Southern Nuclear

Cheryl A. Gayheart
Regulatory Affairs Director

3535 Colonnade Parkway
Birmingham, AL 35243
205 992 5316 tel
205 992 7601 fax
cagayhea@southernco.com

October 26, 2021

Docket Nos.: 50-321
50-366

NL-21-0576
10 CFR 50.90

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

Edwin I. Hatch Nuclear Plant - Units 1 and 2
License Amendment Request to Revise Technical Specifications
to Adopt Risk Informed Completion Times TSTF-505, Revision 2,
"Provide Risk-Informed Extended Completion Times - RITSTF Initiative 4b"

Ladies and Gentlemen:

In accordance with the provisions of Section 50.90 of Title 10 of the *Code of Federal Regulations* (10 CFR), Southern Nuclear Operating Company (SNC) is submitting a request for an amendment to the Technical Specifications (TS) for Edwin I. Hatch Nuclear Plant, Units 1 and 2 (HNP) renewed facility operating licenses DPR-57 and NPF-5, respectively.

The proposed amendment would modify TS requirements to permit the use of Risk Informed Completion Times in accordance with TSTF-505, Revision 2, "Provide Risk-Informed Extended Completion Times - RITSTF Initiative 4b" (ADAMS Accession No. ML18183A493). A model safety evaluation was provided by the NRC to the TSTF on November 21, 2018 (ADAMS Accession No. ML18269A041).

- Attachment 1 provides a description and assessment of the proposed change, the requested confirmation of applicability, and plant-specific verifications.
- Attachment 2 provides the existing TS pages marked up to show the proposed changes.
- Attachment 3 provides existing TS Bases pages marked up to show the proposed changes and is provided for information only.

The proposed amendment would also make administrative changes to the TS.

SNC requests approval of the proposed license amendment 12 months following acceptance. The proposed changes would be implemented within 180 days of issuance of the amendment.

SNC has concluded that the proposed change presents no significant hazards consideration under the standards set forth in 10 CFR 50.92, “Issuance of amendment.”

In accordance with 10 CFR 50.91, SNC is notifying the State of Georgia of this license amendment request by transmitting a copy of this letter, with attachments and enclosures, to the designated State Official.

This letter contains no NRC commitments. If you have any questions, please contact Ryan Joyce at 205.992.6468.

I declare under penalty of perjury that the foregoing is true and correct. Executed on the 26th day of October 2021.

Respectfully submitted,

C. A. Gayheart
Director, Regulatory Affairs
Southern Nuclear Operating Company

CAG/RMJ

Attachments:
1. Description and Assessment
2. Proposed Technical Specification Changes (Mark-Up)
3. Proposed Technical Specification Bases Changes (Mark-Up) - For Information Only

Enclosures:
1. List of Revised Required Actions to Corresponding PRA Functions
2. Information Supporting Consistency with Regulatory Guide 1.200, Revision 2
3. (Not Used)
4. Information Supporting Justification of Excluding Sources of Risk Not Addressed by the PRA Models
5. Baseline CDF and LERF
6. (Not Used)
7. PRA Model Update Process
8. Attributes of the Real-Time Model
9. Key Assumptions and Sources of Uncertainty
10. Program Implementation
11. Monitoring Program
12. Risk Management Action Examples

cc: Regional Administrator, Region II
NRR Project Manager – Hatch
Senior Resident Inspector – Hatch
Director, Environmental Protection Division – State of Georgia
RType: CHA02.004

Edwin I. Hatch Nuclear Plant - Units 1 and 2
License Amendment Request to Revise Technical Specifications
to Adopt Risk Informed Completion Times TSTF-505, Revision 2,
"Provide Risk-Informed Extended Completion Times - RITSTF Initiative 4b"

Attachment 1

Description and Assessment

ATTACHMENT 1

DESCRIPTION AND ASSESSMENT OF THE PROPOSED CHANGE

1.0 DESCRIPTION

The proposed amendment would modify the Edwin I. Hatch Nuclear Plant (HNP), Units 1 and 2 Technical Specification (TS) requirements related to Completion Times (CTs) for Required Actions to provide the option to calculate a longer, risk-informed CT (RICT). A new program, the Risk-Informed Completion Time Program, is added to TS Section 5, “Administrative Controls.”

The methodology for using the RICT Program is described in NEI 06-09, "Risk-Informed Technical Specifications Initiative 4b, Risk-Managed Technical Specifications (RMTS) Guidelines," Revision 0-A (ML12286A322) (hereafter referred to as NEI 06-09-A) was approved by the NRC on May 17, 2007 (ML071200238). Adherence to NEI 06-09-A is required by the RICT Program.

The proposed amendment is generally consistent with TSTF-505, Revision 2 (ML18183A493), "Provide Risk-Informed Extended Completion Times - RITSTF Initiative 4b," with variations identified in Enclosure 1.

The proposed amendment would also make the following administrative change:

- Remove temporary changes from Unit 2 TS 3.5.1, ECCS – Operating, approved in Amendment 254 (ML21109A359), remove temporary changes from Unit 1 TS 3.7.2, Plant Service Water (PSW) System and Ultimate Heat Sink (UHS), approved in Amendment 311 (ML21264A644), and remove temporary changes from Unit 1 and Unit 2 TS 3.8.1, AC Sources – Operating, approved in Amendments 307 and 252 respectively (ML20254A057).

2.0 ASSESSMENT

2.1 Applicability of Published Safety Evaluation

Southern Nuclear Operating Company (SNC) has reviewed TSTF-505, Revision 2, and the model safety evaluation dated November 21, 2018 (ADAMS Accession No. ML18269A041). This review included the supporting information provided to support TSTF-505 and the safety evaluation for NEI 06-09-A. SNC has concluded that the technical basis is applicable to HNP Units 1 and 2 and supports incorporation of this amendment in the HNP TS.

