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

June 1, 2023

Mr. Bob Coffey
Executive Vice President, Nuclear
Division and Chief Nuclear Officer
Florida Power & Light Company
Mail Stop: EX/JB
700 Universe Blvd
Juno Beach, FL 33408

SUBJECT: POINT BEACH NUCLEAR PLANT, UNITS 1 AND 2 - ISSUANCE OF AMENDMENT NOS. 271 AND 273 REGARDING TECHNICAL SPECIFICATIONS TO ADOPT TSTF-505, REVISION 2, "PROVIDE RISK-INFORMED EXTENDED COMPLETION TIMES – RITSTF INITIATIVE 4b" (EPID L-2022-LLA-0074)

Dear Mr. Coffey:

The U.S. Nuclear Regulatory Commission (NRC) has issued the enclosed Amendment Nos. 271 and 273 to Renewed Facility Operating License Nos. DPR-24 and DPR-27, respectively, for the Point Beach Nuclear Plant, Units 1 and 2 (Point Beach). The amendment consists of changes to the technical specifications (TSs) in response to your application dated May 20, 2022, as supplemented by letters dated July 11, 2022, January 11, 2023, and February 21, 2023.

The amendment revises the TS requirements to permit the use of risk-informed completion times for actions to be taken when limiting conditions for operation are not met.

The changes are based on Technical Specifications Task Force (TSTF) Traveler TSTF-505, Revision 2, "Provide Risk-Informed Extended Completion Times – RITSTF [Risk-Informed TSTF] Initiative 4b," dated July 2, 2018. The NRC issued a final model safety evaluation approving TSTF-505, Revision 2 on November 21, 2018.

A copy of our related safety evaluation is also enclosed. The Notice of Issuance will be included in the Commission's monthly *Federal Register* notice.

Sincerely,

/RA/

Scott P. Wall, Senior Project Manager
Plant Licensing Branch III
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket Nos. 50-266 and 50-301

Enclosures:
1. Amendment No. 271 to DPR-24
2. Amendment No. 273 to DPR-27
3. Safety Evaluation

cc: Listserv

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

NEXTERA ENERGY POINT BEACH, LLC

DOCKET NO. 50-266

POINT BEACH NUCLEAR PLANT, UNIT 1

AMENDMENT TO RENEWED FACILITY OPERATING LICENSE

Amendment No. 271
License No. DPR-24

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

   A. The application for amendment by NextEra Energy Point Beach, LLC (the licensee), dated May 20, 2022, as supplemented by letters dated July 11, 2022, January 11, 2023, and February 21, 2023, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and 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 rules and 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 Technical Specifications as indicated in the attachment to this license amendment, and paragraph 4.B of the Renewed Facility Operating License No. DPR-24 is hereby amended to read as follows:

   B. <u>Technical Specifications</u>

   The Technical Specifications contained in Appendices A and B, as revised through Amendment No. 271, are hereby incorporated in the renewed operating license. NextEra Energy Point Beach shall operate the facility in accordance with the Technical Specifications.

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

FOR THE NUCLEAR REGULATORY COMMISSION

Digitally signed by
Venkataiah Sreenivas
Date: 2023.06.01
11:06:50 -04'00'

V. Sreenivas, Acting Chief
Plant Licensing Branch III
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

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

Date of Issuance: June 1, 2023

NEXTERA ENERGY POINT BEACH, LLC

DOCKET NO. 50-301

POINT BEACH NUCLEAR PLANT, UNIT 2

AMENDMENT TO RENEWED FACILITY OPERATING LICENSE

Amendment No. 273
License No. DPR-27

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

    A. The application for amendment by NextEra Energy Point Beach, LLC (the licensee), dated May 20, 2022, as supplemented by letters dated July 11, 2022, January 11, 2023, and February 21, 2023, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and 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 rules and 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 Technical Specifications as indicated in the attachment to this license amendment, and paragraph 4.B of the Renewed Facility Operating License No. DPR-27 is hereby amended to read as follows:

   B. Technical Specifications

   The Technical Specifications contained in Appendices A and B, as revised through Amendment No. 273, are hereby incorporated in the renewed operating license. NextEra Energy Point Beach shall operate the facility in accordance with Technical Specifications.

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

FOR THE NUCLEAR REGULATORY COMMISSION

Digitally signed by Venkataiah Sreenivas
Date: 2023.06.01 11:05:17 -04'00'

V. Sreenivas, Acting Chief
Plant Licensing Branch III
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

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

Date of Issuance: June 1, 2023

ATTACHMENT TO LICENSE AMENDMENT NO. 271 AND 273

TO RENEWED FACILITY OPERATING LICENSE NOS. DPR-24 AND DPR-27

DOCKET NOS. 50-266 AND 50-301

Replace the following pages of Renewed Facility Operating License Nos. DPR-24 and DPR-27, and 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.

Renewed Facility Operating License No. DPR-24

REMOVE	INSERT
-3-	-3-

Renewed Facility Operating License No. DPR-27

REMOVE	INSERT
-3-	-3-

Appendix A, Technical Specifications

REMOVE	INSERT
1.3-13	1.3-13
--	1.3-14
3.3.1-1 through 3.3.1-20	3.3.1-1 through 3.3.1-22
3.3.2-1 through 3.3.2-9	3.3.2-1 through 3.3.2-10
3.4.11-1 through 3.4.11-3	3.4.11-1 through 3.4.11-4
3.5.2-1 through 3.5.2-2	3.5.2-1 through 3.5.2-3
3.6.2-4 through 3.6.2-5	3.6.2-4 through 3.6.2-5
3.6.3-1 through 3.6.3-3	3.6.3-1 through 3.6.3-3
3.7.2-1 through 3.7.2-2	3.7.2-1 through 3.7.2-3
3.7.4-1	3.7.4-1
3.7.5-1 through 3.7.5-2	3.7.5-1 through 3.7.5-2
3.7.7-1 through 3.7.7-2	3.7.7-1 through 3.7.7-2
3.7.8-1 through 3.7.8-4	3.7.8-1 through 3.7.8-5
3.8.1-2 through 3.8.1-8	3.8.1-2 through 3.8.1-10
3.8.4-1 through 3.8.4-2	3.8.4-1 through 3.8.4-2
3.8.7-1	3.8.7-1
5.5-6 through 5.5-19	5.5-6 through 5.5-20

D. Pursuant to the Act and 10 CFR Parts 30, 40 and 70, NextEra Energy Point Beach to receive, possess 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

E. Pursuant to the Act and 10 CFR Parts 30 and 70, NextEra Energy Point Beach to possess such byproduct and special nuclear materials as may be produced by the operation of the facility, but not to separate such materials retained within the fuel cladding.

4. This renewed operating license shall be deemed to contain and is subject to the conditions specified in the following Commission regulations: 10 CFR Part 20, Section 30.34 of 10 CFR Part 30, Section 40.41 of 10 CFR Part 40, Sections 50.54 and 50.59 of 10 CFR Part 50, and Section 70.32 of 10 CFR Part 70; and is subject to all applicable provisions of the Act and to the rules, regulations, and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified below:

A. Maximum Power Levels

NextEra Energy Point Beach is authorized to operate the facility at reactor core power levels not in excess of 1800 megawatts thermal.

B. Technical Specifications

The Technical Specifications contained in Appendices A and B, as revised through Amendment No. 271, are hereby incorporated in the renewed operating license. NextEra Energy Point Beach shall operate the facility in accordance with Technical Specifications.

C. Spent Fuel Pool Modification

The licensee is authorized to modify the spent fuel storage pool to increase its storage capacity from 351 to 1502 assemblies as described in licensee's application dated March 21, 1978, as supplemented and amended. In the event that the on-site verification check for poison material in the poison assemblies discloses any missing boron plates, the NRC shall be notified and an on-site test on every poison assembly shall be performed.

C. Pursuant to the Act and 10 CFR Parts 30, 40 and 70, NextEra Energy Point Beach to receive, possess and use at any time any byproduct, source, and special nuclear material as sealed neutron sources for reactor startup, sealed source for reactor instrumentation and radiation monitoring equipment calibration, and as fission detectors in amounts as required;

D. Pursuant to the Act and 10 CFR Parts 30, 40 and 70, NextEra Energy Point Beach to receive, possess 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

E. Pursuant to the Act and 10 CFR Parts 30 and 70, NextEra Energy Point Beach to possess such byproduct and special nuclear materials as may be produced by the operation of the facility, but not to separate such materials retained within the fuel cladding.

4. This renewed operating license shall be deemed to contain and is subject to the conditions specified in the following Commission regulations: 10 CFR Part 20, Section 30.34 of 10 CFR Part 30, Section 40.41 of 10 CFR Part 40, Sections 50.54 and 50.59 of 10 CFR Part 50, and Section 70.32 of 10 CFR Part 70; and is subject to all applicable provisions of the Act and to the rules, regulations, and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified below:

A. Maximum Power Levels

NextEra Energy Point Beach is authorized to operate the facility at reactor core power levels not in excess of 1800 megawatts thermal.

B. Technical Specifications

The Technical Specifications contained in Appendices A and B, as revised through Amendment No. 273, are hereby incorporated in the renewed operating license. NextEra Energy Point Beach shall operate the facility in accordance with Technical Specifications.

C. Spent Fuel Pool Modification

The licensee is authorized to modify the spent fuel storage pool to increase its storage capacity from 351 to 1502 assemblies as described in licensee's application dated March 21, 1978, as supplemented and amended. In the event that the on-site verification check for poison material in the poison assemblies discloses any missing boron plates, the NRC shall be notified and an on-site test on every poison assembly shall be performed.

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 5.	6 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

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 elapsed time 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.

3.3 INSTRUMENTATION

3.3.1 Reactor Protection System (RPS) Instrumentation

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

APPLICABILITY: According to Table 3.3.1-1.

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Functions with one or more required channels or trains inoperable.	A.1 Enter the Condition referenced in Table 3.3.1-1 for the channel(s) or train(s).	Immediately
B. One Manual Reactor Trip channel inoperable.	B.1 Restore channel to OPERABLE status.	48 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program
C. One Manual Reactor Trip channel inoperable.	C.1 Restore channel to OPERABLE status. <u>OR</u> C.2 Open reactor trip breakers (RTBs).	48 hours 49 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
D. One channel inoperable.	D.1	Place channel in trip.	1 hour OR In accordance with the Risk Informed Completion Time Program
E. One channel inoperable.	E.1	Place channel in trip.	6 hours OR In accordance with the Risk Informed Completion Time Program
F. One Intermediate Range Neutron Flux channel inoperable.	F.1	Reduce THERMAL POWER to < P-6.	24 hours
	OR		
	F.2	Increase THERMAL POWER to > P-10.	24 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
G. Two Intermediate Range Neutron Flux channels inoperable.	G.1	Suspend operations involving positive reactivity additions.	Immediately
	AND		
	G.2	Reduce THERMAL POWER to < P-6.	2 hours
H. One Source Range Neutron Flux channel inoperable.	H.1	Suspend operations involving positive reactivity additions.	Immediately
I. Two Source Range Neutron Flux channels inoperable.	I.1	Open RTBs.	Immediately
J. One Source Range Neutron Flux channel inoperable.	J.1	Restore channel to OPERABLE status.	48 hours
	OR		
	J.2	Open RTBs.	49 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
K. One channel inoperable.	K.1 Place channel in trip.	1 hour <u>OR</u> In accordance with the Risk Informed Completion Time Program
L. One Reactor Coolant Flow-Low (Single Loop) channel inoperable.	L.1 Place channel in trip.	1 hour <u>OR</u> In accordance with the Risk Informed Completion Time Program
M. One Reactor Coolant Pump Breaker Position (Single Loop) channel inoperable.	M.1 Restore channel to OPERABLE status.	1 hour <u>OR</u> In accordance with the Risk Informed Completion Time Program

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
N. One inoperable channel.	N.1 Restore channel to OPERABLE status.	1 hour <u>OR</u> In accordance with the Risk Informed Completion Time Program
O. One turbine trip channel inoperable.	O.1 Place channel in trip.	1 hour <u>OR</u> In accordance with the Risk Informed Completion Time Program
P. One train inoperable.	-----------------NOTE----------------- One train may be bypassed for up to 8 hours for surveillance testing provided the other train is OPERABLE. -- P.1 Restore train to OPERABLE status.	 6 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
Q. One RTB inoperable.	-----------------NOTE----------------- One RTB may be bypassed for up to 8 hours provided the other RTB is OPERABLE. --	
	Q.1 Restore RTB to OPERABLE status.	1 hour <u>OR</u> In accordance with the Risk Informed Completion Time Program
R. One or more channel(s) inoperable.	R.1 Verify interlock is in required state for existing unit conditions.	1 hour
	<u>OR</u>	
	R.2 Be in MODE 3.	7 hours
S. One or more channel(s) inoperable.	S.1 Verify interlock is in required state for existing unit conditions.	1 hour
	<u>OR</u>	
	S.2 Be in MODE 2.	7 hours
T. One RTB or trip mechanism for one RTB inoperable.	T.1 Restore RTB or RTB trip mechanism to OPERABLE status.	48 hours
	<u>OR</u>	
	T.2 Open RTBs.	49 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
U. One trip mechanism inoperable for one RTB.	U.1	Restore trip mechanism to OPERABLE status.	48 hours OR In accordance with the Risk Informed Completion Time Program
V. One reactor trip bypass breaker (RTBB) or trip mechanism for one RTBB inoperable.	V.1	Restore RTBB or RTBB trip mechanism to OPERABLE status.	1 hour
	OR		
	V.2	Be in MODE 3.	7 hours
W. One reactor trip bypass breaker (RTBB) or trip mechanism for one RTBB inoperable.	W.1	Restore RTBB or RTBB trip mechanism to OPERABLE status.	48 hours
	OR		
	W.2	Open RTBs and RTBBs.	49 hours
X. One train inoperable.	X.1	Restore train to OPERABLE status.	48 hours
	OR		
	X.2	Open RTBs.	49 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
Y. Required Action and associated Completion Time of Condition B, D, P, Q, or U not met.	Y.1	Be in Mode 3	6 hours
Z. Required Action and associated Completion Time of Condition E, K or N not met.	Z.1	Reduce THERMAL POWER to < P-7.	6 hours
AA. Required Action and associated Completion Time of Condition L or M not met.	AA.1	Reduce THERMAL POWER to < P-8.	4 hours
BB. Required Action and associated Completion Time of Condition O not met.	BB.1	Reduce THERMAL POWER to < P-9.	4 hours

SURVEILLANCE REQUIREMENTS

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

SURVEILLANCE		FREQUENCY
SR 3.3.1.1	Perform CHANNEL CHECK.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.2	-----NOTES----- 1. Adjust NIS channel if absolute difference is > 2%. 2. Not required to be performed until 12 hours after THERMAL POWER is ≥ 15% RTP. ---------- Compare results of calorimetric heat balance calculation to Nuclear Instrumentation System (NIS) channel output.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.3	-----NOTES----- 1. Adjust NIS channel if absolute difference is ≥ 3%. 2. Not required to be performed until 24 hours after THERMAL POWER is ≥ 50% RTP. ---------- Compare results of the incore detector measurements to NIS AFD.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.4	----------------------------NOTE-------------------------- This Surveillance must be performed on the reactor trip bypass breaker prior to placing the bypass breaker in service. --- Perform TADOT.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.5	----------------------------NOTES-------------------------- 1. Not required to be performed for the Source Range Neutron Flux Trip Function until 8 hours after power is below P-6. 2. Not required to be performed for the RCP Breaker Position (Two Loops), Reactor Coolant Flow — Low (Two Loops) and Underfrequency Bus A01 and A02 Trip Functions and the P-6, P-7, P-8, P-9 and P-10 Interlocks. --- Perform ACTUATION LOGIC TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.6	----------------------------NOTE-------------------------- Not required to be performed until 24 hours after THERMAL POWER is ≥ 50% RTP. --- Calibrate excore channels to agree with incore detector measurements.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.7	-----------------------------NOTE-------------------------- Not required to be performed for source range instrumentation prior to entering MODE 3 from MODE 2 until 4 hours after entry into MODE 3. -- Perform COT.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.8	----------------------------NOTE-------------------------- This Surveillance shall include verification that interlocks P-6 and P-10 are in their required state for existing unit conditions. --- Perform COT.	-------NOTE------- Only required when not performed within the frequency specified in the Surveillance Frequency Control Program ---------------------- Prior to reactor startup AND Four hours after reducing power below P-10 for power and intermediate range instrumentation AND Four hours after reducing power below P-6 for source range instrumentation AND In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.9	Perform TADOT.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.10	---------------------------NOTE------------------------ This Surveillance shall include verification that the time delays are adjusted to the prescribed values. --- Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.11	---------------------------NOTE------------------------ Neutron detectors are excluded from CHANNEL CALIBRATION. --- Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.12	Perform COT.	In accordance with the Surveillance Frequency Control Program
SR 3.3.1.13	Perform TADOT.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.1.14	Perform TADOT.	Prior to exceeding the P-9 interlock whenever the unit has been in MODE 3, if not performed within previous 31 days.
SR 3.3.1.15	---------------------------NOTE--------------------------- This Surveillance must be performed on the RCP Breaker Position (Two Loop), Reactor Coolant Flow - Low (Two Loop) and Underfrequency Bus A01 and A02 Trip Functions and the P-6 , P-7, P-8, P-9 and P-10 Interlocks. --- Perform ACTUATION LOGIC TEST.	In accordance with the Surveillance Frequency Control Program

