30	3.3-30	3.3-62	3.3-62	3.7-3	3.7-3		
3.3-31	3.3-31	3.3-72	3.3-72	3.7-3a	3.7-3a		

(3) Susquehanna Nuclear, LLC, pursuant to the Act and 10 CFR Parts 30, 40, and 70, to receive, posses, and use at any time any byproduct, source and special nuclear material as sealed neutron sources for reactor startup, sealed neutron sources for reactor instrumentation and radiation monitoring equipment calibration, and as fission detectors in amounts as required;

(4) Susquehanna Nuclear, LLC, pursuant to the Act and 10 CFR Parts 30, 40, and 70 to receive, posses, and use in amounts as required any byproduct, source or special nuclear material without restriction to chemical or physical form, for sample analysis or instrument calibration or associated with radioactive apparatus or components; and

(5) Susquehanna Nuclear, LLC, pursuant to the Act and 10 CFR Parts 30, 40, and 70 to possess, but not separate, such byproduct and special nuclear materials as may be produced by the operation of the facility.

C. This license shall be deemed to contain and is subject to the conditions specified in the Commission's regulations set forth in 10 CFR Chapter I and is subject to all applicable provisions of the Act and to the rules, regulations and orders of the Commission nor or hereafter in effect; and is subject to the additional conditions specified or incorporated below:

(1) Maximum Power Level

Susquehanna Nuclear, LLC is authorized to operate the facility at reactor core power levels not in excess of 3952 megawatts thermal in accordance with the conditions specified herein. The preoperational tests, startup tests and other items identified in License Conditions 2.C.(20), 2.C.(21), 2.C.(22), and 2.C.(23) to this license shall be completed as specified.

(2) Technical Specifications and Environmental Protection Plan

The Technical Specifications contained in Appendix A, as revised through Amendment No. 265, and the Environmental Protection Plan contained in Appendix B are hereby incorporated in the license. Susquehanna Nuclear, LLC shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

For Surveillance Requirements (SRs) that are new in Amendment 151 to Facility Operating License No. NPF-22, the first performance is due at the end of the first surveillance interval that begins at implementation of Amendment 151. For SRs that existed prior to Amendment 151, including SRs with modified acceptance criteria and SRs whose frequency of performance is being extended, the first performance is due at the end of the first surveillance interval that begins on the date the Surveillance was last performed prior to implementation of Amendment 151.

1.3 Completion Times

EXAMPLES (continued)

EXAMPLE 1.3-7

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One subsystem inoperable.	A.1 Verify affected subsystem isolated.	1 hour AND Once per 8 hours thereafter
	AND	
	A.2 Restore subsystem to OPERABLE status.	72 hours
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	12 hours
	AND	
	B.2 Be in MODE 4.	36 hours

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

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

1.3 Completion Times

EXAMPLES (continued)

EXAMPLE 1.3-8

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One subsystem inoperable.	A.1 Restore subsystem to OPERABLE status.	7 days OR In accordance with the Risk Informed Completion Time Program
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in MODE 4.	12 hours 36 hours

When a subsystem is declared inoperable, Condition A is entered. The 7 day Completion Time may be applied as discussed in Example 1.3-2. However, the licensee may elect to apply the Risk Informed Completion Time Program which permits calculation of a Risk Informed Completion Time (RICT) that may be used to complete the Required Action beyond the 7 day Completion Time. The RICT cannot exceed 30 days. After the 7 day Completion Time has expired, the subsystem must be restored to OPERABLE status within the RICT, or Condition B must also be entered.

The Risk Informed Completion Time Program requires recalculation of the RICT to reflect changing plant conditions. For planned changes, the revised RICT must be determined prior to implementation of the change in configuration. For emergent conditions, the revised RICT must be determined within the time limits of the Required Action Completion Time (i.e., not the RICT) or 12 hours after the plant configuration change, whichever is less.

1.3 Completion Times

EXAMPLES (continued)	EXAMPLE 1.3-8 (continued) If the 7 day Completion Time clock of Condition A has expired and subsequent changes in plant condition result in exiting the applicability of the Risk Informed Completion Time Program without restoring the inoperable subsystem to OPERABLE status, Condition B is also entered and the Completion Time clocks for Required Actions B.1 and B.2 start. If the RICT expires or is recalculated to be less than the time elapsed since the Condition was entered and the inoperable subsystem has not been restored to OPERABLE status, Condition B is also entered and the Completion Time clocks for Required Actions B.1 and B.2 start. If the inoperable subsystems are restored to OPERABLE status after Condition B is entered, Condition A is exited, and therefore, the Required Actions of Condition B may be terminated.
IMMEDIATE COMPLETION TIME	When "Immediately" is used as a Completion Time, the Required Action should be pursued without delay and in a controlled manner.

3.1 REACTIVITY CONTROL SYSTEMS

3.1.7 Standby Liquid Control (SLC) System

LCO 3.1.7 Two SLC subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Concentration of sodium pentaborate in solution is not within limits of Figure 3.1.7-1.	A.1 Restore concentration of sodium pentaborate in solution to within limits of Figure 3.1.7-1.	8 hours
B. One SLC subsystem inoperable for reasons other than Condition A.	B.1 Restore SLC subsystem to OPERABLE status.	7 days OR In accordance with the Risk Informed Completion Time Program
C. Two SLC subsystems inoperable for reasons other than Condition A.	C.1 Restore one SLC subsystem to OPERABLE status.	8 hours
D. Required Action and associated Completion Time not met.	D.1 Be in MODE 3. AND D.2 Be in MODE 4.	12 hours 36 hours

3.3 INSTRUMENTATION

3.3.1.1 Reactor Protection System (RPS) Instrumentation

LCO 3.3.1.1 The RPS instrumentation for each Function in Table 3.3.1.1-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.1.1-1.

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required channels inoperable.	A.1 Place channel in trip. <u>OR</u>	12 hours <u>OR</u> -----------NOTE----------- Not applicable if there is a loss of function. ----------------------------- In accordance with the Risk Informed Completion Time Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.2 --------------NOTE----------------- Not applicable for Functions 2.a, 2.b, 2.c, 2.d, or 2.f. -- Place associated trip system in trip.	 12 hours OR -----------NOTE----------- Not applicable if there is a loss of function. ------------------------------ In accordance with the Risk Informed Completion Time Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. ------------NOTE-------------- Not applicable for Functions 2.a, 2.b, 2.c, 2.d, or 2.f. --------------------------------- One or more Functions with one or more required channels inoperable in both trip systems.	B.1	Place channel in one trip system in trip.	6 hours <u>OR</u> -----------NOTE----------- Not applicable if there is a loss of function. ------------------------------ In accordance with the Risk Informed Completion Time Program
	<u>OR</u>		
	B.2	Place one trip system in trip.	6 hours <u>OR</u> -----------NOTE----------- Not applicable if there is a loss of function. ------------------------------ In accordance with the Risk Informed Completion Time Program
C. One or more Functions with RPS trip capability not maintained.	C.1	Restore RPS trip capability.	1 hour
D. Required Action and associated Completion Time of Condition A, B, or C not met.	D.1	Enter the Condition referenced in Table 3.3.1.1-1 for the channels.	Immediately

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
E. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	E.1	Reduce THERMAL POWER to < 26% RTP.	4 hours
F. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	F.1	Be in MODE 2.	6 hours
G. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	G.1	Be in MODE 3.	12 hours
H. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	H.1	Initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies.	Immediately
I. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	I.1	Initiate alternate method to detect and suppress thermal hydraulic instability oscillations.	12 hours
	AND		
	I.2	Restore required channels to OPERABLE.	120 days
J. Required Action and associated Completion Time of Condition I not met.	J.1	Reduce THERMAL POWER to < 23% RTP.	4 hours

SURVEILLANCE REQUIREMENTS

--NOTES--

1. Refer to Table 3.3.1.1-1 to determine which SRs apply for each RPS 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 RPS trip capability.

	SURVEILLANCE	FREQUENCY
SR 3.3.1.1.1	Perform CHANNEL CHECK.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.2	Perform CHANNEL CHECK.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.3	------------------------------NOTE------------------------------ Not required to be performed until 12 hours after THERMAL POWER ≥ 23% RTP. --- Verify the absolute difference between the average power range monitor (APRM) channels and the calculated power is ≤ 2% RTP while operating at ≥ 23% RTP.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.4	------------------------------NOTE------------------------------ Not required to be performed when entering MODE 2 from MODE 1 until 12 hours after entering MODE 2. --- Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.5	Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.6	Verify the source range monitor (SRM) and intermediate range monitor (IRM) channels overlap.	Prior to fully withdrawing SRMs from the core.
SR 3.3.1.1.7	-------------------------------NOTE------------------------------- Only required to be met during entry into MODE 2 from MODE 1. -- Verify the IRM and APRM channels overlap.	 In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.8	Calibrate the local power range monitors.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.9	-------------------------------NOTE------------------------------- A test of all required contacts does not have to be performed. -- Perform CHANNEL FUNCTIONAL TEST.	 In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.10	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.11	-------------------------------NOTES------------------------------ 1. Neutron detectors are excluded. 2. For Function 1.a, not required to be performed when entering MODE 2 from MODE 1 until 12 hours after entering MODE 2. --- Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.12	------------------------------NOTES------------------------------- 1. For Function 2.a, not required to be performed when entering MODE 2 from MODE 1 until 12 hours after entering MODE 2. 2. For Functions 2.b and 2.f, the CHANNEL FUNCTIONAL TEST includes the recirculation flow input processing, excluding the flow transmitters. --- Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.13	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.14	Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.15	Perform LOGIC SYSTEM FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.16	Verify Turbine Stop Valve-Closure and Turbine Control Valve Fast Closure, Trip Oil Pressure-Low Functions are not bypassed when THERMAL POWER is ≥ 26% RTP.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.17	--------------------------------NOTE-------------------------------- Neutron detectors are excluded. -- Verify the RPS RESPONSE TIME is within limits.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.18	-------------------------------NOTES------------------------------ 1. Neutron detectors are excluded. 2. For Functions 2.b and 2.f, the recirculation flow transmitters that feed the APRMs are included. -- Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.1.19	Verify OPRM is not bypassed when APRM Simulated Thermal Power is ≥ 25% and recirculation drive flow is ≤ value equivalent to the core flow value defined in the COLR.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.1.20	Adjust recirculation drive flow to conform to reactor core flow.	In accordance with the Surveillance Frequency Control Program

3.3 INSTRUMENTATION

3.3.2.1 Control Rod Block Instrumentation

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

APPLICABILITY: According to Table 3.3.2.1-1.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One rod block monitor (RBM) channel inoperable.	A.1	Restore RBM channel to OPERABLE status.	24 hours OR In accordance with the Risk Informed Completion Time Program
B. Required Action and associated Completion Time of Condition A not met. OR Two RBM channels inoperable.	B.1	Place one RBM channel in trip.	1 hour

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. Rod worth minimizer (RWM) inoperable during reactor startup.	C.1	Suspend control rod movement except by scram.	Immediately
	<u>OR</u>		
	C.2.1.1	Verify ≥ 12 rods withdrawn.	Immediately
		<u>OR</u>	
	C.2.1.2	Verify by administrative methods that startup with RWM inoperable has not been performed in the last calendar year.	Immediately
		<u>AND</u>	
	C.2.2	Verify movement of control rods is in compliance with banked position withdrawal sequence (BPWS) by a second licensed operator or other qualified member of the technical staff.	During control rod movement
D. RWM inoperable during reactor shutdown.	D.1	Verify movement of control rods is in accordance with BPWS by a second licensed operator or other qualified member of the technical staff.	During control rod movement
E. One or more Reactor Mode Switch-Shutdown Position channels inoperable.	E.1	Suspend control rod withdrawal.	Immediately
	<u>AND</u>		
	E.2	Initiate action to fully insert all insertable control rods in core cells containing one or more fuel assemblies.	Immediately

SURVEILLANCE REQUIREMENTS

---NOTES---

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

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

SURVEILLANCE		FREQUENCY
SR 3.3.2.1.1	Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.2.1.2	-------------------------------NOTE------------------------------- Not required to be performed until 1 hour after any control rod is withdrawn at ≤ 10% RTP in MODE 2. --- Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.2.1.3	-------------------------------NOTE------------------------------- Not required to be performed until 1 hour after THERMAL POWER is ≤ 10% RTP in MODE 1. --- Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.2.1.4	Verify the RBM: a. Low Power Range – Upscale Function is not bypassed when APRM Simulated Thermal Power is ≥ 28% RTP and ≤ Intermediate Power Range Setpoint specified in the COLR. b. Intermediate Power Range – Upscale Function is not bypassed when APRM Simulated Thermal Power is > Intermediate Power Range Setpoint specified in the COLR and ≤ High Power Range Setpoint specified in the COLR. c. High Power Range – Upscale Function is not bypassed when APRM Simulated Thermal Power > High Power Range Setpoint specified in the COLR.	In accordance with the Surveillance Frequency Control Program
SR 3.3.2.1.5	Verify the RWM is not bypassed when THERMAL POWER is ≤ 10% RTP.	In accordance with the Surveillance Frequency Control Program
SR 3.3.2.1.6	------------------------------NOTE------------------------------ Not required to be performed until 1 hour after reactor mode switch is in the shutdown position. --- Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.2.1.7	-------------------------------NOTE------------------------------- Neutron detectors are excluded. -- Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program
SR 3.3.2.1.8	Verify control rod sequences input to the RWM are in conformance with BPWS.	Prior to declaring RWM OPERABLE following loading of sequence into RWM

Table 3.3.2.1-1 (page 1 of 1)
Control Rod Block Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Rod Block Monitor				
a. Low Power Range – Upscale	(a)	2	SR 3.3.2.1.1 SR 3.3.2.1.4 SR 3.3.2.1.7(i)(j)	(f)
b. Intermediate Power Range – Upscale	(b)	2	SR 3.3.2.1.1 SR 3.3.2.1.4 SR 3.3.2.1.7(i)(j)	(f)
c. High Power Range – Upscale	(c), (d)	2	SR 3.3.2.1.1 SR 3.3.2.1.4 SR 3.3.2.1.7(i)(j)	(f)
d. Inop	(d), (e)	2	SR 3.3.2.1.1	NA
2. Rod Worth Minimizer	1(g), 2(g)	1	SR 3.3.2.1.2 SR 3.3.2.1.3 SR 3.3.2.1.5 SR 3.3.2.1.8	NA
3. Reactor Mode Switch – Shutdown Position	(h)	2	SR 3.3.2.1.6	NA

(a) THERMAL POWER is ≥ 28% RTP and ≤ Intermediate Power Range Setpoint specified in the COLR and MCPR is less than the limit specified in the COLR.

(b) THERMAL POWER is > Intermediate Power Range Setpoint specified in the COLR and ≤ High Power Range Setpoint specified in the COLR and MCPR is less than the limit specified in the COLR.

(c) THERMAL POWER is > High Power Range Setpoint specified in the COLR and < 90% RTP and MCPR is less than the limit specified in the COLR.

(d) THERMAL POWER is ≥ 90% RTP and MCPR is less than the limit specified in the COLR.

(e) THERMAL POWER is ≥ 28% RTP and < 90% RTP and MCPR is less than the limit specified in the COLR.

(f) Allowable Value specified in the COLR.

(g) With THERMAL POWER ≤ 10% RTP.

(h) Reactor mode switch in the shutdown position.

(i) If the as-found channel setpoint is not the Nominal Trip Setpoint but is conservative with respect to the Allowable Value, then the channel shall be evaluated to verify that it is functioning as required before returning the channel to service.

(j) The instrument channel setpoint shall be reset to the Nominal Trip Setpoint at the completion of the surveillance; otherwise, the channel shall be declared inoperable. The NTSP and the methodology used to determine the NTSP is specified in the SSES Final Safety Analysis Report.

3.3 INSTRUMENTATION

3.3.2.2 Feedwater – Main Turbine High Water Level Trip Instrumentation

LCO 3.3.2.2 Three channels of feedwater- main turbine high water level trip instrumentation shall be OPERABLE.

APPLICABILITY: THERMAL POWER ≥ 23% RTP.

ACTIONS

--NOTE--

Separate Condition entry is allowed for each channel.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One feedwater – main turbine high water level trip channel inoperable.	A.1 Place channel in trip.	7 days <u>OR</u> In accordance with the Risk Informed Completion Time Program
B. Two or more feedwater – main turbine high water level trip channels inoperable.	B.1 Restore feedwater – main turbine high water level trip capability.	2 hours
C. Required Action and associated Completion Time of Conditions A or B not met.	C.1 Reduce THERMAL POWER to < 23% RTP.	4 hours

SURVEILLANCE REQUIREMENTS

--NOTE--
When a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed for up to 6 hours provided feedwater - main turbine high water level trip capability is maintained.

SURVEILLANCE		FREQUENCY
SR 3.3.2.2.1	Perform CHANNEL CHECK.	In accordance with the Surveillance Frequency Control Program
SR 3.3.2.2.2	-----------------------------NOTES------------------------------ 1. A test of all required contacts does not have to be performed. 2. For the Feedwater- Main Turbine High Water Level Function, a test of all required relays does not have to be performed. --- Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.2.2.3	Perform CHANNEL CALIBRATION. The Allowable Value shall be ≤ 55.5 inches.	In accordance with the Surveillance Frequency Control Program
SR 3.3.2.2.4	Perform LOGIC SYSTEM FUNCTIONAL TEST including valve actuation.	In accordance with the Surveillance Frequency Control Program

3.3 INSTRUMENTATION

3.3.4.1 End of Cycle Recirculation Pump Trip (EOC-RPT) Instrumentation

LCO 3.3.4.1

a. Two channels per trip system for each EOC-RPT instrumentation Function listed below shall be OPERABLE:

1. Turbine Stop Valve (TSV)-Closure; and

2. Turbine Control Valve (TCV) Fast Closure, Trip Oil Pressure Low.

OR

b. LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)," limits for inoperable EOC-RPT as specified in the COLR are made applicable.

APPLICABILITY: THERMAL POWER > 26% RTP.

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more channels inoperable. AND MCPR limit for inoperable EOC-RPT not made applicable.	A.1 Restore channel to OPERABLE status. OR	72 hours OR -----NOTE----- Not applicable if there is a loss of function. ----- In accordance with the Risk Informed Completion Time Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. (continued)	A.2	---------------NOTE-------------- Not applicable if inoperable channel is the result of an inoperable breaker. -------------------------------------	
		Place channel in trip.	72 hours <u>OR</u> -----------NOTE----------- Not applicable if there is a loss of function. ----------------------------- In accordance with the Risk Informed Completion Time Program
	<u>OR</u>		
	A.3	Apply the MCPR limit for inoperable EOC-RPT as specified in the COLR.	72 hours
B. One or more Functions with EOC-RPT trip capability not maintained. <u>AND</u> MCPR limit for inoperable EOC-RPT not made applicable.	B.1	Restore EOC-RPT trip capability.	2 hours
	<u>OR</u>		
	B.2	Apply the MCPR limit for inoperable EOC-RPT as specified in the COLR.	2 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. Required Action and associated Completion Time not met.	C.1	Remove the associated recirculation pump from service.	4 hours
	<u>OR</u>		
	C.2	Reduce THERMAL POWER to < 26% RTP.	4 hours

SURVEILLANCE REQUIREMENTS

---NOTE---

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

SURVEILLANCE		FREQUENCY
SR 3.3.4.1.1	------------------------------NOTE------------------------------ A test of all required contacts does not have to be performed. --- Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.4.1.2	Perform CHANNEL CALIBRATION. The Allowable Values shall be: TSV-Closure: ≤ 7% closed; and TCV Fast Closure, Trip Oil Pressure – Low: ≥ 460 psig.	In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.4.1.3	Perform LOGIC SYSTEM FUNCTIONAL TEST including breaker actuation.	In accordance with the Surveillance Frequency Control Program
SR 3.3.4.1.4	Verify TSV-Closure and TCV Fast Closure, Trip Oil Pressure – Low Functions are not bypassed when THERMAL POWER is ≥ 26% RTP.	In accordance with the Surveillance Frequency Control Program
SR 3.3.4.1.5	-------------------------------NOTE------------------------------- Breaker arc suppression time may be assumed from the most recent performance of SR 3.3.4.1.6. -- Verify the EOC-RPT SYSTEM RESPONSE TIME is within limits.	In accordance with the Surveillance Frequency Control Program
SR 3.3.4.1.6	Determine RPT breaker arc suppression time.	In accordance with the Surveillance Frequency Control Program

3.3 INSTRUMENTATION

3.3.4.2 Anticipated Transient Without Scram Recirculation Pump Trip (ATWS-RPT) Instrumentation

LCO 3.3.4.2 Two channels per trip system for each ATWS-RPT instrumentation Function listed below shall be OPERABLE:

a. Reactor Vessel Water Level – Low Low, Level 2; and

b. Reactor Steam Dome Pressure – High.

APPLICABILITY: MODE 1.