2.2 Verifications and Regulatory Commitments

In accordance with Section 4.0, Limitations and Conditions, of the safety evaluation for NEI 06-09-A, the following is provided:

1. Enclosure 1 identifies each of the TS Required Actions to which the RICT Program will apply, with a comparison of the TS functions to the functions modeled in the unit-specific probabilistic risk assessment (PRA) for the structures, systems and components (SSCs) subject to those actions. Enclosure 1 also includes a TSTF-505 cross reference to associated HNP TS which includes additional justifications as requested by TSTF-505 and includes an evaluation of instrumentation and control systems for redundancy and diversity. Finally, estimated RICTs are provided for in-scope electrical TS Actions.

2. Enclosure 2 provides a discussion of the results of peer reviews and self-assessments conducted for the plant-specific PRA models which support the RICT Program, as discussed in Regulatory Guide (RG) 1.200 Section C.4.2.

3. Enclosure 3 is not applicable since each PRA model used for the RICT Program is addressed using a standard endorsed by the Nuclear Regulatory Commission.

4. Enclosure 4 provides appropriate justification for excluding sources of risk not addressed by the PRA models.

5. Enclosure 5 provides the unit-specific baseline CDF and LERF to confirm that the potential risk increases allowed under the RICT Program are acceptable.

6. Enclosure 6 is not applicable since the RICT Program is not being applied to shutdown modes.

7. Enclosure 7 provides a discussion of SNC's programs and procedures that assure the PRA models that support the RICT Program are maintained consistent with the as-built, as-operated plant.

8. Enclosure 8 provides a description of how the baseline PRA model, which calculates average annual risk, is evaluated and modified to assess real-time configuration risk, and describes the scope of, and quality controls applied to the real-time model.

9. Enclosure 9 provides a discussion of how the key assumptions and sources of uncertainty in the PRA models were identified, and how their impact on the RICT Program was assessed and dispositioned.

10. Enclosure 10 provides a description of the implementing programs and procedures regarding the plant staff responsibilities for the RICT Program implementation, including risk management action (RMA) implementation.

11. Enclosure 11 provides a description of the implementation and monitoring program as described in NEI 06-09-A, Section 2.3.2, Step 7.

12. Enclosure 12 provides a description of the process to identify and provide RMAs.

2.3 Optional Variations

SNC is proposing the following variations from the TS changes described in TSTF-505, Revision 2, or the applicable parts of the NRC staff's model safety evaluation dated November 21, 2018. These options were recognized as acceptable variations in TSTF-505 and the NRC staff's model safety evaluation or are justified below.

1. HNP Required Actions that have identical numbers to the corresponding NUREG-1433 Required Actions are not variations from TSTF-505, except for administrative variations (if any) such as formatting. These variations are administrative with no impact on the NRC model safety evaluation.

2. HNP Actions that have different numbering or titles than the NUREG-1433 Required Actions are an administrative variation from TSTF-505 with no impact on the NRC model safety evaluation. These numbering and title differences are identified as variations in Enclosure 1, Table E1-2.

3. TSTF-505 Required Actions applicable to NUREG-1433 that are not applicable to HNP are not included in the proposed HNP TS. This is an administrative variation from TSTF-505 with no impact on the NRC model safety evaluation. These differences are identified as variations in Enclosure 1, Table E1-2.

4. There is one HNP TS for which SNC is proposing to apply the RICT Program that is in addition to those proposed in TSTF-505, Revision 2. As noted in Enclosure 1, Table E1-2, LCO 3.6.2.5, Residual Heat Removal (RHR) Drywell Spray, is not identified in the TSTF and thus, does not propose the RICT for drywell spray Actions. However, the HNP drywell spray Actions are similar to NUREG-1433 Actions for RHR Suppression Pool Cooling (TS 3.6.2.3), RHR Suppression Pool Spray (TS 3.6.2.4), and Drywell Cooling System Fans (TS 3.6.3.1), which provide for application of RICT for one of two required subsystems inoperable.

   Refer to Peach Bottom Atomic Power Station, Units 2 and 3, Amendments 338 and 341 respectively (ADAMS Accession No. ML21074A411) as precedent for applying the RICT Program for Residual Heat Removal (RHR) Drywell Spray.

5. The model application provided in TSTF-505 includes an attachment for revised, clean typed TS pages reflecting the proposed changes. SNC is not including such an attachment due to the number of TS pages included in this submittal and the straightforward nature of the proposed changes. Providing only mark-ups of the proposed TS changes satisfies the requirements of 10 CFR 50.90, "Application for amendment of license, construction permit, or early site permit," in that the mark-ups fully describe the changes desired. This is an administrative deviation from TSTF-505 with no impact on the NRC's model safety evaluation. Because of this deviation, the contents and numbering of the attachments for this amendment request differ from the attachments specified in the model application in TSTF-505.

6. As provided in the proposed HNP RICT Program TS, RICTs will only be applied in MODE 1.

7. To preclude the RICT from being applied where a loss of safety function might be possible (e.g., Conditions that allow for “one or more channels inoperable”), TSTF-505, Revision 2, specifies the addition of a Note, where appropriate, that reads “Not applicable when [all] required [channels] are inoperable.” For HNP, a Note is not considered necessary since a separate Condition exists (e.g., for TS 3.3.1.1, Reactor Protection System (RPS) Instrumentation, “One or more Functions with RPS trip capability not maintained”), which addresses a loss of function and does not apply use of RICT. These separate actions (without use of RICT) must be applied regardless, and thus, a loss of Function is adequately addressed without the need for additional Notes.

8. SNC proposes to make two minor editorial change to the Required Action in the new proposed Example 1.3-8 relative to the Example 1.3-8 provided in TSTF-505, Revision 2. TSTF-505, Revision 2, Example 1.3-8 provides a standard default Condition of “Required Action and associated Completion Time not met,” with a Required Action of “Be in MODE 3 [in 6 hours] <u>AND</u> Be in MODE 5 [in 36 hours].” However, the typical default Required Action found in TS Section 1.3 Examples as well as TS Section 3 Limiting Conditions for Operation (LCOs) is “Be in MODE 3 [in 12 hours] <u>AND</u> Be in MODE 4 [in 36 hours].” Therefore, as noted in the TS markups in Attachment 2, SNC proposes to change the Completion Time for the MODE 3 Required Action to 12 hours and also to specify MODE 4 rather than MODE 5 in the Required Action of the default Condition in the new proposed Example 1.3-8. These changes are administrative in nature and do not affect the applicability of TSTF-505, Revision 2, to the HNP TS.