Table 3.3.1-1 (page 1 of 8)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	NOMINAL TRIP SETPOINT
1. Manual Reactor Trip	1,2	2	B	SR 3.3.1.13	NA	NA
	3(a), 4(a), 5(a)	2	C	SR 3.3.1.13	NA	NA
2. Power Range Neutron Flux						
a. High	1,2	4	D	SR 3.3.1.1 SR 3.3.1.2 SR 3.3.1.7(m) SR 3.3.1.11(m)	≤ 108% RTP	106% RTP
b. Low	1(b),2	4	D	SR 3.3.1.1 SR 3.3.1.8(m) SR 3.3.1.11(m)	≤ 27% RTP	20% RTP
3. Intermediate Range Neutron Flux	1(b), 2(c)	2	F,G	SR 3.3.1.1 SR 3.3.1.8(m) SR 3.3.1.11(m)	≤ 43% RTP	25% RTP
4. Source Range Neutron Flux	2(d)	2	H,I	SR 3.3.1.1 SR 3.3.1.8(m) SR 3.3.1.11(m)	≤ 3.0 E5 cps	1.5 E5 cps
	3(a), 4(a), 5(a)	2	I,J	SR 3.3.1.1 SR 3.3.1.7(m) SR 3.3.1.11(m)	≤ 3.0 E5 cps	1.5 E5 cps
5. Overtemperature ΔT	1,2	4	D	SR 3.3.1.1 SR 3.3.1.3 SR 3.3.1.6 SR 3.3.1.7(m) SR 3.3.1.11(m)	Refer to Note 1 (Page 3.3.1-18)	Refer to Note 1 (Page 3.3.1-18)
6. Overpower ΔT	1,2	4	D	SR 3.3.1.1 SR 3.3.1.7(m) SR 3.3.1.11(m)	Refer to Note 2 (Page 3.3.1-19)	Refer to Note 2 (Page 3.3.1-19)

(continued)

(a) With Reactor Trip Breakers (RTBs) closed and Rod Control System capable of rod withdrawal.
(b) Below the P-10 (Power Range Neutron Flux) interlock.
(c) Above the P-6 (Intermediate Range Neutron Flux) interlock.
(d) Below the P-6 (Intermediate Range Neutron Flux) interlock.
(m) Table 3.3.1-1 Notes 3 and 4 are applicable

Table 3.3.1-1 (page 2 of 8)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	NOMINAL TRIP SETPOINT
7. Pressurizer Pressure						
a. Low	1(e)	4	K	SR 3.3.1.1 SR 3.3.1.7(m) SR 3.3.1.11(m)	≥ 1860 psig	1925 psig
b. High	1,2	3	D	SR 3.3.1.1 SR 3.3.1.7(m) SR 3.3.1.11(m)	≤ 2380 psig	2365 psig
8. Pressurizer Water Level — High	1(e)	3	K	SR 3.3.1.1 SR 3.3.1.7(m) SR 3.3.1.11(m)	≤ 85%	80%
9. Reactor Coolant Flow-Low						
a. Single Loop	1(f)	3 per loop	L	SR 3.3.1.1 SR 3.3.1.7(m) SR 3.3.1.11(m)	≥91%	93%
b. Two Loops	1(g)	3 per loop	K	SR 3.3.1.1 SR 3.3.1.7(m) SR 3.3.1.11(m)	≥91%	93%
10. Reactor Coolant Pump (RCP) Breaker Position						
a. Single Loop	1(f)	1 per RCP	M	SR 3.3.1.13	NA	NA
b. Two Loops	1(g)	1 per RCP	N	SR 3.3.1.13	NA	NA
11. Undervoltage Bus A01 & A02	1(e)	2 per bus	K	SR 3.3.1.9 SR 3.3.1.10(m)	≥ 3120 V	3170 V

(continued)

(e) Above the P-7 (Low Power Reactor Trips Block) interlock.
(f) Above the P-8 (Power Range Neutron Flux) interlock.
(g) Above the P-7 (Low Power Reactor Trips Block) interlock and below the P-8 (Power Range Neutron Flux) interlock.
(m) Table 3.3.1-1 Notes 3 and 4 are applicable

Table 3.3.1-1 (page 3 of 8)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	NOMINAL TRIP SETPOINT
12. Underfrequency Bus A01 & A02	1(e)	2 per bus	E	SR 3.3.1.10(m)	≥ 55.0 Hz	57 Hz
13. Steam Generator (SG) Water Level — Low Low	1,2	3 per SG	D	SR 3.3.1.1 SR 3.3.1.7(m) SR 3.3.1.11(m)	≥ 29.5%	31%
14. SG Water Level — Low	1,2	2 per SG	D	SR 3.3.1.1 SR 3.3.1.7(m) SR 3.3.1.11(m)	≥ 11%	31%
Coincident with Steam Flow/Feedwater Flow Mismatch	1,2	2 per SG	D	SR 3.3.1.1 SR 3.3.1.7(m) SR 3.3.1.11(m)	≤ 1 E6 lbm/hr	0.8 E6 lbm/hr
15. Turbine Trip						
a. Low Autostop Oil Pressure	1(j)	3	O	SR 3.3.1.14	NA	NA
b. Turbine Stop Valve Closure	1(j)	2	O	SR 3.3.1.14	NA	NA
16. Safety Injection (SI) Input from Engineered Safety Feature Actuation System (ESFAS)	1,2	2 trains	P	SR 3.3.1.13	NA	NA

(continued)

(e) Above the P-7 (Low Power Reactor Trips Block) interlock.
(j) Above the P-9 (Power Range Neutron Flux) interlock.
(m) Table 3.3.1-1 Notes 3 and 4 are applicable

Table 3.3.1-1 (page 4 of 8)
Reactor Protection System Instrumentation

FUNCTION	APPLICABLE MODES	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	NOMINAL TRIP SETPOINT
17. Reactor Trip System Interlocks						
a. Intermediate Range Neutron Flux, P-6	2(d)	2	R	SR 3.3.1.11 SR 3.3.1.12	≥ 4E-11 amp	1E-10 amp
b. Low Power Reactor Trips Block, P-7						
(1) Power Range Neutron Flux	1	4	S	SR 3.3.1.11 SR 3.3.1.12	≤ 13% RTP	10% RTP
(2) Turbine First Stage Pressure	1	2	S	SR 3.3.1.11 SR 3.3.1.12	≤ 12.8% turbine power	10% turbine power
c. Power Range Neutron Flux, P-8	1	4	S	SR 3.3.1.11 SR 3.3.1.12	≤ 38% RTP	35% RTP
d. Power Range Neutron Flux, P-9	1(k)	4	S	SR 3.3.1.11 SR 3.3.1.12	(h)	(i)
e. Power Range Neutron Flux, P-10	1,2	4	R	SR 3.3.1.11 SR 3.3.1.12	≥ 6% RTP and ≤ 12% RTP	9% RTP
18. Reactor Trip Breakers (RTBs)	1,2	2 trains	Q	SR 3.3.1.4	NA	NA
	3(a), 4(a), 5(a)	2 trains	T	SR 3.3.1.4	NA	NA
19. Reactor Trip Breaker Undervoltage and Shunt Trip Mechanisms	1,2	1 each per RTB	U	SR 3.3.1.4	NA	NA
	3(a), 4(a), 5(a)	1 each per RTB	T	SR 3.3.1.4	NA	NA

(continued)

(a) With the RTBs closed and the Rod Control System capable of rod withdrawal.
(d) Below the P-6 (Intermediate Range Neutron Flux) interlock.
(h) ≤ 38% RTP for full design power T_{avg} < 572°F or ≤ 53% RTP for full design power T_{avg} ≥ 572°F. For EOC coastdown, P-9 is not reset if T_{avg} decreases to < 572°F.
(i) 35% RTP for full design power T_{avg} < 572°F or 50% RTP for full design power T_{avg} ≥ 572°F. For EOC coastdown, P-9 is not reset if T_{avg} decreases to < 572°F.
(k) With 1 of 2 circulating water pump breakers closed and condenser vacuum ≥ 22 "Hg.

Table 3.3.1-1 (page 5 of 8)
Reactor Protection System Instrumentation

	FUNCTION	APPLICABLE MODES	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	NOMINAL TRIP SETPOINT
20.	Reactor Trip Bypass Breaker and associated Undervoltage Trip Mechanism	$1^{(l)}$, $2^{(l)}$	1	V	SR 3.3.1.4	NA	NA
		$3^{(l)}$, $4^{(l)}$, $5^{(l)}$	1	W	SR 3.3.1.4	NA	NA
21.	Automatic Trip Logic	1, 2,	2 trains	P	SR 3.3.1.5 SR 3.3.1.15	NA	NA
		$3^{(a)}$, $4^{(a)}$, $5^{(a)}$	2 trains	X	SR 3.3.1.5	NA	NA

(a) With RTBs closed and Rod Control System capable of rod withdrawal.
(l) When Reactor Trip Bypass Breakers are racked in and closed and the Rod Control System is capable of rod withdrawal.

Table 3.3.1-1 (page 6 of 8)
Reactor Protection System Instrumentation

Note 1: Overtemperature ΔT

$$\Delta T \left(\frac{1}{1+\tau_3 S}\right) \leq \Delta T_o \left(K_1 - K_2\left(T\left(\frac{1}{1+\tau_4 S}\right) - T'\right)\left(\frac{1+\tau_1 S}{1+\tau_2 S}\right) + K_3 (P - P') - f(\Delta I)\right)$$

Where:

ΔT_o	=	indicated ΔT at RTP, °F
T	=	average temperature, °F
T'	≤	[*]°F
P	=	pressurizer pressure, psig
P'	=	[*] psig
K_1	≤	[*]
K_2	=	[*]
K_3	=	[*]
τ_1	=	[*] sec
τ_2	=	[*] sec
τ_3	=	[*] sec
τ_4	=	[*] sec

f(ΔI) =	[*] {[*] - (q_t - q_b)}	when (q_t - q_b) ≤ [*]% RTP
	0% of RTP	when [*]% RTP < (q_t - q_b) ≤ [*]% RTP
	[*] {(q_t - q_b) - [*]}	when (q_t - q_b) > [*]% RTP

Where q_t and q_b are percent RTP in the upper and lower halves of the core, respectively, and (q_t + q_b) is the total THERMAL POWER in percent RTP.

* The values denoted with [*] are specified in the COLR.

Table 3.3.1-1 (page 7 of 8)
Reactor Protection System Instrumentation

Note 2: Overpower ΔT

$$\Delta T \left(\frac{1}{1+\tau_3 S}\right) \leq \Delta T_o [K_4 - K_5 \left(\frac{\tau_5 S}{\tau_5 S + 1}\right)\left(\frac{1}{1+\tau_4 S}\right) T - K_6 [T \left(\frac{1}{1+\tau_4 S}\right) - T']]$$

Where:

ΔT_o	=	indicated ΔT at RTP, °F
T	=	average temperature, °F
T'	≤	[*]°F
K_4	≤	[*]
K_5	=	[*] for increasing T
	=	[*] for decreasing T
K_6	=	[*] for T ≥ T'
	=	[*] for T < T'
τ_5	=	[*] sec
τ_3	=	[*] sec
τ_4	=	[*] sec

* The values denoted with [*] are specified in the COLR.

Table 3.3.1-1 (page 8 of 8)
Reactor Protection System Instrumentation

Note 3:

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

Note 4:

The instrument channel setpoint shall be reset to a value that is within the as-left tolerance around the Nominal Trip Setpoint (NTSP) at the completion of the surveillance; otherwise, the channel shall be declared inoperable. Setpoints more conservative than the NTSP are acceptable provided that the as-found and as-left tolerances apply to the actual setpoint implemented in the Surveillance procedures (field setting) to confirm channel performance. The methodologies used to determine the as-found and the as-left tolerances are specified in FSAR Section 7.2.

3.3 INSTRUMENTATION

3.3.2 Engineered Safety Feature Actuation System (ESFAS) Instrumentation

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

APPLICABILITY: According to Table 3.3.2-1.

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more Functions with one or more required channels or trains inoperable.	A.1 Enter the Condition referenced in Table 3.3.2-1 for the channel(s) or train(s).	Immediately
B. One channel inoperable.	B.1 Restore channel to OPERABLE status.	48 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One train inoperable.	C.1 Restore train to OPERABLE status.	6 hours <u>OR</u> --------NOTE-------- Not applicable to Function 2b, Containment Spray – Automatic Actuation Logic and Actuation Relays, of Table 3.3-2. -------------------------- In accordance with the Risk Informed Completion Time Program
D. One channel inoperable.	D.1 Place channel in trip.	1 hour <u>OR</u> --------NOTE-------- Not applicable to Function 2c, Containment Spray – Containment Pressure High-High, of Table 3.3-2. ------------------------- In accordance with the Risk Informed Completion Time Program

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
E. One or both channel(s) inoperable.	E.1	Restore channel(s) to OPERABLE status.	1 hour
	OR		
	E.2.1	Be in MODE 3.	7 hours
	AND		
	E.2.2	Be in MODE 5.	37 hours
F. One channel inoperable.	F.1	Restore channel to OPERABLE status.	1 hour OR In accordance with the Risk Informed Completion Time Program
G. One train inoperable.	G.1	Restore train to OPERABLE status.	6 hours OR In accordance with the Risk Informed Completion Time Program
H. One channel inoperable.	H.1	Place channel in trip.	6 hours OR In accordance with the Risk Informed Completion Time Program

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
I. One or more channels inoperable.	I.1	Verify interlock is in required state for existing unit condition.	1 hour
	<u>OR</u>		
	I.2.1	Be in MODE 3.	7 hours
	<u>AND</u>		
	I.2.2	Be in MODE 4.	13 hours
------------------NOTE------------------ Separate Condition entry is allowed for each AFW pump. --	J.1	Restore channel to OPERABLE status.	48 hours
	<u>OR</u>		
J. One channel inoperable.	J.2	Declare associated AFW pump inoperable.	
K. Required Action and associated Completion Time of Condition H not met.	K.1	Be in MODE 3.	6 hours
L. Required Action and associated Completion Time of Condition B or C not met.	L.1	Be in MODE 3.	6 hours
	<u>AND</u>		
	L.2	Be in MODE 5.	36 hours
M. Required Action and associated Completion Time of Condition D, F or G not met.	M.1	Be in MODE 3.	6 hours
	<u>AND</u>		
	M.2	Be in MODE 4.	12 hours

SURVEILLANCE REQUIREMENTS

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

SURVEILLANCE		FREQUENCY
SR 3.3.2.1	Perform CHANNEL CHECK.	In accordance with the Surveillance Frequency Control Program
SR 3.3.2.2	-----NOTE----- The continuity check may be excluded. ----- Perform ACTUATION LOGIC TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.2.3	Perform COT.	In accordance with the Surveillance Frequency Control Program
SR 3.3.2.4	Perform MASTER RELAY TEST.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.3.2.5	Perform SLAVE RELAY TEST.	In accordance with the Surveillance Frequency Control Program
SR 3.3.2.6	Perform TADOT.	In accordance with the Surveillance Frequency Control Program
SR 3.3.2.7	Perform TADOT.	In accordance with the Surveillance Frequency Control Program
SR 3.3.2.8	---------------------------NOTE-------------------------- This Surveillance shall include verification that the time constants are adjusted to the prescribed values. -- Perform CHANNEL CALIBRATION.	In accordance with the Surveillance Frequency Control Program

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

FUNCTION	APPLICABLE MODES	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	NOMINAL TRIP SETPOINT
1. Safety Injection						
a. Manual Initiation	1,2,3,4	2	B	SR 3.3.2.7	NA	NA
b. Automatic Actuation Logic and Actuation Relays	1,2,3,4	2 trains	C	SR 3.3.2.2 SR 3.3.2.4 SR 3.3.2.5	NA	NA
c. Containment Pressure—High	1,2,3	3	D	SR 3.3.2.1 SR 3.3.2.3[f] SR 3.3.2.8[f]	≤ 5.1 psig	4.8 psig
d. Pressurizer Pressure—Low	1,2,3[a]	3	D	SR 3.3.2.1 SR 3.3.2.3[f] SR 3.3.2.8[f]	≥ 1730 psig	1735 psig
e. Steam Line Pressure—Low	1,2,3[b]	3 per steam line	D	SR 3.3.2.1 SR 3.3.2.3[f] SR 3.3.2.8[f]	≥ 535[c] psig	545 psig
2. Containment Spray						
a. Manual Initiation	1,2,3,4	2	E	SR 3.3.2.7	NA	NA
b. Automatic Actuation Logic and Actuation Relays	1,2,3,4	2 trains	C	SR 3.3.2.2 SR 3.3.2.4 SR 3.3.2.5	NA	NA
c. Containment Pressure—High High	1,2,3	2 sets of 3	D	SR 3.3.2.1 SR 3.3.2.3[f] SR 3.3.2.8[f]	≤ 28 psig	25 psig

(continued)

(a) Pressurizer Pressure > 2000 psig.
(b) Pressurizer Pressure > 2000 psig, except during Reactor Coolant System hydrostatic testing.
(c) Time constants used in the lead/lag controller are $t_1 \geq 18$ seconds and $t_2 \leq 2$ seconds.
(f) Table 3.3.2-1 Notes 1 and 2 are applicable.

Table 3.3.2-1 (page 2 of 4)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	NOMINAL TRIP SETPOINT
3. Containment Isolation						
a. Manual Initiation	1,2,3,4	2	B	SR 3.3.2.7	NA	NA
b. Automatic Actuation Logic and Actuation Relays	1,2,3,4	2 trains	C	SR 3.3.2.4 SR 3.3.2.5	NA	NA
c. Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements, except Manual SI initiation.					
4. Steam Line Isolation						
a. Manual Initiation						
	$1,2^{(d)},3^{(d)}$	1/loop	F	SR 3.3.2.7	NA	NA
b. Automatic Actuation Logic and Actuation Relays	$1,2^{(d)},3^{(d)}$	2 trains	G	SR 3.3.2.2 SR 3.3.2.5	NA	NA
c. Containment Pressure—High High	$1,2^{(d)},3^{(d)}$	3	D	SR 3.3.2.1 SR 3.3.2.3(f) SR 3.3.2.8(f)	≤ 18 psig	15 psig
d. High Steam Flow	$1,2^{(d)},3^{(d)}$	2 per steam line	D	SR 3.3.2.1 SR 3.3.2.3(f) SR 3.3.2.8(f)	≤ Δp corresponding to 0.8 x 10^6 lb/hr at 1005 psig	Δp corresponding to 0.52 x 10^6 lb/hr at 1005 psig
Coincident with Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.					
and						
Coincident with T_{avg}—Low	$1,2^{(d)},3^{(d)}$	3	D	SR 3.3.2.1 SR 3.3.2.3(f) SR 3.3.2.8(f)	≥ 542°F	543°F
e. High High Steam Flow	$1,2^{(d)},3^{(d)}$	2 per steam line	D	SR 3.3.2.1 SR 3.3.2.3(f) SR 3.3.2.8(f)	≤ Δp corresponding to 4.9 x 10^6 lb/hr at 586 psig	Δp corresponding to 4.85 x 10^6 lb/hr at 586 psig
Coincident with Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.					