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more channels inoperable.	A.1 Restore channel to OPERABLE status. <u>OR</u>	14 days <u>OR</u> -----------NOTE----------- Not applicable if there is a loss of function. ------------------------------ In accordance with the Risk Informed Completion Time Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. (continued)	A.2	---------------NOTE-------------- Not applicable if inoperable channel is the result of an inoperable breaker. ------------------------------------- Place channel in trip.	14 days <u>OR</u> -----------NOTE----------- Not applicable if there is a loss of function. ------------------------------ In accordance with the Risk Informed Completion Time Program
B. One Function with ATWS-RPT trip capability not maintained.	B.1	Restore ATWS-RPT trip capability.	72 hours
C. Both Functions with ATWS-RPT trip capability not maintained.	C.1	Restore ATWS-RPT trip capability for one Function.	1 hour
D. Required Action and associated Completion Time not met.	D.1	Remove the associated recirculation pump from service.	6 hours
	<u>OR</u>		
	D.2	Be in MODE 2.	6 hours

SURVEILLANCE REQUIREMENTS

---NOTE---

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

SURVEILLANCE		FREQUENCY
SR 3.3.4.2.1	Perform CHANNEL CHECK of Reactor Vessel Water Level, Low Low, Level 2.	In accordance with the Surveillance Frequency Control Program
SR 3.3.4.2.2	------------------------------NOTE------------------------------ A test of all required contacts does not have to be performed. -- Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.4.2.3	Perform CHANNEL CALIBRATION of the Reactor Steam Dome Pressure – High. The Allowable Values shall be ≤ 1150 psig.	In accordance with the Surveillance Frequency Control Program
SR 3.3.4.2.4	Perform CHANNEL CALIBRATION of the Reactor Vessel Water Level Low Low, Level 2. The Allowable Values shall be ≥ -45 inches.	In accordance with the Surveillance Frequency Control Program
SR 3.3.4.2.5	Perform LOGIC SYSTEM FUNCTIONAL TEST including breaker actuation.	In accordance with the Surveillance Frequency Control Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. (continued)	B.2	--------------NOTE---------------- Only applicable for Functions 3.a and 3.b. --------------------------------------	
		Declare High Pressure Coolant Injection (HPCI) System inoperable.	1 hour from discovery of loss of HPCI initiation capability
	<u>AND</u>		
	B.3	Place channel in trip.	24 hours <u>OR</u> -----------NOTE----------- Not applicable if there is a loss of function. ----------------------------- In accordance with the Risk Informed Completion Time Program
C. As required by Required Action A.1 and referenced in Table 3.3.5.1-1.	C.1	--------------NOTE---------------- Only applicable for Functions 1.d, 2.d, and 2.e. --------------------------------------	
		Declare supported feature(s) inoperable when its redundant feature ECCS initiation capability is inoperable.	1 hour from discovery of loss of initiation capability for feature(s) in both divisions
	<u>AND</u>		

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. (continued)	C.2 Restore channel to OPERABLE status.	24 hours <u>OR</u> -----------NOTE----------- Not applicable if there is a loss of function. ----------------------------- In accordance with the Risk Informed Completion Time Program
D. As required by Required Action A.1 and referenced in Table 3.3.5.1-1.	D.1 ---------------NOTE--------------- Only applicable if HPCI pump suction is not aligned to the suppression pool. -------------------------------------- Declare HPCI System inoperable.	 1 hour from discovery of loss of HPCI initiation capability
	<u>AND</u>	
	D.2.1 Place channel in trip.	24 hours <u>OR</u> -----------NOTE----------- Not applicable if there is a loss of function. ----------------------------- In accordance with the Risk Informed Completion Time Program
	<u>OR</u>	

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. (continued)	D.2.2 Align the HPCI pump suction to the suppression pool.	24 hours
E. As required by Required Action A.1 and referenced in Table 3.3.5.1-1.	E.1 Declare Automatic Depressurization System (ADS) valves inoperable.	1 hour from discovery of loss of ADS initiation capability in both trip systems
	<u>AND</u>	
	E.2 Place channel in trip.	96 hours from discovery of inoperable channel concurrent with HPCI or reactor core isolation cooling (RCIC) inoperable <u>OR</u> -----------NOTE----------- Not applicable if there is a loss of function. ------------------------------ In accordance with the Risk Informed Completion Time Program <u>AND</u>

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. (continued)	E.2 (continued)	8 days <u>OR</u> -----------NOTE----------- Not applicable if there is a loss of function. ------------------------------ In accordance with the Risk Informed Completion Time Program
F. As required by Required Action A.1 and referenced in Table 3.3.5.1-1.	F.1 ----------------NOTE--------------- Only applicable for Functions 4.c, 4.e, 4.f, 4.g, 5.c, 5.e, 5.f, and 5.g. --------------------------------------- Declare ADS valves inoperable. <u>AND</u>	1 hour from discovery of loss of ADS initiation capability in both trip systems

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
F. (continued)	F.2 Restore channel to OPERABLE status.	96 hours from discovery of inoperable channel concurrent with HPCI or RCIC inoperable OR -----------NOTE----------- Not applicable if there is a loss of function. ------------------------------ In accordance with the Risk Informed Completion Time Program AND 8 days OR -----------NOTE----------- Not applicable if there is a loss of function. ------------------------------ In accordance with the Risk Informed Completion Time Program
G. Required Action and associated Completion Time of Condition B, C, D, E, or F not met.	G.1 Declare associated supported feature(s) inoperable.	Immediately

SURVEILLANCE REQUIREMENTS

---NOTES---

1. Refer to Table 3.3.5.1-1 to determine which SRs apply for each ECCS 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 as follows: (a) for up to 6 hours for Functions 3.c and 3.e; and (b) for up to 6 hours for Functions other than 3.c and 3.e provided the associated Function or the redundant Function maintains ECCS initiation capability.

SURVEILLANCE		FREQUENCY
SR 3.3.5.1.1	Perform CHANNEL CHECK.	In accordance with the Surveillance Frequency Control Program
SR 3.3.5.1.2	-----------------------------NOTE------------------------------ A test of all required contacts does not have to be performed. --- Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.5.1.3	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program
SR 3.3.5.1.4	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program
SR 3.3.5.1.5	Perform LOGIC SYSTEM FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program

3.3 INSTRUMENTATION

3.3.5.3 Reactor Core Isolation Cooling (RCIC) System Instrumentation

LCO 3.3.5.3 The RCIC System instrumentation for each Function in Table 3.3.5.3-1 shall be OPERABLE.

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

ACTIONS

---NOTE---

Separate Condition entry is allowed for each channel.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more channels inoperable.	A.1 Enter the Condition referenced in Table 3.3.5.3-1 for the channel.	Immediately

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. As required by Required Action A.1 and referenced in Table 3.3.5.3-1.	B.1	Declare RCIC System inoperable.	1 hour from discovery of loss of RCIC initiation capability
	<u>AND</u>		
	B.2	Place channel in trip.	24 hours <u>OR</u> -----------NOTE----------- Not applicable if there is a loss of function. ------------------------------ In accordance with the Risk Informed Completion Time Program
C. As required by Required Action A.1 and referenced in Table 3.3.5.3-1.	C.1	Restore channel to OPERABLE status.	24 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
D. As required by Required Action A.1 and referenced in Table 3.3.5.3-1.	D.1	---------------NOTE-------------- Only applicable if RCIC pump suction is not aligned to the suppression pool. ------------------------------------- Declare RCIC System inoperable.	1 hour from discovery of loss of RCIC initiation capability
	AND		
	D.2.1	Place channel in trip.	24 hours OR -----------NOTE----------- Not applicable if there is a loss of function. ----------------------------- In accordance with the Risk Informed Completion Time Program
		OR	
	D.2.2	Align RCIC pump suction to the suppression pool.	24 hours
E. Required Action and associated Completion Time of Condition B, C, or D not met.	E.1	Declare RCIC System inoperable.	Immediately

SURVEILLANCE REQUIREMENTS

---NOTES---

1. Refer to Table 3.3.5.3-1 to determine which SRs apply for each RCIC 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 as follows: (a) for up to 6 hours for Functions 2 and 4 and (b) for up to 6 hours for Functions other than Functions 2 and 4 provided the associated Function maintains RCIC initiation capability.

SURVEILLANCE		FREQUENCY
SR 3.3.5.3.1	Perform CHANNEL CHECK.	In accordance with the Surveillance Frequency Control Program
SR 3.3.5.3.2	-------------------------------NOTE------------------------------- A test of all required contacts does not have to be performed. --- Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.5.3.3	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program
SR 3.3.5.3.4	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program
SR 3.3.5.3.5	Perform LOGIC SYSTEM FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program

Table 3.3.5.3-1 (page 1 of 1)
Reactor Core Isolation System Instrumentation

FUNCTION	REQUIRED CHANNELS PER FUNCTION	CONDITIONS REFERENCED FROM REQUIRED ACTION A.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. Reactor Vessel Water Level – Low Low, Level 2	4	B	SR 3.3.5.3.1 SR 3.3.5.3.2 SR 3.3.5.3.4 SR 3.3.5.3.5	≥ -45 inches
2. Reactor Vessel Water Level – High Level 8	2	C	SR 3.3.5.3.1 SR 3.3.5.3.2 SR 3.3.5.3.3 SR 3.3.5.3.5	≤ 55.5 inches
3. Condensate Storage Tank Level – Low	2	D	SR 3.3.5.3.2 SR 3.3.5.3.3 SR 3.3.5.3.5	≥ 36.0 inches above the tank bottom
4. Manual Initiation	1	C	SR 3.3.5.3.5	NA

3.3 INSTRUMENTATION

3.3.6.1 Primary Containment Isolation Instrumentation

LCO 3.3.6.1 The primary containment isolation instrumentation for each Function in Table 3.3.6.1-1 shall be OPERABLE.

APPLICABILITY: According to Table 3.3.6.1-1.

ACTIONS

---NOTES---

1. Penetration flow paths may be unisolated intermittently under administrative controls.

2. Separate Condition entry is allowed for each channel.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required channels inoperable.	A.1 Place channel in trip.	12 hours for Functions 2.a, 2.d, 6.b, 7.a, and 7.b <u>OR</u> -----------NOTE----------- Not applicable if there is a loss of function. ----------------------------- In accordance with the Risk Informed Completion Time Program <u>AND</u>

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.1 (continued)	24 hours for Functions other than Functions 2.a, 2.d, 6.b, 7.a, and 7.b <u>OR</u> -----------NOTE----------- Not applicable if there is a loss of function. ------------------------------ In accordance with the Risk Informed Completion Time Program
B. One or more automatic Functions with isolation capability not maintained.	B.1 Restore isolation capability.	1 hour
C. Required Action and associated Completion Time of Condition A or B not met.	C.1 Enter the Condition referenced in Table 3.3.6.1-1 for the channel.	Immediately
D. As required by Required Action C.1 and referenced in Table 3.3.6.1-1.	D.1 Isolate associated main steam line (MSL). <u>OR</u> D.2.1 Be in MODE 3. <u>AND</u> D.2.2 Be in MODE 4.	12 hours 12 hours 36 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
E. As required by Required Action C.1 and referenced in Table 3.3.6.1-1.	E.1	Be in MODE 2.	6 hours
F. As required by Required Action C.1 and referenced in Table 3.3.6.1-1.	F.1	Isolate the affected penetration flow path(s).	1 hour
G. As required by Required Action C.1 and referenced in Table 3.3.6.1-1.	G.1	Isolate the affected penetration flow path(s).	24 hours
H. As required by Required Action C.1 and referenced in Table 3.3.6.1-1. OR Required Action and associated Completion Time for Condition F or G not met.	H.1 AND H.2	Be in MODE 3. Be in MODE 4.	12 hours 36 hours
I. As required by Required Action C.1 and referenced in Table 3.3.6.1-1.	I.1 OR I.2	Declare associated standby liquid control subsystem (SLC) inoperable. Isolate the Reactor Water Cleanup System.	1 hour 1 hour

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
J. As required by Required Action C.1 and referenced in Table 3.3.6.1-1.	J.1	Initiate action to restore channel to OPERABLE status.	Immediately

SURVEILLANCE REQUIREMENTS

-----NOTES-----

1. Refer to Table 3.3.6.1-1 to determine which SRs apply for each Primary Containment Isolation 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 isolation capability.

SURVEILLANCE		FREQUENCY
SR 3.3.6.1.1	Perform CHANNEL CHECK.	In accordance with the Surveillance Frequency Control Program
SR 3.3.6.1.2	-----NOTES----- 1. A test of all required contacts does not have to be performed. 2. For Functions 2.e, 3.a, and 4.a, a test of all required relays does not have to be performed. ----- Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.6.1.3	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program
SR 3.3.6.1.4	Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program
SR 3.3.6.1.5	Perform LOGIC SYSTEM FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.6.1.6	------------------------------NOTES------------------------------ 1. For Function 1.b, channel sensors are excluded. 2. Response time testing of isolating relays is not required for Function 5.a. --- Verify the ISOLATION SYSTEM RESPONSE TIME is within limits.	In accordance with the Surveillance Frequency Control Program

Table 3.3.6.1-1 (page 6 of 6)
Primary Containment Isolation Instrumentation

FUNCTION	APPLICABLE MODES OR OTHER SPECIFIED CONDITIONS	REQUIRED CHANNELS PER TRIP SYSTEM	CONDITIONS REFERENCED FROM REQUIRED ACTION C.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
6. Shutdown Cooling System Isolation					
a. Reactor Steam Dome Pressure - High	1,2,3	1	F	SR 3.3.6.1.2 SR 3.3.6.1.3 SR 3.3.6.1.5	≤ 108 psig
b. Reactor Vessel Water Level - Low, Level 3	3	2	J	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.3 SR 3.3.6.1.5	≥ 11.5 inches
c. Manual Initiation	3	1	G	SR 3.3.6.1.5	NA
7. Traversing Incore Probe Isolation					
a. Reactor Vessel Water Level - Low, Level 3	1,2,3	2	G	SR 3.3.6.1.1 SR 3.3.6.1.2 SR 3.3.6.1.3 SR 3.3.6.1.5	≥ 11.5 inches
b. Drywell Pressure - High	1,2,3	2	G	SR 3.3.6.1.2 SR 3.3.6.1.4 SR 3.3.6.1.5	≤ 1.88 psig

3.3 INSTRUMENTATION

3.3.8.1 Loss of Power (LOP) Instrumentation

LCO 3.3.8.1 The LOP instrumentation for each Function in Table 3.3.8.1-1 shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required channels inoperable for reasons other than Condition B.	A.1 Enter the Condition referenced in Table 3.3.8.1-1 for the channel.	Immediately
B. One or more required channels associated with Unit 1 4.16 kV ESS Buses in one Division inoperable for the performance of Unit 1 SR 3.8.1.19.	B.1 Restore the inoperable channels.	8 hours OR -----------NOTE----------- Not applicable if there is a loss of function. ------------------------------ In accordance with the Risk Informed Completion Time Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. As required by Required Action A.1 and referenced in Table 3.3.8.1-1.	C.1	Place channel in trip.	1 hour <u>OR</u> -----------NOTE----------- Not applicable if there is a loss of function. ------------------------------ In accordance with the Risk Informed Completion Time Program
D. As required by Required Action A.1 and referenced in Table 3.3.8.1-1.	D.1	Restore the inoperable Channel.	1 hour <u>OR</u> -----------NOTE----------- Not applicable if there is a loss of function. ------------------------------ In accordance with the Risk Informed Completion Time Program
E. As required by Required Action A.1 and referenced in Table 3.3.8.1-1.	E.1	Declare associated diesel generator (DG) inoperable.	Immediately

SURVEILLANCE REQUIREMENTS

--NOTES--

1. Refer to Table 3.3.8.1-1 to determine which SRs apply for each LOP 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 DG initiation capability.

SURVEILLANCE		FREQUENCY
SR 3.3.8.1.1	Perform CHANNEL CHECK.	In accordance with the Surveillance Frequency Control Program
SR 3.3.8.1.2	Perform CHANNEL FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.8.1.3	Perform CHANNEL CALIBRATION	In accordance with the Surveillance Frequency Control Program
SR 3.3.8.1.4	Perform LOGIC SYSTEM FUNCTIONAL TEST.	In accordance with the Surveillance Frequency Control Program

Table 3.3.8.1-1 (page 1 of 1)
Loss of Power Instrumentation

FUNCTION	REQUIRED CHANNELS PER BUS	CONDITIONS REFERENCED FROM REQUIRED ACTION A.1	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE
1. 4.16 kV Emergency Bus Undervoltage (Loss of Voltage < 20%)				
a. Bus Undervoltage	1	D	SR 3.3.8.1.3 SR 3.3.8.1.4	≥ 780.4 V and ≤ 899.6 V
b. Time Delay	1	D	SR 3.3.8.1.3 SR 3.3.8.1.4	≥ 0.4 sec and ≤ 0.6 sec
2. 4.16 kV Emergency Bus Undervoltage Low Setting (Degraded Voltage 65%)				
a. Bus Undervoltage	2	C	SR 3.3.8.1.1 SR 3.3.8.1.2 SR 3.3.8.1.3 SR 3.3.8.1.4	≥ 2503 V and ≤ 2886 V
b. Time Delay	1	D	SR 3.3.8.1.2 SR 3.3.8.1.3 SR 3.3.8.1.4	≥ 2.7 sec and ≤ 3.3 sec
3. 4.16 kV Emergency Bus Undervoltage LOCA (Degraded Voltage 93%)				
a. Bus Undervoltage	2	C	SR 3.3.8.1.1 SR 3.3.8.1.2 SR 3.3.8.1.3 SR 3.3.8.1.4	≥ 3801 V and ≤ 3935 V
b. Time Delay (LOCA)	1	D	SR 3.3.8.1.3 SR 3.3.8.1.4	≥ 9 sec and ≤ 11 sec
c. Time Delay (Non-LOCA)	1	D	SR 3.3.8.1.2 SR 3.3.8.1.3 SR 3.3.8.1.4	≥ 4 min 30 sec and ≤ 5 min 30 sec

3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS), REACTOR PRESSURE VESSEL (RPV) WATER INVENTORY CONTROL, AND REACTOR CORE ISOLATION COOLING (RCIC) SYSTEM

3.5.1 ECCS – Operating

LCO 3.5.1 Each ECCS injection/spray subsystem and the Automatic Depressurization System (ADS) function of six safety/relief valves shall be OPERABLE.

APPLICABILITY: MODE 1,
MODES 2 and 3, except high pressure coolant injection (HPCI) and ADS valves are not required to be OPERABLE with reactor steam dome pressure ≤ 150 psig.

ACTIONS

--NOTE--

LCO 3.0.4.b is not applicable to HPCI.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One low pressure ECCS injection/spray subsystem inoperable for reasons other than Condition B.	A.1 Restore low pressure ECCS injection/spray subsystem to OPERABLE status.	7 days <u>OR</u> In accordance with the Risk Informed Completion Time Program
B. One LPCI pump in one or both LPCI subsystems inoperable.	B.1 Restore LPCI pump(s) to OPERABLE status.	7 days <u>OR</u> In accordance with the Risk Informed Completion Time Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Required Action and associated Completion Time of Condition A or Condition B not met.	C.1 Be in MODE 3. <u>AND</u> C.2 Be in MODE 4.	12 hours 36 hours
D. HPCI System inoperable.	D.1 Verify by administrative means RCIC System is OPERABLE. <u>AND</u> D.2 Restore HPCI System to OPERABLE status.	Immediately 14 days <u>OR</u> In accordance with the Risk Informed Completion Time Program
E. HPCI System inoperable. <u>AND</u> Condition A or Condition B entered.	E.1 Restore HPCI System to OPERABLE status. <u>OR</u> E.2 Restore low pressure ECCS injection/spray subsystem to OPERABLE status.	72 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program 72 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
F. One ADS valve inoperable.	F.1 Restore ADS valve to OPERABLE status.	14 days <u>OR</u> In accordance with the Risk Informed Completion Time Program
G. One ADS valve inoperable. <u>AND</u> Condition A or Condition B entered.	G.1 Restore ADS valve to OPERABLE status. <u>OR</u> G.2 Restore low pressure ECCS injection/spray subsystem to OPERABLE status.	72 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program 72 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program
H. Two or more ADS valves inoperable. <u>OR</u> Required Action and associated Completion Time of Condition D, E, F, or G not met.	H.1 Be in MODE 3. <u>AND</u> H.2 Reduce reactor steam dome pressure to ≤ 150 psig.	12 hours 36 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
I. Two Core Spray subsystems inoperable. <u>OR</u> One LPCI subsystem inoperable for reasons other than Condition B and One Core Spray subsystem inoperable. <u>OR</u> Two LPCI subsystems inoperable for reasons other than Condition B. <u>OR</u> HPCI System and one or more ADS valves inoperable.	I.1 Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.1.1	Verify, for each ECCS injection/spray subsystem, the piping is filled with water from the pump discharge valve to the injection valve.	In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.5.1.2	-------------------------------NOTE------------------------------- Low pressure coolant injection (LPCI) subsystems may be considered OPERABLE during alignment and operation for decay heat removal with reactor steam dome pressure less than the Residual Heat Removal (RHR) cut in permissive pressure in MODE 3, if capable of being manually realigned and not otherwise inoperable. --- Verify each ECCS injection/spray subsystem manual, power operated, and automatic valve in the flow path, that is not locked, sealed, or otherwise secured in position, and the HPCI flow controller are in the correct position.	In accordance with the Surveillance Frequency Control Program
SR 3.5.1.3	Verify ADS gas supply header pressure is ≥ 135 psig.	In accordance with the Surveillance Frequency Control Program
SR 3.5.1.4	Verify at least one RHR System cross tie valve is closed and power is removed from the valve operator.	In accordance with the Surveillance Frequency Control Program
SR 3.5.1.5	Verify each 480 volt AC swing bus transfers automatically from the normal source to the alternate source on loss of power.	In accordance with the Surveillance Frequency Control Program
SR 3.5.1.6	-------------------------------NOTE------------------------------- Not required to be performed if performed within the previous 31 days. --- Verify each recirculation pump discharge valve and bypass valve cycles through one complete cycle of full travel or is de-energized in the closed position.	Once each startup prior to exceeding 25% RTP

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.5.1.7	Verify the following ECCS pumps develop the specified flow rate against a system head corresponding to the specified reactor pressure. SYSTEM / FLOW RATE / NO. OF PUMPS / SYSTEM HEAD CORRESPONDING TO A REACTOR PRESSURE OF Core Spray / ≥ 6350 gpm / 2 / ≥ 105 psig LPCI / ≥ 12,200 gpm / 1 / ≥ 20 psig	In accordance with the Inservice Testing Program
SR 3.5.1.8	------------------------------NOTE------------------------------ Not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. --- Verify, with reactor pressure ≤ 1060 and ≥ 920 psig, the HPCI pump can develop a flow rate ≥ 5000 gpm against a system head corresponding to reactor pressure.	In accordance with the Inservice Testing Program
SR 3.5.1.9	------------------------------NOTE------------------------------ Not required to be performed until 12 hours after reactor steam pressure and flow are adequate to perform the test. --- Verify, with reactor pressure ≤ 165 psig, the HPCI pump can develop a flow rate ≥ 5000 gpm against a system head corresponding to reactor pressure.	In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.5.1.10	------------------------------NOTE------------------------------ Vessel injection/spray may be excluded. -- Verify each ECCS injection/spray subsystem actuates on an actual or simulated automatic initiation signal.	In accordance with the Surveillance Frequency Control Program
SR 3.5.1.11	------------------------------NOTE------------------------------ Valve actuation may be excluded. -- Verify the ADS actuates on an actual or simulated automatic initiation signal.	In accordance with the Surveillance Frequency Control Program
SR 3.5.1.12	Verify each ADS valve actuator strokes when manually actuated.	In accordance with the Surveillance Frequency Control Program
SR 3.5.1.13	------------------------------NOTE------------------------------ Instrumentation response time is based on historical response time data. -- Verify the ECCS RESPONSE TIME for each ECCS injection/spray subsystem is within limit.	In accordance with the Surveillance Frequency Control Program

3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS), REACTOR PRESSURE VESSEL (RPV) WATER INVENTORY CONTROL, AND REACTOR CORE ISOLATION COOLING (RCIC) SYSTEM

3.5.3 RCIC System

LCO 3.5.3 The RCIC System shall be OPERABLE.