9. The model application provided in TSTF-505 includes mark-ups to Completion Times in a format using an "OR" Logical Connector followed by "In accordance with the Risk Informed Completion Time Program." SNC proposes to use a modified format in presenting the optional RICT Completion Time in TS 3.3.6.1 and TS 3.6.1.3 where there is one or more “AND” logics and conditional qualifiers in the existing Completion Times for a Required Action. For example, the Completion Time for TS 3.6.1.3 Required Action A.1 states “4 hours except for main steam line <u>AND</u> 8 hours for main steam line” where “except for main steam line” and “for main steam line” are the conditional qualifiers. TS Section 1.2, "Logical Connectors," specifies that Completion Times only use first level logic. Therefore, the proposed markups have been modified for these Required Actions to use multiple Required Actions with the conditional qualifier reformatted as a Note above the appropriate Required Action. For example, TS 3.6.1.3 Required Action A.1 will be broken into Required Actions A.1 and A.2, with Note applicable to Required Action A.1 stating “Not applicable to main steam line” and a Note applicable to Required Action A.2 stating “Only applicable to main steam line.” The revised TS formatting meets the intent of the existing TS Actions and provides the identical requirement. In addition, the revised formatting follows HNP TS Section 1.2 and does not create a second-level logic for the Completion Times. Similar reformatting is proposed for TS 3.3.6.1 Required Action A.1. This is an administrative deviation from TSTF-505 with no impact on the NRC's model safety evaluation.

10. With the issuance of HNP license amendment numbers 259 and 203 (ADAMS Accession No. ML082280076), HNP TS 3.8.1, Required Actions B.4.1 and C.4.1, provide an option for an extended risk-informed Completion Time of 14-days for a unit or swing diesel generator inoperability, and for an opposite unit diesel generator inoperability, respectively, when specific conditions are met. The optional Required Action B.4.2 is removed (see Additional Change Requests item 2 below) and the

Required Action B.4.1 72-hour Completion Time applicable when the specific conditions are not met is replaced with Required Action B.4 proposed Completion Time of "72 hours OR In accordance with the Risk Informed Completion Time Program." Similarly , the optional Required Action C.4.2 is removed (see Additional Change Requests item 2 below) and the Required Action C.4.1 7-day Completion Time, applicable when the specific conditions are not met is replaced with Required Action C.4 proposed Completion Time of "7 days OR In accordance with the Risk Informed Completion Time Program." These changes are based on TSTF-505 Required Action B.4 addition of the Risk Informed Completion Time and are made for consistency of application of risk-informed Completion Times.

2.4 Additional Change Requests

SNC is proposing the following additional administrative changes, which are not reflected in the TS changes described in TSTF--505, Revision 2.

1. SNC proposes to remove temporary changes from Unit 2 TS 3.5.1, ECCS – Operating, approved in Amendment 254 (ML21109A359). The changes were made to Required Action A.2 of TS 3.5.1, "ECCS [Emergency Core Cooling System] – Operating," to extend the Completion Time from 7 days to 15 days only while repairs of the 2D Residual Heat Removal (RHR) pump repair were ongoing, and only until May 1, 2021. This allowance is no longer applicable and is proposed for deletion as an administrative change.

2. SNC proposes to remove temporary changes from Unit 1 and Unit 2 TS 3.8.1, AC Sources – Operating, approved in Amendments 307 and 252 respectively (ML20254A057). The changes were made to provide a one-time extension of the Unit 1 Required Action B.4 Completion Time and Unit 2 Required Actions B.4 and C.4 for each HNP Unit 1 emergency diesel generator (EDG) and the swing EDG from 14 days to 19 days and only until June 30, 2021. This allowance is no longer applicable and is proposed for deletion as an administrative change.

3. Current TS 3.5.1 Condition G is required to be entered if one low pressure coolant injection (LPCI) pump in one or both LPCI subsystems is inoperable concurrent with one core spray (CS) subsystem inoperable. This configuration, however, does not represent a loss of function from either a design basis or PRA success criteria perspective. Unit 2 FSAR Table 6.3-2 provides the TRACG-LOCA single failure assessment. The limiting single failure from this table is a dedicated diesel battery, which shows the availability of one core spray pump, one LPCI pump for each recirculation line (two LPCI pumps total), plus high pressure coolant injection (HPCI) and automatic depressurization system (ADS) to provided successful ECCS mitigation. To allow a RICT to be applied to this configuration, new Conditions C and D are added to TS 3.5.1. The Required Actions and associated Completion Times applied to new Conditions C and D are consistent with those of current Condition G (i.e., LCO 3.0.3) but will allow a RICT to be applied to the restoration action (i.e., Required Action C.1) for this configuration.

   Although Unit 2 FSAR Table 6.3-2 lists HPCI as an available system (i.e. not impacted by the single failure assumption) to provide successful ECCS mitigation, the LOCA ECCS analysis does not take credit for HPCI operation to meet 10 CFR 50.46

requirements as discussed in FSAR subsection 6.3.2.2.1. If HPCI were inoperable while new Condition C was entered, HNP would concurrently be in (renumbered) TS 3.5.1 Condition A, C, E, and F. The limiting “front-stop” CT would be the 1 hour CT from new Condition C. The calculated RICT for each of these Conditions would be adjusted based the available SSCs. Based on the very short front-stop CT (1 hour) of new Condition C, a new Condition reflecting Condition C entry concurrent with HPCI inoperability is unnecessary.