(continued)

(d) Except when all MSIVs are closed and de-activated.
(f) Table 3.3.2-1 Notes 1 and 2 are applicable.

Table 3.3.2-1 (page 3 of 4)
Engineered Safety Feature Actuation System Instrumentation

FUNCTION	APPLICABLE MODES	REQUIRED CHANNELS	CONDITIONS	SURVEILLANCE REQUIREMENTS	ALLOWABLE VALUE	NOMINAL TRIP SETPOINT
5. Feedwater Isolation						
a. Automatic Actuation Logic and Actuation Relays	1,2(e),3(e)	2 trains	G	SR 3.3.2.2 SR 3.3.2.4 SR 3.3.2.5	NA	NA
b. SG Water Level—High	1,2(e),3(e)	3 per SG	D	SR 3.3.2.1 SR 3.3.2.3(f) SR 3.3.2.8(f)	≤ 90%	78%
c. Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.					
6. Auxiliary Feedwater						
a. Automatic Actuation Logic and Actuation Relays	1,2,3	2 trains	G	SR 3.3.2.2	NA	NA
b. SG Water Level—Low Low	1,2,3	3 per SG	D	SR 3.3.2.1 SR 3.3.2.3(f) SR 3.3.2.8(f)	≥ 29.5%	31%
c. Safety Injection	Refer to Function 1 (Safety Injection) for all initiation functions and requirements.					
d. Undervoltage Bus A01 and A02	1,2	2 per bus	H	SR 3.3.2.6 SR 3.3.2.8(f)	≥ 3120 V	3255 V
e. AFW Pump Suction Transfer on Suction Pressure - Low	1,2,3	1 per pump	J	SR 3.3.2.1 SR 3.3.2.3(f) SR 3.3.2.8(f)	≥ 5.8 psig	6.1 psig
7. SI Block-Pressurizer Pressure	1,2,3	3	I	SR 3.3.2.1 SR 3.3.2.3 SR 3.3.2.8	≤ 2005 psig	2000 psig

(e) Except when all MFIVs, MFRVs and associated bypass valves are closed and de-activated.
(f) Table 3.3.2-1 Notes 1 and 2 are applicable.

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

Note 1:

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

Note 2:

The instrument channel setpoint shall be reset to a value that is within the as-left tolerance around the Nominal Trip Setpoint (NTSP) at the completion of the surveillance; otherwise, the channel shall be declared inoperable. Setpoints more conservative than the NTSP are acceptable provided that the as-found and as-left tolerances apply to the actual setpoint implemented in the Surveillance procedures (field setting) to confirm channel performance. The methodologies used to determine the as-found and the as-left tolerances are specified in FSAR Section 7.2.

3.4 REACTOR COOLANT SYSTEM (RCS)

3.4.11 Pressurizer Power Operated Relief Valves (PORVs)

LCO 3.4.11 Each PORV and associated block valve shall be OPERABLE.

APPLICABILITY: MODES 1, 2, MODE 3 with RCS average temperature (T_{avg}) ≥ 500°F.

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more PORVs inoperable and capable of being manually cycled.	A.1 Close and maintain power to associated block valve.	1 hour
B. One PORV inoperable and not capable of being manually cycled.	B.1 Close associated block valve.	1 hour
	<u>AND</u>	
	B.2 Remove power from associated block valve.	1 hour
	<u>AND</u>	
	B.3 Restore PORV to OPERABLE status.	72 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One block valve inoperable.	-----------------NOTE----------------- Required Actions C.1 and C.2 do not apply when block valve is inoperable solely as a result of complying with Required Actions B.2 or E.2 --	
	C.1 Place associated PORV in manual control.	1 hour
	AND	
	C.2 Restore block valve to OPERABLE status.	72 hours OR In accordance with the Risk Informed Completion Time Program
D. Required Action and associated Completion Time of Condition A, B, or C not met.	D.1 Be in MODE 3.	6 hours
	AND	
	D.2 Reduce T_{avg} to < 500°F.	12 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
E. Two PORVs inoperable and not capable of being manually cycled.	E.1	Close associated block valves.	1 hour
	<u>AND</u>		
	E.2	Remove power from associated block valves.	1 hour
	<u>AND</u>		
	E.3	Be in MODE 3.	6 hours
	<u>AND</u>		
	E.4	Reduce T_{avg} to < 500°F.	12 hours
F. Two block valves inoperable.	-----------------NOTE----------------- Required Action F.1 does not apply when block valve is inoperable solely as a result of complying with Required Actions B.2 or E.2 --		
	F.1	Restore one block valve to OPERABLE status.	2 hours
G. Required Action and associated Completion Time of Condition F not met.	G.1	Be in MODE 3.	6 hours
	<u>AND</u>		
	G.2	Reduce T_{avg} to < 500°F.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.4.11.1	---------------------------NOTE-------------------------- Not required to be met with block valve closed in accordance with the Required Action of Condition B or E. -- Perform a complete cycle of each block valve.	In accordance with the Surveillance Frequency Control Program
SR 3.4.11.2	Perform a complete cycle of each PORV.	In accordance with the Surveillance Frequency Control Program

3.5 EMERGENCY CORE COOLING SYSTEMS (ECCS)

3.5.2 ECCS – Operating

LCO 3.5.2 Two ECCS trains shall be OPERABLE.

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

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One ECCS train inoperable.	A.1 Restore train to OPERABLE status.	72 hours <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. <u>AND</u> B.2 Be in MODE 4.	6 hours 12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.5.2.1	-------------------------NOTE------------------------- Not required to be met for system vent flow paths opened under administrative controls. -- Verify each ECCS 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.	In accordance with the Surveillance Frequency Control Program
SR 3.5.2.2	Verify ECCS locations susceptible to gas accumulation are sufficiently filled with water.	In accordance with the Surveillance Frequency Control Program
SR 3.5.2.3	Verify each ECCS pump's developed head at the test flow point is greater than or equal to the required developed head.	In accordance with the INSERVICE TESTING PROGRAM
SR 3.5.2.4	Verify each ECCS automatic valve in the flow path that is not locked, sealed, or otherwise secured in position, actuates to the correct position on an actual or simulated actuation signal.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.5.2.5	Verify each ECCS pump starts automatically on an actual or simulated actuation signal.	In accordance with the Surveillance Frequency Control Program
SR 3.5.2.6	Verify, by visual inspection, each ECCS train containment sump suction inlet is not restricted by debris and the suction inlet debris screens show no evidence of structural distress or abnormal corrosion.	In accordance with the Surveillance Frequency Control Program

ACTIONS

CONDITIONS	REQUIRED ACTION		COMPLETION TIME
B. (continued)	B.3	-----------NOTE----------- Bulkhead doors and equalizing valves in high radiation areas may be verified locked closed by administrative means. ------------------------------	
		Verify the bulkhead door and equalizing valve on an OPERABLE bulkhead in the affected airlock are locked closed.	Once per 31 days
C. One or more containment air locks inoperable for reasons other than Condition A or B.	C.1	Initiate action to evaluate overall containment leakage rate per LCO 3.6.1.	Immediately
	<u>AND</u>		
	C.2	Verify a bulkhead door and associated equalizing valve are closed in the affected air lock.	1 hour
	<u>AND</u>		
	C.3	Restore air lock to OPERABLE status.	36 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program

(continued)

ACTIONS (continued)

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

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.6.2.1	-------------------------NOTES------------------------- 1. An inoperable air lock bulkhead does not invalidate the previous successful performance of the overall air lock leakage test. 2. Results shall be evaluated against acceptance criteria applicable to SR 3.6.1.1. --- Perform required air lock leakage rate testing in accordance with the Containment Leakage Rate Testing Program.	In accordance with the Containment Leakage Rate Testing Program
SR 3.6.2.2	Verify only one bulkhead door and its associated equalizing valve in the air lock can be opened at a time.	In accordance with the Surveillance Frequency Control Program

3.6 CONTAINMENT SYSTEMS

3.6.3 Containment Isolation Valves

LCO 3.6.3 Each containment isolation valve shall be OPERABLE.

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

ACTIONS

---NOTES---

1. Penetration flow path(s) except for the purge supply and exhaust flow paths may be unisolated intermittently under administrative controls.

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

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

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

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. -----------NOTE----------- Only applicable to penetration flow paths with two containment isolation valves. ---------------------------- One or more penetration flow paths with one containment isolation valve inoperable.	A.1 AND	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 OR In accordance with the Risk Informed Completion Time Program (continued)

ACTIONS

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

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. -----------NOTE----------- Only applicable to penetration flow paths with only one containment isolation valve and a closed system. ----------------------------- One or more penetration flow paths with one containment isolation valve inoperable.	C.1	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 <u>OR</u> In accordance with the Risk Informed Completion Time Program
	<u>AND</u>		
	C.2	-----------NOTES---------- 1. Isolation devices in high radiation areas may be verified by use of administrative means. 2. Isolation devices that are locked, sealed, or otherwise secured may be verified by use of administrative means. ----------------------------- Verify the affected penetration flow path is isolated.	Once per 31 days following isolation for isolation devices outside containment <u>AND</u> Prior to entering Mode 4 from Mode 5 if not performed within the previous 92 days for isolation devices inside containment

(continued)

3.7 PLANT SYSTEMS

3.7.2 Main Steam Isolation Valves (MSIVs) and Non-Return Check Valves

LCO 3.7.2 Two MSIVs and two non-return check valves shall be OPERABLE.

APPLICABILITY: MODES 1, 2 and 3

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One Steam Generator flowpath with one or more inoperable valves in MODE 1.	A.1	Restore valve to OPERABLE status.	8 hours <u>OR</u> -------NOTE------- Not applicable when more than one valve inoperable in one SG flowpath. --------------------- In accordance with the Risk Informed Completion Time Program
B. Required Action and associated Completion Time of Condition A not met.	B.1	Be in MODE 2.	6 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. -----------NOTE----------- Separate Condition entry is allowed for each Steam Generator flowpath. ------------------------------	-------------------NOTE------------------- An inoperable flowpath may be opened under administrative controls to allow cool down of the affected unit. ---		
One or both MSIVs inoperable in MODE 2 or 3.	C.1	Close and de-activate the MSIV in the affected flowpath.	8 hours
<u>OR</u>	<u>AND</u>		
One or both non-return check valves inoperable in MODE 2 or 3.	C.2	Close non-return check valve in the affected flowpath.	8 hours
	<u>AND</u>		
	C.3	Verify MSIV and non-return check valve in the affected flowpath are closed and the MSIV is de-activated.	Once per 7 days
D. Required Action and associated Completion Time of Condition C not met.	D.1	Be in MODE 3.	6 hours
	<u>AND</u>		
	D.2	Be in MODE 4.	12 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.2.1	--------------------------NOTE------------------------- Only required to be performed in MODE 1. --- Verify closure time of each MSIV is within limits.	In accordance with the INSERVICE TESTING PROGRAM
SR 3.7.2.2	--------------------------NOTE------------------------- Only required to be performed in MODE 1. --- Verify each MSIV actuates to the isolation position on an actual or simulated actuation signal.	In accordance with the Surveillance Frequency Control Program
SR 3.7.2.3	Verify each main steam non-return check valve can close.	In accordance with the INSERVICE TESTING PROGRAM

3.7 PLANT SYSTEMS

3.7.4 Atmospheric Dump Valve (ADV) Flowpaths

LCO 3.7.4 Two ADV flowpaths shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3,
MODE 4 when steam generator is relied upon for heat removal.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required ADV flowpath inoperable.	A.1 Restore required ADV flowpath to OPERABLE status.	7 days <u>OR</u> In accordance with the Risk Informed Completion Time Program
B. Two required ADV flowpaths inoperable.	B.1 Restore one ADV flowpath to OPERABLE status.	1 hour
C. Required Action and associated Completion Time not met.	C.1 Be in MODE 3. <u>AND</u> C.2 Be in MODE 4 without reliance upon steam generator for heat removal.	6 hours 18 hours

3.7 PLANT SYSTEMS

3.7.5 Auxiliary Feedwater (AFW)

LCO 3.7.5 The AFW System shall be OPERABLE with; one turbine driven AFW pump system and one motor driven AFW pump system:

--------------------------------------NOTE---------------------------------------
Only the motor driven AFW pump system is required to be OPERABLE in MODE 4.

APPLICABILITY: MODES 1, 2, and 3,
MODE 4 when steam generator is relied upon for heat removal.

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Turbine driven AFW pump system inoperable due to one inoperable steam supply. <u>OR</u> -----------NOTE------------ Only applicable if MODE 2 has not been entered following refueling. ------------------------------- Turbine driven AFW pump system inoperable in MODE 3 following refueling.	A.1 Restore affected equipment to OPERABLE status.	7 days <u>OR</u> In accordance with the Risk Informed Completion Time Program

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. One AFW pump system inoperable in MODE 1, 2 or 3 for reasons other than Condition A.	B.1 Restore AFW pump system to OPERABLE status.	72 hours OR In accordance with the Risk Informed Completion Time Program
C. Turbine driven AFW pump system inoperable due to one inoperable steam supply. AND Motor driven AFW pump system inoperable.	C.1 Restore the steam supply to the turbine driven pump system to OPERABLE status. OR C.2 Restore the motor driven AFW pump system to OPERABLE status.	24 hours OR 48 hours if motor driven AFW pump system is available from the opposite unit.

(continued)

3.7 PLANT SYSTEMS

3.7.7 Component Cooling Water (CC) System

LCO 3.7.7 The CC System shall be OPERABLE with; two CC pumps, and two required CC heat exchangers.

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

ACTIONS

---NOTE---
Enter applicable Conditions and Required Actions of LCO 3.4.6, "RCS Loops — MODE 4," for residual heat removal loops made inoperable by CC.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One CC pump inoperable.	A.1 Restore CC pump to OPERABLE status.	72 hours OR In accordance with the Risk Informed Completion Time Program
B. One required CC heat exchanger inoperable.	B.1 Restore required CC heat exchanger to OPERABLE status.	72 hours OR In accordance with the Risk Informed Completion Time Program

(continued)

ACTIONS (continued)

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

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.7.1	--------------------------NOTE------------------------- Isolation of CC flow to individual components does not render the CC System inoperable. --- Verify each CC manual, power operated, and automatic valve in the flow path servicing safety related equipment, that is not locked, sealed, or otherwise secured in position, is in the correct position.	In accordance with the Surveillance Frequency Control Program

3.7 PLANT SYSTEMS

3.7.8 Service Water (SW) System

LCO 3.7.8 The SW System shall be OPERABLE with:

a. Six OPERABLE SW pumps;

b. SW ring header continuous flowpath not interrupted;

c. Required automatic non-essential-SW-load isolation valves OPERABLE or affected non-essential flowpath isolated; and

d. Opposite unit containment accident fan cooler unit SW outlet motor operated valves closed or SW flowpath isolated.

-------------------------------------NOTE-------------------------------------
Only five SW pumps are required to be OPERABLE with one unit in MODE 5 or 6, or defueled, and the SW System capable of providing required cooling water flow to required equipment.