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

ACTIONS

---NOTE---
LCO 3.0.4.b is not applicable to RCIC.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. RCIC System inoperable.	A.1 Verify by administrative means High Pressure Coolant Injection System is OPERABLE.	Immediately
	AND	
	A.2 Restore RCIC System to OPERABLE status.	14 days OR In accordance with the Risk Informed Completion Time Program
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3.	12 hours
	AND	
	B.2 Reduce reactor steam dome pressure to ≤ 150 psig.	36 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. (continued)	B.2 Lock an OPERABLE door closed.	24 hours
	<u>AND</u>	
	B.3 --------------NOTE--------------- Air lock doors in high radiation areas or areas with limited access due to inerting may be verified locked closed by administrative means. -------------------------------------	
	Verify an OPERABLE door is locked closed.	Once per 31 days
C. Primary containment air lock inoperable for reasons other than Condition A or B.	C.1 Initiate action to evaluate primary containment overall leakage rate per LCO 3.6.1.1, using current air lock test results.	Immediately
	<u>AND</u>	
	C.2 Verify a door is closed.	1 hour
	<u>AND</u>	
	C.3 Restore air lock to OPERABLE status.	24 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program

3.6 CONTAINMENT SYSTEMS

3.6.1.3 Primary Containment Isolation Valves (PCIVs)

LCO 3.6.1.3 Each PCIV shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

---NOTES---

1. Penetration flow paths may be unisolated intermittently under administrative controls.
2. Separate Condition entry is allowed for each penetration flow path.
3. Enter applicable Conditions and Required Actions for systems made inoperable by PCIVs.
4. Enter applicable Conditions and Required Actions of LCO 3.6.1.1, "Primary Containment," when PCIV leakage results in exceeding overall containment leakage rate acceptance criteria in MODES 1, 2, and 3.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. ------------NOTE-------------- Only applicable to penetration flow paths with two PCIVs except for the H_2 O_2 Analyzer penetrations. --------------------------------- One or more penetration flow paths with one PCIV inoperable except for purge valve leakage not within limit.	A.1 Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, blind flange, or check valve with flow through the valve secured.	4 hours except for main steam line <u>OR</u> In accordance with the Risk Informed Completion Time Program <u>AND</u>

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.1 (continued)	8 hours for main steam line OR In accordance with the Risk Informed Completion Time Program
	AND	
	A.2 ---------------NOTE--------------- Isolation devices in high radiation areas may be verified by use of administrative means. ------------------------------------- Verify the affected penetration flow path is isolated.	Once per 31 days following isolation for isolation devices outside primary containment AND Prior to entering MODE 2 or 3 from MODE 4, if primary containment was de-inerted while in MODE 4, if not performed within the previous 92 days, for isolation devices inside primary containment

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. -------------NOTE------------- Only applicable to penetration flow paths with two PCIVs except for the H_2 O_2 Analyzer penetrations. ---------------------------------- One or more penetration flow paths with two PCIVs inoperable except for purge valve leakage not within limit.	B.1 Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, or blind flange.	1 hour
C. -------------NOTE------------- Only applicable to penetration flow paths with only one PCIV. ---------------------------------- One or more penetration flow paths with one PCIV inoperable.	C.1 Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, or blind flange.	72 hours except for excess flow check valves (EFCVs) AND 12 hours for EFCVs
	AND	
	C.2 -------------NOTE----------------- Isolation devices in high radiation areas may be verified by use of administrative means. -------------------------------------- Verify the affected penetration flow path is isolated.	Once per 31 days following isolation

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
D. --------------NOTE------------ Only applicable to the H_2O_2 Analyzer penetrations. --------------------------------- One or more H_2 O_2 Analyzer penetrations with one or two PCIVs inoperable.	D.1	Isolate the affected penetration flow path by the use of at least one closed and de-activated automatic valve, closed manual valve, or blind flange.	72 hours
	<u>AND</u>		
	D.2	Verify the affected penetration flow path is isolated.	Once per 31 days following isolation
E. Secondary containment bypass leakage rate not within limit.	E.1	Restore leakage rate to within limit.	4 hours
F. One or more penetration flow paths with one or more containment purge valves not within purge valve leakage limit.	F.1	Restore the valve leakage to within valve leakage limit.	24 hours
G. Required Action and associated Completion Time of Condition A, B, C, D, E, or F not met.	G.1	Be in MODE 3.	12 hours
	<u>AND</u>		
	G.2	Be in MODE 4.	36 hours

3.6 CONTAINMENT SYSTEMS

3.6.1.6 Suppression Chamber-to-Drywell Vacuum Breakers

LCO 3.6.1.6 Five suppression chamber-to-drywell vacuum breaker pairs shall be OPERABLE and closed, except when performing their intended function.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One suppression chamber-to-drywell vacuum breaker pair inoperable for opening.	A.1 Restore the vacuum breaker pair to OPERABLE status.	72 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program
B. One suppression chamber-to-drywell vacuum breaker not closed.	B.1 Verify the other vacuum breaker in the pair is closed. <u>AND</u> B.2 Close the open vacuum breaker.	2 hours 72 hours
C. Both Suppression Chamber-to-Drywell vacuum breakers in one vacuum breaker pair not closed.	C.1 Close one open vacuum breaker in the affected vacuum breaker pair.	2 hours

3.6 CONTAINMENT SYSTEMS

3.6.2.3 Residual Heat Removal (RHR) Suppression Pool Cooling

LCO 3.6.2.3 Two RHR suppression pool cooling subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One RHR suppression pool cooling subsystem inoperable.	A.1 Restore RHR suppression pool cooling subsystem to OPERABLE status.	7 days OR In accordance with the Risk Informed Completion Time Program
B. Two RHR suppression pool cooling subsystems inoperable.	B.1 Restore one RHR suppression pool cooling subsystem to OPERABLE status.	8 hours
C. Required Action and associated Completion Time not met.	C.1 Be in MODE 3. AND C.2 Be in MODE 4.	12 hours 36 hours

3.6 CONTAINMENT SYSTEMS

3.6.2.4 Residual Heat Removal (RHR) Suppression Pool Spray

LCO 3.6.2.4 Two RHR suppression pool spray subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One RHR suppression pool spray subsystem inoperable.	A.1 Restore RHR suppression pool spray subsystem to OPERABLE status.	7 days <u>OR</u> In accordance with the Risk Informed Completion Time Program
B. Two RHR suppression pool spray subsystems inoperable.	B.1 Restore one RHR suppression pool spray subsystem to OPERABLE status.	8 hours
C. Required Action and associated Completion Time not met.	C.1 Be in MODE 3. <u>AND</u> C.2 Be in MODE 4.	12 hours 36 hours

3.7 PLANT SYSTEMS

3.7.1 Residual Heat Removal Service Water (RHRSW) System and the Ultimate Heat Sink (UHS)

LCO 3.7.1 Two RHRSW subsystems and the UHS shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

---NOTE---

Enter applicable Conditions and Required Actions of LCO 3.4.8, “Residual Heat Removal (RHR) Shutdown Cooling System-Hot Shutdown,” for RHR shutdown cooling made inoperable by RHRSW System.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. --------------NOTE------------ Separate Condition entry is allowed for each valve. --------------------------------- One valve in Table 3.7.1-1 inoperable. <u>OR</u> One valve in Table 3.7.1-2 inoperable. <u>OR</u> One valve in Table 3.7.1-3 inoperable. <u>OR</u>	A.1 Declare the associated RHRSW subsystems inoperable. <u>AND</u> A.2 Establish an open flow path to the UHS. <u>AND</u> A.3 Restore the inoperable valve(s) to OPERABLE status.	Immediately 8 hours 8 hours from the discovery of an inoperable RHRSW subsystem in the opposite loop from the inoperable valve(s) <u>AND</u>

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
Any combination of valves in Table 3.7.1-1, Table 3.7.1-2, or Table 3.7.1-3 in the same return loop inoperable.	A.3 (continued)	72 hours OR In accordance with the Risk Informed Completion Time Program
B. One Unit 2 RHRSW subsystem inoperable.	B.1 Restore the Unit 2 RHRSW subsystem to OPERABLE status. OR	72 hours from discovery of the associated Unit 1 RHRSW subsystem inoperable OR In accordance with the Risk Informed Completion Time Program AND 7 days OR In accordance with the Risk Informed Completion Time Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. (continued)	--------------------NOTE-------------------- The Risk Informed Completion Time Program cannot be applied if the temporary 14-day Completion Time is in effect. --	
	B.2 Restore the Unit 2 RHRSW subsystem to OPERABLE status.	14 days during the replacement of the Unit 1 ESW piping[1]
C. Both Unit 2 RHRSW subsystems inoperable.	C.1 Restore one Unit 2 RHRSW subsystem to OPERABLE status.	8 hours from discovery of one Unit 1 RHRSW subsystem not capable of supporting associated Unit 2 RHRSW subsystem <u>AND</u> 72 hours
D. Required Action and associated Completion Time not met. <u>OR</u> UHS inoperable.	D.1 Be in MODE 3. <u>AND</u> D.2 Be in MODE 4.	12 hours 36 hours

[1] This Completion Time is only applicable during the Unit 1 ‘A’ and ‘B’ ESW piping replacement while the compensatory measures identified in Enclosure 2 to letter PLA-7830 are in place. Upon completion of pipe replacement activities, this temporary extension is no longer applicable and will expire on June 25, 2026.

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.1.1	Verify the water level is greater than or equal to 678 feet 1 inch above Mean Sea Level.	In accordance with the Surveillance Frequency Control Program
SR 3.7.1.2	Verify the average water temperature of the UHS is: a. ----------------------------NOTE---------------------------- Only applicable with both units in MODE 1 or 2, or with either unit in MODE 3 for less than twelve (12) hours. -- ≤ 85°F; or b. ----------------------------NOTE---------------------------- Only applicable when either unit has been in MODE 3 for at least twelve (12) hours but not more than twenty-four (24) hours. -- ≤ 87°F; or c. ----------------------------NOTE---------------------------- Only applicable when either unit has been in MODE 3 for at least twenty-four (24) hours. -- ≤ 88°F.	In accordance with the Surveillance Frequency Control Program
SR 3.7.1.3	Verify each RHRSW manual, power operated, and automatic valve in the flow path, that is not locked, sealed, or otherwise secured in position, is in the correct position or can be aligned to the correct position.	In accordance with the Surveillance Frequency Control Program
SR 3.7.1.4	Verify that valves HV-01222A and B (the spray array bypass valves) close upon receipt of a closing signal and open upon receipt of an opening signal.	In accordance with the Surveillance Frequency Control Program

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.7.1.5	Verify that valves HV-01224A1 and B1 (the large spray array valves) close upon receipt of a closing signal and open upon receipt of an opening signal.	In accordance with the Surveillance Frequency Control Program
SR 3.7.1.6	Verify that valves HV-01224A2 and B2 (the small spray array valves) close upon receipt of a closing signal and open upon receipt of an opening signal.	In accordance with the Surveillance Frequency Control Program
SR 3.7.1.7	Verify that valves 012287A and 012287B (the spray array bypass manual valves) are capable of being opened and closed.	In accordance with the Surveillance Frequency Control Program

3.7 PLANT SYSTEMS

3.7.2 Emergency Service Water (ESW) System

LCO 3.7.2 Two ESW subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

---NOTE---

Enter applicable Conditions and Required Actions of LCO 3.8.1, “AC Sources − Operating,” for DGs made inoperable by ESW.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One ESW pump in each subsystem inoperable.	A.1 Restore both ESW pumps to OPERABLE status.	7 days <u>OR</u> In accordance with the Risk Informed Completion Time Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One or two ESW subsystems not capable of supplying ESW flow to at least three required DGs.	B.1 Restore ESW flow to the required DGs to ensure that each ESW subsystem is supplying at least three DGs.	7 days <u>OR</u> -----------NOTE----------- Not applicable if there is a loss of function. ------------------------------ In accordance with the Risk Informed Completion Time Program
	<u>OR</u> --------------------NOTE-------------------- The Risk Informed Completion Time Program cannot be applied if the temporary 14-day Completion Time is in effect. --	
	B.2 Restore ESW flow to the required DGs to ensure that each ESW subsystem is supplying at least three DGs.	14 days during the replacement of the Unit 1 ESW piping[1]

[1] This Completion Time is only applicable during the Unit 1 ‘A’ and ‘B’ ESW piping replacement while the compensatory measures identified in Enclosure 2 to letter PLA-7830 are in place. Upon completion of pipe replacement activities, this temporary extension is no longer applicable and will expire on June 25, 2026.

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One ESW subsystem inoperable for reasons other than Condition B.	C.1 Restore the ESW subsystem to OPERABLE status. <u>OR</u> --------------------NOTE-------------------- The Risk Informed Completion Time Program cannot be applied if the temporary 14-day Completion Time is in effect. -- C.2 Restore the ESW subsystem to OPERABLE status.	7 days <u>OR</u> In accordance with the Risk Informed Completion Time Program 14 days during the replacement of the Unit 1 ESW piping[1]
D. Required Action and associated Completion Time of Condition A, B, or C not met. <u>OR</u> Both ESW subsystems inoperable for reasons other than Conditions A and B.	D.1 Be in MODE 3. <u>AND</u> D.2 Be in MODE 4.	12 hours 36 hours

[1]This Completion Time is only applicable during the Unit 1 ‘A’ and ‘B’ ESW piping replacement while the compensatory measures identified in Enclosure 2 to letter PLA-7830 are in place. Upon completion of pipe replacement activities, this temporary extension is no longer applicable and will expire on June 25, 2026.

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.2.1	-------------------------------NOTE------------------------------ Isolation of flow to individual components does not render ESW System inoperable. --- Verify each ESW subsystem manual, power operated, and automatic valve in the flow paths servicing safety related systems or components, that is not locked, sealed, or otherwise secured in position, is in the correct position.	In accordance with the Surveillance Frequency Control Program
SR 3.7.2.2	Verify each ESW subsystem actuates on an actual or simulated initiation signal.	In accordance with the Surveillance Frequency Control Program

3.8 ELECTRICAL POWER SYSTEMS

3.8.1 AC Sources-Operating

LCO 3.8.1 The following AC electrical power sources shall be OPERABLE:

a. Two qualified circuits between the offsite transmission network and the onsite Class 1E AC Electrical Power Distribution System; and

b. Four diesel generators (DGs).

c. Two qualified circuits between the offsite transmission network and the Unit 1 onsite Class 1E AC electrical power distribution subsystem(s) required by LCO 3.8.7, "Distribution Systems - Operating;" and

d. The DG(s) capable of supplying the Unit 1 onsite Class 1E electrical power distribution subsystem(s) required by LCO 3.8.7.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

---NOTES---

1. LCO 3.0.4.b is not applicable to DGs.

2. When an OPERABLE diesel generator is placed in an inoperable status solely for the purpose of alignment of DG E to or from the Class 1E distribution system, entry into associated Conditions and Required Actions may be delayed for up to 8 hours, provided both offsite circuits are OPERABLE and capable of supplying the affected 4.16 kV ESS Bus.

3. When Unit 1 is in Modes 4 or 5 and an OPERABLE Unit 1 4160 V subsystem is placed in an inoperable status solely for the purpose of performing bus maintenance with both offsite circuits and four diesel generators otherwise OPERABLE, only entry into LCO 3.8.7 Condition C is required.

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One offsite circuit inoperable.	A.1	Perform SR 3.8.1.1 for OPERABLE offsite circuit.	1 hour AND Once per 8 hours thereafter
	AND		
	A.2	Declare required feature(s) with no offsite power available inoperable when the redundant required feature(s) are inoperable.	24 hours from discovery of no offsite power to one 4.16 kV ESS bus concurrent with inoperability of redundant required feature(s)
	AND		
	A.3	Restore offsite circuit to OPERABLE status.	72 hours OR In accordance with the Risk Informed Completion Time Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. One required DG inoperable.	B.1	Perform SR 3.8.1.1 for OPERABLE offsite circuits.	1 hour <u>AND</u> Once per 8 hours thereafter
	<u>AND</u>		
	B.2	Declare required feature(s), supported by the inoperable DG, inoperable when the redundant required feature(s) are inoperable.	4 hours from discovery of Condition B concurrent with inoperability of redundant required feature(s)
	<u>AND</u>		
	B.3.1	Determine OPERABLE DGs are not inoperable due to common cause failure.	24 hours
		<u>OR</u>	
	B.3.2	Perform SR 3.8.1.7 for OPERABLE DGs.	24 hours <u>OR</u> 24 hours prior to entering Condition B
	<u>AND</u>		
	B.4	Restore required DG to OPERABLE status.	72 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Two offsite circuits inoperable.	C.1 Restore one offsite circuit to OPERABLE status.	24 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program
D. One offsite circuit inoperable. <u>AND</u> One required DG inoperable.	--------------------NOTE-------------------- Enter applicable Conditions and Required Actions of LCO 3.8.7, "Distribution Systems-Operating," when Condition D is entered with no AC power source to any 4.16 kV ESS bus. ---	
	D.1 Restore offsite circuit to OPERABLE status.	12 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program
	<u>OR</u>	
	D.2 Restore required DG to OPERABLE status.	12 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program
E. Two or more required DGs inoperable.	E.1 Restore at least three required DGs to OPERABLE status.	2 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
F. Required Action and Associated Completion Time of Condition A, B, C, D, or E not met.	F.1 Be in MODE 3. AND F.2 Be in MODE 4.	12 hours 36 hours
G. One or more offsite circuits and two or more required DGs inoperable. OR One required DG and two offsite circuits inoperable.	G.1 Enter LCO 3.0.3.	Immediately
H. Manual synchronization circuit inoperable.	H.1 Restore manual synchronization circuit to OPERABLE status.	14 days

3.8 ELECTRICAL POWER SYSTEMS

3.8.4 DC Sources-Operating

LCO 3.8.4 The DC electrical power subsystems in Table 3.8.4-1 shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A -------------NOTE------------- Not applicable to DG E DC electrical power system. --------------------------------- One Unit 2 battery charger on one 125 VDC electrical power subsystem inoperable. <u>OR</u> One Unit 2 battery charger on 250 VDC Division II electrical power subsystem inoperable. <u>OR</u> Two Unit 2 battery chargers on 250 VDC Division 1 electrical power subsystem inoperable.	A.1 Restore battery terminal voltage to greater than or equal to the minimum established float voltage. <u>AND</u> A.2 Verify battery float current ≤ 2 amps. <u>AND</u> A.3 Restore battery charger(s) to OPERABLE status.	2 hours Once per 12 hours 72 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. -------------NOTE------------ Not applicable to DG E DC electrical power system. One Unit 2 125 VDC battery bank inoperable. <u>OR</u> One Unit 2 250 VDC battery bank inoperable.	B.1 Restore battery bank to OPERABLE status.	2 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program
C. ------------NOTE------------ Not applicable to DG E DC electrical power subsystem. ------------------------------- One Unit 2 DC electrical power subsystem inoperable for reasons other than Conditions A or B.	C.1 Restore Unit 2 DC electrical power subsystem to OPERABLE status.	2 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program
D. Two or more Unit 2 subsystems inoperable. <u>OR</u> Required Action and associated Completion Time of Conditions A, B, or C not met.	D.1 Be in MODE 3. <u>AND</u> D.2 Be in MODE 4.	12 hours 36 hours

3.8 ELECTRICAL POWER SYSTEMS

3.8.7 Distribution Systems-Operating

LCO 3.8.7 The electrical power distribution subsystems in Table 3.8.7-1 shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. --------------NOTE------------ Not applicable to DG E DC Bus 0D597 ---------------------------------- One or more Unit 2 AC electrical power distribution subsystems inoperable.	------------------NOTE-------------------- Enter applicable Conditions and Required Actions of LCO 3.8.4, "DC Sources - Operating," for DC source(s) made inoperable by inoperable power distribution subsystem(s). -- A.1 Restore Unit 2 AC electrical power distribution subsystem(s) to OPERABLE status.	 8 hours OR ----------NOTES---------- 1. Not applicable if there is a loss of function. 2. Only applicable to AC electrical power sources included in the PRA model. ------------------------------ In accordance with the Risk Informed Completion Time Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. -------------NOTE------------ Not applicable to DG E DC Bus 0D597. ---------------------------------- One or more Unit 2 DC electrical power distribution subsystems inoperable.	B.1	Restore Unit 2 DC electrical power distribution subsystem(s) to OPERABLE status.	2 hours OR -----------NOTE---------- Not applicable if there is a loss of function. ------------------------------ In accordance with the Risk Informed Completion Time Program
C. One Unit 1 AC electrical power distribution subsystem inoperable.	C.1 OR	Restore Unit 1 AC electrical power distribution subsystem to OPERABLE status.	72 hours OR -----------NOTE---------- Only applicable to AC electrical power sources included in the PRA model. ------------------------------ In accordance with the Risk Informed Completion Time Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. (continued)	--------------------NOTE-------------------- The Risk Informed Completion Time Program cannot be applied if the temporary 7-day Completion Time is in effect. -- C.2 Restore Unit 1 AC electrical power distribution subsystem to OPERABLE status.	 7 days during the replacement of 480 V ESS Load Center Transformers in Unit 1[(1)]
D. Two Unit 1 AC electrical power distribution subsystems on one Division inoperable for performance of Unit 1 SR 3.8.1.19.	D.1 Restore at least one Unit 1 AC electrical power distribution subsystems to OPERABLE status.	8 hours <u>OR</u> -----------NOTE---------- Only applicable to AC electrical power sources included in the PRA model. ------------------------------ In accordance with the Risk Informed Completion Time Program
E. Required Action and Associated Completion Time of Condition A, B, or C not met.	E.1 Be in MODE 3. <u>AND</u> E.2 Be in MODE 4.	12 hours 36 hours

(1) This temporary 7-day completion time is applicable during the replacement of Unit 1 480 V ESS Load Center Transformers 1X230 and 1X240, while Unit 1 is in MODES 4 or 5, and will expire on June 15, 2024.