4. SNC proposes to remove temporary changes from Unit 1 TS 3.7.2, Plant Service Water (PSW) System and Ultimate Heat Sink (UHS), approved in Amendment 311 (ML21264A644). The changes were made to add optional Required Actions A.2.1 and A.2.2 to extend the Completion Time from 30 days to 45 days only while repairs of the 1C PWS pump repair were ongoing, and only until October 10, 2021, at 1620 EDT. This allowance is no longer necessary and is proposed for deletion as an administrative change.

3.0 REGULATORY SAFETY ANALYSIS

3.1 No Significant Hazards Consideration Analysis

Southern Nuclear Operating Company (SNC) has evaluated the proposed change to the TS using the criteria in 10 CFR 50.92 and has determined that the proposed change does not involve a significant hazards consideration.

Edwin I. Hatch Nuclear Plant (HNP), Units 1 and 2 requests adoption of an approved change to the standard technical specifications (STS) and unit-specific technical specifications (TS), to modify the TS requirements related to Completion Times for Required Actions to provide the option to calculate a longer, risk-informed Completion Time. The allowance is described in a new program in Chapter 5, "Administrative Controls," titled the "Risk Informed Completion Time Program."

In addition, HNP Units 1 and 2 requests administrative changes as described in this Attachment.

As required by 10 CFR 50.91(a), an analysis of the issue of no significant hazards consideration is presented below:

1. Does the proposed change involve a significant increase in the probability or consequences of an accident previously evaluated?

   Response: No.

   The proposed change permits the extension of Completion Times provided the associated risk is assessed and managed in accordance with the NRC approved Risk-Informed Completion Time Program. The proposed change does not involve a significant increase in the probability of an accident previously evaluated because the change involves no change to the plant or its modes of operation. The proposed change does not increase the consequences of an accident because the design-basis mitigation function of the affected systems is not changed and the consequences of an accident during the extended Completion Time are no different from those during the existing Completion Time.

In addition, this request contains administrative changes to the TS, which do not impact the probability or consequences of an accident.

Therefore, the proposed change does not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the proposed change create the possibility of a new or different kind of accident from any accident previously evaluated?

   Response: No.

   The proposed change does not change the design, configuration, or method of operation of the plant. The proposed change does not involve a physical alteration of the plant (no new or different kind of equipment will be installed).

   Therefore, the proposed change does not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Does the proposed change involve a significant reduction in a margin of safety?

   Response: No.

   The proposed change permits the extension of Completion Times provided risk is assessed and managed in accordance with the NRC approved Risk-Informed Completion Time Program. The proposed change implements a risk-informed configuration management program to assure that adequate margins of safety are maintained. Application of these new specifications and the configuration management program considers cumulative effects of multiple systems or components being out of service and does so more effectively than the current TS.

   In addition, this request contains administrative changes to the TS, which do not impact a margin of safety.

   Therefore, the proposed change does not involve a significant reduction in a margin of safety.

Based on the above, SNC concludes that the proposed change presents no significant hazards consideration under the standards set forth in 10 CFR 50.92(c), and, accordingly, a finding of "no significant hazards consideration" is justified.

3.2 Conclusion

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

4.0 ENVIRONMENTAL CONSIDERATION

SNC has reviewed the environmental evaluation included in the model safety evaluation published on November 21, 2018. SNC has concluded that the NRC staff findings presented in that evaluation are applicable to HNP Units 1 and 2.

The proposed change would change a requirement with respect to installation or use of a facility component located within the restricted area, as defined in 10 CFR 20, or would change an inspection or surveillance requirement. However, the proposed change does not involve (i) a significant hazards consideration, (ii) a significant change in the types or significant increase in the amounts of any effluents that may be released offsite, or (iii) a significant increase in individual or cumulative occupational radiation exposure. Accordingly, the proposed change meets the eligibility criterion for categorical exclusion set forth in 10 CFR 51.22(c)(9).

Therefore, pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the proposed change.

Edwin I. Hatch Nuclear Plant - Units 1 and 2
License Amendment Request to Revise Technical Specifications
to Adopt Risk Informed Completion Times TSTF-505, Revision 2,
"Provide Risk-Informed Extended Completion Times - RITSTF Initiative 4b"

Attachment 2

Proposed Technical Specification Changes (Mark-Up)

1.3 Completion Times

EXAMPLES (continued)

EXAMPLE 1.3-8

ACTIONS

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

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

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

(continued)

1.3 Completion Times

EXAMPLES

EXAMPLE 1.3-8 (continued)

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

If the RICT expires or is recalculated to be less than the 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.

3.1 REACTIVITY CONTROL SYSTEMS

3.1.7 Standby Liquid Control (SLC) System

LCO 3.1.7 Two SLC subsystems shall be OPERABLE.

APPLICABILITY: MODES 1 and 2.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Sodium pentaborate solution not within Region A limits of Figure 3.1.7-1 or 3.1.7-2, but within the Region B limits.	A.1 Restore sodium pentaborate solution to within Region A limits.	72 hours
B. One SLC subsystem inoperable for reasons other than Condition A.	B.1 Restore SLC subsystem to OPERABLE status.	7 days OR In accordance with the Risk Informed Completion Time Program
C. Two SLC subsystems inoperable for reasons other than Condition A.	C.1 Restore one SLC subsystem to OPERABLE status.	8 hours
D. Required Action and associated Completion Time not met.	D.1 Be in MODE 3.	12 hours

3.3 INSTRUMENTATION

3.3.1.1 Reactor Protection System (RPS) Instrumentation

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

APPLICABILITY: According to Table 3.3.1.1-1.