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

ACTIONS

-------------------------------------NOTE-------------------------------------
Enter applicable Conditions and Required Actions for systems made inoperable by SW System.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One SW pump inoperable. AND Both units in MODES 1, 2, 3, or 4.	A.1 Restore SW pump to OPERABLE status.	7 days OR In accordance with the Risk Informed Completion Time Program

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Two or three SW pumps inoperable.	B.1 Restore SW pump(s) to OPERABLE status.	72 hours
C. SW ring header continuous flowpath interrupted.	C.1 Verify SW System capable of providing required cooling water flow to required equipment.	1 hour
	AND	
	C.2 Restore the SW ring header continuous flowpath.	7 days OR In accordance with the Risk Informed Completion Time Program

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. ----------NOTE--------- Separate Condition entry is allowed for each non-essential-SW-load flowpath. -------------------------- One or more non-essential-SW-load flowpath(s) with one required automatic isolation valve inoperable. AND Affected non-essential flowpath(s) not isolated.	D.1 -----------NOTE---------- Not required to be met if in Condition E. ----------------------------- Verify required redundant automatic isolation valve in the affected non-essential flowpath(s) OPERABLE. AND D.2 Isolate the affected non-essential flowpath(s).	 1 hour 72 hours OR In accordance with the Risk Informed Completion Time Program
E. One or more non-essential-SW-load flowpath(s) with two required automatic isolation valves inoperable. AND Affected non-essential flowpath(s) not isolated.	E.1 Isolate the affected non-essential flowpath(s).	1 hour

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
F. One or more opposite unit containment accident fan cooler unit SW outlet motor operated valves open. AND Opposite unit containment accident fan cooler unit SW flowpath not isolated.	F.1 Verify SW System capable of providing required cooling water flow to required equipment. AND F.2 Isolate the opposite unit containment accident fan cooler unit SW flowpath.	1 hour 72 hours AND 14 days from discovery of failure to meet the LCO
G. Four or more SW pumps inoperable.	G.1 Restore SW pump(s) to OPERABLE status.	1 hour
H. Required Action and associated Completion Time not met.	H.1 Be in MODE 3. AND H.2 Be in MODE 5.	6 hours 36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.7.8.1	--------------------------NOTE-------------------------- Isolation of SW flow to individual components does not render the SW System inoperable. --- Verify each SW manual, power operated, and automatic valve in the flow path servicing safety related equipment, that is not locked, sealed, or otherwise secured in position, is in the correct position.	In accordance with the Surveillance Frequency Control Program
SR 3.7.8.2	Verify each required SW automatic non-essential-SW-load isolation valve that is not locked, sealed, or otherwise secured in the closed position, actuates to the closed position on an actual or simulated actuation signal.	In accordance with the Surveillance Frequency Control Program
SR 3.7.8.3	Verify each SW pump starts automatically on an actual or simulated actuation signal.	In accordance with the Surveillance Frequency Control Program

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. (continued)	A.2	Verify gas turbine in operation.	24 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program
B. Associated unit's 13.8/4.16 kV (X04) transformer inoperable.	B.1	Restore associated unit's 13.8/4.16 kV (X04) transformer to OPERABLE status.	24 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program
C. Associated unit's required offsite power source to buses A05 and A06 inoperable. <u>OR</u> Required offsite power source to buses 1A05 and 2A06 inoperable.	C.1	Restore required offsite power source(s) to OPERABLE status.	24 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
D. One or more required offsite power source(s) to one or more required Class 1E 4.16 kV bus(es) inoperable.	D.1	Declare required feature(s) supported by the inoperable required offsite power source inoperable when its required redundant feature(s) is inoperable.	12 hours from discovery of Condition D concurrent with inoperability of redundant required feature(s)
	AND		
	D.2	Restore required offsite power source(s) to OPERABLE status.	7 days OR --------NOTE-------- Not applicable when more than one offsite power source inoperable or when one offsite power source to more than one required Class 1E 4.16kV bus inoperable. ----------------------- In accordance with the Risk Informed Completion Time Program

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
------------NOTE------------ Separate Condition entry is allowed for each inoperable standby emergency power source. -------------------------------- E. One or more required standby emergency power source(s) inoperable.	E.1	Declare required feature(s) supported by the inoperable standby emergency power source inoperable when its required redundant feature(s) is inoperable.	4 hours from discovery of Condition E concurrent with inoperability of redundant required feature(s)
	<u>AND</u>		
	E.2.1	Determine other required standby emergency power source(s) is not inoperable due to common cause failure.	24 hours
	<u>OR</u>		
	E.2.2	Perform SR 3.8.1.2 for other required standby emergency power source(s).	24 hours
	<u>OR</u>		
	E.2.3	Declare other required standby emergency power source(s) inoperable.	24 hours
	<u>AND</u>		
	E.3	Restore required standby emergency power source(s) to OPERABLE status.	7 days <u>AND</u> 14 days from discovery of failure to meet LCO

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
F. One or more required offsite power source to one or more Class 1E 4.16 kV safeguards bus(es) inoperable. AND Standby emergency power inoperable to redundant equipment.	--------------NOTE-------------------- Enter applicable Conditions and Required Actions of LCO 3.8.9, "Distribution Systems–Operating," when Condition F is entered with no AC power to any train. -- F.1 Restore required offsite circuit to OPERABLE status.	12 hours OR --------NOTE-------- Not applicable when more than one offsite power source inoperable or when one offsite power source to more than one Class 1E 4.16kV safeguard bus inoperable. ----------------------- In accordance with the Risk Informed Completion Time Program (continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
F. (continued)	OR		
	F.2	Restore required standby emergency power source to OPERABLE status.	12 hours OR --------NOTE-------- Not applicable when more than one offsite power source inoperable or when one offsite power source to more than one Class 1E 4.16kV safeguard bus inoperable. ----------------------- In accordance with the Risk Informed Completion Time Program
G. Standby emergency power to buses 1A05/1B03 and 1A06/1B04 inoperable. OR Standby emergency power to buses 2A05/2B03 and 2A06/2B04 inoperable. OR Standby emergency power to buses 1A05/1B03 and 2A06/2B04 inoperable.	G.1	Restore one required standby emergency power source to OPERABLE status.	2 hours

(continued)

ACTIONS (continued)

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

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.1.1	Verify correct breaker alignment and indicated power availability for each required offsite circuit.	In accordance with the Surveillance Frequency Control Program
SR 3.8.1.2	--------------------------NOTES-------------------------- 1. All standby emergency power source starts may be preceded by an engine prelube period and followed by a warmup period prior to loading. 2. A modified standby emergency power source start involving idling and gradual acceleration to synchronous speed may be used for this SR as recommended by the manufacturer. -- Verify each standby emergency power source starts from standby conditions and achieves rated voltage and frequency.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.3	--------------------------NOTES-------------------------- 1. Standby emergency power source loadings may include gradual loading. 2. Momentary transients outside the load range do not invalidate this test. 3. This SR shall be preceded by and immediately follow without shutdown a successful performance of SR 3.8.1.2. --- Verify each standby emergency power source is synchronized and loaded and operates for ≥ 60 minutes at a load ≥ 2500 kW and ≤ 2850 kW.	In accordance with the Surveillance Frequency Control Program
SR 3.8.1.4	Verify the fuel oil transfer system operates to automatically transfer fuel oil from storage tank to the day tank.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.5	-------------------------NOTE----------------------------- This surveillance shall not normally be performed with the associated unit in MODE 1, 2, 3, or 4. However, portions of the Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. --- Verify on an actual or simulated loss of offsite power signal in conjunction with an actual or simulated ESF actuation signal: a. De-energization of emergency buses; b. Load shedding from emergency buses; and c. Standby emergency power source auto-starts from standby condition and: 1. energizes permanently connected loads, 2. energizes auto-connected emergency loads through load logic and sequencer, 3. achieves steady state voltage within limits, 4. achieves steady state frequency within limits, and 5. supplies permanently connected and auto-connected emergency loads for $\geq$ 5 minutes.	In accordance with the Surveillance Frequency Control Program

(continued)

SURVEILLANCE REQUIREMENTS (continued)

SURVEILLANCE		FREQUENCY
SR 3.8.1.6	Verify each standby emergency power source: a. Synchronizes with offsite power source while loaded with emergency loads upon a simulated restoration of offsite power; b. Transfers loads to offsite power source; and c. Returns to ready-to-load operation.	In accordance with the Surveillance Frequency Control Program
SR 3.8.1.7	-----------------------NOTES------------------------------ 1. Momentary transients outside the load and power factor ranges do not invalidate this test. 2. This Surveillance may be performed to reestablish OPERABILITY provided an assessment determines the safety of the plant is maintained or enhanced. Credit may be taken for unplanned events that satisfy this SR. 3. If performed with the standby emergency power source synchronized with offsite power, it shall be performed at a power factor ≤ 0.87. However, if grid conditions do not permit, the power factor limit is not required to be met. Under this condition, the power factor shall be maintained as close to the limit as practicable. --- Verify each standby emergency power source operates for ≥ 24 hours at ≥ 2850 kW (G01/G02), ≥ 2848 kW (G03/04).	In accordance with the Surveillance Frequency Control Program

3.8 ELECTRICAL POWER SYSTEMS

3.8.4 DC Sources—Operating

LCO 3.8.4 The D-01, D-02, D-03, and D-04 DC electrical power subsystems shall be OPERABLE.

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

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One DC electrical power subsystem inoperable.	-----------------NOTE---------------- Enter applicable Conditions and Required Actions of LCO 3.8.9, "Distribution Systems—Operating," when any DC bus is de-energized. --		
	A.1	Restore DC electrical power subsystem to OPERABLE status.	2 hours <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.	6 hours
	<u>AND</u>		
	B.2	Be in MODE 5.	36 hours

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.4.1	Verify correct battery terminal voltage is within limits on float charge.	In accordance with the Surveillance Frequency Control Program
SR 3.8.4.2	Verify no visible corrosion at battery terminals and connectors. <u>OR</u> Verify battery connection resistance is within limits.	In accordance with the Surveillance Frequency Control Program
SR 3.8.4.3	Verify battery cells, cell plates, and racks show no visual indication of physical damage or abnormal deterioration that could degrade battery performance.	In accordance with the Surveillance Frequency Control Program
SR 3.8.4.4	Remove visible terminal corrosion, and verify battery cell to cell and terminal connections are coated with anti-corrosion material.	In accordance with the Surveillance Frequency Control Program
SR 3.8.4.5	Verify battery connection resistance is within limits.	In accordance with the Surveillance Frequency Control Program

(continued)

3.8 ELECTRICAL POWER SYSTEMS

3.8.7 Inverters—Operating

LCO 3.8.7 Four inverters shall be OPERABLE.

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

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One required inverter inoperable.	A.1	-----------NOTE------------ Enter applicable Conditions and Required Actions of LCO 3.8.9, "Distribution Systems - Operating" with any vital bus de-energized. ------------------------------ Restore inverter to OPERABLE status.	8 hours 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.	6 hours
	AND		
	B.2	Be in MODE 5.	36 hours

5.5 Programs and Manuals

5.5.7 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, “Risk-Informed Technical Specifications Initiative 4b: Risk-Managed Technical Specifications (RMTS) Guidelines,” Revision 0-A, November 2006. The program shall include the following:

a. The RICT may not exceed 30 days;

b. A RICT may only be utilized in MODES 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 function(s) performed by the inoperable SSCs.

5.5 Programs and Manuals

5.5.7 Risk Informed Completion Time Program (continued)

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.

5.5.8 Steam Generator (SG) Program

A Steam Generator Program shall be established and implemented to ensure that SG tube integrity is maintained. In addition, the Steam Generator Program shall include the following:

a. Provisions for condition monitoring assessments. Condition monitoring assessment means an evaluation of the “as found” condition of the tubing with respect to the performance criteria for structural integrity and accident induced leakage. The “as found” condition refers to the condition of the tubing during an SG inspection outage, as determined from the inservice inspection results or by other means, prior to the plugging of tubes. Condition monitoring assessments shall be conducted during each outage during which the SG tubes are inspected or plugged to confirm that the performance criteria are being met.

b. Performance criteria for SG tube integrity. SG tube integrity shall be maintained by meeting the performance criteria for tube structural integrity, accident induced leakage, and operational LEAKAGE.

   1. Structural integrity performance criterion: All in-service steam generator tubes shall retain structural integrity over the full range of normal operating conditions (including startup, operation in the power range, hot standby, and cool down), and all anticipated transients included in the design specification, and design basis accidents. This includes retaining a safety factor of 3.0 against burst under normal steady state full power operation primary-to-secondary pressure differential and a safety factor of 1.4 against burst applied to the design basis accident primary-to-secondary pressure differentials. Apart from the above requirements, additional loading conditions associated with the design basis accidents, or combination of accidents in accordance with the design and licensing basis, shall also be evaluated to

5.5 Programs and Manuals

5.5.8 Steam Generator (SG) (continued)

determine if the associated loads contribute significantly to burst or collapse. In the assessment of tube integrity, those loads that do significantly affect burst or collapse shall be determined and assessed in combination with the loads due to pressure with a safety factor of 1.2 on the combined primary loads and 1.0 on axial secondary loads.

2. Accident induced leakage performance criterion: The primary to secondary accident induced leakage rate for any design basis accident, other than a SG tube rupture, shall not exceed the leakage rate assumed in the accident analysis in terms of total leakage rate for all SGs and leakage rate for an individual SG. Leakage is not to exceed 500 gallons per day per SG.

3. The operational LEAKAGE performance criterion is specified in LCO 3.4.13, “RCS Operational LEAKAGE.”

c. Provisions for SG tube plugging criteria. Tubes found by inservice inspection to contain flaws with a depth equal to or exceeding 40% of the nominal tube wall thickness shall be plugged.

The following alternate tube plugging criteria shall be applied as an alternative to the 40% depth based criteria:

For Unit 1 only, tubes with service-induced flaws located greater than 20.6 inches below the top of the tubesheet do not require plugging. Tubes with service-induced flaws located in the portion of the tube from the top of the tubesheet to 20.6 inches below the top of the tubesheet shall be plugged upon detection.

This alternate tube plugging criteria is not applicable to the tube at row 38 column 69 in the A steam generator, which is not expanded in the hot leg the full length of the tubesheet. This tube has been removed from service by plugging (during U1R31).

d. Provisions for SG tube inspections. Periodic SG tube inspections shall be performed. For Unit 1, the number and portions of the tubes inspected and methods of inspection shall be performed with the objective of detecting flaws of any type (e.g., volumetric flaws, axial and circumferential cracks) that may be present along the length of the tube from 20.6 inches below the top of the tubesheet on the hot leg side to 20.6 inches below the top of the

5.5 Programs and Manuals

5.5.8 Steam Generator (SG) (continued)

tubesheet on the cold leg side and that may satisfy the applicable tube plugging criteria. For Unit 2, the number and portions of the tubes inspected and methods of inspection shall be performed with the objective of detecting flaws of any type (e.g., volumetric flaws, axial and circumferential cracks) that may be present along the length of the tube, from the tube-to-tubesheet weld at the tube inlet to the tube-to-tubesheet weld at the tube outlet, and that may satisfy the applicable tube plugging criteria.

For Unit 1 and Unit 2: The tube-to-tubesheet weld is not part of the tube. In addition to meeting the requirements of d.1, d.2, and d.3 below, the inspection scope, inspection methods, and inspection intervals shall be such as to ensure that SG tube integrity is maintained until the next SG inspection. A degradation assessment shall be performed to determine the type and location of flaws to which the tubes may be susceptible and, based on this assessment, to determine which inspection methods need to be employed and at what location.

1. Inspect 100% of the tubes in each SG during the first refueling outage following SG installation.

2. i. Unit 1 (alloy 600 Thermally Treated tubes): After the first refueling outage following SG installation, inspect each SG at least every 48 effective full power months or at least every other refueling outage (whichever results in more frequent inspections). In addition, the minimum number of tubes inspected at each scheduled inspection shall be the number of tubes in all SGs divided by the number of SG inspection outages scheduled in each inspection period as defined in a, b, and c below. If a degradation assessment indicates the potential for a type of degradation to occur at a location not previously inspected with a technique capable of detecting this type of degradation at this location and that may satisfy the applicable tube plugging criteria, the minimum number of locations inspected with such a capable inspection technique during the remainder of the inspection period may be prorated. The fraction of locations to be inspected for this potential type of degradation at this location at the end of the inspection period shall be no less than the ratio of the number of times the SG is scheduled to be inspected in the inspection period after the determination that a new form of degradation could potentially be occurring at this location divided by the total number of times the SG is scheduled to be inspected in the inspection period. Each inspection period defined below may be extended up to 3 effective full power months to include a SG inspection outage in an inspection period and

5.5 Programs and Manuals

5.5.8 Steam Generator (SG) (continued)

the subsequent inspection period begins at the conclusion of the included SG inspection outage.

a) After the first refueling outage following SG installation, inspect 100% of the tubes during the next 120 effective full power months. This constitutes the first inspection period;

b) During the next 96 effective full power months, inspect 100% of the tubes. This constitutes the second inspection period; and

c) During the remaining life of the SGs, inspect 100% of the tubes every 72 effective full power months. This constitutes the third and subsequent inspection periods.

ii. Unit 2 (alloy 690 Thermally Treated tubes): After the first refueling outage following SG installation, inspect each SG at least every 72 effective full power months or at least every third refueling outage (whichever results in more frequent inspections). In addition, the minimum number of tubes inspected at each scheduled inspection shall be the number of tubes in all SGs divided by the number of SG inspection outages scheduled in each inspection period as defined in a, b, c and d below. If a degradation assessment indicates the potential for a type of degradation to occur at a location not previously inspected with a technique capable of detecting this type of degradation at this location and that may satisfy the applicable tube plugging criteria, the minimum number of locations inspected with such a capable inspection technique during the remainder of the inspection period may be prorated. The fraction of locations to be inspected for this potential type of degradation at this location at the end of the inspection period shall be no less than the ratio of the number of times the SG is scheduled to be inspected in the inspection period after the determination that a new form of degradation could potentially be occurring at this location divided by the total number of times the SG is scheduled to be inspected in the inspection period. Each inspection period defined below may be extended up to 3 effective full power months to include a SG inspection outage in an inspection period and the subsequent inspection period begins at the conclusion of the included SG inspection outage.

5.5 Programs and Manuals

5.5.8 Steam Generator (SG) (continued)

a) After the first refueling outage following SG installation, inspect 100% of the tubes during the next 144 effective full power months. This constitutes the first inspection period;

b) During the next 120 effective full power months, inspect 100% of the tubes. This constitutes the second inspection period;

c) During the next 96 effective full power months, inspect 100% of the tubes. This constitutes the third inspection period; and

d) During the remaining life of the SGs, inspect 100% of the tubes every 72 effective full power months. This constitutes the fourth and subsequent inspection periods.

3. For Unit 1, if crack indications are found in any SG tube from 20.6 inches below the top of the tubesheet on the hot leg side to 20.6 inches below the top of the tubesheet on the cold leg side, then the next inspection for each affected and potentially affected SG for the degradation mechanism that caused the crack indication shall not exceed 24 effective full power months or one refueling outage (whichever results in more frequent inspections). If definitive information, such as from examination of a pulled tube, diagnostic non-destructive testing, or engineering evaluation indicates that a crack-like indication is not associated with a crack(s), then the indication need not be treated as a crack.

For Unit 2, if crack indications are found in any SG tube, then the next inspection for each affected and potentially affected SG for the degradation mechanism that caused the crack indication shall not exceed 24 effective full power months or one refueling outage (whichever results in more frequent inspections). If definitive information, such as from examination of a pulled tube, diagnostic non-destructive testing, or engineering evaluation indicates that a crack-like indication is not associated with a crack(s), then the indication need not be treated as a crack.

e. Provisions for monitoring operational primary to secondary LEAKAGE.

5.5 Programs and Manuals

5.5.9 Secondary Water Chemistry Program

This program provides controls for monitoring secondary water chemistry to inhibit SG tube degradation. The program shall include:

a. Identification of a sampling schedule for the critical variables and control points for these variables;

b. Identification of the procedures used to measure the values of the critical variables;

c. Identification of process sampling points, which shall include monitoring the discharge of the condensate pumps for evidence of condenser in leakage;

d. Procedures for the recording and management of data;

e. Procedures defining corrective actions for all off control point chemistry conditions; and

f. A procedure identifying the authority responsible for the interpretation of the data and the sequence and timing of administrative events, which is required to initiate corrective action.