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
F. Diesel Generator E DC electrical power subsystem inoperable, while not aligned to the Class 1E distribution system.	F.1	Verify that all ESW valves associated with Diesel Generator E are closed.	2 hours
G. Diesel Generator E DC electrical power subsystem inoperable, while aligned to the Class 1E distribution system.	G.1	Declare Diesel Generator E inoperable.	2 hours
H. Two or more electrical power distribution subsystems inoperable that result in a loss of safety function.	H.1	Enter LCO 3.0.3.	Immediately
I. -------------NOTE------------- Not applicable to DG E DC Bus 0D597. --------------------------------- One or more Unit 1 DC electrical power distribution subsystem(s) inoperable.	I.1	Transfer associated Unit 1 and common loads to corresponding Unit 2 DC electrical power distribution subsystem.	2 hours
	<u>AND</u>		
	I.2	Restore Unit 1 and common loads to corresponding Unit 1 DC electrical power distribution subsystem.	72 hours after Unit 1 DC electrical power subsystem is restored to OPERABLE status
J. Required Actions and associated Completion Times of Condition I not met.	J.1	Declare associated common loads inoperable.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.7.1	Verify correct breaker alignments and voltage or indicated power availability to required AC and DC electrical power distribution subsystems.	In accordance with the Surveillance Frequency Control Program

Table 3.8.7-1 (page 1 of 2)
Unit 2 AC and DC Electrical Power Distribution Subsystems

TYPE	VOLTAGE	DIVISION I	DIVISION II
AC Buses	4160 V Load Groups	1A201 (Subsys. A) 1A203 (Subsys. C) 2A201 (Subsys. A) 2A203 (Subsys. C)	1A202 (Subsys. B) 1A204 (Subsys. D) 2A202 (Subsys. B) 2A204 (Subsys. D)
	480 V Load Centers	1B210 (Subsys. A) 1B230 (Subsys. C) 2B210 (Subsys. A) 2B230 (Subsys. C)	1B220 (Subsys. B) 1B240 (Subsys. D) 2B220 (Subsys. B) 2B240 (Subsys. D)
	480 V Motor Control Centers	0B516 (Subsys. A) 0B517 (Subsys. A) 1B216 (Subsys. A) 1B217 (Subsys. A) 0B536 (Subsys. C) 0B136 (Subsys. C) 1B236 (Subsys. C) 2B216 (Subsys. A) 2B236 (Subsys. C) 2B237 (Subsys. C) 2B217 (Subsys. A)	0B526 (Subsys. B) 0B527 (Subsys. B) 1B226 (Subsys. B) 1B227 (Subsys. B) 0B546 (Subsys. D) 0B146 (Subsys. D) 1B246 (Subsys. D) 2B246 (Subsys. D) 2B247 (Subsys. D) 2B226 (Subsys. B) 2B227 (Subsys. B)
	208/120 V Distribution Panels	1Y216 (Subsys. A) 1Y236 (Subsys. C) 2Y216 (Subsys. A) 2Y236 (Subsys. C)	1Y226 (Subsys. B) 1Y246 (Subsys. D) 2Y226 (Subsys. B) 2Y246 (Subsys. D)

Table 3.8.7-1 (page 2 of 2)
Unit 2 AC and DC Electrical Power Distribution Subsystems

TYPE	VOLTAGE	DIVISION I	DIVISION II
DC Buses	250 V Buses	2D652 2D254	2D662 2D264 2D274
	125 V Buses	1D612 (Subsys. A) 1D614 (Subsys. A) 1D632 (Subsys. C) 1D634 (Subsys. C) 2D612 (Subsys. A) 2D614 (Subsys. A) 2D632 (Subsys. C) 2D634 (Subsys. C)	1D622 (Subsys. B) 1D624 (Subsys. B) 1D642 (Subsys. D) 1D644 (Subsys. D) 2D622 (Subsys. B) 2D624 (Subsys. B) 2D642 (Subsys. D) 2D644 (Subsys. D)
DG E DC Bus	125 V Bus	0D597	

5.5 Programs and Manuals

5.5.14 Control Room Envelope Habitability Program (continued)

e. The quantitative limits on unfiltered air inleakage into the CRE. These limits shall be stated in a manner to allow direct comparison to the unfiltered air inleakage measured by the testing described in paragraph c. The unfiltered air inleakage limit for radiological challenges is the inleakage flow rate assumed in the licensing basis analyses of DBA consequences. Unfiltered air inleakage limits for hazardous chemicals must ensure that exposure of CRE occupants to these hazards will be within the assumptions in the licensing basis.

f. The provisions of SR 3.0.2 are applicable to the Frequencies for assessing CRE habitability, determining CRE unfiltered inleakage, and measuring CRE pressure and assessing the CRE boundary as required by paragraphs c and d, respectively.

5.5.15 Surveillance Frequency Control Program

This program provides controls for Surveillance Frequencies. The program shall ensure that Surveillance Requirements specified in the Technical Specifications are performed at intervals sufficient to assure the associated Limiting Conditions for Operation are met.

a. The Surveillance Frequency Control Program shall contain a list of Frequencies of those Surveillance Requirements for which the Frequency is controlled by the program.

b. Changes to the Frequencies listed in the Surveillance Frequency Control Program shall be made in accordance with NEI 04-10, "Risk-Informed Method for Control of Surveillance Frequencies," Revision 1.

c. The provisions of Surveillance Requirements 3.0.2 and 3.0.3 are applicable to the Frequencies established in the Surveillance Frequency Control Program.

5.5.16 Risk Informed Completion Time Program

This program provides controls to calculate a Risk Informed Completion Time (RICT) and must be implemented in accordance with NEI 06-09-A, Revision 0, "Risk-Managed Technical Specifications (RMTS) Guidelines." The program shall include the following:

a. The RICT may not exceed 30 days;

5.5 Programs and Manuals

5.5.16 Risk Informed Completion Time Program (continued)

b. A RICT may only be utilized in MODE 1 and 2;

c. When a RICT is being used, any change to the plant configuration, as defined in NEI 06-09-A, Appendix A, must be considered for the effect on the RICT.

   1. For planned changes, the revised RICT must be determined prior to implementation of the change in configuration.

   2. For emergent conditions, the revised RICT must be determined within the time limits of the Required Action Completion Time (i.e., not the RICT) or 12 hours after the plant configuration change, whichever is less.

   3. Revising the RICT is not required if the plant configuration change would lower plant risk and would result in a longer RICT.

d. For emergent conditions, if the extent of condition evaluation for inoperable structures, systems, or components (SSCs) is not complete prior to exceeding the Completion Time, the RICT shall account for the increased possibility of common cause failure (CCF) by either:

   1. Numerically accounting for the increased possibility of CCF in the RICT calculation; or

   2. Risk Management Actions (RMAs) not already credited in the RICT calculation shall be implemented that support redundant or diverse SSCs that perform the function(s) of the inoperable SSCs, and, if practicable, reduce the frequency of initiating events that challenge the functions(s) performed by the inoperable SSCs.

e. The risk assessment approaches and methods shall be acceptable to the NRC. The plant PRA shall be based on the as-built, as-operated, and maintained plant; and reflect the operating experience at the plant, as specified in Regulatory Guide 1.200, Revision 2. Methods to assess the risk from extending the Completion Times must be PRA methods approved for use with this program, or other methods approved by the NRC for generic use; and any change in the PRA methods to assess risk that are outside these approval boundaries require prior NRC approval.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

Safety Evaluation by the Office of Nuclear Reactor Regulation for Amendment No. 282 to Renewed Facility Operating License No. NPF-14 Amendment No. 265 to Renewed Facility Operating License No. NPF-22 Susquehanna Nuclear, LLC Allegheny Electric Cooperative, Inc., Susquehanna Steam Electric Station, Units 1 and 2

Docket Nos. 50-387 and 50-388

TABLE OF CONTENTS

1.0 INTRODUCTION

1.1 Background

By letter dated April 8, 2021 [1], as supplemented by letters dated March 8, 2022 [2], and June 27, 2022 [3], Susquehanna Nuclear, LLC, (the licensee) requested a license amendment for Susquehanna Steam Electric Station, Units 1 and 2.[1] The licensee proposed changes to various technical specifications to allow the use of risk-informed completion times (RICTs) in accordance with initiative 4b of the Technical Specifications Task Force (TSTF), "Risk Informed Completion Times with Configuration Risk Management Program or Maintenance Rule Backstop." The licensee proposed the changes in accordance with TSTF-505, revision 2, "Provide Risk-Informed Extended Completion Times" [4].[2] The licensee also proposed variations from this traveler and some changes to technical specifications not associated with it.

To support the licensing review, the U.S. Nuclear Regulatory Commission (NRC) staff audited various licensee documents and interviewed licensee personnel. The staff issued its audit plan on June 15, 2021 [5]; conducted a virtual audit through multiple videoconferences from September 15, 2021, to January 19, 2022; and issued its audit summary report on March 31, 2022 [6]. The staff sent the licensee a request for additional information by email dated May 25, 2022 [7]. The licensee responded to the request by letter dated June 27, 2022 [3].

The licensee's supplements dated March 8, 2022 [2], and June 27, 2022 [3], provided additional information that clarified the application, did not expand the scope of the application as originally noticed, and did not change the NRC staff's original proposed no significant hazards consideration determination as published in the *Federal Register* on November 2, 2021 [8].

1.2 Description of the RICT Program

The technical specification limiting conditions for operation (LCO) are the lowest functional capability or performance levels of equipment required for safe operation of the facility. When an LCO is not met, the licensee must shut down the reactor or follow any remedial or required action (e.g., testing, maintenance, or repair activity) permitted by the technical specifications until the condition can be met. The remedial actions (i.e., ACTIONS) associated with an LCO contain conditions that typically describe the ways in which the requirements of the LCO can fail to be met. Specified with each stated Condition are Required Actions and Completion Times. The Completion Times are referred to as the "front stops." For certain conditions, the technical specifications require exiting the Mode of Applicability of an LCO (i.e., shut down the reactor).

The Nuclear Energy Institute (NEI) prepared an industry guidance document, NEI 06-09, Revision 0-A, "Risk-Informed Technical Specifications Initiative 4b, Risk-Managed Technical Specifications (RMTS) Guidelines" (NEI 06-09-A) [9]. The guidance describes an NRC-approved methodology for calculating a RICT and describes the administrative controls

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1 Renewed Facility Operating License Nos. NPF-14 and NPF-22, respectively.

2 All references to TSTF-505 in this document are to Revision 2 unless another revision is explicitly cited.

needed for an acceptable RICT program. By assessing and managing risk within the limits established for its RICT program, a licensee can use a RICT to make more time available for required actions. A RICT allows the licensee to delay the exit from an LCO mode of applicability.

A RICT program would add administrative control requirements to the technical specifications. However, it would not change the safety functions or required performance levels of equipment for which technical specifications are provided. It would not alter the required actions specified for an LCO. Adopting an approved RICT program would only allow licensees to modify certain completion times within program limits.

1.3 Description of Proposed Changes

The licensee proposed to add a RICT program to the administrative controls section of the technical specifications, an example showing how to apply the RICT program, and the modification of selected completion times to allow extending them if the licensee assesses and manages risk per NEI 06-09-A [9]. In its license amendment request (LAR) [1], the licensee discussed the technical acceptability of the probabilistic risk assessment (PRA) models for the RICT program and stated that it assessed its PRA models against NRC Regulatory Guide 1.200, revision 2, "An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities" (RG 1.200) [10].[3] The licensee also proposed variations from TSTF-505 [4] and technical specifications changes not associated with TSTF-505 [4]. The specific proposed changes are as follows, with noted differences between the technical specifications of the two units.

1.3.1 TS 5.5.16, "Risk Informed Completion Time Program"

The licensee proposed to add TS 5.5.16, "Risk Informed Completion Time Program," to section 5.5, "Programs and Manuals," of TS 5.0, "Administrative Controls." The content of this proposed technical specification for each unit is in Enclosures 3 and 4 to the licensee's supplement [2]. This technical specification would describe the RICT program and its controls, including time limits and mode applicability of technical specifications, consideration of changing plant configurations in RICT calculations, and PRA acceptability.

1.3.2 TS 1.0, "Use and Application" (Example 1.3-8)

The licensee proposed to add an example to Section 1.3, "Completion Times," of TS 1.0, "Use and Application," to show how it will apply the RICT program. The content of proposed Example 1.3-8 is presented in attachments 2 and 3 of the LAR [1]. The example explains that a licensee may apply the given completion time or the optional RICT. The example also addresses consideration of changing plant conditions in RICT calculations and impacts of expired RICTs. The licensee proposed two variations from Example 1.3-8 in TSTF-505 [4]: to change the completion time for the MODE 3 required action to 12 hours and to specify MODE 4 rather than MODE 5 in the required action of the default condition. The licensee proposed these variations because the typical default Required Action found in the Susquehanna TS

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[3] All references to RG 1.200 in this document are to Revision 2 [10] unless another revision is explicitly cited.

Section 1.3 examples and Section 3 LCO states, "Be in MODE 3 [in *12 hours*] (emphasis added) AND Be in *MODE 4* (emphasis added) [in 36 hours]."

1.3.3 Application of the RICT Program to Existing LCOs and Conditions

Attachment 2 of the LAR [1] and as updated in enclosure 3 of its supplement [2], shows the proposed revisions to completion times in the technical specifications. These changes would add optional RICTs to specific completion times in the Required Actions in technical specifications 3.1, "Reactivity Control Systems"; 3.3, "Instrumentation"; 3.5, "Emergency Core Cooling Systems (ECCS), Reactor Pressure Vessel (RPV) Water Inventory Control, and Reactor Core Isolation Cooling (RCIC) System"; 3.6, "Containment Systems"; 3.7, "Plant Systems"; and 3.8, "Electrical Power Systems."

The typical Completion Time would be modified by the application of the RICT program as shown in the following example. The proposed changed portion of the completion time is indicated in italics.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One subsystem inoperable.	A.1 Restore subsystem to OPERABLE status.	7 days *OR* *In accordance with the Risk Informed Completion Time Program*

The licensee proposed adding a note that states, "Not applicable if there is a loss of function," before the statement, "In accordance with the Risk Informed Completion Time Program," in the Completion Time column for the following Required Actions:

- TS 3.3.1.1, Required Actions A.1, A.2, B.1, and B.2
- TS 3.3.4.1, Required Actions A.1 and A.2
- TS 3.3.4.2, Required Actions A.1 and A.2
- TS 3.3.5.1, Required Actions B.3, C.2, D.2.1, E.2, and F.2
- TS 3.3.5.3, Required Actions B.2 and D.2.1
- TS 3.3.6.1, Required Action A.1
- TS 3.3.8.1 (Unit 1), Required Actions B.1, and C.1
- TS 3.3.8.1 (Unit 2), Required Actions B.1, C.1, and D.1
- TS 3.7.2, Required Action B.1
- TS 3.8.7, Required Actions A.1 and B.1

The loss of function note would prohibit using a RICT under conditions where a loss of function occurs. Section 3.1.1 of this safety evaluation further explains loss of function.

The licensee also proposed conforming changes, when necessary, to periodic completion times following use of a RICT. For example, most technical specifications have required actions to close or isolate containment isolation devices if one or more containment penetrations have inoperable devices. The technical specifications would then have completion times for initially isolating the penetration and periodically verifying that the penetration remains isolated. By adding the flexibility to determine the completion time for initially isolating the penetration using a RICT, the completion time for the periodic verifications would need to be written in terms of "following isolation."

1.3.4 Variations from TSTF-505, Revision 2 and Other Changes

The licensee proposed variations from TSTF-505 [4] and other TS changes not related to TSTF-505, which are evaluated in section 3.2 of this safety evaluation. TSTF-505 [4] uses the standard technical specifications in NUREG-1433, Revision 3.1 [11]; however, Susquehanna's technical specifications are based on NUREG-1433, Revision 1 [12]. The Susquehanna conversion to the improved technical specifications retained elements of the original technical specifications, elements that were consistent with its licensing basis and that differ from NUREG-1433, Revision 1 [12]. Therefore, the licensee proposed formatting variations from TSTF-505 [4], including different numbering of some required actions. In attachment 1 to the LAR [1] and its supplement [2], the licensee proposed editorial and administrative changes to its technical specifications to correct formatting issues, typographical errors, grammatical errors, and punctuation errors.

The licensee also requested the following variations relating to the applicability of TSTF-505 [4] to the Susquehanna technical specifications.

- Add a loss-of-function note, as discussed in section 1.3.3 of this safety evaluation that states, "Not applicable if there is a loss of function," instead of the phrasing of the TSTF-505 [4] note that states, "Not applicable when [all] required [channels] are inoperable."
- Add a note (i.e., "Only applicable to AC electrical power sources included in the PRA model") modifying the RICT applicability in Unit 1 TS 3.8.7, Required Action A.1 and in Unit 2 TS 3.8.7, Required Actions A1, C.1, and D.1.
- Apply the RICT program to the following plant-specific technical specifications and Required Actions either excluded from or not covered in TSTF-505 [4]:
    - TS 3.3.2.1, Required Action A.1
    - TS 3.3.8.1 (Unit 1), Required Actions B.1 and C.1
    - TS 3.3.8.1 (Unit 2), Required Actions B.1, C.1, and D.1
    - TS 3.5.1, Required Action B.1
    - TS 3.7.1, Required Actions A.3 and B.1
    - TS 3.7.2, Required Action B.1
    - TS 3.8.7 (Unit 2), Required Actions C.1 and D.1

The licensee also proposed to remove temporary technical specifications that have expired.

2.0 REGULATORY EVALUATION

2.1 Regulations

Title 10 of the *Code of Federal Regulations* (10 CFR) Part 50 provides the general provisions for *Domestic Licensing of Production and Utilization Facilities*. The NRC staff reviewed the LAR against the following regulations in 10 CFR Part 50.

- 10 CFR 50.36, "Technical specifications," particularly paragraphs 50.36(a)(1), (b), (c)(2), and (c)(5)
- 10 CFR 50.55a(h), "Protection and safety systems"
- 10 CFR 50.65, "Requirements for monitoring the effectiveness of maintenance at nuclear power plants" (the Maintenance Rule)

2.2 Licensing Basis

- Chapter 8, "Electric Power," of the updated final safety analysis report (UFSAR) [13] describes the design of applicable safety-related electrical power systems.
- Chapter 7, "Instrumentation and Controls," of the UFSAR [13] in combination with the section 2, "Evaluation of Instrumentation and Control Systems," of enclosure 1 to the LAR [1] describe the design and defense-in-depth features of applicable safety-related instrumentation and control (I&C) systems.
- Susquehanna Unit 2 Amendment Nos. 248 [14] and 263 [15] changed the technical specifications to allow the licensee to replace load center transformers.

2.3 Guidance

- RG 1.174, Revision 2, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis" [16] [4]
- RG 1.177, Revision 1 "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications" [17] [5]
- RG 1.200, Revision 2 "An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities" [10],[6] which endorses, with clarifications and qualifications, the use of the consensus standard developed jointly by the American Society of Mechanical Engineers (ASME) and the

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[4] The NRC issued RG 1.174, Revision 3 in January 2018 [49]. The NRC staff determined that this update does not introduce any discrepancies that would affect the staff's review of the RICT program. Therefore, the staff finds the licensee's use of RG 1.174, Revision 2 to be acceptable for implementation of the RICT program. Unless otherwise noted, citations of RG 1.174 refer to Revision 2.

[5] The NRC issued RG 1.177, Revision 2 in January 2021 [46]. The NRC staff determined that this update does not introduce any discrepancies that would affect the staff's review of the RICT program. Therefore, the staff finds the licensee's use of RG 1.177, Revision 1 to be acceptable for implementation of the RICT program. Unless otherwise noted, citations of RG 1.177 refer to Revision 1.

[6] The NRC issued RG 1.200, Revision 3 in December 2020 [47]. The NRC staff determined that this update does not introduce any discrepancies that would affect the staff's review of the RICT program. Therefore, the staff finds the licensee's use of RG 1.200, Revision 2 to be acceptable for implementation of the RICT program. Unless otherwise noted, citations of RG 1.200 refer to Revision 2.

American Nuclear Society (ANS), ASME/ANS RA-Sa-2009, “Addenda to ASME/ANS RA-S-2008, Standard for Level 1/Large Early Release Frequency Probabilistic Risk Assessment for Nuclear Power Plant Applications,” dated February 2009 (the PRA Standard) [18]

- NUREG-1792, “Good Practices for Implementing Human Reliability Analysis (HRA)” [19]
- NUREG-1855, Revision 1, “Guidance on the Treatment of Uncertainties Associated with PRAs in Risk-Informed Decision-making” [20] (This NUREG, in association with EPRI 1016737, “Treatment of Parameter and Model Uncertainty for probabilistic Risk Assessments” [21] and EPRI 1026511, “Practical Guidance on the Use of PRA in Risk-Informed Applications with a Focus on the Treatment of Uncertainty” [22], provides guidance on how to meet the PRA standard’s requirements for uncertainties.)
- NUREG-1921, “EPRI/NRC-RES Fire Human Reliability Analysis Guidelines—Final Report” [23]
- NUREG/CR-6850 (EPRI 1011989), “EPRI/NRC-RES Fire PRA Methodology for Nuclear Power Facilities,” Volume 1, “Summary & Overview,” and Volume 2, “Detailed Methodology” [24]
- Frequently Asked Question (FAQ) 08-0042, “Fire Propagation from Electrical Cabinets,” from Supplement 1 of NUREG/CR-6850 [25]
- FAQ 12-0064, “Hot Work/Transient Fire Frequency Influence Factors” [26]
- FAQ 13-0004, “Clarifications on Treatment of Sensitive Electronics” [27]
- FAQ 14-0009, “Treatment of Well-Sealed MCC [motor control center] Electrical Panels Greater than 440V” [28]
- TSTF-505, Revision 2 [4], which is approved by the NRC letter dated November 21, 2018 [29]
- NEI 06-09-A [9], which is endorsed by the NRC letter dated May 17, 2007 [30]
- Appendix X to NEI 05-04/07-12/12-13 [31], which is accepted by the NRC in its letter dated May 3, 2017 [32]
- The NRC letter dated June 21, 2012, “Recent Fire PRA Methods Review Panel Decisions and EPRI 1022993, Evaluation of Peak Heat Release Rates in Electrical Cabinet Fires” [33]

3.0 TECHNICAL EVALUATION

In determining whether an amendment to a license will be issued, the NRC staff is guided by the considerations that govern the issuance of initial licenses to the extent applicable and appropriate. The staff evaluated the LAR [1], as supplemented [2] [3], to determine whether the proposed changes are consistent with the applicable regulations, licensing and design basis information, and guidance discussed in section 2.0 of this safety evaluation. The staff reviewed the proposed changes to technical specifications to determine whether they provide reasonable assurance of continued compliance with 10 CFR 50.36. The staff reviewed the licensee’s PRA methods and the history of the licensee’s PRA peer review and results. The staff assessed proposed alternative methods and approaches to determine whether they are acceptable for use in developing RICTs. The staff also reviewed the licensee’s proposed RICT program to determine if it provides the necessary administrative controls to allow RICT extensions.

3.1 Evaluation of Key Principles

RG 1.174 [16] and RG 1.177 [17] identify five key safety principles to be applied to risk-informed changes to the technical specifications:

- Principle 1: The proposed change meets the current regulations unless it is explicitly related to a requested exemption.
- Principle 2: The proposed change is consistent with the defense-in-depth philosophy.
- Principle 3: The proposed change maintains sufficient safety margins.
- Principle 4: When the proposed change results in an increase in CDF or risk, the increase should be small and consistent with the intent of the Commission's policy statement on safety goals for the operations of nuclear power plants. RG 1.177 [17] describes a three-tiered approach for evaluating this principle:
    - Tier 1: PRA capability and insights
    - Tier 2: avoidance of risk-significant plant configurations
    - Tier 3: risk-informed configuration risk management
- Principle 5: The impact of the proposed change should be monitored by using performance measures strategies.

NEI 06-09-A [9] incorporates these principles. The NRC staff evaluated the licensee's proposed use of RICTs against these key safety principles, as described in the following sections of this safety evaluation.

3.1.1 Principle 1: Compliance with Current Regulations

As discussed in RG 1.174 [16] and RG 1.177 [17], principle 1 states that the proposed change meets the current regulations unless it is explicitly related to a requested exemption. Section 50.36(c)(2) of 10 CFR states that LCO are the lowest functional capability or performance levels of equipment required for safe operation of the facility and requires that when an LCO is not met, the licensee shall shut down the reactor or follow any remedial action permitted by the technical specifications until the condition can be met. Section 50.36(c)(5) states that administrative controls are the provisions relating to organization and management, procedures, recordkeeping, review and audit, and reporting necessary to assure operation of the facility in a safe manner.

The current completion times are fixed periods ("front stops"). Experiential data, risk insights, and engineering judgment informed the completion times. A RICT program would allow the licensee to extend specific completion times by using risk insights. The licensee proposed to perform its RICT evaluation consistent with NEI 06-09-A [9] and TS 5.5.16. The RICT program would limit the RICT to a maximum of 30 days (the "back stop"). The RICT program would also provide the necessary administrative controls to allow extending the completion times and, thereby, delaying reactor shutdown or other required actions if the licensee assesses and manages risk within specified limits and programmatic requirements. Therefore, the NRC staff finds that the proposed TS 5.5.16 meets the requirements of 10 CFR 50.36(c)(5) for including administrative controls in the technical specifications.