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required channels inoperable.	A.1 Place channel in trip. OR	12 hours OR ------------NOTE--------- Not applicable to Functions 7.a, 7.b, and 10. ----------------------------- In accordance with the Risk Informed Completion Time Program

(continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.2 -----------NOTE------------ Not applicable for Functions 2.a, 2.b, 2.c, 2.d, and 2.f. ------------------------------- Place associated trip system in trip.	12 hours <u>OR</u> ------------NOTE--------- Not applicable to Functions 7.a, 7.b, and 10. ----------------------------- In accordance with the Risk Informed Completion Time Program
B. ---------------NOTE------------- Not applicable for Functions 2.a, 2.b, 2.c, 2.d, and 2.f. ------------------------------------ One or more Functions with one or more required channels inoperable in both trip systems.	B.1 Place channel in one trip system in trip. <u>OR</u>	6 hours <u>OR</u> ------------NOTE--------- Not applicable to Functions 7.a, 7.b, and 10. ----------------------------- In accordance with the Risk Informed Completion Time Program (continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. (continued)	B.2	Place one trip system in trip.	6 hours OR ------------NOTE--------- Not applicable to Functions 7.a, 7.b, and 10. ------------------------------ In accordance with the Risk Informed Completion Time Program
C. One or more Functions with RPS trip capability not maintained.	C.1	Restore RPS trip capability.	1 hour
D. Required Action and associated Completion Time of Condition A, B, or C not met.	D.1	Enter the Condition referenced in Table 3.3.1.1-1 for the channel.	Immediately
E. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	E.1	Reduce THERMAL POWER to < 27.6% RTP.	4 hours
F. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	F.1	Be in MODE 2.	6 hours
G. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	G.1	Be in MODE 3.	12 hours

(continued)

3.3 INSTRUMENTATION

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

LCO 3.3.4.1

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

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

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

OR

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

APPLICABILITY: THERMAL POWER ≥ 27.6% RTP.

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more channels inoperable.	A.1 Restore channel to OPERABLE status. OR	72 hours OR In accordance with the Risk Informed Completion Time Program

(continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. (continued)	A.2	-----------NOTE------------ Not applicable if inoperable channel is the result of an inoperable breaker. -------------------------------- Place channel in trip.	72 hours OR In accordance with the Risk Informed Completion Time Program
B. One or more Functions with EOC-RPT trip capability not maintained. AND MCPR limit for inoperable EOC-RPT not made applicable.	B.1	Restore EOC-RPT trip capability.	2 hours
	OR		
	B.2	Apply the MCPR limit for inoperable EOC-RPT as specified in the COLR.	2 hours
C. Required Action and associated Completion Time not met.	C.1	Remove the associated recirculation pump from service.	4 hours
	OR		
	C.2	Reduce THERMAL POWER to < 27.6% RTP.	4 hours

3.3 INSTRUMENTATION

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

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

a. Reactor Vessel Water Level - ATWS-RPT Level; and

b. Reactor Steam Dome Pressure - High.

APPLICABILITY: MODE 1.

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more channels inoperable.	A.1 Restore channel to OPERABLE status. OR	14 days OR In accordance with the Risk Informed Completion Time Program (continued)

ACTIONS

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

ACTIONS

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

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. (continued)	C.2 Restore channel to OPERABLE status.	24 hours OR ------------NOTE--------- Not applicable to Function 3.c. ------------------------------ In accordance with the Risk Informed Completion Time Program
D. As required by Required Action A.1 and referenced in Table 3.3.5.1-1.	D.1 ------------NOTE----------- Only applicable if HPCI pump suction is not aligned to the suppression pool. -------------------------------- Declare HPCI System inoperable.	1 hour from discovery of loss of HPCI initiation capability
	AND	
	D.2.1 Place channel in trip.	24 hours OR In accordance with the Risk Informed Completion Time Program
	OR	
	D.2.2 Align the HPCI pump suction to the suppression pool.	24 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. As required by Required Action A.1 and referenced in Table 3.3.5.1-1.	E.1 -----------NOTE---------- Only applicable for Functions 1.d and 2.g. --------------------------------	
	Declare supported feature(s) inoperable.	1 hour from discovery of loss of initiation capability for subsystems in both divisions
	AND	
	E.2 Restore channel to OPERABLE status.	7 days OR In accordance with the Risk Informed Completion Time Program

(continued)

3.3 INSTRUMENTATION

3.3.5.3 Reactor Core Isolation Cooling (RCIC) System Instrumentation

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

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

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more channels inoperable.	A.1 Enter the Condition referenced in Table 3.3.5.3-1 for the channel.	Immediately
B. As required by Required Action A.1 and referenced in Table 3.3.5.3-1.	B.1 Declare RCIC System inoperable. AND B.2 Place channel in trip.	1 hour from discovery of loss of RCIC initiation capability 24 hours OR In accordance with the Risk Informed Completion Time Program

(continued)

ACTIONS (continued)

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

3.3 INSTRUMENTATION

3.3.6.1 Primary Containment Isolation Instrumentation

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

APPLICABILITY: According to Table 3.3.6.1-1.

ACTIONS

---NOTES---

1. Penetration flow paths except for 18 inch purge valve penetration flow paths may be unisolated intermittently under administrative controls.

2. Separate Condition entry is allowed for each channel.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required channels inoperable.	A.1 ------------NOTE----------- Only applicable to Functions 2.a, 2.b, 6.b, 7.a, and 7.b. -------------------------------	
	Place channel in trip.	12 hours ~~for Functions 2.a, 2.b, 6.b, 7.a, and 7.b~~ ~~AND~~ ~~24 hours for Functions other than Functions 2.a, 2.b, 6.b, 7.a, and 7.b~~ OR ------------NOTE--------- Not applicable to Functions 6.b, 7.a, and 7.b. ----------------------------- In accordance with the Risk Informed Completion Time Program
	AND	

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. (continued)	A.2	------------NOTE----------- Not applicable to Functions 2.a, 2.b, 6.b, 7.a, and 7.b. ------------------------------- Place channel in trip.	24 hours <u>OR</u> ------------NOTE--------- Not applicable to Functions 2.c, 2.d, 2.e, and 6.a. ------------------------------ In accordance with the Risk Informed Completion Time Program
B. ---------------NOTE------------- Not applicable for Function 5.c. ------------------------------------ One or more automatic Functions with isolation capability not maintained.	B.1	Restore isolation capability.	1 hour
C. Required Action and associated Completion Time of Condition A or B not met.	C.1	Enter the Condition referenced in Table 3.3.6.1-1 for the channel.	Immediately
D. As required by Required Action C.1 and referenced in Table 3.3.6.1-1.	D.1	Isolate associated main steam line (MSL).	12 hours
	<u>OR</u>		
	D.2.1	Be in MODE 3.	12 hours
	<u>AND</u>		
	D.2.2	Be in MODE 4.	36 hours