5.5.10 Ventilation Filter Testing Program (VFTP)

A program shall be established to implement the following required testing of the Control Room Emergency Filtration System (F-16) at the frequencies specified in Regulatory Guide 1.52, Revision 2, and in accordance with ASTM D3803-1989 and the methodology of ANSI N510-1980, as prescribed below.

a. Demonstrate for the Control Room Emergency Filtration System (F-16) that an inplace test of the high efficiency particulate air (HEPA) filters shows a penetration and system bypass $\leq$1.0% when tested in accordance with the methodology of ANSI N510-1980, Section 10, excluding subsection 10.3, at a system flowrate of 4950 cfm ± 10%.

b. Demonstrate for the Control Room Emergency Filtration System (F-16) that an inplace test of the charcoal adsorber shows a penetration and system bypass $\leq$ 1.0% when tested in accordance with the methodology of ANSI N510-1980, Section 12, excluding subsection 12.3, at a system flowrate of 4950 cfm ± 10%.

5.5 Programs and Manuals

5.5.10 Ventilation Filter Testing Program (VFTP) (continued)

c. Demonstrate for the Control Room Emergency Filtration System (F-16) that a laboratory test of a sample of the charcoal adsorber, when obtained in accordance with the methodology of ANSI N510-1980, Section 13, excluding subsection 12.3, shows the methyl iodide penetration ≤ 2.5%, when tested in accordance with ASTM D3803-1989 at a temperature of 30°C and a relative humidity of 95%, applying the tolerances of ASTM D3803-1989.

d. Demonstrate for the Control Room Emergency Filtration System (F-16) that the pressure drop across the combined HEPA filters and the charcoal adsorbers is less than 6 inches of water when tested in accordance with the methodology of ANSI N510-1980, Sections 10 and 12, excluding subsections 10.3 and 12.3, at a system flowrate of 4950 cfm ± 10%.

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the VFTP test frequencies.

5.5.11 Explosive Gas Monitoring Program

This program provides controls for potentially explosive gas mixtures contained in the on-service Gas Decay Tank.

The program shall include a limit for oxygen concentration in the on-service Gas Decay Tank and a surveillance program to ensure the limit is maintained. This limit shall be appropriate to the system's design criteria (i.e., whether or not the system is designed to withstand a hydrogen explosion).

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Explosive Gas Monitoring Program surveillance frequencies.

5.5 Programs and Manuals

5.5.12 Diesel Fuel Oil Testing Program

A diesel fuel oil testing program to implement required testing of both new fuel oil and stored fuel oil shall be established. The program shall include sampling and testing requirements, and acceptance criteria, all in accordance with applicable ASTM Standards. The purpose of the program is to establish the following:

a. Acceptability of new fuel oil for use prior to addition to storage tanks by determining that the fuel oil has:

   1. an API gravity or an absolute specific gravity within limits,

   2. a flash point and kinematic viscosity within limits for ASTM 2D fuel oil, and

   3. a clear and bright appearance with proper color;

b. Within 31 days of addition of the new fuel oil to storage tanks verify that the properties of the new fuel oil, other than those addressed in a. above, are within limits for ASTM 2D fuel oil; and

c. Total particulate concentration of the fuel oil is ≤ 10 mg/l when tested every 92 days in accordance with the applicable ASTM standard.

d. The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Diesel Fuel Oil Testing Program test frequencies.

5.5.13 Technical Specifications (TS) Bases Control Program

This program provides a means for processing changes to the Bases of these Technical Specifications.

a. Changes to the Bases of the TS shall be made under appropriate administrative controls and reviews.

b. Licensees may make changes to Bases without prior NRC approval provided the changes do not involve either of the following:

   1. a change in the TS incorporated in the license; or

   2. a change to the updated FSAR or Bases that requires NRC approval pursuant to 10 CFR 50.59.

5.5 Programs and Manuals

5.5.13 Technical Specifications (TS) Bases Control Program (continued)

c. The Bases Control Program shall contain provisions to ensure that the Bases are maintained consistent with the FSAR.

d. Proposed changes that meet the criteria of Specification 5.5.13b above shall be reviewed and approved by the NRC prior to implementation. Changes to the Bases implemented without prior NRC approval shall be provided to the NRC on a frequency consistent with 10 CFR 50.71(e).

5.5.14 Safety Function Determination Program (SFDP)

This program ensures loss of safety function is detected and appropriate actions taken. Upon entry into LCO 3.0.6, an evaluation shall be made to determine if loss of safety function exists. Additionally, other appropriate actions may be taken as a result of the support system inoperability and corresponding exception to entering supported system Condition and Required Actions. This program implements the requirements of LCO 3.0.6. The SFDP shall contain the following:

a. Provisions for cross train checks to ensure a loss of the capability to perform the safety function assumed in the accident analysis does not go undetected;

b. Provisions for ensuring the plant is maintained in a safe condition if a loss of function condition exists;

c. Provisions to ensure that an inoperable supported system's Completion Time is not inappropriately extended as a result of multiple support system inoperabilities; and

d. Other appropriate limitations and remedial or compensatory actions.

5.5 Programs and Manuals

5.5.14 Safety Function Determination Program (SFDP) (continued)

A loss of safety function exists when, assuming no concurrent single failure, and assuming no concurrent loss of offsite power or loss of onsite diesel generator(s), a safety function assumed in the accident analysis cannot be performed. For the purpose of this program, a loss of safety function may exist when a support system is inoperable, and:

a. A required system redundant to the system(s) supported by the inoperable support system is also inoperable; or

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

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

The SFDP identifies where a loss of safety function exists. If a loss of safety function is determined to exist by this program, the appropriate Conditions and Required Actions of the LCO in which the loss of safety function exists are required to be entered.

When a loss of safety function is caused by the inoperability of a single Technical Specification support system, the appropriate Conditions and Required Actions to enter are those of the support system.

5.5.15 Containment Leakage Rate Testing Program

a. A program shall be established to implement the leakage rate testing of the containment as required by 10 CFR 50.54(o) and 10 CFR 50, Appendix J, Option B, as modified by approved exemptions. This program shall be in accordance with Nuclear Energy Institute (NEI) 94-01, Revision 3-A, “Industry Guidance for Implementing Performance Based Option of 10 CFR 50, Appendix J,” and the conditions and limitations specified in NEI 94-01, Revision 2-A.

5.5.15 Containment Leakage Rate Testing Program (continued)

b. The peak design containment internal accident pressure, P_a, is 60 psig.

c. The maximum allowable containment leakage rate, L_a at P_a, shall be 0.2% of containment air weight per day.

d. Leakage rate acceptance criteria are:

1. Containment leakage rate acceptance criterion is $\leq$ 1.0 L_a.

2. During the first unit startup following testing in accordance with this program, the leakage rate acceptance are $\leq$ 0.6 L_a for the combined Type B and Type C tests and $\leq$ 0.75 L_a for the Type A tests.

3. Air lock testing acceptance criteria are:

i. Overall air lock leakage rate is $\leq$ 0.05 L_a when tested at $\geq$ P_a.

ii. For each door seal, leakage rate is equivalent to $\leq$ 0.02 L_a at $\geq$ P_a when tested at a differential pressure of $\geq$ to 10 inches of Hg.

e. The provisions of SR 3.0.2 do not apply to the test frequencies in the Containment Leakage Rate Testing Program.

f. The provisions of SR 3.0.3 are applicable to the Containment Leakage Rate Testing Program.

5.5 Programs and Manuals

5.5.16 Reactor Coolant System (RCS) Pressure Isolation Valve (PIV) Leakage Program

A program shall be established to verify the leakage from each RCS PIV is within the limits specified below, in accordance with the Event V Order, issued April 20, 1981.

a. Minimum differential test pressure shall not be less than 150 psid.

b. Leakage rate acceptance criteria are:

1. Leakage rates less than or equal to 1.0 gpm are considered acceptable.

2. Leakage rates greater than 1.0 gpm but less than or equal to 5.0 gpm are considered acceptable if the latest measured rate has not exceeded the rate determined by the previous test by an amount that reduces the margin between measured leakage rate and the maximum permissible rate of 5.0 gpm by 50% or greater.

3. Leakage rates greater than 1.0 gpm but less than or equal to 5.0 gpm are considered unacceptable if the latest measured rate exceeded the rate determined by the previous test by an amount that reduces the margin between measured leakage rate and the maximum permissible rate of 5.0 gpm by 50% or greater.

4. Leakage rates greater than 5.0 gpm are considered unacceptable.

5.5.17 Pre-Stressed Concrete Containment Tendon Surveillance Program

This program provides controls for monitoring any tendon degradation in pre-stressed concrete containments, including effectiveness of its corrosion protection medium, to ensure containment structural integrity. The program shall include baseline measurements prior to initial operations. The Tendon Surveillance Program, inspection frequencies, and acceptance criteria shall be in accordance with Regulatory Guide 1.35, Revision 3, 1990.

The provisions of SR 3.0.2 and SR 3.0.3 are applicable to the Tendon Surveillance Program inspection frequencies.

5.5 Programs and Manuals

5.5.18 Control Room Envelope Habitability Program

A Control Room Envelope (CRE) Habitability Program shall be established and implemented to ensure that CRE habitability is maintained such that, with an OPERABLE Control Room Emergency Filtration System (CREFS), CRE occupants can control the reactor safely under normal conditions and maintain it in a safe condition following a radiological event. The program shall ensure that adequate radiation protection is provided to permit access and occupancy of the CRE under design basis accident (DBA) conditions without personnel receiving radiation exposures in excess of 5 rem total effective dose equivalent (TEDE) for the duration of the accident. Additionally, separate from the CREFS, the program shall ensure CRE occupants can maintain the reactor in a safe condition following a hazardous chemical release or smoke challenge. The program shall include the following elements:

a. The definition of the CRE and the CRE boundary.

b. Requirements for maintaining the CRE boundary in its design condition including configuration control and preventive maintenance.

c. Requirements for (i) determining the unfiltered air inleakage past the CRE boundary into the CRE in accordance with the testing methods and at the Frequencies specified in Sections C.1 and C.2 of Regulatory Guide 1.197, "Demonstrating Control Room Envelope Integrity at Nuclear Power Reactors," Revision 0, May 2003, and (ii) assessing CRE habitability at the Frequencies specified in Sections C.1 and C.2 of Regulatory Guide 1.197, Revision 0.

d. Measurement, at designated locations, of the CRE Pressure relative to all external areas adjacent to the CRE boundary during the technical specification emergency mode of operation by the CREFS, operating at the flow rate required by the VFTP, at a Frequency of 18 months. The results shall be trended at a frequency of 18 months and used as part of the periodic assessment of the CRE boundary.

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.

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 Programs and Manuals

5.5.18 Control Room Envelope Habitability Program (continued)

g. An adequate supply of self contained breathing apparatus (SCBA) units in the CRE to protect CRE occupants from a hazardous chemical release.

h. Portable smoke ejection equipment per the Fire Protection Evaluation Report and Safe Shutdown Analysis Report to address a potential smoke challenge.

5.5.19 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 Operations 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.

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

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NOS. 271 AND 273, RESPECTIVELY, TO

RENEWED FACILITY OPERATING LICENSE NOS. DPR-24 AND DPR-27

NEXTERA ENERGY POINT BEACH, LLC

POINT BEACH NUCLEAR PLANT, UNITS 1 AND 2

DOCKET NOS. 50-266 AND 50-301

1.0 INTRODUCTION

By application dated May 20, 2022 (Reference 1), as supplemented by letters dated July 11, 2022 (Reference 2), January 11, 2023 (Reference 3), and February 21, 2023 (Reference 4), NextEra Energy Point Beach, LLC (NextEra, the licensee) submitted a license amendment request (LAR) for Point Beach Nuclear Plant, Units 1 and 2 (Point Beach).

The amendment would revise technical specification (TS) requirements to permit the use of risk-informed completion times (RICTs) for actions to be taken when limiting conditions for operation (LCOs) are not met. The proposed changes are based on Technical Specifications Task Force (TSTF) Traveler TSTF-505, Revision 2, “Provide Risk-Informed Extended Completion Times – RITSTF Initiative 4b,” dated July 2, 2018 (Reference 5). The U.S. Nuclear Regulatory Commission (NRC, the Commission) issued a final revised model safety evaluation (SE) to be used when preparing a plant-specific SE of an LAR to adopt TSTF-505, Revision 2, on November 21, 2018 (Reference 6).

The licensee has proposed variations from the TS changes approved in TSTF-505, Revision 2, which are provided in Section 2.4 of attachment 1, “Evaluation of Proposed Changes,” (Reference 7) to the LAR and evaluated in sections 3.2 and 3.3 of this SE.

The NRC staff participated in a regulatory audit from August 11, 2022, to February 3, 2023, to ascertain the information needed to support its review of the application and to develop requests for additional information (RAIs), as needed. On February 21, 2023, the NRC staff issued an audit summary (Reference 8). Following the regulatory audit, the NRC issued requests for additional information (RAIs) in email correspondence dated December 20, 2022 (Reference 9) and January 31, 2023 (Reference 10).

The supplemental letters of July 11, 2022, January 11, 2023, and February 21, 2023, 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 August 9, 2022 (87 FR 48517).

2.0 REGULATORY EVALUATION

2.1 Regulatory Review

2.1.1 Applicable 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 general provisions include but are not limited to establishing the regulatory requirements that a licensee must adhere to for the submittal of a license application. The NRC staff has identified the following applicable sections within 10 CFR Part 50, along with the provision provided in 10 CFR Part 20 for the staff's review of the licensee's application to adopt TSTF-505, Revision 2.

- Section 50.36, "Technical Specifications," of 10 CFR Part 50, paragraphs (c)(2), "Limiting conditions for operation," and (c)(5), "Administrative controls"

- Section 50.55a, "Codes and Standards," of 10 CFR Part 50, paragraph (h), "Protection and safety systems"

- Section 50.65, "Requirements for monitoring the effectiveness of maintenance at nuclear power plants" (i.e., the Maintenance Rule) of 10 CFR Part 50

- 10 CFR Part 20, "Standards for Protection Against Radiation"

2.1.2 Regulatory Guidance

NRC Regulatory Guides (RGs) provide one way to ensure that the codified regulations continue to be met. The NRC staff considered the following guidance, along with industry guidance endorsed by the NRC, during its review of the proposed changes:

- RG 1.200, Revision 2, "An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment [PRA] Results for Risk-Informed Activities," dated March 2009 (Reference 11).

- RG 1.200, Revision 3, "Acceptability of Probabilistic Risk Assessment Results for Risk-Informed Activities," dated December 2020 (Reference 12).

- RG 1.174, Revision 2, "An approach for using Probabilistic Risk Assessment I Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," dated May 2011 (Reference 13).

- RG 1.174, Revision 3, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," dated January 2018 (Reference 14).

- RG 1.177, Revision 0, "An Approach for Plant-Specific, Risk-Informed Decision-making: Technical Specifications," dated August 1998 (Reference 15).

- RG 1.177, Revision 2, "An Approach for Plant-Specific, Risk-Informed Decision-making: Technical Specifications," Dated January 2021 (Reference 16).

- NUREG-1855, Revision 1, “Guidance on the Treatment of Uncertainties Associated with PRAs in Risk-Informed Decisionmaking,” Dated March 2017 (Reference 17).

- NUREG-0800, “Standard Review Plan [SRP] for the Review of Safety Analysis Reports for Nuclear Power Plants: LWR [light-water reactor] Edition,” Chapter 19, Section 19.2, “Review of Risk Information Used to Support Permanent Plant-Specific Changes to the Licensing Basis: General Guidance,” dated June 2007 (Reference 18), Section 16.0, “Technical Specifications,” dated March 2010 (Reference 19), and Section 16.1, “Risk-Informed Decision Making: Technical Specifications,” Dated March 2007 (Reference 20).

- Nuclear Energy Institute (NEI) Topical Report NEI 06-09, Revision 0-A, “Risk-Informed Technical Specifications Initiative 4b, Risk-Managed Technical Specifications (RMTS) Guidelines,” dated October 2012 (NEI 06-09-A) (Reference 21), provides guidance for risk-informed TS. The NRC staff issued a final SE approving NEI 06-09 on May 17, 2007 (Reference 22).

The licensee’s submittal cites RG 1.200, Revision 2, RG 1.174, Revision 2, and RG 1.177, Revision 0. RG 1.200 and RG 1.174 have been updated to Revision 3, and RG 1.177 has been updated to Revision 2. The updates do not include any technical changes that impact the consistency with NEI 06-09-A; therefore, the NRC staff finds the updated revision to RG 1.174 and RG 1.177 also applicable for use in the licensee’s adoption of TSTF-505, Revision 2.

2.2 Description of Changes

2.2.1 Description of Risk Informed Completion Time Program

The TS LCOs 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 TSs 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 Action(s) and Completion Time(s) (CT). The CTs are referred to as the “front stops” in the context of this SE. For certain conditions, the TSs require exiting the Mode of Applicability of an LCO (i.e., shut down the reactor).

The licensee’s submittal requested approval to add a RICT Program to the Administrative Controls section of the TSs, and modify selected CTs to permit extending the CTs, provided risk is assessed and managed as described in NEI 06-09-A. The licensee also proposed variations from the TS changes approved in TSTF-505, Revision 2, which are provided in section 2.4 of attachment 1 to the LAR and evaluated in sections 3.2.1 and 3.3 of this SE.

The licensee is proposing no changes to the design of the plant or any operating parameter, and no new changes to the design basis in the proposed changes to the TSs. The effect of the proposed changes when implemented will allow CTs to vary, based on the risk significance of the given plant configuration (i.e., the equipment out of service at any given time), provided that the system(s) retain(s) the capability to perform the applicable safety function(s) without any further failures (e.g., one train of a two-train system is inoperable). These restrictions on inoperability of all required trains of a system ensure that consistency with the defense-in-depth

(DID) philosophy is maintained by following existing guidance when the capability to perform TS safety function(s) is lost.