If the licensee does not maintain necessary equipment redundancy and the system loses the capability to perform its intended functions (i.e., there is a "loss of function"), then the plant must exit the LCO mode of applicability, or the licensee must take required actions specified in the technical specifications. This could occur, for example, if both trains of a two-train system become inoperable. When the capability to perform a required function is lost, the licensee may not use a configuration-specific RICT. Therefore, the licensee proposed loss-of-function notes for several RICTs. The NRC staff finds that these notes would appropriately exclude the licensee from applying a RICT if a loss of function occurred under the conditions and actions that would have RICTs.

The NRC staff reviewed the proposed changes and concluded that incorporation of the RICT program into technical specifications does not change the required performance levels of equipment specified in LCOs. Rather, the RICT program would only modify the required completion time for the required actions, such that 10 CFR 50.36(c)(2) will still be met. Therefore, the staff finds that adopting the RICT program would meet the first key safety principle of RG 1.174 [16] and RG 1.177 [17].

3.1.2 Principle 2: Defense in Depth

As discussed in RG 1.174 [16] and RG 1.177 [17], principle 2 states that the proposed change is consistent with the defense-in-depth philosophy. As discussed in RG 1.174 [16] and RG 1.177 [17], consistency with the defense-in-depth philosophy is maintained under the following circumstances:

- A reasonable balance is preserved among prevention of core damage, prevention of containment failure, and consequence mitigation (i.e., the three layers of defense).
- Overreliance on programmatic activities as compensatory measures associated with the change in the licensing basis is avoided.
- System redundancy, independence, and diversity are preserved commensurate with the expected frequency, consequences of challenges to the system, and uncertainties.
- Defenses against potential common-cause failures are preserved, and the potential for the introduction of new common-cause failure mechanisms is assessed.
- Independence of barriers is not degraded.
- Defenses against human errors are preserved.
- The intent of the plant's design criteria is maintained.

3.1.2.1 General Evaluation of Defense-in-Depth

The licensee requested to use the RICT program to extend the existing completion times for the technical specifications identified in Attachment 2 of the LAR [1], as supplemented [2]. In Attachment 5 and Enclosure 1 of the LAR [1], as supplemented [2], the licensee provided a description and assessment of the redundancy and diversity for the proposed changes. The NRC staff's evaluation of the proposed changes assessed the redundant or diverse means to mitigate accidents to ensure consistency with requirements using the guidance in RG 1.174 [16], RG 1.177 [17], and TSTF-505 [4] to ensure that the changes are consistent with the defense-in-depth philosophy.

The licensee did not propose any changes to the design of the plant, operating parameters or configurations, or design bases. Therefore, the licensee would be maintaining capability and intent of design features that preserve the three layers of defense; system redundancy, independence, and diversity; defense against potential common-cause failures; multiple fission product barriers; and sufficient defense against human errors, as discussed below. Technical specifications currently allow redundancy to be temporarily reduced between the time when the plant enters a condition that results in the LCO not being met and the licensee's front stop completion time of the associated Required Actions.

The proposed RICT program would allow completion times to vary according to the risk significance of the plant configuration (i.e., equipment in service at any given time). Using a RICT would be permitted only so long as all intended functions can be performed by operable plant systems that remain in service. The NRC staff finds that restricting the use of RICTs in this way is consistent with the defense-in-depth philosophy of RG 1.177 [17].

The proposed RICT program would require the licensee to use plant-specific operating experience for component reliability and availability data. Thus, the allowances permitted by the RICT program would reflect actual component performance. When using the RICT program, the licensee would also determine the risk significance of plant configurations and identify equipment having the greatest effect on the existing configuration risk. With this information, the licensee could manage the duration of out-of-service equipment and determine the consequences of removing additional equipment from service.

The RICT program may use compensatory actions to reduce calculated risk in some configurations. When credited in the PRA, NEI-06-09-A [9] (via the new TS 5.5.16), would require the licensee to incorporate these actions into station procedures or work instructions and model these actions using appropriate human reliability considerations. The RICT program would assist the licensee in identifying effective compensatory actions for various plant maintenance configurations to maintain and manage acceptable risk levels. NEI 06-09-A [9] has examples of acceptable compensatory measures. The NRC staff finds that using compensatory actions in this way is consistent with the defense-in-depth philosophy of RG 1.177 [17].

3.1.2.2 Evaluation of RICTs for Electrical Power Systems Technical Specifications

The NRC staff evaluated whether the proposed changes maintain the defense-in-depth philosophy for electrical power system configurations during application of the proposed RICT program. The licensee proposed to apply the RICT program to the following electrical system technical specifications (applies to both units' technical specifications unless otherwise noted, and the '*' denotes the RICT would not be applicable if there is a loss of function):

- TS 3.8.1, Required Actions A.3, B.4, C.1, D.1, and D.2
- TS 3.8.4, Required Actions A.3, B.1, and C.1
- *TS 3.8.7 (Unit 1), Required Actions A.1 and B.1
- *TS 3.8.7 (Unit 2), Required Actions A.1, B.1, C.1, and D.1

In enclosure 12, "Risk Management Action Examples [RMAs]," to the LAR [1] and the supplement [2], the licensee provided multiple examples of RMAs that may be considered during a RICT program entry for the above required actions to reduce the risk impact and ensure adequate defense in depth.

The staff reviewed information pertaining to the proposed electrical power systems technical specification changes in the LAR [1], as supplemented [2]; Chapter 8 of UFSAR [13], which describes the design of applicable safety related electrical power systems; and applicable technical specifications and technical specification bases to verify the capacity and capability of the affected electrical power systems to perform their safety functions (assuming no additional failures) are maintained. The staff verified that the design success criteria of the proposed technical specification condition (as provided in enclosure 1 to the LAR [1] and supplement [2]) reflect the redundant or absolute minimum electrical power source or subsystem required to be operable by the LCOs to support the safety functions necessary to mitigate a postulated design basis accident (DBA), safely shut down the reactor, and maintain the reactor in a safe shutdown condition. The staff also reviewed the proposed RMA examples and found that these RMAs are consistent with NEI 06-09-A [9] and are appropriate to monitor and control risk for the condition applicable to the proposed technical specification change.

Given that the completion time extension would be implemented in accordance with the RICT program, and that the proposed RMAs would be implemented consistently with NEI 06-09-A [9], the staff finds that the licensee will maintain adequate defense in depth during extended completion times. The staff finds that completion time extensions are acceptable because the affected systems' capacity and capability to perform their safety functions (assuming no additional failures) are maintained, and the licensee's controls for identifying and implementing compensatory measures or RMAs, in accordance with the RICT program, are appropriate to monitor and control risk. Therefore, the staff finds the application of the RICT program to the technical specifications listed in this section of this safety evaluation acceptable.

3.1.2.3 Evaluation of RICTs for Instrumentation and Control Systems Technical Specifications

The licensee proposed to apply the RICT program to extend the existing completion times for the following technical specification actions for safety related I&C systems (the '*' denotes the RICT would not be applicable if there is a loss of function):

- *TS 3.3.1.1, Required Actions A.1, A.2, B.1, and B.2
- TS 3.3.2.1, Required Action A.1
- TS 3.3.2.2, Required Action A.1
- *TS 3.3.4.1, Required Actions A.1 and A.2
- *TS 3.3.4.2, Required Actions A.1 and A.2
- *TS 3.3.5.1, Required Actions B.3, C.2, D.2.1, E.2, and F.2
- *TS 3.3.5.3, Required Actions B.2 and D.2.1
- *TS 3.3.6.1, Required Action A.1
- *TS 3.3.8.1 (Unit 1), Required Actions B.1 and C.1
- *TS 3.3.8.1 (Unit 2), Required Actions B.1, C.1, and D.1

Enclosure 1 to the LAR [1] provided information supporting the evaluation of the redundancy, diversity, and defense-in-depth for each LCO and required action as it related to I&C systems. The NRC staff evaluated the proposed changes against the design and defense-in-depth features described in chapter 7 of the UFSAR [13] and the enclosure to determine whether they would maintain defense in depth for the I&C system configurations during application of the proposed RICT program. The staff evaluated whether the changes would be consistent with the defense-in-depth philosophy of preserving: (1) redundancy and diversity commensurate with the expected frequency and consequences of challenges to the system and (2) adequate design feature capability without an overreliance on programmatic activities as compensatory measures. For the RICTs specific to I&C systems, the staff reviewed the specific trip logic arrangements, redundancy, backup systems, manual actions, and diverse trips specified for each of the protective functions and associated instrumentation. The staff evaluated the proposed changes' effects on the availability of diverse means to mitigate DBAs during a RICT. The staff also evaluated the adequacy of the loss-of-function notes for applicable RICTs.

The staff verified that there is at least one diverse means available to mitigate DBAs that credit the risk-informed individual functional units for these technical specifications. The subject action statements for TS 3.3.2.2, TS 3.3.4.1, TS 3.3.4.2, TS 3.3.5.1 (except for function 3.d), TS 3.3.5.3, and TS 3.3.6.1 have at least one diverse means, other than manual actions, available to mitigate an accident.

The diverse means for subject action statements TS 3.3.1.1 (functions 1.b, 2.d, 2.e, 10, and 11), TS 3.3.5.1 (function 3.d), and TS 3.3.8.1 are manual actions. For TS 3.3.1.1 functions 1.b, 2.d, 2.e, 10, and 11, the diverse means of mitigating an accident is manual actions. In its supplement [2], the licensee confirmed that its PRA models do not credit the manual actions for TS 3.3.1.1, functions 1.b, 2.d, 2.e, 10, and 11; however, these actions are not time critical, and plant operation manuals and procedures prescribe the manual actions. The licensee also confirmed that the diverse means for TS 3.3.5.1, function 3.d is for the operators to manually realign the high-pressure coolant injection (HPCI) system from the condensate storage tank to the suppression pool. The automatic depressurization system (ADS) with a low pressure ECCS (core spray or low-pressure coolant injection (LPCI)) available is functionally redundant to HPCI. The licensee has approved plant procedures that have this manual action. The steps are simple operator actions performed in the control room. The licensee evaluated and confirmed that this manual action is not a time critical operator action. The licensee confirmed that for the subject actions in TS 3.3.8.1, the voltage detection functions are tiered, which provides defense in depth for instrumentation, including time delay relays. Furthermore, the operator would have multiple indications or alarms of degraded grid voltage conditions, and approved plant procedures would direct operator actions if the automatic actions of the undervoltage relays did not occur. Operations manuals or procedures prescribe these manual actions, and the manual actions are not time critical. Therefore, the staff finds that the licensee did not over rely on programmatic activities as compensatory measures.

The NRC staff determined the proposed changes are consistent with the defense-in-depth philosophy by preserving the diversity commensurate with the expected frequency and consequences of challenges to the system and, when applicable, by preserving adequate capability of design features without an overreliance on programmatic activities as compensatory measures. The staff finds that while the I&C redundancy would be reduced temporarily during a RICT, the completion time extensions implemented in accordance with the RICT program are acceptable because the capability of the I&C systems to perform their intended functions is maintained, the licensee demonstrated there is at least one redundant or diverse means to accomplish each function, the licensee will identify and implement RMAs to monitor and control risk in accordance with the RICT program, and the technical specification excludes potential loss of function. The staff finds that the availability of the redundant or diverse protective features provide sufficient defense-in-depth to accomplish the safety functions and would allow extending completion times in accordance with the RICT program. The staff finds that applying the proposed RICT program to the subject I&C systems would comply with 10 CFR 50.36(b) and 10 CFR 50.55a(h).

3.1.2.4 Principle 2 Conclusions

The NRC staff has reviewed the licensee's proposed technical specification changes and supporting documentation. The staff finds that the temporary reduced redundancy during an extended completion time is acceptable when the licensee maintains the affected systems' safety functions and defense in depth via appropriate compensatory measures.

NEI 06-09-A [9] would require the licensee to initiate compensatory measures when it exceeds the PRA-calculated risk management action time (RMAT) or, for preplanned maintenance for which the licensee expects to exceed the PRA-calculated RMAT, to implement RMAs at the earliest appropriate time. Therefore, the NRC staff finds that the quantitative risk analysis, qualitative considerations, and the prohibition on the loss of all trains of a required system would enable the licensee to maintain a reasonable balance of defense in depth.

As discussed above, the NRC staff has evaluated key safety functions in the proposed completion time extensions and finds that the proposed completion time changes are consistent with the defense-in-depth philosophy because the changes:

- preserve system redundancy (with the exceptions discussed above), independence, and diversity commensurate with the expected frequency and consequences of challenges to the systems
- preserve adequate capability of design features without an overreliance on programmatic activities as compensatory measures
- preserve a reasonable balance among redundant and diverse key safety functions that preserve the three layers of defense
- meet the intent of the plant's design criteria

Therefore, the NRC staff concludes that the proposed adoption of the RICT program meets the second key safety principle of RG 1.177 [17] and, therefore, is acceptable. The staff also concludes that the proposed changes are consistent with the defense-in-depth philosophy as described in RG 1.174 [16].

3.1.3 Principle 3: Safety Margins

As discussed in RG 1.174 [16] and RG 1.177 [17], principle 3 states that the proposed licensing basis change maintains sufficient safety margins. Section 2.2.2 of RG 1.177 [17] states, in part, that sufficient safety margins are maintained under the following circumstances:

- Codes and standards…or alternatives approved for use by the NRC are met….
- Safety analysis acceptance criteria in the final safety analysis report (FSAR) are met or proposed revisions provide sufficient margin to account for analysis and data uncertainties….

The licensee's proposal to add the RICT program to its technical specifications does not change the licensee's conformance or compliance with any codes and standards; result in physical changes to equipment, such as equipment material, design, or function; or change accident analyses assumptions. Therefore, the licensee's proposed changes do not affect safety margin values in its calculations and design basis analyses.

The NRC staff evaluated the effect on safety margins if the licensee extends a completion time to a backstop of 30 days. The temporary reduction in redundancy of equipment subject to a RICT would not adversely impact the capability of performing the safety function because the acceptance criteria for equipment operability are not changed. If sufficient equipment remains operable to fulfill the technical specification safety function, then the operability of the remaining equipment provides reasonable assurance that the current safety margins are maintained. If the technical specification safety function cannot be fulfilled, then the technical specifications would require the licensee to take other remedial actions, such as shutting down the reactor. Therefore, the staff finds that the licensee would maintain safety margins when applying a RICT.

The licensee may also consider the "PRA functionality," as described in NEI 06-09-A [9], of inoperable equipment when figuring out safety margin in a RICT calculation. Additionally, NEI 06-09-A identifies that the licensee's RICT calculations should accurately reflect the risk of the specific plant configuration in terms of the available mitigating capability of inoperable SSCs. NEI 06-09-A also identifies that the licensee should document its justification for crediting inoperable but PRA-functional SSCs in the RICT calculation.

The NRC finds that the licensee would maintain safety margins when applying the RICT program because the proposed changes do not affect safety margin values in its calculations and design basis analyses, the technical specifications already require actions that maintain safety margins when certain equipment is inoperable, and any increase in unavailability would be included in the RICT evaluation per NEI 06-09-A [9]. The staff finds that the proposed adoption of the RICT program meets the third key safety principle of RG 1.177 [17] and, therefore, is acceptable.

3.1.4 Principle 4: Consistency with the Safety Goals Policy Statement

As discussed in RG 1.174 [16] and RG 1.177 [17], principle 4 states that when proposed licensing basis changes result in an increase in risk, the increases should be small and consistent with the intent of the Commission's policy statement on safety goals for the operation of nuclear power plants. NEI 06-09-A [9] provides licensees with a methodology to evaluate and manage the risk impact of technical specification completion time extensions. The licensee's proposed RICT program uses the three-tiered approach described in RG 1.177 [17] to address the calculated change in risk as measured by the change in core damage frequency (ΔCDF), change in large early release frequency (ΔLERF), incremental conditional core damage probability, and incremental conditional large early release probability; the use of compensatory measures to reduce risk; and the implementation of a configuration risk management program (CRMP) to identify risk-significant plant configurations.

The NRC staff evaluated the licensee's processes and methodologies for determining that the change in risk from implementing RICTs will be small and consistent with and RG 1.174 [16]. The staff evaluated the licensee's proposed changes and methods for determining the risk for a proposed RICT against the three-tiered approach in RG 1.177 [17]. The results of the staff's review are discussed below.

3.1.4.1 Tier 1: PRA Capability and Insights

The NRC staff reviewed the licensee's proposed application of the three-tiered approach in RG 1.177 [17]. The first tier evaluates the impact of the proposed changes on plant operational risk. RG 1.174 [16] states that the PRA's scope, level of detail, and technical acceptability are to be commensurate with the application for which it is intended and with the role the PRA results play in the integrated decision-making process. The NRC's safety evaluation [30] for NEI 06-09 states that the PRA models should conform to the guidance in RG 1.200, revision 1 [34]. Revision 2 of RG 1.200 [10] clarifies that the applicable PRA standard is ASME/ANS RA-Sa-2009 [18].

To determine if the licensee's application met the first tier of RG 1.177 [17], the NRC staff reviewed technical acceptability of the licensee's PRA models, including the models' results and insights, and the models' application to the proposed changes. The staff evaluated the PRAs scope, acceptability, results, insights, key assumptions, and uncertainty analysis for internal events, internal flooding, fires, and external hazards, including seismic events and analyses other hazards.

3.1.4.1.1 PRA Scope

RG 1.174 states that the scope of a PRA is defined in terms of the causes of initiating events and the plant operating modes it addresses. The causes of initiating events are classified into hazard groups. Typical hazard groups considered in a nuclear power plant PRA include internal events, internal floods, seismic events, internal fires, high winds, and external flooding. A qualitative treatment of the missing modes and hazard groups may be sufficient when there is not a PRA of such scope if the licensee can demonstrate that those risk contributions would not affect the decision. The NRC staff reviewed the types of PRA models that the licensee plans to use for the RICT program. For external hazards for which a PRA is not available, the guidance in NEI 06-09-A [9] allows for the use of bounding analysis of the risk contribution of the hazard for incorporation into the RICT calculation or justification for why the hazard is not significant to the RICT calculation.

Enclosures 2 and 4 to the LAR [1] identify the following modeled hazards and alternate methodologies the licensee proposed to use in the RICT program to assess the risk contribution from extending a completion time:

- internal events PRA (IEPRA) and internal flooding PRA models
- fire PRA (FPRA) model
- seismic hazard with a CDF penalty of 1.70E-06 per year and a LERF penalty of 8.72E-07 per year
- other external hazards that are screened out from consideration in the RICT program based on appendix 6-A of the PRA Standard [18]

Based on the above, the licensee considered all hazard groups in support of the RICT program using PRAs, bounding methods, or screening analyses. The NRC staff finds the scope of modeled PRA hazards and other hazards (for which a modeled PRA is not available and the licensee proposed use of alternative methods) is consistent with RG 1.174 [16] and is appropriate and adequate for the RICT application.

3.1.4.1.2 Internal Events and Fire PRA Acceptability

3.1.4.1.2.1 Internal Events PRA

To determine if the IEPRA models, which include the internal flooding PRA models, are acceptable for use in the RICT program, the NRC staff reviewed the adequacy of the IEPRA model reviews and assessments, including facts and observations (F&Os) closure and impacts of open F&Os on the RICT program.

In section 3 of enclosure 2 to the LAR [1], the licensee stated that the IEPRA model received a peer review in October 2012, using NEI 05-04 [35], the PRA Standard [18], and revision 2 of RG 1.200 [10]. The licensee stated that it performed multiple IEPRA model adjustments to resolve the F&Os identified from the 2012 IEPRA peer review. The licensee had subsequent independent assessments performed in April 2018, and September 2020, on the IEPRA (not including internal flooding, as discussed in the next paragraph) to close F&Os using appendix X to NEI 05-04/07-12/12-13 [31], as accepted by the NRC staff [32]. As a result of the F&O closure review, one IEPRA F&O (F&O 1-18) remained open.

In 2014, the licensee separated the internal flooding PRA from the IEPRA. In June 2015, the licensee had a focused scope peer review of the internal flooding PRA performed. The licensee stated that it made multiple internal flooding PRA model adjustments to resolve the F&Os found during the June 2015 internal flooding PRA peer review. In August 2018, the licensee had a subsequent independent assessment of the internal flooding PRA performed for closure of F&Os using appendix X to NEI 05-04/07-12/12-13 [31], as accepted by the NRC staff [32]. The licensee closed all internal flooding PRA F&Os as a result of the F&O closure review.

The NRC staff reviewed F&O 1-18, which was the one remaining open IEPRA F&O, and the licensee’s proposed disposition of the F&O described in table E2-1 in enclosure 2 to the LAR [1]. The licensee stated that it planned to review and update the list of IEPRA modeling assumptions and sources of uncertainties and provide dispositions that are specific to this application. In its response to audit question Q-002 [2], the licensee stated that during an F&O

closure meeting in November 2021, it resolved and closed F&O 1-18 in accordance with appendix X to NEI 05-04/07-12/12-13 [31]. The staff confirmed that the licensee resolved F&O 1-18, reviewed and updated the list of IEPRA modeling assumptions and sources of uncertainties, and provided dispositions specific to this application. The also confirmed that the licensee addressed assumptions and sources of uncertainty determined to be key to this application in a sensitivity study demonstrating that uncertainty has an inconsequential impact on the RICT calculations. The staff finds that there are no open IEPRA F&Os that can affect the RICT program.

The NRC staff finds that the licensee had the IEPRA and internal flooding PRA models appropriately peer reviewed consistent with RG 1.200 [10]; closed F&Os consistent with appendix X to NEI 05-04/07-12/12-13 [31], as accepted by the NRC staff [32]; and there are no open F&Os that can affect the RICT program. Therefore, the staff concludes that the IEPRA and internal flooding PRA models are acceptable for use in the RICT program.

3.1.4.1.2.2 Fire PRA

To determine if the internal FPRA model is acceptable for use in the RICT program, the NRC staff reviewed the adequacy of the FPRA peer reviews and assessments, including closure of F&Os and impacts of open F&Os on the RICT program, and FPRA methodologies.

3.1.4.1.2.2.1 Peer Reviews and Assessments

In section 4 of enclosure 2 to the LAR [1], the licensee stated that the FPRA model received a full-scope peer review in February 2018, using NEI 07-12 [36], the PRA Standard [18], and RG 1.200 [10]. The licensee also stated that it performed multiple FPRA model adjustments to resolve the F&Os identified during the 2018 FPRA peer review. In June 2019, the licensee had an independent assessment performed consistent with appendix X to NEI 05-04/07-12/12-13 [31], as accepted by the NRC staff [32].