(continued)

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

3.5.1 ECCS - Operating

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

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

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One low pressure ECCS injection/spray subsystem inoperable. <u>OR</u> One LPCI pump in both LPCI subsystems inoperable.	A.1 Restore low pressure ECCS injection/spray subsystem to OPERABLE status.	7 days <u>OR</u> In accordance with the Risk Informed Completion Time Program
B. Required Action and associated Completion Time of Condition A not met.	B.1 ------------NOTE----------- LCO 3.0.4.a is not applicable when entering MODE 3. -------------------------------- Be in MODE 3.	 12 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One LPCI pump in one subsystem or one LPCI pump in both LPCI subsystems inoperable. AND One CS subsystem inoperable.	C.1 Restore low pressure ECCS injection/spray subsystem(s) to OPERABLE status.	1 hour OR In accordance with the Risk Informed Completion Time Program
D. Required Action and associated Completion Time of Condition C not met.	D.1 Be in MODE 2. AND D.2 Be in MODE 3. AND D.3 Be in MODE 4.	6 hours 12 hours 36 hours
E~~C~~. HPCI System inoperable.	E~~C~~.1 Verify by administrative means RCIC System is OPERABLE. AND E~~C~~.2 Restore HPCI System to OPERABLE status.	1 hour 14 days OR In accordance with the Risk Informed Completion Time Program
F~~D~~. HPCI System inoperable. AND Condition A entered.	F~~D~~.1 Restore HPCI System to OPERABLE status. OR	72 hours OR In accordance with the Risk Informed Completion Time Program

(continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
F~~D~~. (continued)	F~~D~~.2	Restore low pressure ECCS injection/spray subsystem to OPERABLE status.	72 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program
G~~E~~. Required Action and associated Completion Time of Condition E~~C~~ or F~~D~~ not met.	G~~E~~.1	------------NOTE----------- LCO 3.0.4.a is not applicable when entering MODE 3. -------------------------------- Be in MODE 3.	 12 hours
H~~F~~. Two or more ADS valves inoperable.	H~~F~~.1 <u>AND</u> H~~F~~.2	Be in MODE 3. Reduce reactor steam dome pressure to $\leq$ 150 psig.	12 hours 36 hours
I~~G~~. Two or more low pressure ECCS injection/spray subsystems inoperable for reasons other than Condition A or C. <u>OR</u> HPCI System and two or more ADS valves inoperable.	I~~G~~.1	Enter LCO 3.0.3.	Immediately

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

3.5.3 RCIC System

LCO 3.5.3 The RCIC System shall be OPERABLE.

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

ACTIONS

---NOTE---

LCO 3.0.4.b is not applicable to RCIC.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. RCIC System inoperable.	A.1 Verify by administrative means high pressure coolant injection (HPCI) System is OPERABLE. AND A.2 Restore RCIC System to OPERABLE status.	1 hour 14 days OR In accordance with the Risk Informed Completion Time Program
B. Required Action and associated Completion Time not met.	B.1 ------------NOTE--------- LCO 3.0.4.a is not applicable when entering MODE 3. ------------------------------- Be in MODE 3.	12 hours

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. (continued)	B.3 -----------NOTE------------- Air lock doors in high radiation areas or areas with limited access due to inerting may be verified locked closed by administrative means. -------------------------------- Verify an OPERABLE door is locked closed.	 Once per 31 days
C. Primary containment air lock inoperable for reasons other than Condition A or B.	C.1 Initiate action to evaluate primary containment overall leakage rate per LCO 3.6.1.1, using current air lock test results. AND C.2 Verify a door is closed. AND C.3 Restore air lock to OPERABLE status.	Immediately 1 hour 24 hours OR In accordance with the Risk Informed Completion Time Program
D. Required Action and associated Completion Time not met.	D.1 Be in MODE 3. AND D.2 Be in MODE 4.	12 hours 36 hours

3.6 CONTAINMENT SYSTEMS

3.6.1.3 Primary Containment Isolation Valves (PCIVs)

LCO 3.6.1.3 Each PCIV, except reactor building-to-suppression chamber vacuum breakers, shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

--NOTES--

1. Penetration flow paths except for 18 inch purge valve penetration flow paths may be unisolated intermittently under administrative controls.

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

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

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. -------------NOTE--------------- Only applicable to penetration flow paths with two PCIVs. ----------------------------------- One or more penetration flow paths with one PCIV inoperable except due to leakage not within limit.	A.1 -------------NOTE----------- Not applicable to main steam line. -------------------------------- 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. AND	4 hours ~~except for main steam line~~ OR In accordance with the Risk Informed Completion Time Program ~~AND~~ ~~8 hours for main steam line~~

(continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.2 -------------NOTE----------- Only applicable to main steam line. -------------------------------- 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.	8 hours ~~for main steam line~~ <u>OR</u> In accordance with the Risk Informed Completion Time Program
	<u>AND</u>	
	A.3~~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 administrative means. ----------------------------------- Verify the affected penetration flow path is isolated.	Once per 31 days following isolation for isolation devices outside primary containment <u>AND</u> Prior to entering MODE 2 or 3 from MODE 4 if primary containment was de-inerted while in MODE 4, if not performed within the previous 92 days, for isolation devices inside primary containment

(continued)

ACTIONS (continued)

<table>
<tr><th>CONDITION</th><th>REQUIRED ACTION</th><th>COMPLETION TIME</th></tr>
<tr><td>B. -------------NOTE---------------
Only applicable to penetration flow paths with two PCIVs.

One or more penetration flow paths with two PCIVs inoperable except due to leakage not within limit.</td><td>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.</td><td>1 hour</td></tr>
<tr><td>C. ---------------NOTE-------------
Only applicable to penetration flow paths with only one PCIV.