The proposed RICT Program uses plant specific operating experience for component reliability and availability data. Thus, the allowances permitted by the RICT Program are directly reflective of actual component performance in conjunction with component risk significance.

2.2.2 TS 1.0 Use and Application:

Example 1.3 8, will be added to TS 1.3, “Completion Times,” and reads as follows:

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 5.	6 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.

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 elapsed time 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.

3.0 TECHNICAL EVALUATION

For TSTF-505, Revision 2, an acceptable approach for making risk informed decisions about proposed TS changes, including both permanent and temporary changes, is to demonstrate that the proposed licensing basis changes meet the five key principles provided in section C of RG 1.174, Revision 3 and the three-tiered approach outlined in section C of RG 1.177, Revision 2 which supports key principle 4. These key principles and tiers are:

Principle 1: The proposed licensing basis change meets the current regulations unless it is explicitly related to a requested exemption (i.e., a specific exemption under 10 CFR 50.12).

Principle 2: The proposed licensing basis change is consistent with the DID philosophy.

Principle 3: The proposed licensing basis change maintains sufficient safety margins.

Principle 4: When the proposed licensing basis change results in an increase in risk, the increase should be small and consistent with the intent of the Commission’s policy statement on safety goals (Reference 23) for the operations of nuclear power plants.

- 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 licensing basis change should be monitored by using performance measures strategies.

TSTF-439, Revision 2, “Eliminate Second Completion Times Limiting Time From Discovery of Failure to Meet an LCO,” (Reference 24) provides an acceptable approach to demonstrate that the proposed licensing basis changes are satisfactory and consists of demonstrating adherence to 10 CFR 50.36(c)(2), 10 CFR 50.36(c)(5), 10 CFR 50.65, and elements included in the Reactor Oversight Process (ROP). The NRC issued a letter approving TSTF-439, Revision 2, on January 11, 2006 (Reference 25).

3.1 Method of Staff Review

Each of the key principles and tiers are addressed in NEI 06-09-A and approved in the final model SE issued by the NRC for TSTF-505, Revision 2. NEI 06-09-A provides a methodology for extending existing CTs, and thereby delay exiting the operational mode of applicability or taking Required Actions if risk is assessed and managed within the limits and programmatic requirements established by a RICT Program. The NRC staff's evaluation of the licensee's proposed use of RICTs against the key safety principles of RG 1.174, Revision 3, and RG 1.177, Revision 2, is discussed below.

TSTF-439 provides a method for removing the second CTs and highlights the controls of the monitoring report, the ROP, and the new requirement in Standard Technical Specifications (STS), Section 1.3. The LAR included proposed changes to the TS Bases. Although the TS Bases are not part of the TSs, the NRC staff confirmed that that the TS Bases described the basis for each revised TS requirement accurately, as described in Section 16.0 of NUREG-0800. The NRC staff's evaluation of the licensee's proposed removal of the second CTs is provided within key principle 1, section 3.2.1 of this SE. Although TSTF-439 was not submitted as a risk-informed application, NRC staff found that key principles 1 through 3 and the applicability of the monitoring report along with the performance indicators for key principle 5 applied and included their findings on TSTF-439.

3.2 Review of Key Principles

3.2.1 Key Principle 1: Evaluation of Compliance with Current Regulations

Paragraph 50.36(c)(2) of 10 CFR Part 50 requires that LCOs are the lowest functional capability or performance levels of equipment required for safe operation of the facility. When an LCO of a nuclear reactor is not met, the licensee shall shut down the reactor or follow any remedial action permitted by the TS until the condition can be met.

The CTs in the current TSs were established using experiential data, risk insights, and engineering judgement. The RICT Program provides the necessary administrative controls to permit extension of CTs and, thereby, delay reactor shutdown or Required Actions, if risk is assessed and managed appropriately within specified limits and programmatic requirements, and the safety margins and DID remains sufficient. The option to determine the extended CT in accordance with the RICT Program allows the licensee to perform an integrated evaluation in accordance with the methodology identified in NEI 06-09-A and proposed TS 5.5.7, "Risk Informed Completion Time Program." The RICT is limited to a maximum of 30 days (termed the "back stop").

The typical CT for TSTF-505, Revision 2, is modified by the application of the RICT Program as shown in the following example. The changed portion 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*

In attachment 1, section 2.4.1, "Administrative Variations," item 8 the licensee proposes to delete the second CT from the listed Required Actions that are proposed for inclusion in the RICT Program. Second CTs were included in certain Required Actions to prevent alternating between Conditions in such a manner that operation could continue indefinitely without ever restoring systems to meet the LCO, which is inconsistent with the basis of the CTs and is inappropriate. In the supplement dated July 11, 2022, the licensee described the programmatic and administrative controls that are in place which prohibit prolonged periods of failing to satisfy an LCO. Therefore, the licensee shall have administrative controls to limit the maximum time allowed for any combination of Conditions that result in a single contiguous occurrence of failing to meet the LCO. These administrative controls shall ensure that the maximum time allowed for any combination of Conditions that result in a single contiguous occurrence of failing to meet the LCO is not inappropriately extended. The NRC staff reviewed the proposed changes to the TSs and determined that they meet the requirements set forth in 10 CFR 50.36. Additionally, the changes to the TSs were reviewed for technical clarity and consistency with customary terminology and format in accordance with section 16.0 of NUREG-0800.

In attachment 2, "Proposed Technical Specification Changes (Mark-Up)," (Reference 26), attachment 4, "Cross-Reference of TSTF-505, Revision 2, and Point Beach Proposed Changes" (Reference 27), and enclosure 1, "List of Revised Required Actions to Corresponding PRA Functions and Additional Supporting Information," (Reference 28) to the LAR, as supplemented, the licensee provided a list of the TSs, associated LCOs, and Required Actions for the CTs that included modifications and variations from the approved TSTF-505. The modifications and variations consisted of proposed changes to the Required Actions and CTs. Furthermore, consistent with table 1 of TSTF-505 for Point Beach TS 3.3.1.D, TS 3.3.1.Q, TS 3.6.2.C, and TS 3.7.2.A in attachment 5, "Evaluation of Plant-Specific Variations," (Reference 29) to the LAR the licensee included additional technical justification to demonstrate the acceptability for including these TSs in the RICT Program. The licensee corrected table E1-1 to accurately reflect the applicable structures, systems and components (SSCs) in TS 3.6.2 Condition C and acknowledged the proposed change is also a plant-specific variation that was inadvertently omitted from the evaluations in attachment 5. The NRC staff reviewed the proposed changes to the TSs, associated LCOs, Required Actions and CTs provided by the licensee for the scope of the RICT Program and removal of second CTs for TSTF-439, Revision 2. The NRC staff concluded that with the incorporation of the RICT Program, existing regulations, and processes, along with administrative controls, the required performance levels of equipment specified in LCOs are not changed, only the required CTs for the Required Actions are modified, such that 10 CFR 50.36(c)(2) will continue to be met. Based on the discussion provided above, the NRC staff finds that for the RICT Program provided in section 2.0 of this SE, LCOs, Required Actions, and CTs meet the first key principle of RG 1.174, Revision 3, and RG 1.177, Revision 2, and therefore is acceptable for meeting the requirements in 10 CFR 50.36.

The licensee proposed the following variation from TSTF-505, Revision 2:

TS 3.6.3 Condition C – Containment System

TS 3.6.3 Condition C requires the containment penetration flow path associated with an inoperable containment isolation valve to be isolated within 72 hours. This is followed by a requirement to periodically verify the penetration is isolated every 31 days and limits the verification to isolation devices located outside containment. In attachment 5 to the LAR the licensee states that the STS of NUREG-1431, Revision 4, "Standard Technical Specifications Westinghouse Plants," (Reference 30) in TSTF-505, Revision 2, does not restrict the 31-day verification requirement to only containment isolation valves located outside containment.

However, the NRC staff finds that Point Beach TS 3.6.3, Condition C is equivalent to Condition B of the Westinghouse STS in TSTF-505, Revision 2, and it does restrict the 31-day verification requirement to only containment isolation valves located outside containment. The 31-day verification limitation was an element retained from an earlier version of the Point Beach TS that is consistent with the licensing basis but also differed from the STS version upon which the Point Beach TS are based NUREG-1431, Revision 1, “Standard Technical Specifications Westinghouse Plants,” (Reference 31) which does not have a restriction associated to only containment isolation valves located outside containment.

The proposed change allows a RICT for isolation of the associated containment penetration but not for the performance of the 31-day penetration isolation verification requirement. By adding the flexibility to use a RICT to determine a time to isolate the penetration, the periodic verification must then be based on the time “following isolation.” The NRC staff finds this to be a conforming change made to the CT to make it accurate following use of a RICT. The NRC staff finds this change to be acceptable because the 31-day verification requirement is not included in the RICT program, is a conforming change necessary for accurate TS usage, and is consistent with the Point Beach licensing basis. Based on the above, the NRC staff concludes that the proposed variation in TS 3.6.3 is acceptable, and 10 CFR 50.36 will continue to be met.

3.2.2 Key Principle 2: Evaluation of Defense-in-Depth (DID)

In RG 1.174, Revision 3, the NRC identified the following considerations used for evaluation of how the licensing basis change is maintained for the DID philosophy:

- Preserve a reasonable balance among the layers of defense.
- Preserve adequate capability of design features without an overreliance on programmatic activities as compensatory measures.
- Preserve system redundancy, independence, and diversity commensurate with the expected frequency and consequences of challenges to the system, including consideration of uncertainty.
- Preserve adequate defense against potential CCFs [common cause failures].
- Maintain multiple fission product barriers.
- Preserve sufficient defense against human errors.
- Continue to meet the intent of the plant’s design criteria.

The licensee requested to use the RICT Program to extend the existing CTs for the respective TS LCOs prescribed in attachment 2 to the LAR, as supplemented. For the TS LCOs in attachment 5 and enclosure 1 of the LAR, as supplemented, 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 for these LCOs assessed the Point Beach’s redundant or diverse means to mitigate accidents to ensure consistency with the plant licensing basis requirements using the guidance in RG 1.174, RG 1.177, and TSTF-505, to ensure adequate DID (for each of the functions) to operate the facility in the proposed manner (i.e., that the changes are consistent with the DID criteria).

Enclosure 1 to the LAR, as supplemented, provided information supporting the Point Beach evaluation of the redundancy, diversity, and DID for each TS LCO and TS Required Action as it relates to instrumentation and control (I&C) and electrical power systems. The NRC confirmed that for the following TS LCOs, the above DID criteria were applicable except for the criteria for maintaining multiple fission product barriers.

- TS 3.3.1, “Reactor Protection System (RPS) Instrumentation”
- TS 3.3.2, “Engineered Safety Feature Actuation System (ESFAS) Instrumentation”
- TS 3.8.1, “AC [Alternating Current] Sources – Operating”
- TS 3.8.4, “DC [Direct Current] Sources – Operating”
- TS 3.8.7, “Inverters – Operating”

For the TS LCOs specific to I&C (i.e., TS 3.3.1 and 3.3.2), the NRC staff reviewed the specific trip logic arrangements, redundancy, backup systems, manual actions, and diverse trips specified for each of the protective safety functions and associated instrumentation as described in the associated Updated Final Safety Analysis Report (UFSAR) (Reference 32) sections, and as reflected in enclosure 1 of the LAR for each I&C LCO above. The NRC staff verified that, in accordance with the Point Beach UFSAR and equipment and actions credited in enclosure 1 of the LAR, in all applicable operating modes, the affected protective feature would perform its intended function by ensuring the ability to detect and mitigate the associated event or accident when the CT of a channel is extended. Furthermore, the NRC staff concludes that there is sufficient redundancy, diversity, and DID, to protect against common cause failures (CCFs) and potential single failure for the Point Beach instrumentation systems evaluated in LAR enclosure 1 during a RICT. There is at least one diverse means specified by the licensee for initiating mitigating action for each accident event, thus providing DID against a failure of instrumentation during the RICT for each TS LCO. The DID specified by the licensee does not overly rely on manual actions as the diverse means; therefore, there is not over reliance of programmatic activities as compensatory measures. The NRC staff confirmed that the RICT Program would not allow a loss-of-function condition for the design-basis accidents (DBAs) evaluated in the Point Beach UFSAR.

Therefore, the NRC staff finds that the intent of the plant’s design criteria (e.g., safety functions) for the above TS LCOs related to I&C are maintained.

For the TS LCOs specific to the electrical power systems (i.e., TS 3.8.1, 3.8.4, and 3.8.7), the NRC staff reviewed the electrical power systems design to determine whether there is a potential loss of function (LOF) for each electrical proposed RICT in the LAR based on TSTF-505, with no LOFs identified by the NRC staff. Additionally, the NRC staff reviewed the LAR and its supplements (1) to verify each effected electrical TS LCO can be entered voluntarily or involuntarily based on NEI 06-09-A and (2) to evaluate if the affected electrical power systems for those LCOs could perform their safety functions (assuming no additional failures other than for LCO being implemented) for the proposed RICTs. Based on the NRC staff review, and because the LAR imposes no physical or operational changes on either Point Beach unit, the NRC staff finds that the Point Beach electrical power systems would function as intended with the proposed RICTs. The NRC staff also verified that the design success criteria in enclosure 1 to the LAR, table E1-1 for each of the electrical TS LCOs reflects the minimum operable electrical power sources to support their safety functions to mitigate postulated DBAs, safely shut down the reactor, and maintain the reactor in a safe shutdown condition, and that there are RICT estimates for each of these electrical TS LCOs in enclosure 1 to the LAR table E1-2 consistent with NEI 06-09-A.

In enclosure 12, “Risk Management Action Examples,” (Reference 33) to the LAR, the licensee provided examples of risk management actions (RMAs) that may be considered during a RICT program entry for the above electrical TS LCO required actions to reduce the risk impact and ensure adequate DID. The NRC staff reviewed the proposed RMA examples which provide reasonable assurance that the actual RMAs implemented to monitor and control risk for each TS LCO will be of similar quality and tailored for that LCO.

The NRC staff reviewed the licensee’s proposed electrical TS LCO changes and supporting documentation. Based on the evaluation above, the NRC staff finds that given each electrical TS LCO’s reduced redundancy, the CT extensions, as allowed by the RICT Program, are acceptable because (a) the capacity and capability of the remaining operable electrical systems to perform their safety functions (assuming no additional failures) is maintained, and (b) the licensee’s identification and implementation of RMAs as compensatory measures, in accordance with the RICT Program, will be effective.

Licensee Proposed Variations from TSTF-505, Revision 2

The I&C TS LCOs addressed above are also subject to Point Beach variations. These variations are evaluated below. In TSs, I&C functions with a 1-hour CT are typically associated with a LOF condition; therefore, for each 1-hour CT below, the NRC staff confirmed there was not a LOF and therefore it is acceptable to apply a RICT.

TS 3.3.1 Condition D – Power Range Neutron Flux High

TS 3.3.1, Condition D, requires the power range neutron flux channel to be placed in tripped position within 1 hour of inoperability. Condition D differs from the Westinghouse STS in TSTF-505, Revision 2 in not additionally requiring either a thermal power reduction to less than 75 percent Rated Thermal Power (RTP) within 78 hours or verification every 12 hours of the quadrant power tilt ratio (QPTR) within limit using the movable in-core detectors.

The NRC staff notes that while there is no requirement of reducing thermal power to 75 precent RTP within 78 hours or verification every 12 hours of the QPTR within limit using the movable in-core detectors, the QPTR is addressed in TS 3.2.4 where Required Action A.1 requires reduction of thermal power by ≥ 3 percent from RTP for each 1 percent of QPTR > 1.00 and Required Action A.2 requires determination of QPTR every 12 hours.

Since the power range neutron flux high trip function has two-out-of-four trip logic, in the case of one of the channels failing (while one other channel is inoperable) the NRC staff finds that there is sufficient redundancy to implement the trip function if needed during the extended period allowed by the RICT.

Based on TS 3.2.4 and sufficient redundancy to perform the function, the NRC staff finds the proposed variation to TS 3.3.1 Condition D for the power range neutron flux high function to be acceptable and concludes that the plant will maintain adequate DID.

TS 3.3.1 Condition L – Reactor Coolant Flow – Low, Single Loop & Condition K – Reactor Coolant Flow – Low, Two Loops

TS 3.3.1, Conditions K and L, require the reactor coolant flow low channel to be placed in tripped position within 1 hour of inoperability when above the P-8 interlock setpoint (Condition L) and when below the P-8 interlock setpoint and above the P-7 interlock setpoint (Condition K).

Conditions K and L differ from the Westinghouse STS in TSTF-505, Revision 2, which specifies a single functional unit for the reactor coolant flow low trip instrumentation without distinction of one versus two affected reactor coolant system (RCS) loops, thus requiring power reduction below the P-7 interlock setpoint. Tripping one reactor coolant flow low channel while above the P-8 interlock setpoint results in a partial trip condition requiring only one additional channel in the same RCS loop to initiate a reactor trip.

Similarly, tripping one RCS flow low channel in each of the RCS loops results in a partial trip condition requiring one additional channel in both RCS loops to initiate a reactor trip when between P-7 and P-8 interlock setpoints. Sufficient redundancy exists in the RCS flow low circuitry to ensure at least two channels are available to implement the RCS flow low trip function if needed during the extended period allowed by the RICT.

Since sufficient redundancy exists in the RCS flow low channels to ensure at least two channels are available to implement the RCS flow low trip function during the extended period allowed by the RICT program, the NRC staff finds the proposed variation to TS 3.3.1 Conditions K and L for the reactor coolant flow low function to be acceptable and concludes that the plant will maintain adequate DID.