The licensee had its latest full-scope peer review of the FPRA performed in February 2018, which is before the IEPRA F&O closure review in April 2018. The licensee also had the FPRA F&O closure review performed in June 2019, which is before the final IEPRA F&O closure review in September 2020. Given that the IEPRA provides the modeling foundation for the FPRA and the timing of the reviews and F&O closures, the NRC staff evaluated whether the licensee incorporated into its FPRA all internal events modeling updates performed to resolve F&Os that could impact fire risk. In its response to audit question Q-023 [2], the licensee stated that the PRA uses a common backbone model that is shared across multiple hazard PRAs (i.e., internal events, internal flooding, and fire PRA modeling). Based on the common backbone model approach, the licensee uses one logic model to model all hazards and, therefore, internal events model updates are automatically reflected in the hazard-specific modeling. The licensee also stated that the same is true for updates to the fire or internal flooding PRA models. Based on this information, the NRC staff finds that the licensee incorporated into its FPRA internal events modeling updates performed to resolve internal events F&Os that could impact fire risk.

The NRC staff also reviewed the open F&Os and their dispositions provided by the licensee in table E2-2 in enclosure 2 to the LAR [1]. The staff considered whether the FPRA F&O

dispositions for F&Os 1-9, 5-4, and 7-1 resolved the associated F&Os. The licensee provided additional information in its supplement [2] regarding whether those F&Os have a consequential impact on the RICT program.

F&O 1-9: The licensee's disposition of F&O 1-9 provided in its LAR stated that the licensee had not yet incorporated modeling for multiple spurious operation scenario 2aj (i.e., spurious opening of valves causing draindown of the hotwell and failure of control rod drive injection), but that it would during the PRA maintenance process. The NRC staff considered whether the omission of scenario 2aj from the FPRA would impact the RICT calculations for certain plant configurations. In its response to audit question Q-020 [2], the licensee explained that it reviewed scenario 2aj and determined that it can cause failure of control rod drive injection and, therefore, the licensee added model logic for scenario 2aj to the FPRA to resolve F&O 1-9. Because the licensee updated its FPRA to now incorporate scenario 2aj, the staff concludes that F&O 1-9 is resolved for this application.

F&O 5-4: The licensee's disposition of F&O 5-4 provided in its LAR stated that there is one credited cable that remained unlocated, but that it is very unlikely that one cable will have an impact of the overall FPRA results. The NRC staff considered whether the failure of PRA components supported by the unlocated cable could impact the RICT calculations for certain plant configurations. In its response to audit question Q-021 [2], the licensee explained that because of ongoing FPRA refinements, the licensee has located the cited cable and incorporated its fire impacts into the FPRA cable and raceway database. The licensee also stated that it will use the updated FPRA to calculate RICTs. Because the licensee updated its FPRA model to address this cable, the staff concludes that F&O 5-4 is resolved for this application.

F&O 7-1: The licensee's disposition of F&O 7-1 (regarding inadequate discussion and justification in the PRA documentation for crediting active partitions in the FPRA) provided in its LAR stated that the licensee updated PRA documentation to show that the fire barrier rating is indicated in the barrier name. However, the disposition also stated that the licensee has not added the justification for crediting active partitioning elements but that this documentation deficiency does not impact this application. The NRC staff considered whether the RICT calculations for certain plant configurations would be affected by whether other active partitions credited in the FPRA would perform reliably during the accident scenarios for which the licensee credits them. In its response to audit question Q-022 [2], the licensee provided a list of active barriers and their locations and fire ratings. This list consisted of doors and dampers that the licensee considers active barriers because they would change position in a fire event. The licensee stated that it did not credit any barriers requiring AC power or a water supply in the plant partitioning. The licensee also stated that fusible links activate all fire dampers, including motor-operated dampers that control smoke and dampers that have a carbon dioxide-actuated pneumatic release. The licensee stated that fire doors have hold-open devices with fusible links. Based on this information, the staff finds that mechanisms used to close fire dampers and doors for fire barriers credited in the FPRA are passive mechanisms that do not rely on active support systems and, therefore, further review of this F&O is not needed for the RICT application, and F&O 7-1 is resolved for this application.

3.1.4.1.2.2.2 Methodologies

The following discussion describes the staff's review and conclusions on how the licensee's PRA, as used to support the licensee's application for the RICT program, compares to methods in the NRC's published fire PRA methodology, NUREG/CR-6850 [24], or other related guidance, as identified below.

Heat Release Rates

The NRC staff reviewed the licensee's treatment of transient fire heat release rates (HRR) in its FPRA. The staff compared the licensee's HRR to the bounding HRR in NUREG/CR-6850 [24]. The NRC letter dated June 21, 2012 [33], discusses the key factors in justifying using transient fire HRRs below those identified in NUREG/CR-6850 [24]. The staff considered whether the licensee's reduced HRRs would affect the RICT application and whether the licensee's justification for its HRR included: identification of fire areas where a reduced transient fire HRR is credited and the value used, discussion of administrative controls, discussion of the controls required for ignition sources and the types and quantities of combustible materials needed to perform maintenance, discussion of expected personnel traffic in the fire areas, and the review results related to compliance with transient combustible and hot work controls.

In its response to audit question Q-024 [2], the licensee explained that it used a reduced HRR of 145 kilowatts, which is below the bounding 98th percentile HRR of 317 kilowatts in NUREG/CR-6850 [24], for two physical analysis units (PAUs) (the division 1 and 2 DC equipment rooms) in each unit. The licensee identified that it chose this HRR based on the results of fire tests reported in NUREG/CR-6850 [24] and the combustible materials potentially present in these PAUs. The licensee stated that these PAUs are combustible-restricted areas and that rooms in these PAUs have low occupancy and are not typical access or ingress paths. The licensee also stated that it uses a plant procedure on control of transient combustibles and hazardous material to control transient combustibles in the power block where the PAUs are located. This procedure establishes a permitting process for combustible materials and fire load limits for safety-related areas of the plant and requires that exceptions have specific technical justification or specific compensatory actions. The procedure prohibits the licensee from storing transient combustibles in combustible-restricted areas without a fire watch. In its supplement [2], the licensee stated that no transient combustible violations have occurred in the last three years. The licensee explained that it considers three years of historical records representative of current operating experience since the 2018 FPRA results when it first credited the reduced HRR.

The NRC staff finds using a reduced HRR for the specific PAUs acceptable for this application because the licensee satisfactorily used NRC guidance to justify its treatment of HRR in its FPRA.

Sensitive Electronics

The NRC staff reviewed the licensee's treatment of sensitive electronics in its FPRA against the guidance in FPRA FAQ 13-0004 [27]. The staff considered how the licensee addressed the caveats to the FAQ about configurations (i.e., sensitive electronics mounted on the surface of cabinets and the presence of louvers or vents) that can invalidate the FPRA model. In its response to audit question Q-025 [2], the licensee confirmed that its treatment of sensitive electronics in the FPRA is consistent with the guidance provided in FAQ 13-0004 [27]. The licensee explained that it used walkdowns to note the configuration of cabinets with sensitive electronics and observed that no cabinets had sensitive electronics mounted on the surface of cabinets or in the presence of louvers or vents. Based on this information, the staff concludes that the licensee's approach to the treatment of sensitive electronics for this application is consistent with NRC-approved guidance in FAQ 13-0004 [27] and, therefore, is acceptable.

Human Error Probability Values

The NRC staff reviewed the licensee's treatment of human error probabilities (HEP) in its FPRA. The staff reviewed the licensee's minimum joint HEP values against NUREG-1921 [23] and NUREG-1792 [19]. NUREG-1921 [23] discusses the need to consider a minimum value for the joint probability of human failure events and refers to table 2-1 of NUREG-1792 [19], which recommends that joint HEP values should not be below 1E-05. However, the guidance in NUREG-1921 [23] allows for assigning joint HEPs that are less than 1E-05 through assigning proper levels of dependency.

In its response to audit question Q-026 [2], the licensee explained it used a minimum joint HEP of 1E-06 for FPRA dependency analysis unless the timeframe for completing one or more actions in the combination of actions was longer than 12 hours. In these cases, the licensee used a lower minimum joint HEP of 5E-07. The licensee also explained that it performed a sensitivity study in which it applied a minimum joint HEP of 1E-05 and calculated RICTs for a sample of five LCO conditions. The licensee selected these LCO conditions because they represented plant configurations for which the RICTs are most likely to change in the sensitivity case and are less than the backstop of 30 days. The results of the sensitivity study show that the calculated RICTs and associated ΔCDF and ΔLERF values did not change. The licensee stated that future updates to the FPRA dependency analysis will include a review of the sensitivity of the RICT application to minimum joint HEP values.

The guidance in figure 6-1 of NUREG-1921 [23] identifies an operator action performed by a different crew leads to low dependency for even high stress scenarios. The NRC staff finds that for this application, the credit taken by the licensee for applying a lower joint HEP for combinations of actions that include a long-term action is consistent with the table 6-1 of NUREG-1921 [23]. The staff finds that for this application, the licensee demonstrated its HEP treatment meets the intent of applicable guidance for establishing an appropriate minimum joint HEP value, with allowance for further decrease consistent with the level of dependency of HEPs in the combination of actions. The staff also finds that even though the minimum joint HEP value for the FPRA is set at 1E-06, as opposed to the 1E-05 value cited in NUREG-1921 [23] and NUREG-1792 [19], the licensee showed via a sensitivity study that setting the minimum joint HEP for the FPRA to 1E-05 rather than 1E-06 or 5E-07 has a minimal impact on the RICT application. The licensee also stated that it will review the sensitivity study as part of future FPRA dependency analysis updates to confirm the sensitivity study results remain valid. Based on these findings and the licensee's updates of its FPRA dependency analysis, the staff concludes that the licensee's application of minimum joint HEP values for this application is acceptable.

Sealed Electrical Cabinets

The NRC staff reviewed the licensee's treatment of well-sealed electrical cabinets in its FPRA against the NRC guidance in FAQ 08-0042 from Supplement 1 of NUREG/CR-6850 [25] and FPRA FAQ 14-0009 [28]. FAQ 08-0042 [25] applies to electrical cabinets below 440 V. With respect to Bin 15, as discussed in chapter 6 of the supplement, the FAQ clarifies the meaning of "robustly or well-sealed." Thus, for cabinets of less than 440 V, fires from well-sealed cabinets do not propagate outside the cabinet. For cabinets of 440 V and higher, the original guidance in chapter 6 remains and states that Bin 15 panels that house circuit voltages of 440 V or greater are counted because an arcing fault could compromise panel integrity (i.e., an arcing fault could burn through the panel sides, but this should not be confused with the high energy arcing fault type fires). FPRA FAQ 14-0009 [28] provides the technique for evaluating fire damage from motor control center cabinets having a voltage of 440 V or greater. Propagation of fire outside the ignition source panel must be evaluated for all motor control center cabinets that house circuits of 440 V or greater. The staff considered whether the licensee included well-sealed cabinets less than 440 V in the Bin 15 count of ignition sources consistent with guidance in FAQ 08-0042 [25]. The staff also considered whether the licensee's evaluation of fire propagation outside of well-sealed motor control center cabinets of 440 V or greater was consistent with the NRC guidance in FPRA FAQ 14-0009 [28].

In its response to audit question Q-027 [2], the licensee confirmed that well-sealed cabinets less than 440 V are not included in the Bin 15 count of fire ignition sources per the guidance in NUREG/CR-6850 [25]. The licensee also stated that its treatment of well-sealed cabinets of 440 V or greater in the FPRA is consistent with the guidance provided in FAQ 14-0009 [28], in which a factor of 0.23 is used to model the fraction of fires assumed to breach a well-sealed cabinet or independent cabinet section. Based on this information, the NRC staff concludes that the licensee's approach to the treatment of well-sealed cabinets is acceptable for this application because it is consistent with NRC-approved guidance.

Hot Work and Transient Fires

The NRC staff reviewed the licensee's treatment of hot work and transient fires in its FPRA against section 6 of NUREG/CR-6850 [24] and FAQ 12-0064 [26], which describe the process for assigning influence factors for hot work and transient fires. The licensee's fire ignition frequency report (EC-RISK-1176, revision 2), which the staff reviewed during its audit of the LAR, discusses apportionment of the transient ignition source frequency using the guidance and weighting values provided in FAQ 12-0064 [26]. However, the licensee did not use the "very high" influence factor, which has a weighting factor of 50, applicable to the maintenance category. Therefore, the staff considered whether assigning weighting factors of 50, per the guidance in FAQ 12-0064 [26], would affect the RICT calculations.

In its response to audit question Q-028 [2], the licensee stated that the distribution of influence factors used in its FPRA followed a normal distribution as suggested by the guidance in FAQ 12-0064 [26] for the three major regions of the plant. The licensee explained that based on a panel that included the fire protection engineer and a representative from mechanical maintenance, no PAUs were determined to have a level of maintenance or hot work significantly higher than other PAUs that were assessed as "high." The licensee also presented the results of a sensitivity study in which the licensee raised the influence factor for four of the highest maintenance and hot work activity PAUs from "high" to "very high" (i.e., 50) in the sensitivity case. The results of the sensitivity study show that the calculated RICTs and the associated ΔCDF and ΔLERF values in the RICT calculation did not change.

The NRC staff finds that the distribution of influence factors was normal per NUREG/CR-6850 [24] and that the licensee applied them according to a panel that judged the "very high" transient fire influence factor of 50 not to be applicable. The staff also finds that the licensee showed that even if a "very high" influence factor of 50 was assigned to the four highest maintenance and hotwork activity PAUs, the impact on the RICT calculations would be negligible. Therefore, the staff finds the licensee's treatment of influence factors in its FPRA acceptable for this application.

Multi-Unit and Common Area Risk

The NRC staff reviewed the licensee's treatment of the risk contribution from fires affecting multiple units and common areas in its FPRA, including the risk contribution of fires originating in the other unit because of possible impacts from the physical proximity of equipment and cables. In its response to audit question Q-029 [2], the licensee stated that it accounts for the risk contribution of fires that originate in one unit but impact cables and equipment in the opposite unit by quantifying all fire initiators for all unit end states. The licensee explained that its fire scenario development for the FPRA considered all targets within the zone of influence, regardless of location within the respective units, and selected and analyzed them for fire-induced failures. The licensee clarified that it determined for each unit the fire risk associated with common areas where a fire can damage equipment associated with both units. Based on this information, the staff finds that the licensee's treatment of fire dependencies between units is acceptable for this application because fires that originate in Unit 1 but impact Unit 2 are quantified for Unit 2, and fires that originate in Unit 2, but impact Unit 1 are quantified for Unit 1. The staff also finds that the licensee adequately determined for each unit the fire risk associated with common areas where fire can damage equipment associated with both units.

3.1.4.1.2.2.2 Summary of Internal FPRA Review

Based on the above findings, the NRC staff concludes that the licensee had the FPRA appropriately peer reviewed consistent with RG 1.200 [10]; closed F&Os consistent with appendix X to NEI 05-04/07-12/12-13 [31], as accepted by the NRC staff [32]; and adequately assessed the remaining open F&Os for their impact on the RICT program. The staff also concludes that the licensee appropriately considered and implemented fire methodologies in its FPRA for this application. Therefore, the staff concludes that the FPRA is acceptable for use in the RICT program.

3.1.4.1.3 Evaluation of External Hazards

NRC's safety evaluation for NEI 06-09-A [9] states that sources of risk (i.e., such as seismic and other external events or hazards), must be quantitatively assessed if those events contribute significantly to configuration-specific risk. The safety evaluation further provides that bounding analyses or other conservative quantitative evaluations are permitted where realistic PRA models are unavailable. In addition, the safety evaluation notes that if sources of risk can be shown to be insignificant contributors to configuration risk, then they may be excluded from the RICT application.

The NRC staff reviewed the licensee's scope of seismic and other external hazards and the licensee's evaluation of those hazards to determine the acceptability of the consideration of risk from seismic and other external hazards for this application and whether those hazards are significant contributors to configuration risk.

3.1.4.1.3.1 External Hazards Scope and Evaluation Approach

The NRC staff reviewed the scope of external hazards considered by the licensee for this application. NUREG-1855, revision 1 [20] and the endorsed PRA Standard [18] provide guidance for identifying possible external hazards at a plant site and assessing the risk from those hazards. Enclosure 4 to the LAR [1] addresses the risk from seismic events and other external hazards in the context of the RICT program. Table E4-9 of enclosure 4 to the LAR [1] lists the external hazards the licensee assessed. The staff finds these hazards are consistent with those listed in appendix 6-A of the endorsed PRA Standard [18] and table 4-1 of NUREG-1855, Revision 1 [20].

Enclosure 4 to the LAR [1] provides an estimate for the risk from seismic events for use in determining the configuration risk for the RICTs identified in the LAR, as discussed further in section 3.1.4.1.3.2 of this safety evaluation. Enclosure 4 to the LAR [1] also provides the licensee's basis for excluding other external hazards from consideration in the determination of RICTs because of their insignificance to the configuration risk calculation, which is discussed further in section 3.1.4.1.3.3 of this safety evaluation. The licensee stated that its individual plant examination for external events (IPEEE) external screening evaluation was updated to support this LAR.

In section 2 of enclosure 4 to the LAR [1], the licensee stated that for the RICT program, it addresses external hazards by: (1) screening the hazard based on its low frequency of occurrence, (2) bounding the hazard's potential impact and including it in the decision making, or (3) developing a PRA model to be used in the RMAT and RICT calculations. The licensee stated that this approach is consistent with NUREG-1855, revision 1 [20]. The NRC staff notes that the licensee's screening criteria (i.e., for screening out the hazard from consideration in the RICT program) used and presented in table E4-6 of the LAR [1] are the same criteria (i.e., EXT-B1 and EXT-C1) in the endorsed PRA Standard [18] for screening external hazards and, therefore, are acceptable.

3.1.4.1.3.2 Seismic Events

The NRC staff reviewed how the licensee considered the effects of seismic event risk on RICT calculations. As described in section 3 of enclosure 4 to the LAR [1], the licensee's approach for including the seismic risk contribution in the RICT calculation is to add seismic CDF and LERF penalties to each RICT calculation. The staff reviewed the adequacy of the licensee's values of the seismic penalty factors. The staff also reviewed the impact of seismic-induced loss of offsite power (LOOP) risk on RICT calculations.

Seismic CDF Estimate

The licensee's proposed seismic CDF estimate is based on the convolution of the mean seismic hazard curve developed in response to the Near-Term Task Force Recommendation 2.1 for Susquehanna [37] with the mean plant-level fragility curve derived from a high confidence of low probability of failure (HCLPF) capacity of 0.3g (g is the force per unit mass due to gravity at the Earth's surface) from the IPEEE. The licensee referenced both the hazard and fragility curves to peak ground acceleration (PGA). The licensee represented the uncertainty parameter for seismic capacity by a composite beta factor (βc) of 0.4.

The plant-level HCLPF capacity of 0.3g proposed by the licensee for this application is higher than the value (0.21g) cited for Susquehanna in Generic Issue (GI)-199, "Implications of Updated Probabilistic Seismic Hazard Estimates in Central and Eastern United States on Existing Plants" [38]. A few components identified in the IPEEE had a HCLPF capacity as low as 0.21g. In its supplement [2], the licensee provided its basis for using the 0.3g value in estimating a seismic CDF penalty. The staff reviewed the licensee's information and determined that the licensee resolved the issue of low HCPLF components by modifying the configuration or condition of these components such that 0.3g plant level HCPLF capacity is established. Therefore, the NRC staff concludes that the licensee's use of a plant level HCLPF capacity of 0.3g is acceptable. The licensee's calculated seismic CDF penalty is 1.70E-06 per year. The staff confirmed this value by convolving the licensee-provided input parameters. The staff also finds that the licensee's method for determining the baseline seismic CDF is acceptable because it is consistent with the approach used in GI-199 [38].

The staff finds the seismic penalty is acceptable because (1) it estimates the seismic CDF penalty for all individual SSCs included in the RICT program, as the estimate is based on the plant-level HCPLF, which represents the lower bound of the individual SSC HCPLF values, and (2) the licensee's method for determining the seismic CDF penalty is consistent with the approach in GI-199 [38].

Seismic LERF Estimate

In its supplement [2], the licensee explains that its proposed seismic LERF estimate is obtained by convolving the estimated seismic CDF (as described above) with a limiting fragility for containment integrity, which is also based on 0.3g PGA HCLPF. This convolution estimation approach applied by the licensee in this application has been used in previous RICT seismic penalty calculations and accepted by the NRC staff. The licensee's calculated seismic LERF penalty is 8.72E07 per year. The staff finds the licensee's seismic LERF estimate is acceptable because it is estimated using a fragility value that is comparable with or lower than the fragility of components that are known to be dominant contributors to seismically induced LERF.

Seismic-Induced LOOP

The licensee also addressed the incremental risk associated with a seismic-induced LOOP in section 6 of enclosure 4 to the LAR [1]. A seismic LOOP frequency across the entire hazard interval is 1.5E-05 per year. This is about 2.6 percent of the total internal events' 24-hour nonrecovered LOOP frequency of 5.8E-04 per year, which is already addressed in the IEPRA. The NRC staff evaluated the licensee's analysis and finds that it adequately addressed the impact of a seismically induced LOOP on plant risk and that its exclusion from the nonrecovered LOOP frequency has an insignificant impact on the RICT calculations.

Conclusions

The NRC staff finds that, during RICTs for SSCs credited in the design basis to mitigate seismic events, the licensee's proposed methodology captures the risk associated with seismically induced failures of redundant SSCs because such SSCs are assumed to be fully correlated. By assuming full correlation, the seismic risk for those RICTs will not increase if one of the redundant SSCs is unavailable because simultaneous failure of all redundant trains would be assumed in a seismic PRA. During RICTs for SSCs not credited in the design-basis seismic event, but which could be used when credited SSCs fail, the proposed methodology for considering seismic risk contributions may be nonconservative because the seismically induced failure of such SSCs during the RICT may not be included in the risk increase. However, the occurrence and degree of nonconservatism depends on the plant HCLPF value used for the RICT calculations, as compared to the HCLPF values for credited SSCs. The degree of nonconservatism will be low or nonexistent if the plant HCLPF value is lower than that of most or all SSCs impacted by a seismic event. During RICTs for SSCs that are not used to mitigate a seismic event, the proposed methodology for considering seismic risk contributions is conservative because the seismically induced failure of such SSCs would not result in a risk increase associated with the plant configuration during the RICT, but the seismic penalty is still included in the calculation.

The NRC staff finds the licensee's proposal to use a seismic CDF penalty of 1.70E-06 per year and a seismic LERF penalty of 8.72E-07 per year is acceptable for the licensee's proposed RICT program because the licensee: (1) used the most current site-specific seismic hazard information, (2) used an acceptably low HCLPF value of 0.3g PGA as determined above and a composite beta factor of 0.4, consistent with the approach used in GI-199 [38], (3) developed a seismic LERF penalty based on the use of its estimated seismic CDF and conservative fragility values, which is consistent with an approach previously accepted by the NRC staff, and (4) will add the baseline seismic risk to RICT calculations with an assumption of fully correlated failures, which is conservative for SSCs credited in seismic events, and any potential for nonconservative results for SSCs that are not credited in seismic events is small or nonexistent.

3.1.4.1.3.3 Other External Hazards

The licensee evaluated external hazards other than seismic hazards. Table E4-9 in enclosure 4 to the LAR [1] provides the licensee's screening disposition for each nonseismic external hazard. The licensee concluded that a unique PRA model for these hazards is not required to assess configuration risk for the RICT program, except for internal flooding and fire, which are addressed by a PRA. The licensee concluded that the other external hazards have insignificant contributions to RICT configuration risk and, therefore, proposed to screen these hazards out from the RICT program.