One or more penetration flow paths with one PCIV inoperable except due to leakage not within limits.</td><td>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.

<u>AND</u>

C.2 -----------NOTES----------
1. Valves and blind flanges 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 administrative means.

Verify the affected penetration flow path is isolated.</td><td>4 hours except for excess flow check valve (EFCV) line and penetrations with a closed system

<u>AND</u>

72 hours for EFCV line and penetrations with a closed system

Once per 31 days following isolation</td></tr>
</table>

3.6 CONTAINMENT SYSTEMS

3.6.2.3 Residual Heat Removal (RHR) Suppression Pool Cooling

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

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One RHR suppression pool cooling subsystem inoperable.	A.1 Restore RHR suppression pool cooling subsystem to OPERABLE status.	7 days OR In accordance with the Risk Informed Completion Time Program
B. Required Action and associated Completion Time of Condition A not met.	B.1 ------------NOTE--------- LCO 3.0.4.a is not applicable when entering MODE 3. ------------------------------- Be in MODE 3.	12 hours
C. Two RHR suppression pool cooling subsystems inoperable.	C.1 Restore one RHR suppression pool cooling subsystem to OPERABLE status.	8 hours
D. Required Action and associated Completion Time of Condition C not met.	D.1 Be in MODE 3. AND D.2 Be in MODE 4.	12 hours 36 hours

3.6 CONTAINMENT SYSTEMS

3.6.2.4 Residual Heat Removal (RHR) Suppression Pool Spray

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

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One RHR suppression pool spray subsystem inoperable.	A.1	Restore RHR suppression pool spray subsystem to OPERABLE status.	7 days OR In accordance with the Risk Informed Completion Time Program
B. Two RHR suppression pool spray subsystems inoperable.	B.1	Restore one RHR suppression pool spray subsystem to OPERABLE status.	8 hours
C. Required Action and associated Completion Time not met.	C.1	------------NOTE--------- LCO 3.0.4.a is not applicable when entering MODE 3. ------------------------------- Be in MODE 3.	12 hours

3.6 CONTAINMENT SYSTEMS

3.6.2.5 Residual Heat Removal (RHR) Drywell Spray

LCO 3.6.2.5 Two RHR drywell spray subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One RHR drywell spray subsystem inoperable.	A.1 Restore RHR drywell spray subsystem to OPERABLE status.	7 days <u>OR</u> In accordance with the Risk Informed Completion Time Program
B. Two RHR drywell spray subsystems inoperable.	B.1 Restore one RHR drywell spray subsystem to OPERABLE status.	8 hours
C. Required Action and associated Completion Time not met.	C.1 --------NOTE-------- LCO 3.0.4.a is not applicable when entering MODE 3. ------------------------ Be in MODE 3.	12 hours

3.7 PLANT SYSTEMS

3.7.1 Residual Heat Removal Service Water (RHRSW) System

LCO 3.7.1 Two RHRSW subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One RHRSW pump inoperable.	A.1 Restore RHRSW pump to OPERABLE status.	30 days
B. One RHRSW pump in each subsystem inoperable.	B.1 Restore one RHRSW pump to OPERABLE status.	7 days OR In accordance with the Risk Informed Completion Time Program
C. One RHRSW subsystem inoperable for reasons other than Condition A.	------------------NOTE------------------ Enter applicable Conditions and Required Actions of LCO 3.4.7, "Residual Heat Removal (RHR) Shutdown Cooling System - Hot Shutdown," for RHR shutdown cooling made inoperable by RHRSW System. -- C.1 Restore RHRSW subsystem to OPERABLE status.	 7 days OR In accordance with the Risk Informed Completion Time Program

(continued)

3.7 PLANT SYSTEMS

3.7.2 Plant Service Water (PSW) System and Ultimate Heat Sink (UHS)

LCO 3.7.2 Two PSW subsystems and UHS shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One PSW pump inoperable.	A.1 Restore PSW pump to OPERABLE status. ~~OR~~ ~~-----NOTES-----~~ ~~1. Only applicable during 1C PSW pump repair.~~ ~~2. Only applicable until October 10, 2021 at 1620 EDT.~~ ~~-----~~ ~~A.2.1 Establish compensatory measures as described in letter NL-21-0862 dated September 23, 2021, Enclosure 5.~~ ~~AND~~ ~~A.2.2 Restore PSW pump to OPERABLE status.~~	30 days ~~30 days~~ ~~45 days~~
B. One PSW turbine building isolation valve inoperable.	B.1 Restore PSW turbine building isolation valve to OPERABLE status.	30 days
C. One PSW pump in each subsystem inoperable.	C.1 Restore one PSW pump to OPERABLE status.	7 days OR In accordance with the Risk Informed Completion Time Program

(continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. One PSW turbine building isolation valve in each subsystem inoperable.	D.1 Restore one PSW turbine building isolation valve 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
E. Required Action and associated Completion Time of Condition A, B, C, or D not met.	E.1 ------------NOTE--------- LCO 3.0.4.a is not applicable when entering MODE 3. ------------------------------- Be in MODE 3.	12 hours
F. One PSW subsystem inoperable for reasons other than Conditions A and B.	----------------NOTES----------------- 1. Enter applicable Conditions and Required Actions of LCO 3.8.1, "AC Sources - Operating," for diesel generator made inoperable by PSW System. 2. Enter applicable Conditions and Required Actions of LCO 3.4.7, "Residual Heat Removal (RHR) Shutdown Cooling System - Hot Shutdown," for RHR shutdown cooling made inoperable by PSW System. ---	
	F.1 Restore the PSW subsystem to OPERABLE status.	72 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program

ACTIONS

---NOTE---

LCO 3.0.4.b is not applicable to DGs.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required offsite circuit inoperable.	A.1 Perform SR 3.8.1.1 for OPERABLE required offsite circuits.	1 hour AND Once per 8 hours thereafter
	AND	
	A.2 Declare required feature(s) with no offsite power available inoperable when the redundant required feature(s) are inoperable.	24 hours from discovery of no offsite power to one 4160 V ESF bus concurrent with inoperability of redundant required feature(s)
	AND	
	A.3 Restore required offsite circuit to OPERABLE status.	72 hours OR In accordance with the Risk Informed Completion Time Program