TS 3.3.1 Condition Q – Reactor Trip Breakers

TS 3.3.1, Condition Q, requires restoration of an inoperable reactor trip breaker (RTB) to operable status in modes 1 and 2 which corresponds to the Westinghouse STS 3.3.1, Condition U, which requires restoration of an inoperable RTB train to operable status in Modes 1 and 2. The NRC staff finds that since an inoperable RTB renders the RTB train inoperable, the two conditions are functionally equivalent. Because the variation is functionally identical with regards to its application, the NRC staff finds the proposed variation to TS 3.3.1, Condition Q, for the RTBs to be acceptable and concludes that the plant will maintain adequate DID.

TS 3.3.2 Condition G and Condition M – Feedwater Isolation Automatic Actuation Logic and Actuation Relays

TS 3.3.2, Condition G, requires restoration of one inoperable Feedwater Isolation Automatic Logic and Actuation Relay train within 6 hours or be in mode 3 in 12 hours and mode 4 in 18 hours, if the CT is not met. The proposed change relocates the Required Actions to be in Mode 3 and mode 4 into Condition M which requires the plant to be in Mode 3 within 6 hours and Mode 4 within 12 hours, if Condition G CT is not met. Conditions G and M correspond to the Westinghouse STS in TSTF-505, Revision 2 Conditions H and O which specify restoration of one inoperable train within 24 hours and require the plant to be in Mode 3 in 6 hours if Condition H CT is not met.

The required action for proposed Condition G requires restoration of one inoperable train within 6 hours versus the corresponding TSTF-505, Revision 2, Condition H, which requires completion within 24 hours. The NRC staff finds that because the CT is consistent with the current TS and is less than that in TSTF-505, Revision 2, the proposed Condition G variation is conservative and therefore acceptable. The required action for proposed Condition M, requires entry into Mode 3 in 6 hours and Mode 4 in 12 hours versus the corresponding TSTF-505, Revision 2, Condition O, which requires entry into Mode 3 in 6 hours. The variation of an additional end state, Mode 4, is appropriate since it is consistent with the current TS and entry into Mode 4 no longer requires these functions to be operable since the mode of applicability is

Modes 1, 2 and 3. Sufficient redundancy exists to ensure feedwater isolation can be initiated by either train for automatic actuation logic and actuation relays. Additionally, Westinghouse STS in TSTF-505, Revision 2 specifies a turbine trip function with actuation of feedwater isolation, where the current Point Beach feedwater isolation signals do not initiate a turbine trip. This variation is specific to the Point Beach design basis which uses the non-safety related anticipated transient without scram (ATWS) Mitigation System Actuation Circuitry (AMSAC) function to trip the turbine in the event of a total loss of main feedwater without reactor or turbine trip and does not impact the application of TSTF-505, Revision 2. Therefore, the NRC staff finds the proposed variation to TS 3.3.2 Conditions G and M for the feedwater isolation automatic actuation logic and actuation relays to be acceptable and concludes that the plant will maintain adequate DID.

TS 3.3.2 Condition D and Condition M – Feedwater Isolation Steam Generator (SG) Water Level – High

TS 3.3.2, Condition D, requires one inoperable Feedwater Isolation SG Water Level – High channel to be placed in trip within one hour or be in Mode 3 in 7 hours and Mode 4 in 13 hours, if the CT is not met. The proposed change relocates the Required Actions to be in Mode 3 and Mode 4 into Condition M which requires the plant to be in Mode 3 within 6 hours and Mode 4 within 12 hours, if Condition D CT not met. Conditions D and M correspond to Westinghouse STS in TSTF-505, Revision 2, Conditions I and O which specify one inoperable channel to be placed in trip within 72 hours and require the plant to be in Mode 3 in 6 hours, if Condition I CT is not met.

The required action for proposed Condition D requires one inoperable channel to be placed in trip within one hour versus the corresponding TSTF-505, Revision 2, Condition I, which requires completion within 72 hours. The NRC staff finds that because the completion time is consistent with the current TS and is less than TSTF-505, Revision 2, the proposed Condition D variation is conservative and therefore acceptable. The required action for proposed Condition M, requires entry into Mode 3 in 6 hours and Mode 4 in 12 hours versus the corresponding TSTF-505, Revision 2, Condition O, that requires entry into Mode 3 in 6 hours. The variation in the additional end state, Mode 4, is appropriate since it is consistent with the current TS and entry into Mode 4 would no longer require these functions to be operable since the mode of applicability is 1, 2 and 3. Sufficient redundancy exists to ensure feedwater isolation can be initiated given the two-out-of-three logic on SG Water Level – High. Additionally, Westinghouse STS in TSTF-505, Revision 2 specifies a turbine trip function with actuation of feedwater isolation, where the current Point Beach feedwater isolation signals do not initiate a turbine trip. This variation is specific to the Point Beach design basis which uses the non-safety related ATWS AMSAC function to trip the turbine in the event of a total loss of main feedwater without reactor or turbine trip and does not impact the application of TSTF-505, Revision 2. Therefore, the NRC staff finds the proposed variation to TS 3.3.2, Conditions D and M, for the Feedwater Isolation SG Water Level – High to be acceptable and concludes that the plant will maintain adequate DID.

TS 3.7.2 Condition A – Main Steam Isolation Valves and Non-Return Check Valves

TS 3.7.2, Condition A, addresses one SG flow path with one or more inoperable main steam isolation valves (MSIV) or non-return check valves. Further, with both the MSIV and the non-return check valve of the same SG flow path inoperable, a non-faulted steam line cannot be isolated from a main steam line break outside containment, which constitutes a LOF. To prevent application of a RICT to a LOF condition, the licensee proposes a note to TS 3.7.2 Condition A

CT which limits the application of the RICT to either one inoperable MSIV or one inoperable non-check valve, but not both, in an SG flow path. The proposed note is consistent with the NRC model SE which states that the addition of a note to Required Actions is an acceptable method for limiting the application of RICTs to a LOF condition. TS 3.7.2, Condition A, differs from the Westinghouse STS in TSTF-505, Revision 2, as the latter does not specify requirements for the non-return check valves. The NRC staff finds the proposed variation in TS 3.7.2, Condition A, CT is consistent with the NRC's revised model SE to limit application of the RICT to only either the MSIV or non-check return valve in a steam flow path thus preventing LOF.

Because the RICT Program will not be applied to a LOF, the NRC staff concludes that the proposed variation in TS 3.7.2, Condition A, is acceptable and concludes that the plant will maintain adequate DID.

TS 3.7.7 – Conditions A, Component Cooling Pumps & Condition B, Component Cooling Heat Exchangers

TS 3.7.7, Conditions A and B, address the condition of an inoperable component cooling (CC) pump and an inoperable CC heat exchanger, respectively. TS 3.7.7, Conditions A and B, differ from the Westinghouse STS in TSTF-505, Revision 2, which addresses in one condition an inoperable CC train. There is sufficient redundancy within each CC loop to provide 100 percent of the required cooling capacity during normal operations and post-accident conditions using the associated standby CC pumps and heat exchangers if a single CC pump or CC heat exchanger remains inoperable. The CC system has sufficient component level redundancy to ensure required peak cooling capacity under all plant conditions.

The NRC staff finds that there is sufficient redundancy to ensure cooling capacity during normal and accident conditions. The CC loops of each unit operate independently with two CC pumps and one CC heat exchanger being available for use, while the two CC heat exchangers serve as shared standby units. The remaining pumps and heat exchangers are used to provide CC to auxiliary and containment buildings or are in standby mode. Based on the available redundancy to provide sufficient CC during normal and accident conditions, the NRC staff finds the variations in TS 3.7.7, Conditions A and B, are acceptable and concludes that the plant will maintain adequate DID.

TS 3.7.8 – Conditions A, C, and D Service Water System

TS 3.7.8, Condition A, addresses the condition of one inoperable service water (SW) pump with both units in Modes 1, 2, 3 or 4. TS 3.7.8, Condition A, differs from the Westinghouse STS in TSTF-505, Revision 2, which specifies requirements for an inoperable SW train. The loss of a SW pump does not render the SW system incapable of performing its required function during normal operating or DBA conditions, as all six SW pumps feed into a continuous discharge ring header that effectively results in two SW flow paths directing flow to both trains of all loads for both units. This means with one inoperable SW pump, failure of a safeguards train supporting the start signal for three of the operable SW pumps would leave two remaining operable SW pumps providing sufficient heat sink for the safety related components on both units.

The NRC staff finds that sufficient redundancy is available with six pumps powered by four different safeguard buses on two units feeding into a continuous discharge ring header that results in two SW flow paths directing flow to both trains of all loads for both units. Based on sufficient redundancy being available, the NRC staff finds the proposed variation in TS 3.7.8, Condition A, to be acceptable and concludes that the plant will maintain adequate DID.

TS 3.7.8, Condition C, addresses the interruption of the SW ring header continuous flow path and differs from the Westinghouse STS in TSTF-505, Revision 2, which specifies requirements for an inoperable SW train in Condition A. By employing system manual and automatic valves, during plant operation the ring header continuous flow path can be interrupted for maintenance purposes during which all SW loads are supplied from either the north or south SW header without losing redundancy provided the ring header is intact in both directions around the ring. Further, in attachment 5 to the LAR, the licensee states that isolation of any SW header will not impact the ability of the SW system to supply cooling water to the required number of essential loads on either unit.

The NRC staff finds that redundancy is available for the SW ring header continuous flow path which can be interrupted for maintenance purposes during which all SW loads are supplied, and the isolation of any SW header will not impair the ability of the SW system to supply cooling water to the essential loads on either unit. Based on sufficient redundancy being available, the NRC staff finds the proposed variation in TS 3.7.8, Condition C, to be acceptable and concludes that the plant will maintain adequate DID.

TS 3.7.8, Condition D, addresses one or more non-essential SW load flow paths with one required automatic isolation valve inoperable and the affected non-essential flow paths not isolated. TS 3.7.8, Condition D, differs from the Westinghouse STS in TSTF-505, Revision 2, which specifies the requirements for an inoperable SW train in Condition A. The non-essential loads are supplied by five branches that connect to the SW ring header accompanied by redundant isolation valves that close upon receiving a safety injection signal from either of the units. Thus, the condition of multiple non-essential SW load flow paths, where each has one required automatic valve inoperable, would not necessitate additional operating SW pumps during plant operations or DBA conditions.

The NRC staff finds that the SW system capacity is unaffected by single inoperable isolation valve(s) associated with a non-essential SW flow path during an extended period of inoperability based on the supply of non-essential loads by five branches connected to the SW ring header accompanied by redundant isolation valves. Based on the discussion provided above, the NRC staff finds the proposed variation in TS 3.7.8, Condition D, to be acceptable and concludes that the plant will maintain adequate DID.

3.2.2.1 Key Principle 2: Evaluation of Defense-in-Depth Conclusions

The NRC staff notes that while in a TS LCO condition, the redundancy of the affected system will be temporarily relaxed and, consequently, the system reliability is degraded accordingly. The NRC staff examined the design information from the Point Beach UFSAR and the risk informed TS LCO conditions for the affected safety functions. Based on this information, the NRC staff confirmed that under any given DBA evaluated in the Point Beach UFSAR, the affected protective features maintain adequate DID.

Considering that the CT extensions will be implemented in accordance with the NEI 06-09-A guidance, which also considers RMAs, and the redundancy of the offsite and onsite power systems, the NRC staff finds that the plant will maintain adequate DID. Therefore, the NRC staff finds the TS LCOs proposed by the licensee in attachment 2 to the LAR, as supplemented are acceptable for the RICT Program.

The NRC staff reviewed all TS LCOs proposed by the licensee in attachment 2 to the LAR, as supplemented, and concludes that the proposed changes do not alter the ways in which the Point Beach systems fail, do not introduce new CCF modes, and the system independence is maintained.

The NRC staff finds that some proposed changes reduce the level of redundancy of the affected systems, and this reduction may reduce the level of defense against some CCFs; however, such reductions in redundancy and defense against CCFs are acceptable due to existing diverse means available to maintain adequate DID against a potential single failure during a RICT. The NRC staff finds that extending the selected CTs with the RICT Program following loss of redundancy, but maintaining the capability of the system to perform its safety function, is an acceptable reduction in DID during the proposed RICT period provided that the licensee identifies and implements compensatory measures in accordance with the RICT Program during the extended CT.

Based on the above, the NRC staff concludes that the licensee's proposed changes are consistent with the NRC endorsed guidance prescribed in NEI 06-09-A, along with TSTF-439, Revision 2, and satisfy the second key principle in RG 1.174 and RG 1.177. Additionally, the NRC staff concludes that the changes are consistent with the DID philosophy as described in RG 1.174 and that the removal of the second CTs remain consistent with the DID philosophy.

3.2.3 Key Principle 3: Evaluation of Safety Margins

Paragraph 50.55a(h) of 10 CFR Part 50 requires, in part, that "[p]rotection systems of nuclear power reactors of all types must meet the requirements specified in this paragraph. Section 2.2.2, "Technical Specification Change Maintains Sufficient Safety Margin (Principle 3)," of RG 1.177 states, in part, that sufficient safety margins are maintained when:

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

The licensee is not proposing in this application to change any quality standard, material, or operating specification. In the LAR, as supplemented the licensee proposed to add the RICT Program in section 5.0, "Administrative Controls," of the TSs, which requires adherence to NEI 06-09-A. Furthermore, the licensee proposed to remove second CTs for the specified TS provided in the LAR, as supplemented.

The NRC staff evaluated the effect on safety margins when the RICT is applied to extend the CT up to a backstop of 30 days in a TS condition with sufficient trains remaining operable to fulfill the TS safety function. Although the licensee will be able to have design-basis equipment out of service longer than the current TS allow, any increase in unavailability is expected to be insignificant and is addressed by the consideration of the single failure criterion in the design basis analyses. Acceptance criteria for operability of equipment are not changed and, if sufficient trains remain operable to fulfill the TS safety function, the operability of the remaining train(s) ensure(s) that the current safety margins are maintained. The NRC staff finds that if the specified TS safety function remains operable, sufficient safety margins would be maintained during the extended CT of the RICT Program.

Safety margins are also maintained if PRA functionality is determined for the inoperable train, which would result in an increased CT. Credit for PRA functionality, as described in NEI 06-09-A, is limited to the inoperable train, subsystem, or component.

Based on the above, the NRC staff finds that the design basis analyses for Point Beach remain applicable and unchanged, sufficient safety margins would be maintained during the extended CT, and the proposed changes to the TSs do not include any change in the standards applied or the safety analysis acceptance criteria. The NRC staff concludes that the proposed changes meet 10 CFR 50.55a(h), and therefore, the third key principle in RG 1.174 is satisfied.

3.2.4 Key Principle 4: Change in Risk Consistent with the Safety Goal Policy Statement

NEI 06-09-A provides a methodology for a licensee to evaluate and manage the risk impact of extensions to TS CTs. Permanent changes to the fixed TS CTs are typically evaluated by using the three-tiered approach described in Section 16.1 of NUREG-0800, and RG 1.177. This approach addresses the calculated change in risk as measured by the change in core damage frequency (CDF) and large early release frequency (LERF), as well as the 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 implementation of RICTs will be small and consistent with the intent of the Commission's Safety Goals Policy Statement. In addition, the NRC staff evaluated the licensee's proposed changes against the three-tiered approach in RG 1.177 for the licensee's evaluation of the risk associated with a proposed TS CT change. The results of the NRC staff's review are discussed below.

3.2.4.1 Tier 1: PRA Capability and Insights

The first tier evaluates the impact of the proposed changes on plant operational risk. The Tier 1 review involves two aspects: (1) scope and acceptability of the PRA models and their application to the proposed changes, and (2) a review of the PRA results and insights described in the licensee's application.

Enclosures 2, "Information Supporting PRA Consistency with RG 1.200," (Reference 28) and 4, "Information Supporting Justification of Excluding Sources of Risk not Addressed by PRA Models," (Reference 34) to the LAR, as supplemented, identified the following modeled hazards and alternate methodologies the licensee proposed to be used in the Point Beach RICT Program to assess the risk contribution for extending the CT of a TS LCO.

- Internal Events Probabilistic Risk Assessment (IEPRA) model (includes internal floods)

- Internal Fire Events Probabilistic Risk Assessment (FPRA) model

- Seismic Hazard: CDF penalty of 6.2E-6 per year, and a LERF penalty of 2.8E-6 per year

- Other External Hazards: screened out from RICT Program based on Appendix 6-A of the American Society of Mechanical Engineers (ASME)/American Nuclear Society (ANS) RA-Sa-2009 PRA Standard, “Standard for Level 1/Large Early Release Frequency Probabilistic Risk Assessment for Nuclear Power Plant Applications” (Reference 35)

Evaluation of IEPRA and FPRA Models

The IEPRA and FPRA models supporting the RICT Program are discussed in enclosure 2 to the LAR, as supplemented. The licensee stated that the PRA models have been peer reviewed using the ASME/ANS RA Sa 2009 PRA Standard for the IEPRA and FPRA and RG 1.200, Revision 2. Additionally, the licensee stated that the PRA models have been peer reviewed to the requirements of NEI 05-04, Revision 2, “Process for Performing Internal Events PRA Peer Reviews Using the ASME/ANS PRA Standard,” (Reference 36) and NEI 07-12, Revision 1, “Fire Probabilistic Risk Assessment (FPRA) Peer Review Process Guidelines,” (Reference 37). For the open facts and observations (F&Os) resulting from these peer reviews, the licensee stated that closure of the F&Os was performed using an independent assessment process. The NRC staff confirmed that the licensee performed closure of the F&Os consistent with Appendix X to NEI 05-04, NEI 07-12, and NEI 12-13, as endorsed in RG 1.200. The NRC evaluated the remaining open F&O, along with its disposition.

In enclosure 9, “Key Assumptions and Sources of Uncertainty,” (Reference 38) to the LAR, the licensee provided a discussion and list of the potential key assumptions and sources of uncertainty, along with treatment for the application of TSTF-505. In enclosure 2 to the LAR, the licensee stated that no portable FLEX mitigating strategies are incorporated into the Point Beach PRA models used in this LAR.