The basis for the licensee's conclusions that extreme wind and tornado hazards, including tornado-generated missiles, have an insignificant impact on this application relies on the design of SSCs and a tornado missile analysis. To screen out the extreme winds and tornado hazards, the licensee used criteria C1 (event damage potential is less than events for which plant is designed), PS2 (design basis for the event meets the criteria in the NRC 1975 standard review plan [39]), and PS4 (bounding mean CDF is less than 1E-06 per year) in table E4-6 of the LAR [1].

The licensee's conclusions that external floods have an insignificant risk contribution to RICT calculations are based on the flood hazard reevaluation report [40] and flooding procedures, as noted in the licensee's supplement [2]. Table E4-9 of enclosure 4 to the LAR [1] shows that the licensee used screening criteria C1 and C3 (event cannot occur close enough to the plant to affect it) in table E4-6 of the LAR [1] to disposition the risk for the external flooding hazard.

Based on its review of the information in the LAR [1] and supplement [2], the NRC staff finds that the contributions from extreme winds and tornados, including tornado-generated missiles, external floods, and other external hazards, have an insignificant effect on configuration risk. The staff finds that the licensee can exclude these events from RICT calculations because the events either do not challenge the plant or they are bounded by the external hazards analyzed for the plant. Furthermore, the staff finds that plant procedures exist to ensure that flood protection features will be available during RICTs to manage the external flooding risk in the RICT program. The staff finds that the licensee appropriately screened out all other external hazards from consideration in the RICT program because the licensee's preliminary and progressive screening criteria used and presented in table E4-6 of the LAR [1] are the same criteria (i.e., EXT-B1 and EXT-C1) in the PRA Standard [18] for screening external hazards and, therefore, are acceptable.

3.1.4.1.4 PRA Results and Insights

NEI 06-09-A [9] provides that a licensee should perform periodic assessments of the risk incurred from operation beyond the completion time front stop values. NEI 06-09-A [9] states that these assessments should include a comparison of this incurred risk to RG 1.174 guidance for small increases in risk. In enclosure 5 to the LAR [1], the licensee provided the estimated total CDF and LERF to demonstrate that it meets the 1E-04 per year CDF and 1E-05 per year LERF criteria in RG 1.174 [16], that its LAR is consistent with NEI 06-09-A [9], and that it will satisfy RG 1.174 and NEI 06-09-A when implementing a RICT. The NRC staff confirmed that the licensee proposed incorporating NEI 06-09-A [9] into TS 5.5.16 and that the estimated current total CDF and LERF for the PRAs are consistent with RG 1.174 [16]. Therefore, the staff concludes the PRA results and insights the licensee will use in the RICT program will be consistent with NEI 06-09-A [9].

3.1.4.1.5 Key Assumptions and Uncertainty Analyses

The licensee considered PRA modeling uncertainties and their potential impact on the RICT program and identified RMAs that limit the impact of these uncertainties. In enclosure 9 to the LAR [1], the licensee discusses the process for identifying key assumptions and sources of uncertainty from plant-specific and generic industry sources that appear to have the potential to impact the application and discusses the bases for screening modeling uncertainties from further consideration. The licensee reviewed generic industry assumptions and sources of modeling uncertainty from EPRI 1016737 [21] and EPRI 1026511 [22]. The licensee's evaluation process includes identifying the approach used (e.g., consensus approach or other applicable guidance) and the level of detail included in the PRA model.

The licensee stated that it evaluated its PRA model to identify the key assumptions and sources of uncertainty for this application consistent with the definitions in RG 1.200 [10]. The licensee provided dispositions for the candidate key assumptions and sources of uncertainty in tables E9-1, E9-2, and E9-3 in enclosure 9 to the LAR [1], as supplemented [2] [3] for this application. The NRC staff evaluated the licensee's dispositions provided in tables E9-1, E9-2, and E9-3, as supplemented. The following discussion presents the staff findings of this evaluation for this application.

Plant Configurations (Condition Statements) Selected for Sensitivity Studies

The NRC staff reviewed the licensee's IEPRA modeling uncertainties. In its response to audit question Q-003 [2], the licensee indicated that it chose the plant configurations (condition statements) for the sensitivity studies based on the impact of the system associated with the modeling uncertainty on the safety function important to the condition statement. The licensee stated that if the source of uncertainty was not directly tied with a system, then it chose a variety of conditions. For each condition statement described in the response, the staff reviewed its bases and found that the condition statements were those impacted by the source of uncertainty. The staff finds this sampling approach acceptable because it is consistent with guidance in NEI 06-09-A [9] that states, "[a]lthough this assessment is not intended to be exhaustive, the general guidance should be that the impact of the key modeling uncertainties and associated key assumptions is limited when reasonable alternate modeling assumptions do not result in significant increases to plant risk."

Modeling Uncertainty for ESSW Pumphouse Door Operator Action

The NRC staff reviewed the licensee's modeling uncertainty associated with an operator action of the engineered safeguard service water system (ESSW). Table E9-1 in enclosure 9 to the LAR [1] states that concerning the room heat-up calculations, operator failure to open the ESSW pumphouse door is a source of modeling uncertainty. The LAR [1], as supplemented by the response to audit question Q-004 [2], provided a sensitivity study for this source of modeling uncertainty by increasing the operator HEPs associated with opening the ESSW pumphouse doors in the sensitivity case by a factor of three. The licensee stated that a factor of three was reasonably conservative for both dependent and independent HEPs because it is low enough not to be unrealistic and high enough to test the impact of the modeling uncertainty. The licensee also stated that a factor of three is the approximate difference between the mean and 95th percentile value for probability distributions of typical failures modeled in a PRA. The licensee explained that it selected conditions statements for the sensitivity study to explore a range of cases (plant configurations) that might be susceptible to the operator action for opening the pumphouse doors. The results show that the impact of the modeling uncertainty on the selected calculated RICTs is negligible. Additionally, the licensee explained that as part of the RICT program, RMAs will be informed by use of the CRMP tool, station procedures, and other information to identify configuration-specific RMA candidates to manage risk. The staff finds the cited HEP modeling uncertainty acceptable because the licensee has shown it to have an inconsequential impact on the application.

FPRA Human Reliability Analysis Modeling Uncertainty

The NRC staff reviewed the licensee's modeling uncertainty associated with HRA in the FPRA. Table E9-3 in enclosure 9 to the LAR [1] states that the licensee performed the HRA for the FPRA using industry consensus modeling approaches. The staff reviewed the licensee's disposition of the modeling uncertainty against NRC's most current guidance on fire HRA [19] [23], and the licensee's justifications for any deviations from the guidance that could be characterized as potential key assumptions or sources of uncertainty.

In its response to audit question Q-030 [2], the licensee stated that it largely followed the guidance in NUREG-1921 [23], with minor exceptions. One exception is for actions taken outside the main control room. Rather than evaluate all travel paths, the licensee assumed actions that require unique travel pathways are failed if the fire could prohibit access to the execution location. Otherwise, where access is available, a bounding access delay of ten minutes (based on operator interviews) is added to the execution time. The other exception concerns identification of errors of commission. The licensee explained that although it assessed the alarm response procedures for errors of commission per the guidance in NUREG-1921 [23], the emergency operating procedures were not reviewed for such errors. The licensee explained that spurious indications from fire damage would likely be detected by the operations crew because emergency operating procedures require multiple verification steps and because spurious actuations create conditions that "prompt additional review and scrutiny." Furthermore, the operators can identify protected and safe shutdown equipment list indications for specific fire areas by using attachment A in its fire response procedure to determine which indications are safe and which may be impacted by fire.

The NRC staff finds the licensee's assessment of uncertainty associated with HRA in the FPRA acceptable because the licensee used NRC's most current guidance with two exceptions. The first exception concerns travel pathways for actions taken outside the main control room; however, the staff finds that the licensee's approach is conservative because the action is assumed to fail, and bounding because additional time is added to the assumed performance time. The second exception concerns incomplete review for errors of commission; however, the staff finds that the licensee reviewed the main contributor to such an error (i.e., the alarm response procedures) and that the plant procedures provide instructions on fire impact that would prevent errors of commission.

PRA Modeling Uncertainty for I&C Systems

The NRC staff reviewed the licensee's modeling uncertainty associated with I&C systems. Table E1-1 in enclosure 1 to the LAR [1] shows that for several conditions, the I&C modeling in PRAs is insufficient to model the plant configuration and, therefore, the licensee will model the inoperability of the associated SSC (e.g., channel) using a surrogate event. The staff considered how the licensee modeled I&C in the PRA and whether the modeling uncertainty associated with crediting I&C systems in the PRA models has an inconsequential impact on the RICT calculations. The staff considered whether the general variability in the level of detail used to model the I&C systems created uncertainty about whether there is sufficient detail to support implementation of the proposed conditions other than those specifically identified in table E1-1 that will be modeled using a surrogate event.

In its response to audit question Q-016 [2], the licensee explained that in many cases, the Susquehanna PRA explicitly models analog I&C instrumentation using industry failure rates in sufficient detail to reflect the LCO conditions in the RICT program. However, as indicated in table E1-1 of the LAR [1] and its supplement [2], the licensee will need to use surrogate events to model many of the LCO conditions proposed for the RICT program. In many of these cases, the licensee will assume component unavailability to occur at the function level rather than channel level, which the licensee stated is conservative. In its supplement [2], the licensee described the I&C associated with the LCO in the RICT program. The description shows the PRA models primarily include component failures of limit switches (e.g., pressure, level, and temperature), relays, and circuit breakers. These have active failure modes and have higher failure probabilities than passive failure modes that exist in I&C systems.

The NRC staff finds the licensee's modeling of analog I&C equipment is sufficient for the RICT program because where I&C systems are modeled in sufficient detail, the licensee uses PRA modeling to calculate RICTs, and where I&C systems are modeled in insufficient detail, the licensee uses surrogate events that are consistent with NEI 06-09-A [9].

PRA Modeling Uncertainty for Digital I&C Systems

The NRC staff reviewed the licensee's modeling uncertainty associated with digital I&C systems. Given the lack of consensus industry guidance for modeling digital I&C systems in plant PRAs used to support risk-informed applications (e.g., lack of industry data for digital I&C components, the difference between digital and analog system failure modes, and the complexities associated with modeling software failures including common-cause software failures), the staff considered how the licensee credited digital I&C systems in its PRA models for the RICT program and whether any modeling uncertainty has an inconsequential impact on the RICT calculations.

In its response to audit question Q-017 [2], the licensee explained the only digital system at the plant is the feedwater and recirculation control system. However, the licensee stated that this system is not modeled in the PRA and, therefore, does not affect the PRA models. Therefore, NRC staff finds that the RICT calculations are not affected by the uncertainty associated with modeling of digital systems.

Modeling Uncertainty for Open Phase Conditions

The NRC staff reviewed the licensee's modeling uncertainty associated with open phase conditions because whether and how the licensee treats open phase condition (OPC) events in the PRA could be a source of PRA modeling uncertainty. The staff considered the impact on RICT calculations associated with OPC events and whether the licensee credited OPC installed equipment or operator actions in the PRA models.

In its response to audit question Q-054 [2], the licensee explained that the open phase detection system (OPD) detects OPCs on the 230-kV and 500-kV startup transformers by monitoring incoming power. The licensee stated that even though the OPD can function in an automatic mode (i.e., an alarm and trip), the licensee operates it in the manual mode (i.e., alarm only). The licensee stated that the PRA models do not include installed OPD equipment and associated operator actions. The licensee stated that the risk contribution from OPC events is very small (i.e., within region III of the risk acceptance guidance specified in RG 1.174 [16]). The licensee also provided the results of a probabilistic assessment. The risk increase (contribution) from OPC events in terms of CDF is 1.10E-09 and 1.74E-08 per year for Units 1 and 2, respectively, and in terms of LERF, is 2.70E-10 and 4.47E-09 per year for Units 1 and 2, respectively.

Because the risk increase from OPC events is very small, the NRC staff finds the uncertainty associated with not modeling OPC events or the OPD in the PRA models has a negligible impact on the RICT calculations.

Modeling Uncertainty in PRA Quantification—Impact of SOKC Uncertainty

The NRC staff reviewed the licensee's modeling uncertainty associated with PRA quantification. RG 1.174 [16] states that mean values are the appropriate numerical measures to use when comparing the PRA results with the risk acceptance guidelines. Because the licensee developed the risk management threshold values for the RICT program based on RG 1.174 [16], the most appropriate measures with which to make a comparison are mean values. However, the licensee used point estimate values. Per NUREG-1855, Revision 1 [20], point estimate values do not account for the state-of-knowledge correlation (SOKC) between nominally independent basic event probabilities and, therefore, the calculated mean values that account for the SOKC are typically larger than point estimates. NUREG-1855, Revision 1 [20] has guidance on evaluating how the SOKC uncertainty affects the comparison of the PRA results with the guideline values.

In its response to audit question Q-009 [2], the licensee explained that it investigated the impact of using quantified mean values that include SOKC versus using point estimate values in the RICT calculations through Monte Carlo sampling using an approach consistent with guidance in NUREG-1855 [20]. The licensee stated that even though it determined the calculated mean CDF and LERF values to be higher than the point estimate values, this impact on the RICT calculations was shown to be minimal and, therefore, the licensee would use point values in the RICT program. The licensee provided the results of a sensitivity study on a range of representative LCO conditions with completion times less than 30 days (i.e., less than the back stop) that compared the results of using point estimate values and calculated (i.e., "propagated') mean values on the RICTs. The results show that the uncertainty associated with SOKC does not significantly impact the calculated RICTs.

The NRC staff finds that the licensee applied the SOKC correlation across the entire PRA model as opposed to being associated with specific component failures and, therefore, its impact tends to be the same for this application on both sides of the delta risk determinations (i.e., the base case and component-inoperable case used in in the RICT calculations). Therefore, the staff concludes that the impact of using point estimate values as opposed to mean values, which include consideration of the SOKC, in the RICT calculations has a minimal impact on the licensee's RICT application.

Modeling Uncertainty in PRA Quantification—Total Risk and Accounting for the SOKC

The NRC staff reviewed the licensee's modeling uncertainty associated with PRA quantification. The guidance in RG 1.174 [16] and section 6.4 of NUREG-1855 [20] for a capability category II risk evaluation, states that the mean values of both the total and the change in CDF and LERF values need to be compared against the risk acceptance guidelines. Obtaining point estimate CDF and LERF values by quantification of the PRA models using mean basic event probabilities does not produce the true mean CDF and LERF values. Section 2 of enclosure 5 to the LAR [1] states that the total CDF and LERF values presented in table E5-1 of the LAR [1] are point estimate values. Therefore, the true or calculated mean values are typically larger than the point estimate values, which the licensee confirmed was the case for Susquehanna. The staff considered whether the total risk for Units 1 and 2 would be in conformance with RG 1.174 [16] risk acceptance guidelines (i.e., CDF less than 1E-04 and LERF less than 1E-05 per year) after the licensee calculates the total mean CDF and LERF values to account for the SOKC. The staff also considered the fire parameters that came from a common data set that the licensee correlated in the SOKC study.

In its response to audit question Q-010 [2], the licensee provided the results of a sensitivity study of the total CDF and LERF values based on using point estimates compared to calculated (i.e., propagated) mean values for the internal events (including internal flooding) and fire PRAs. The results show that the total CDF and LERF values determined using the calculated means are well below the RG 1.174 [16] risk acceptance guidelines. The licensee also explained that in addition to correlating failure mode types, the following fire parameters were correlated: fire ignition frequencies, nonsuppression probabilities, severity factors, spurious probabilities, and fire HEPs based on information from NRC-accepted guidance documents.

The NRC staff finds that the licensee’s response demonstrates that besides component failure modes, the licensee correlated fire parameters from the same data sets and, therefore, SOKC appears to be fully considered for use in this application. The staff concludes that the use of CDF and LERF point estimate values in the RICT calculations is acceptable because: (1) using point estimate values as opposed to mean values, which include consideration of the SOKC, in the RICT calculations has a minimal impact on the licensee’s RICT application, and (2) the total CDF and LERF using the calculated means are well below the RG 1.174 [16] risk acceptance guidelines.

PRA Modeling Uncertainty for Flexible and Diverse Coping Strategies (FLEX) Equipment

In a memorandum dated May 30, 2017 [41], NRC staff assessed challenges to incorporating FLEX into a PRA model. Such models support risk-informed decision making in accordance with the guidance in RG 1.174 [16]. The staff focused on two areas of uncertainty for crediting FLEX in the PRA in its review of this application: (1) FLEX equipment failure probabilities and (2) human reliability analysis of the operator actions credited for deploying FLEX. These areas are discussed in sections 7.5.4 and 7.5.5 of NEI 16-06 [42]. NEI 06-09-A [9] states that before implementing a RICT program, a licensee should perform sensitivity studies to assess the potential effect of uncertainties on the results of RICT calculations. These studies should be performed on the base PRA model. The licensee should use insights from the sensitivity studies to develop RMAs that compensate for the uncertainty. RMAs may include highlighting risk significant operator actions, confirming the availability and operability of important standby equipment, and assessing the presence of severe or unusual environmental conditions.

Section 6 of enclosure 2 to the LAR [1] states that credit is taken for FLEX strategies in the internal events PRA and fire PRA models. In its supplements to the LAR [2] [3], the licensee identifies the FLEX equipment and associated operator actions that were credited in these PRA models. The licensee further stated that credited FLEX operator actions include those activities described in sections 7.5.4 and 7.5.5 of NEI 16-06 [42], for which current HRA methods may not be applicable. The licensee reported the results of the sensitivity studies performed to assess the impact of FLEX modeling uncertainties on calculated RICTs.

In its second supplement [3], the licensee reported the results of revised calculations. FLEX equipment failure probabilities were increased to assess the effect of newly available failure data for portable equipment [43]. The licensee also addressed uncertainties in the probability of human error during operator actions to implement FLEX (FLEX HEPs). The licensee increased FLEX HEPs by a factor of three to represent likely upper bound values. With exception of the RICT associated with TS 3.8.1 Condition C, the updated sensitivity studies demonstrated that the RICTs were not sensitive to the uncertainties associated with FLEX HEPs and FLEX equipment failure probabilities. FLEX modeling uncertainty significantly affected the RICT for TS 3.8.1 Condition C. Consistent with the guidance in NEI 06-09-A [9], the licensee identified RMAs that would be considered on entering TS 3.8.1 Condition C. These RMAs, in addition to those that are otherwise implemented in accordance with station procedures, account for this source of uncertainty in the RICT Program. The licensee also described the process used to update the PRA for updates to industry and plant-specific data on portable equipment failure [3]. The NRC staff found that the process is consistent with the general requirements for PRA configuration control described in the PRA Standard and with the PRA update guidance of NEI 06-09-A [9].

The NRC staff also considered whether the licensee included modeling of FLEX mitigation strategies in the latest PRA model peer reviews and whether the modeling was a PRA upgrade that required a focused-scope peer review. In its response to audit question Q-008 [2], the licensee clarified that it included the FLEX modeling in the last peer review of the PRA models (i.e., the FPRA peer review in 2018). This review included an evaluation of whether model updates constitute PRA upgrades. The licensee described the modeling changes required to implement the three credited FLEX strategies. The licensee assessed whether those changes should be considered a PRA upgrade. The licensee showed that the modeling changes performed to incorporate the three FLEX strategies did not represent a new method, did not result in a change in PRA scope, did not result in a change in PRA capability, and did not impact significant accident sequences or significant accident progression sequences. Because this is consistent with the criteria of RG 1.200 [10] and the PRA Standard [18], the staff finds the licensee's modeling of FLEX strategies in the PRA models does not constitute a PRA upgrade for this application. Therefore, it does not require a focused-scope peer review as defined in section 1-2 of the PRA Standard for this application.

Conclusions about Modeling Uncertainty

The NRC staff confirmed that the licensee performed an adequate assessment to identify the potential sources of uncertainty and that the identification of key assumptions and sources of uncertainty was appropriate and consistent with NUREG-1855 [20] (in association with EPRI 1016737 [21], and EPRI 1026511 [22]). Therefore, the staff finds that the licensee has satisfied the guidance in RG 1.174 [16] and RG 1.177 [17], and that the identification of assumptions and treatment of model uncertainties for risk evaluation of extended completion times are appropriate for this application and consistent with NEI 06-09-A [9].

Based on its review of the licensee's dispositions of the identified key assumptions and sources of modeling uncertainty provided in enclosure 9 to the LAR [1], key assumptions and sources uncertainty analyses provided during the audit, and the licensee's supplementals [2] [3], the NRC staff finds the licensee's treatment of the identified key assumptions and key sources of uncertainty for this application is consistent with NUREG-1855 [20] and NEI 06-09-A [9].

3.1.4.1.6 PRA Scope and Acceptability Conclusions

The licensee has had its PRA models peer-reviewed and submitted the results of the peer review. The NRC staff reviewed the peer review results and findings, the licensee's resolutions of peer-review findings, and the identification and disposition of key assumptions and sources of uncertainty. The staff concludes that the licensee's PRA models are acceptable to support the RICT program and that the licensee identified key assumptions for the PRAs consistent with the guidance in RG 1.200 [10] and NUREG-1855 [20]. The staff also concludes that the licensee's approach for considering the impact of seismic events, nonseismic external hazards, and other hazards using alternative methods is consistent with NEI 06-09-A [9].

Based on the above conclusions discussed in sections 3.1.4.1.1 through 3.1.4.1.5 of this safety evaluation, the NRC staff finds that the licensee has satisfied the intent of tier 1 in RG 1.177 [17] for determining the PRA acceptable. The staff also finds that the scope of the PRA models (i.e., IEPRA and FPRA) and the use of a bounding analysis for seismic events are appropriate for this application.

3.1.4.1.7 Application of PRA Models, Results, and Insights in the RICT Program

Evaluation of the CRMP Tool and RTR Model in the RICT Program

The NRC staff evaluated the licensee's CRMP tool for use in the RICT program against NEI 06-09-A [9]. In the LAR, as supplemented, the licensee provided supporting information to show that implementation of the RICT program will be consistent with the limitations and conditions in section 4.0 of NRC's safety evaluation for NEI 06-09 [30]. The staff evaluated how the licensee will modify the base PRA models (models that the staff found acceptable for this application as documented in section 3.1.4.1.6 of this safety evaluation) in the models used to evaluate risk in real time (RTR models). These are used in the CRMP tool for analyzing the risk associated with an extended completion time. The staff evaluated the capability of the CRMP tool to produce results (risk metrics) that are consistent with NEI 06-09-A [9]. The staff evaluated how the licensee considered configurations of systems shared between the two units and the impact of seasonal variation on the PRA modeling.

The NRC staff considered whether the licensee credited systems shared between units in the internal events and fire PRA models and how the licensee treated the shared systems in the RTR model for dual unit events. In its response to audit question Q-011 [2], the licensee identified credited shared systems and equipment and described the PRA modeling for a dual unit event. The licensee stated that in general, the system or equipment is designed to provide simultaneous support to both units and, therefore, there is no need to model a preferred alignment for a dual unit event. For the shared refueling water storage tank, the licensee stated that it credits only half of the minimum tank volume in the PRA model for each unit's condensate storage tank. The staff finds that the modeling of shared systems or equipment does not over-credit the system or equipment in a dual unit event.

The NRC staff reviewed the impact of seasonal variation on the PRA modeling. Section 2 in enclosure 8 to the LAR [1] states that when there are seasonal dependences, the RTR model addresses the average configuration of the plant, and that the licensee will evaluate plant-specific configurations as needed. NEI 06-09-A [9] provides that seasonal or time-in-operating cycle variations must be either conservatively assessed or properly quantified for the particular conditions. The staff considered how the licensee will evaluate, as needed, the impact of seasonal variation on the PRA modeling during a RICT evolution and whether the licensee's approach is consistent with NEI 06-09-A [9]. In its response to audit question Q-012 [2], the licensee stated that for time-of-year changes, applied data is either bounding (e.g., raw water storage tank temperature of 120 degrees °F) or averaged across the year as in the case of LOOP frequency, ultimate heat sink temperatures, and heating, ventilation, and air conditioning requirements. The licensee cited an industry benchmark study that examined industry LOOP data for several plants and concluded that existing data does not support modification of LOOP frequency based on weather warnings because of the range of possible outcomes. The licensee explained that concerning heating, ventilation, and air conditioning requirements, maximum operating temperatures at the plant are well above the expected sustained air temperature, which normally does not exceed 90°F. The licensee also stated that for the spray pond, the PRA models the technical specification requirements for average spray pond temperature (less than or equal to 85°F). The staff finds that PRA modeling affected by seasonal variations is consistent with NEI 06-09-A [9] (i.e., is bounding or RICT-specific) and that averaging the data does not impact the success of plant systems modeled in the PRA.

Comparison of Design Basis and PRA Success Criteria

The NRC's safety evaluation for NEI 06-09 [30] specifies that the LAR should provide (1) a comparison of the technical specification functions to the PRA modeled functions in its application and (2) sufficient justification to show that the scope of the PRA modeling is consistent with licensing basis assumptions (and to provide a basis when they are not consistent). Table E1-1 in enclosure 1 to the LAR [1] identifies each LCO (and action statement) proposed for the RICT program, describes whether the systems and components involved in the LCO are implicitly or explicitly modeled in the PRA, and compares the design basis and PRA success criteria. For certain LCOs, the licensee explains that the associated SSCs are not modeled in the PRAs but will be conservatively represented using a surrogate event. The NRC staff reviewed the PRA modeling for the proposed LCO conditions. The licensee provided additional information in its supplement [2] to justify its PRA modeling for some LCO conditions.

Table E1-1 of the LAR [1] stated that for Condition D (HPCI system inoperable) of TS 3.5.1, the design basis and PRA success criterion is "one of one train" (i.e., one HPCI pump). However, Condition D appears to prevent achieving the design basis success criteria and, therefore, is a technical specification loss of function. TSTF-505 [4] does not authorize determination of a RICT when a condition represents a technical specification loss of function. The staff reviewed the HPCI system function and the appropriateness of including the proposed LCO condition in the RICT program. In its response to audit question Q-013 [2], the licensee explained that there are additional ways (i.e., makeup and core cooling) that the HPCI function can be performed, and the licensee added those criteria (i.e., “5/6 ADS valves and one of two Core Spray subsystems” or “5/6 ADS valves and sets of two LPCI subsystems”) to the design basis success criteria description for Condition D in its updated version of table E1-1. The licensee also explained that the PRA success criteria are different from design basis success criteria. The latter criteria are based on thermal hydraulic analysis for specific accident sequences. The licensee clarified both sets of criteria in the updated version of table E1-1. From this, the staff finds that the condition is not a loss of function and that the LAR, as supplemented, justifies the difference between the design basis and PRA success criteria.

Table E1-1 of the LAR [1] stated that for Condition B (one LPCI pump in one or both LPCI subsystems inoperable) of TS 3.5.1, that the PRA success criteria are generally consistent with the design basis. However, the table also showed that for a LOCA in the bottom head, the PRA success criterion was “one RHR pump in each division,” which appeared to be more stringent than the design basis success criterion, which is one of four LPCI pumps. In its response to audit question Q-014 [2], the licensee explained that for accidents besides the medium LOCA in the bottom head, the PRA success criteria are the same as the design basis success criteria. The licensee updated table E1-1 in its supplement [2], to explain that the medium LOCA in the bottom head is a low-likelihood, non-design-basis accident requiring one RHR pump from each subsection. Therefore, the NRC staff finds the difference between the design basis and PRA success criteria justified.

Table E1-1 of the LAR [1] stated that for Conditions A, B, and C of TS 3.7.2, that the success criteria are consistent with the design basis. However, the table indicated that the design basis success criterion was “one emergency service water pump in each loop,” and that the PRA success criterion is “one of two subsystems,” which appeared to be inconsistent. In its response to audit question Q-015 [2], the licensee explained that the terms “division,” “loop,” and “subsection” are used synonymously in table E1-1 but, in its supplement, the licensee updated those entries in table E1-1 to use the term “subsystem,” thus resolving the issue.

Conclusion on Acceptability of the CRMP tool and RTR model

The NRC staff did not identify any insufficiencies in the information or the CRMP tool (based on the real-time risk model) as described in the LAR, as supplemented. Furthermore, as stated in enclosure 1 to the LAR [1], the licensee does not propose changes to the design criteria of the applicable systems nor to physically alter the applicable systems. The staff finds that the PRA models and CRMP tool will continue to reflect the as-built, as-operated plant consistent with RG 1.200 [10] for ensuring PRA acceptability is maintained. Therefore, the staff concludes that the proposed application of the PRA models and CRMP tool are acceptable for use in the adoption of TSTF-505 [4] for performing RICT calculations.

3.1.4.1.8 Tier 1 Evaluation Conclusions

Based on the conclusions in sections 3.1.4.1.1 through 3.1.4.1.7 of this safety evaluation, the NRC staff finds that the licensee has satisfied the intent of the first tier in RG 1.177 [17] for determining the PRA acceptable as it is applied in the licensee's RICT program for calculating RICTs.

3.1.4.2 Tier 2: Avoidance of Risk-Significant Plant Configurations

The second tier of RG 1.177 [17] provides that a licensee should provide reasonable assurance that risk-significant plant equipment outage configurations will not occur when specific equipment is taken out of service consistent with the proposed technical specification change. NEI 06-09-A [9] does not allow voluntary entry into high-risk configurations that would exceed instantaneous CDF and LERF limits of 1E-03 per year and 1E-04 per year, respectively. The guidance in NEI 06-09-A [9] specifies that if configurations exceed the instantaneous CDF and LERF limits for emergent conditions, then the licensee is required to implement RMAs. Per NEI 06-09-A [9], the RMA must be implemented within the RMAT, which is when the actual or anticipated risk accumulation during a RICT will exceed one-tenth of the limit for incremental core damage probability (ICDP) or for incremental large early release probability (ILERP). RMAs may include rescheduling planned activities to limit the duration of a period of elevated risk. Alternatively, an RMA may reduce risk during those activities.

Consistent with NEI 06-09-A [9], in enclosure 12 to the LAR [1], the licensee identifies three kinds of RMAs (i.e., actions to provide increased risk awareness and control, actions to reduce the duration of maintenance activities, and actions to minimize the magnitude of the risk increase). The licensee indicated in enclosure 12 to the LAR [1] that it would implement RMAs in accordance with current plant procedures no later than the time at which the 1E-06 ICDP or 1E-07 ILERP threshold is reached and under emergent conditions when the instantaneous CDF and LERF thresholds are exceeded. The licensee indicated in enclosure 12 to the LAR [1] that it would implement RMAs under emergent conditions if the extent of condition is not known prior to exceeding the completion time, to account for the increased possibility of common-cause failures (CCFs). These RMAs may be system-specific and are usually identified in advance as described above.

The NRC staff concludes the licensee's process for developing RMAs is consistent with NEI 06-09-A [9] because it uses configuration-specific risk insights and considers the potential for CCFs in emergent conditions. The staff finds that the licensee's tier 2 program is acceptable and supports the proposed implementation of the RICT program because NEI 06-09-A [9] will be incorporated into the technical specifications as discussed in attachment 1 to the LAR [1], the licensee will use RMAs as discussed in enclosure 12 to the LAR [1], and the proposed changes are consistent with the second tier of RG 1.177 [17].

3.1.4.3 Tier 3: Risk-Informed Configuration Risk Management

The third tier of RG 1.177 [17] provides that a licensee should develop a program to manage risk as the plant configuration changes. The risk impact of out-of-service equipment should be considered prior to performing any maintenance activity. NEI 06-09-A [9] addresses tier 3 guidance by identifying that the RICT for a particular LCO is to be assessed on the basis of the current plant configuration, including considering all SSCs that might affect the RICT, whether they are safety-related or not. It would also require the licensee to implement compensatory measures and RMAs if a risk-significant plant configuration is predicted. A configuration is considered significant if the ICDP or ILERP exceeds one-tenth of the risk on which the RICT is based (which is generally 1E-05 for the ICDP and 1E-06 for the ILERP). NEI 06-09-A [9] indicates that the licensee promptly reassess risk if plant configuration changes (i.e., based on the more restrictive limit of any applicable action requirement or a maximum of 12 hours after the configuration change occurs).

The proposed RICT program would establish a CRMP and an RTR model based on the underlying PRA models. The licensee would use its CRMP tool with the RTR model to evaluate configuration-specific risk for planned activities associated with a RICT, as well as emergent conditions that may arise during an extended completion time. In enclosure 8 to the LAR [1], the licensee explains the adjustments to PRA models (e.g., adjustments to maintenance unavailability) to ensure their proper use in the RTR model calculations. The staff concludes that this assessment of configuration risk, along with the implementation of compensatory measures and RMAs, is consistent with the principle of the third tier of RG 1.177 [17] for assessing and managing the risk of equipment that is out of service.

Per NEI 06-09-A [9], the program for evaluating the risk of out-of-service equipment should consider the treatment of CCFs in the PRA for grouping of equipment that include the equipment taken out of service because this change in configuration has an impact on the CCF modeling in the PRA that could impact the calculated RICT. In section 2 of enclosure 8 to the LAR [1], the licensee stated that for planned conditions, adjustments to CCF grouping and associated probabilities are not necessary when a component is taken out of service for preventive maintenance because (1) the component is not out of service for reasons subject to potential CCF, (2) CCF relationships are retained for the remaining components in service, and (3) the net failure probability for the in-service components include a CCF contribution for the out of service component.

Section 3.3.6 of NEI 06-09-A [9] states that for all RICT assessments of planned configurations, the treatment of CCFs in the quantitative configuration risk management tools may be performed by considering only the removal of the planned equipment and not adjusting CCF terms. However, RG 1.177 [17] states that when a component is rendered inoperable in order to perform preventative maintenance, the CCF contributions in the remaining operable components should be modified to remove the inoperable component and to only include CCF of the remaining components.

In the licensee’s PRA model, the CCF contribution from the out-of-service component is retained in the following ways: (1) the independent failure rate used in the PRA models includes both independent and dependent failure events (i.e., the dependent failures should be subtracted from the total population of failures to calculate the independent failure rate) and (2) the CCF event probabilities that include the out-of-service component are retained. The NRC staff notes that this simplification produces both conservative and non-conservative effects. The staff also notes that common-cause failure probability estimates are very uncertain and that retaining precision in calculations using these probabilities will not necessarily improve the accuracy of the results. Therefore, the staff concludes that the licensee’s method is acceptable because it does not systematically and purposefully produce nonconservative results and because the calculations reasonably include common-cause failures after removing one train for maintenance, consistent with the uncertainty associated with the estimates.

Enclosure 8 to the LAR [1] states that plant procedures control and require documenting future changes made to the baseline PRA models and changes made to the online model (i.e., the RTR model). Enclosure 7 to the LAR [1] states that if a plant change or discovered condition is identified that can have a significant impact on the RICT calculations, then the licensee performs an unscheduled PRA update. The NRC staff reviewed the licensee's criteria for determining when an unscheduled PRA update would be needed prior to the scheduled updates that occur every two refueling cycles. During its review, the staff audited the licensee's procedure for PRA model updates and configuration control. The licensee explained during the staff's audit that procedure or plant changes and discovered conditions are tracked to determine whether an unscheduled PRA update is warranted to the model of record. The licensee cited quantitative and qualitative criteria to determine if an impact on an application such as a RICT application could occur. Quantitative criteria consist of greater than or equal to (≥) 25 percent change in CDF or LERF, ΔCDF ≥ 1E-5 per year or ΔLERF ≥ 1E-06 per year, ΔCDF or ΔLERF causes entry into Region 1 of Figure 3 or 4 of RG 1.174 [16], and greater than a factor of two increase in percent contribution to an accident class already contributing five percent. Qualitative criteria consist of (1) a significant impact on a basic event importance measure for an existing risk-informed application that is required to be maintained current with plant and model changes, and (2) a significant impact on the zero-maintenance model that would affect online risk assessment colors. The staff finds the licensee's approach is consistent with guidance in NEI 06-09-A [9] to update the PRA models for changes that can impact the RICT calculations.

In enclosure 10 to the LAR [1], the licensee described implementation of the RICT program and associated training, characterizing them as consistent with NEI 06-09-A [9]. The NRC staff reviewed the attributes of the RICT program and the description of the scope and extent of the training program provided in enclosure 10 to the LAR [1]. The staff finds that the licensee has proposed administrative controls for the PRA and for training the personnel implementing the RICT program consistent with the guidance of sections 3.2.1 and 2.3.3 of NEI 06-09-A [9].

The NRC staff finds the licensee's tier 3 program is acceptable and supports the proposed implementation of the RICT program because NEI 06-09-A [9] will be incorporated into the technical specifications, as discussed in attachment 1 to the LAR [1]; the licensee will use RMAs as discussed in enclosure 12 to the LAR [1]; and the proposed changes are consistent with the third tier of RG 1.177 [17].

3.1.4.4 Principle 4 Conclusions

The licensee has demonstrated the technical acceptability and scope of its PRA models and that the models can support implementation of the RICT program for determining completion times. The licensee properly considered key assumptions and sources of uncertainty. The risk metrics are consistent with the approved methodology of NEI 06-09-A [9] and the guidance in RG 1.174 [16] and RG 1.177 [17]. The licensee would control the RICT program administratively through plant procedures and training. The RICT program would follow the NRC-approved methodology in NEI 06-09-A [9]. The NRC staff concludes that the RICT program satisfies the fourth key safety principle of RG 1.174 [16] and RG 1.177 [17] and, therefore, is acceptable.

3.1.5 Principle 5: Performance Measurement Strategies

As discussed in RG 1.174 [16] and RG 1.177 [17], principle 5 identifies that licensees should monitor the impact of proposed licensing basis changes using performance measurement strategies. This guidance establishes the need for an implementation and monitoring program to ensure that extensions to technical specification completion times do not degrade operational safety over time and that no adverse degradation occurs from unanticipated degradation or common-cause mechanisms. An implementation and monitoring program helps to ensure that the impact of the proposed technical specification changes continues to reflect the availability of SSCs affected by the change. RG 1.174 [16] states, in part, that monitoring performed in conformance with the Maintenance Rule, can be used when the monitoring performed is sufficient for the SSCs affected by the risk-informed application.

Enclosure 11 to the LAR [1] states that the SSCs in the scope of the RICT program are also in the scope of the Maintenance Rule. The associated monitoring programs will provide for evaluation and disposition of unavailability impacts which may be incurred from implementation of the RICT program. The licensee also confirms that it calculates cumulative risk at least every refueling cycle and that the recalculation period does not exceed 24 months, which is consistent with NEI 06-09-A [9]. This evaluation assures that RMTS program implementation meets RG 1.174 [16] guidance for small risk increases. In its response to audit question Q-019 [2], the licensee confirmed that its Maintenance Rule program is consistent with the guidance in NUMARC 93-01 [44].

The NRC staff concludes that the RICT program satisfies the fifth principle of RG 1.174 [16] and RG 1.177 [17] because: (1) the RICT program will monitor the average annual cumulative risk increase as described in NEI 06-09-A [9], thereby ensuring the program, as implemented, continues to meet RG 1.174 [16] guidance for small risk increases; and (2) all affected SSCs are within the Maintenance Rule program, which is used to monitor changes to the reliability and availability of these SSCs.

3.2 Evaluation of Variations from TSTF-505 and Other Changes

The NRC staff reviewed the variations and changes discussed in Section 1.3.4 of this safety evaluation. The staff found that the variations to the Mode numbers in proposed technical specifications example 1.3-8 are acceptable because they maintain consistency with how the Susquehanna technical specifications apply mode numbers in other technical specification examples and in the Section 3 LCOs. The staff reviewed the licensee’s proposed formatting, editorial, and administrative variations from TSTF-505 and its proposed change to delete temporary technical specifications that expired and determined that these proposed variations and changes are appropriate for the Susquehanna technical specifications, do not materially change the requirements, and properly correct the technical specifications. Therefore, the staff determined these variations are acceptable.

The NRC staff reviewed the proposed note (i.e., “Only applicable to AC electrical power sources included in the PRA model”) that would modify the RICT applicability in Unit 1 TS 3.8.7, Required Action A.1 and in Unit 2 TS 3.8.7, Required Actions A.1, C.1, and D.1. The staff finds that because the content of this note is already covered by RICT program requirements (i.e., per TSTF-505 [4], the Required Actions will not be modified for systems that do not affect CDF or

LERF or for which a RICT cannot be quantitatively determined), the note is adding assurance that the licensee would correctly apply the RICT program and, therefore, is acceptable.

The staff also reviewed the licensee's proposed variations to apply RICTs to technical specifications not covered in TSTF-505 [4] against the key safety principles discussed above in section 3.1 of this safety evaluation. Based on its evaluation in section 3.1 of this safety evaluation, the NRC staff finds that each of the five key principles in RG 1.177 [17] have been met for these variations and concludes that the proposed variations are acceptable.

3.3 Technical Evaluation Conclusion

The NRC staff concludes that the licensee's proposed implementation of the RICT program for the identified scope of Required Actions is consistent with NEI 06-09-A [9]. The licensee's methodology for assessing the risk impact of extended completion times, including the individual completion time extension impacts in terms of ICDP and ILERP and the overall program impact in terms of ΔCDF and ΔLERF, is accomplished using PRA models of sufficient scope and technical adequacy based on consistency with the guidance of RG 1.200 [10]. For seismic hazards, which do not have a PRA model, the licensee will use bounding analyses in accordance with NEI 06-09-A [9] guidance and the proposed TS 5.5.16. The RICT calculations would use the PRA models and CRMP tool, which will continue to reflect the as-built, as-operated plant consistent with RG 1.200 [10]. The staff also finds that the proposed implementation of the RICT program would support the defense-in-depth philosophy, maintain safety margins, and provide reasonable assurance that the licensee includes adequate administrative controls and performance monitoring programs consistent with RG 1.177 [17].

The NRC staff has evaluated the proposed changes against each of the five key safety principles in RG 1.174 [16] and RG 1.177 [17], as discussed in section 3.1 of this safety evaluation. The staff concludes that the proposed changes satisfy the key safety principles of risk-informed decisionmaking in RG 1.174 [16] and RG 1.177 [17] and, therefore, the requested adoption of the proposed changes to the technical specifications are acceptable.

4.0 STATE CONSULTATION

In accordance with the Commission's regulations, on June 28, 2022, the NRC staff notified the Commonwealth of Pennsylvania official of the proposed issuance of the amendments [45]. The Commonwealth of Pennsylvania official had no comments.

5.0 ENVIRONMENTAL CONSIDERATION

The amendments change a requirement with respect to installation or use of facility components located within the restricted area, as defined in 10 CFR Part 20 and change surveillance requirements. The NRC staff has determined that the amendments involve no significant increase in the amounts, and no significant change in the types, of any effluents that may be released offsite, and that there is no significant increase in individual or cumulative occupational radiation exposure. The NRC has previously issued a proposed finding in the *Federal Register* [8], that the amendments involve no significant hazards consideration, and there has been no public comment on such finding. Accordingly, the amendments meet the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the issuance of the amendments.

6.0 CONCLUSION

The Commission has concluded, based on the considerations discussed above, that: (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner, (2) there is reasonable assurance that such activities will be conducted in compliance with the Commission's regulations, and (3) the issuance of the amendment will not be inimical to the common defense and security or to the health and safety of the public.

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8.0 ABBREVIATIONS

AC	alternating current
ADS	automatic depressurization system
ANS	American Nuclear Society
ASME	American Society of Mechanical Engineers
ATWS	anticipated transient without scram
CCF	common-cause failure
CDF	core damage frequency
CFR	Code of Federal Regulations
CRMP	configuration risk management program
CT	completion time
DBA	design basis accident
DC	direct current
DG	diesel generator
ECCS	emergency core cooling system
EOC	end of cycle
EPRI	Electrical Power Research Institute
ESSW	engineered safeguard service water system
F&O	fact(s) and observation(s)
FAQ	frequently asked question
FLEX	flexible and diverse coping strategies
FPRA	fire probabilistic risk assessment
HCLPF	high confidence of low probability of failure
HEP	human error probability
HPCI	high pressure coolant injection
HRA	human reliability analysis
HRR	heat release rate
HCVS	hardened containment vent system
FR	Federal Register
g	force per unit mass due to gravity at the Earth’s surface
I&C	instrumentation and control
ICDP	incremental core damage probability
ILERP	incremental large early release probability
IEPRA	internal events probabilistic risk assessment
IPEEE	Individual Plant Examination for External Events
kV	kilovolt(s)

LAR	license amendment request
LCO	limiting condition(s) for operation
LERF	large early release frequency
Licensee	Susquehanna Nuclear, LLC
LOOP	loss of offsite power
LPCI	low pressure coolant injection
MCC	motor control center
NEI	Nuclear Energy Institute
NRC	Nuclear Regulatory Commission
OPC	open phase condition(s)
OPD	open phase detection system
PAU	physical analysis unit(s)
PGA	peak ground acceleration
PRA	probabilistic risk assessment
RCIC	reactor core isolation cooling
RG	regulatory guide
RICT	risk-informed completion time
RMA	risk management actions
RMAT	risk management action time
RMTS	risk-managed technical specifications
RPT	recirculation pump trip
RPV	reactor pressure vessel
RTP	rated thermal power
RTR	real-time risk
SR	surveillance requirement
SSC	structures, systems, and components
Susquehanna	Susquehanna Steam Electric Station, Units 1 and 2
TCV	turbine control valve
TR	topical report
TS	technical specifications
TSTF	Technical Specifications Task Force
TSV	turbine stop valve
UFSAR	updated final safety analysis report
V	volt(s)

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Date: August 30, 2022

Subject: SUSQUEHANNA STEAM ELECTRIC STATION, UNITS 1 AND 2—ISSUANCE OF AMENDMENT NOS. 282 AND 265 REGARDING RISK-INFORMED COMPLETION TIMES IN TECHNICAL SPECIFICATIONS(EPID L-2021-LLA-0062)

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