The NRC staff reviewed the PRA models’ peer review history provided by the licensee in enclosure 2 to the LAR, as supplemented. The licensee adequately applied the guidance for establishing PRA technical acceptability for the IEPRA and FPRA models. The NRC staff further considered the potential key assumptions and key sources of uncertainty identified by the licensee, and the proposed use of surrogates in the PRA models for specific TS functions. Therefore, the NRC staff finds the Point Beach IEPRA and FPRA models to be acceptable commensurate with the RICT application because the licensee’s use of the PRA models in the integrated decision-making process is consistent with RG 1.174, Revision 3.

Evaluation of Seismic Hazard

The licensee’s approach for including the seismic risk contribution in the RICT calculation is to add a penalty seismic CDF and a penalty seismic LERF to each RICT calculation. The proposed bounding seismic CDF estimate is based on using the plant-specific seismic hazard curves developed in response to the Near-Term Task Force recommendation 2.1 (Reference 39), and a plant-level high confidence of low probability of failure (HCLPF) capacity of 0.16g referenced to peak ground acceleration (PGA). The uncertainty parameter for seismic capacity was represented by a composite beta factor of 0.45. The calculated seismic CDF penalty is 6.2E-6 per year. The staff finds that the method to determine the baseline seismic CDF acceptable because it is consistent with the approach used in Generic Issue (GI)-199, “Implications of Updated Probabilistic Seismic Hazard Estimates in Central and Eastern United States on Existing Plants” (Reference 40). The NRC staff used the input parameters identified by the licensee to confirm the proposed bounding seismic CDF estimate.

Concerning the proposed bounding seismic LERF estimate, the licensee explains in the LAR supplement that an estimate of the seismic LERF is obtained by using the estimated seismic CDF (as described above) with a limiting fragility for containment integrity, also assumed to be 0.16g PGA HCLPF. The calculated seismic LERF is 2.8E-6 per year. The NRC staff finds that the licensee's approach to determine a seismic LERF estimate to be acceptable because use of a 0.16g PGA HCLPF as the limiting fragility for containment integrity is conservative.

The licensee addressed the incremental risk associated with seismic-induced loss of offsite power (LOOP) in its supplement. A seismic LOOP frequency across the entire hazard interval is 1.6E-5 per year. This is about 1 percent of the total internal events 24-hour non-recovered LOOP frequency of 1.6E-3 per year already addressed in the IEPRA. The NRC staff evaluated the licensee's analysis and finds it adequately addresses the impact of seismically induced LOOP on risk and that its exclusion from the non-recovered LOOP frequency has an insignificant impact on the RICT program calculations.

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. In summary, the NRC staff finds the licensee's proposal to use the seismic CDF contributions of 6.2E-6 per year, and a seismic LERF contribution of 2.8E-6 per year to be acceptable for the licensee's RICT Program for Point Beach, because (1) the licensee used the most current site-specific seismic hazard information for Point Beach, (2) the licensee used an acceptably low plant level HCLPF value of 0.16g and a combined beta factor of 0.45 consistent with the information for Point Beach in the GI-199 evaluation, (3) the licensee determined a seismic LERF penalty based on its estimate of seismic CDF combined with using a containment integrity fragility of 0.16g PGA HCLPF, and (4) adding baseline seismic risk to RICT calculations, which assumes the fully correlated failures, is conservative for SSCs credited in seismic events, while any potential for non-conservative results for SSCs that are not credited in seismic events is small or nonexistent.

Evaluation of Other External Hazards

Besides seismic, the licensee confirmed that other external hazards for Point Beach have insignificant contribution and proposed these hazards be screened out from the RICT program. For external floods, the licensee's conclusions regarding insignificant risk contribution were based on the flood hazard reevaluation report (FHRR) (Reference 41) and Flooding Focused Evaluation report for Point Beach (Reference 42). The NRC staff's assessment of flooding focused evaluation (Reference 43) concluded that the licensee demonstrated a feasible response to the reevaluated local intense precipitation (LIP) flood hazard. For high winds, the licensee stated in section 2.1 of enclosure 4 to the LAR that the hazard can be screened out based on the Point Beach individual plant examination of external events (IPEEE, (Reference 44)) evaluation of a CDF of 3.4E-7 per year for high winds hazard. With significant plant modifications after the IPEEE evaluation, its current risk level should be lower than the IPEEE's CDF. The licensee provided its assessment of other external hazard risk for the RICT Program in LAR enclosure 4. The hazards assessed in LAR are those identified for consideration in non-mandatory Appendix 6-A of the ASME/ANS PRA Standard and provides a guide for identification of most of the possible external events for a plant site.

The NRC staff considered that certain plant configurations under external hazards could place the plant at a high risk and the hazards may not be screened. In its supplement (Reference 3), the licensee explained that the external hazard screening evaluation considered potentially adverse plant configurations and the evaluation still allowed the external hazards to be screened. Based on the inclusion of plant configurations in the external hazard screening, the NRC staff finds the Point Beach approach to external hazard screening to be adequate for this application.

The NRC staff reviewed the information in the submittal and supplements, and finds that the contributions from external flooding, high winds, and other external hazards have an insignificant contribution to configuration risk and can be excluded from the calculation of the proposed RICTs because they either do not challenge the plant or they are bounded by the external hazards analyzed for the plant. For all other external hazards, the NRC staff notes that the preliminary screening criteria and progressive screening criteria used and presented in LAR table E4-2 is the same criteria presented in supporting requirements for screening external hazards EXT-B1, EXT-B2, and EXT-C1 of the ASME/ANS PRA Standard.

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

The Point Beach base PRA models that have been determined to be acceptable in this SE will be modified as an application specific PRA model (i.e., CRMP tool), that will be used to analyze the risk for an extended CT. The CRMP model produces results (i.e., risk metrics) that are consistent with the NEI 06-09-A guidance. The LAR, as supplemented, provided all information needed to support the requested LCO actions proposed for the Point Beach RICT Program consistent with the limitations and conditions detailed in section 4.0 of the NRC's final SE incorporated in NEI 06-09-A.

The NRC staff did not identify any insufficiencies in the licensee's information or the CRMP tool as described in the enclosure 8, "Attributes of the Configuration Risk Management Model," (Reference 38) to the LAR. Furthermore, as stated in attachment 1 to the LAR, the proposed changes do not change the design, configuration, or method of operation of the plant. The proposed changes do not involve a physical alteration of the plant (no new or different kind of equipment will be installed). The NRC staff finds that the Point Beach PRA models and CRMP tool used will continue to reflect the as built, as operated plant, consistent with RG 1.200, for ensuring PRA acceptability is maintained. Therefore, the NRC staff concludes that the proposed application of the Point Beach RICT Program is appropriate for use in the adoption of TSTF-505 for performing RICT calculations.

The licensee provided in enclosure 5, "Total Plant (Baseline) CDF and LERF," (Reference 34) to the LAR, as supplemented, the estimated total CDF and LERF of the base PRA models to demonstrate that Point Beach meets the 1E-4/year CDF and 1E-5/year LERF criteria of RG 1.174, consistent with the guidance in NEI 06-09-A, and that these guidelines will be satisfied for implementation of a RICT.

The licensee has incorporated NEI 06-09-A into TS 5.5.7. The estimated current total CDF and LERF for Point Beach PRAs meet the RG 1.174 guidelines, therefore, the NRC staff concludes the PRA results and insights used by the licensee in the RICT Program will continue to be consistent with NEI 06-09-A.

3.2.4.1.1 Tier 1 Conclusions

Based on the above, the NRC staff finds that the licensee has satisfied the intent of Tier 1 in RG 1.177, for determining the acceptability of the PRA, including the scope of the PRA models (i.e., IEPRA and FPRA), the evaluation of external hazards such as seismic and other external hazards are appropriate for this application.

3.2.4.2 Tier 2: Avoidance of Risk-Significant Plant Configurations

As detailed in RG 1.177, the second tier evaluates the capability of the licensee to identify and avoid risk significant plant configurations that could result if equipment, in addition to that associated with the proposed change, is taken out of service simultaneously or if other risk significant operational factors, such as concurrent system or equipment testing, are also involved. In section 3.1, “Description of Monitoring Program,” of enclosure 11, “Monitoring Program,” (Reference 33) to the LAR the licensee confirmed that the risk thresholds associated with 10 CFR 50.65(a)(4) will be coordinated with the RICT limits. Enclosure 12 to the LAR 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 LAR also explains that RMAs will be implemented in accordance with current plant procedures and no later than the time at which the 1E-6 incremental core damage probability (ICCDP) or 1E-7 incremental large early release probability (ICLERP) threshold is reached and under emergent conditions when the instantaneous CDF and LERF thresholds are exceeded.

The NRC staff concludes that the Tier 2 attributes of the proposed RICT Program, including limits established for entry into a RICT and implementation of RMAs, are consistent with the guidance in NEI 06-09-A. Therefore, the proposed changes are consistent with the intent of Tier 2 in RG 1.177.

3.2.4.3 Tier 3: Risk--Informed Configuration Risk Management

The third tier stipulates that a licensee should develop a program that ensures the risk impact of out of service equipment is appropriately evaluated prior to performing any maintenance activity.

The proposed RICT Program establishes a CRMP based on the underlying PRA models. The CRMP is then used to evaluate configuration specific risk for planned activities associated with the RMTS extended CT, as well as emergent conditions which may arise during an extended CT. This required assessment of configuration risk, along with the implementation of compensatory measures and RMAs, is consistent with the principle of Tier 3 for assessing and managing the risk impact of out of service equipment.

Paragraph 50.36(c)(5) of 10 CFR identifies administrative controls as “the provisions relating to organization and management, procedures, […thereby] assuring operation of the facility in a safe manner.” In enclosure 8 to the LAR, the licensee confirmed that future changes made to the baseline PRA models and changes made to the online model (i.e., CRMP) are controlled and documented by NextEra Energy fleet procedures. Enclosure 10, “Program Implementation,” (Reference 38) to the LAR, provided the attributes that the licensee’s RICT Program procedures will address, which are consistent with NEI 06-09-A. The NRC staff finds that the licensee has identified appropriate administrative controls consistent with NEI 06-09-A and 10 CFR 50.36(c)(5).

Based on the licensee’s incorporation of NEI 06-09-A in the TSs (discussed in LAR attachment 2, as supplemented) and its use of RMAs (discussed in LAR enclosure 12), and because the proposed changes are consistent with the Tier 3 guidance of RG 1.177, the NRC staff finds the licensee's Tier 3 program is acceptable and supports the proposed implementation of the RICT Program.

3.2.4.4 Key Principle 4: Conclusions

The licensee has demonstrated the technical acceptability and scope of its PRA models and alternative methods for considering the impact of seismic events, high winds and other external hazards, and that the models can support implementation of the RICT Program for determining extensions to CTs. The licensee has made proper consideration of the key assumptions and sources of uncertainty. The risk metrics are consistent with the approved methodology of NEI 06-09-A and the acceptance guidance in RG 1.174 and RG 1.177. The RICT Program will be controlled administratively through plant procedures and training and follows the NRC approved methodology in NEI 06-09-A. The NRC staff concludes that the RICT Program satisfies the fourth key principle of RG 1.174 and RG 1.177, and therefore, is acceptable.

3.2.5 Key Principle 5: Performance Measurement Strategies – Implementation and Monitoring

RG 1.174 and RG 1.177 establish the need for an implementation and monitoring program to ensure that extensions to TS CTs do not degrade operational safety over time and that no adverse degradation occurs due to unanticipated degradation or common cause mechanisms. Enclosure 11 to the LAR states, that the SSCs in the scope of the RICT Program are also in the scope of 10 CFR 50.65 for the Maintenance Rule. The Maintenance Rule monitoring programs will provide for evaluation and disposition of unavailability impacts which may be incurred from implementation of the RICT Program. Furthermore, in enclosure 11 to the LAR, the licensee confirmed that the cumulative risk is calculated at least every refueling cycle, but the recalculation period does not exceed 24 months, which is consistent with NEI 06-09-A.

The NRC staff concludes that the RICT Program satisfies the fifth key principle of RG 1.174 and RG 1.177 because: (1) the RICT Program will monitor the average annual cumulative risk increase as described in NEI 06-09-A, thereby, ensuring the program, as implemented, continues to meet the guidance in RG 1.174 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.

For the removal of the second CTs, there are two existing programs that provide a strong disincentive to licensees continuing operation with alternating Required Actions. These programs are the monitoring report (10 CFR 50.65) program and the ROP.

The TS CT for one system within an LCO is not generally affected by inoperable equipment in another LCO. However, the second CT influences the CT for one system based on the condition of another system, but only if the two systems are required by the same LCO. Paragraph 50.65(a)(4) of 10 CFR is a much better mechanism to apply this influence, as the monitoring report considers all inoperable risk-significant equipment, not just the one or two systems governed by the same LCO. Furthermore, as discussed above, the monitoring report requires each licensee to monitor the performance or condition of SSCs against licensee-established goals to ensure the SSCs are capable of fulfilling their intended functions. The performance and condition monitoring activities required by 10 CFR 50.65 identify maintenance practices that would result from multiple entries into the actions of the TSs and unacceptable unavailability of these SSCs. The effectiveness of these performance monitoring activities, and associated corrective actions is evaluated at least every refueling cycle, not to exceed 24 months per 10 CFR 50.65.

In addition to the monitoring report, the reporting of performance indicator data governed by NEI 99-02, “Regulatory Assessment Performance Indicator Guideline” (Reference 45), as endorsed by RIS 2001-11, “Voluntary Submission of Performance Indicator Data” (Reference 46), establishes an acceptable method for the submission of performance indicator data to the NRC. The ROP consists of cornerstones that include inspection of the indicators to ensure all ROP objectives are being met. The mitigating systems cornerstone specifically addresses the AC sources-operating which encompasses the AC sources and distribution system LCOs and the auxiliary feedwater system. Any extended unavailability of these systems due to multiple entries into the TS Actions would affect the NRCs evaluation of the licensee’s performance indicator data provided under the ROP. The licensee’s performance within the mitigating systems ROP cornerstone provides reasonable assurance in monitoring the inappropriate use of TS condition CTs.

In addition to these regulatory programs, NextEra Fleet administrative procedures prohibit the application of LCO Conditions in a manner which extend indefinitely periods of failing to satisfy an LCO, which is consistent with the administrative controls recommended in TSTF-439, Revision 2. Specifically, NextEra Fleet Administrative procedure OP-AA-100-1000, Conduct of Operations, states:

> It may be possible to alternate between Actions in such a manner that operation could continue indefinitely without satisfying an LCO. Doing so, however, would be inconsistent with the basis for the Allowed Outage Time, and is NOT allowed (AR 2007220)

The NRC staff concludes that the licensee continues to have mechanisms in place to monitor and to limit the maximum time allowed for any combination of conditions that could result in a single contiguous occurrence of failing to meet the LCO. The NRC staff finds the proposed deletion of second CTs are acceptable because multiple, continuous entries into TSs conditions, without meeting the LCO, will be adequately controlled by: (1) the licensee’s administrative controls, (2) the CRMPs as implemented to meet the requirements of the monitoring report to assess and manage risk and performance indicators, and (3) assessment of the licensee’s performance within the mitigating systems ROP cornerstone. In addition, the NRC staff finds the monitoring report provides adequate assurance against inappropriate use of combinations of TS conditions that result in a single contiguous occurrence of failing to meet the LCO. Accordingly, consistent with TSTF-439, Revision 2, the NRC staff finds the proposed changes to be acceptable.

3.3 Variations

The licensee proposed variations in TSs 3.3.1, 3.3.2, 3.6.3, 3.7.2, 3.7.7 and 3.7.8 from the Westinghouse STS in TSTF-505, Revision 2. Based on the above review, the NRC staff concludes that the TSs, as amended by the proposed changes, will continue to meet the requirements of 50.36(c)(2) because the LCOs will continue to state the lowest functional capability or performance levels of equipment required for safe operation of the facility. The NRC staff concludes that the remedial actions, as amended by the proposed change, provide reasonable assurance that facility operation remains safe during the time the LCOs are not met. Therefore, the proposed changes to the TSs are acceptable.

3.4 Technical Evaluation Conclusion

The NRC staff has evaluated the proposed changes against each of the five key principles in RG 1.174 and RG 1.177, including the proposed variations from the approved TSTF-505, Revision 2, discussed in sections 3.2 and 3.3 of this SE. The NRC staff concludes that the changes proposed by the licensee satisfy the key principles of risk informed decision-making identified in RG 1.174 and RG 1.177, and, therefore, the requested adoption of the proposed changes to the TSs and associated guidance, is acceptable to assure the paragraphs of 10 CFR Part 50 identified in section 2.0 of this SE continue to be met.

4.0 STATE CONSULTATION

In accordance with the Commission's regulations, on April 12, 2023, the Wisconsin State official was notified of the proposed issuance of the amendments. The State official had no comments.

5.0 ENVIRONMENTAL CONSIDERATION

These amendments change a requirement with respect to the installation or use of a facility component located within the restricted area as defined in 10 CFR part 20 or change a surveillance requirement. The NRC staff has determined that the amendments involve no significant increase in the amounts and no significant change in the types of any effluent that may be released offsite, and that there is no significant increase in individual or cumulative occupational radiation exposure. The Commission has previously published a proposed finding in the Federal Register on August 9, 2022 (87 FR 48517) that these amendments involve no significant hazards consideration and there has been no public comment on such finding. Accordingly, these 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 these 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 amendments will not be inimical to the common defense and security or to the health and safety of the public.

7.0 REFERENCES

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Date: June 1, 2023

SUBJECT: POINT BEACH NUCLEAR PLANT, UNITS 1 AND 2 - ISSUANCE OF AMENDMENT NOS. 271 AND 273 REGARDING TECHNICAL SPECIFICATIONS TO ADOPT TSTF-505, REVISION 2, “PROVIDE RISK-INFORMED EXTENDED COMPLETION TIMES – RITSTF INITIATIVE 4b” (EPID L-2022-LLA-0074) DATED JUNE 1, 2023

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