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. One Unit 1 or the swing DG inoperable.	B.1	Perform SR 3.8.1.1 for OPERABLE required offsite circuit(s).	1 hour AND Once per 8 hours thereafter
	AND		
	B.2	Declare required feature(s), supported by the inoperable DG, inoperable when the redundant required feature(s) are inoperable.	4 hours from discovery of Condition B concurrent with inoperability of redundant required feature(s)
	AND		
	B.3.1	Determine OPERABLE DG(s) are not inoperable due to common cause failure.	24 hours
	OR		
	B.3.2	Perform SR 3.8.1.2.a for OPERABLE DG(s).	24 hours
	AND		
	B.4~~.1~~	Restore DG to OPERABLE status.	72 hours ~~for a Unit 1 DG with the swing DG not inhibited or maintenance restrictions not met~~ OR In accordance with the Risk Informed Completion Time Program

(continued)

~~ACTIONSCONDITION~~	~~REQUIRED ACTION~~	~~COMPLETION TIME~~
~~B. (continued)~~		~~AND~~ ~~14 days for a Unit 1 DG with the swing DG inhibited from automatically aligning to Unit 2 and maintenance restrictions met~~ ~~AND~~ ~~72 hours for the swing diesel with maintenance restrictions not met~~ ~~AND~~ ~~14 days for the swing diesel with maintenance restrictions met~~

~~(continued)~~

~~ACTIONS CONDITION~~	~~REQUIRED ACTION~~	~~COMPLETION TIME~~
~~B. (continued)~~	~~B.4.1 (continued)~~	~~AND~~ ~~14 days for the swing diesel with maintenance restrictions met~~
	~~OR~~	
	~~-----NOTES-----~~ ~~1. Only applicable during diesel engine cylinder liner replacement outage.~~ ~~2. Only applicable once per DG.~~ ~~3. Only applicable until June 30, 2021.~~ ~~----------~~	
	~~B.4.2.1 Establish compensatory and risk management controls for extended DG outage as specified in Attachment 5 of SNC letter NL-20-1000, dated August 23, 2020.~~	~~72 hours~~ ~~AND~~ ~~24 hours thereafter from discovery of compensatory or risk management control not met~~
	~~AND~~	
	~~B.4.2.2 -----NOTE-----~~ ~~Only applicable to Unit 1 DGs (i.e., DG 1A and 1C).~~ ~~----------~~	
	~~Inhibit swing DG from automatically aligning to Unit 2.~~	~~72 hours~~
	~~AND~~	
	~~B.4.2.3 Restore DG to OPERABLE status.~~	~~19 days~~

~~(continued)~~

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One required Unit 2 DG inoperable.	C.1 Perform SR 3.8.1.1 for OPERABLE required offsite circuit(s).	1 hour AND Once per 8 hours thereafter
	AND	
	C.2 Declare required feature(s), supported by the inoperable DG, inoperable when the redundant required feature(s) are inoperable.	4 hours from discovery of Condition C concurrent with inoperability of redundant required feature(s)
	AND	
	C.3.1 Determine OPERABLE DG(s) are not inoperable due to common cause failure.	24 hours
	OR	
	C.3.2 Perform SR 3.8.1.2.a for OPERABLE DG(s).	24 hours
	AND	
	C.4 Restore required DG to OPERABLE status.	7 days ~~with the swing DG not inhibited or maintenance restrictions not met~~ OR In accordance with the Risk Informed Completion Time Program

(continued)

~~ACTIONS (continued)CONDITION~~	~~REQUIRED ACTION~~	~~COMPLETION TIME~~
~~C. (continued)~~		~~AND~~ ~~14 days with the swing DG inhibited from automatically aligning to Unit 1 and maintenance restrictions met~~

~~(continued)~~

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Two or more required offsite circuits inoperable.	D.1 Declare required feature(s) with no offsite power available inoperable when the redundant required feature(s) are inoperable.	12 hours from discovery of Condition D concurrent with inoperability of redundant required feature(s)
	AND	
	D.2 Restore all but one required offsite circuit to OPERABLE status.	24 hours OR In accordance with the Risk Informed Completion Time Program
E. One required offsite circuit inoperable. AND One required DG inoperable.	------------------NOTE------------------ Enter applicable Conditions and Required Actions of LCO 3.8.7, "Distribution Systems - Operating," when Condition E is entered with no AC power source to one 4160 V ESF bus. --	
	E.1 Restore required offsite circuit to OPERABLE status.	12 hours OR In accordance with the Risk Informed Completion Time Program
	OR	
	E.2 Restore required DG to OPERABLE status.	12 hours OR In accordance with the Risk Informed Completion Time Program

(continued)

3.8 ELECTRICAL POWER SYSTEMS

3.8.4 DC Sources - Operating

LCO 3.8.4 The following DC electrical power subsystems shall be OPERABLE:

a. The Unit 1 Division 1 and Division 2 station service DC electrical power subsystems;

b. The Unit 1 and the swing DGs DC electrical power subsystems; and

c. The Unit 2 DG DC electrical power subsystems needed to support the equipment required to be OPERABLE by LCO 3.6.4.3, "Standby Gas Treatment (SGT) System," and LCO 3.8.1, "AC Sources - Operating."

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Swing DG DC electrical power subsystem inoperable due to performance of SR 3.8.4.3 or SR 3.8.6.6. <u>OR</u> One or more required Unit 2 DG DC electrical power subsystems inoperable.	A.1 Restore DG DC electrical power subsystem 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. Required Unit 1 DG DC battery charger on one subsystem inoperable. OR Required swing DG DC battery charger inoperable for reasons other than Condition A.	B.1 Restore battery terminal voltage to greater than or equal to the minimum established float voltage. AND B.2 Verify battery float current is ≤ 5 amps. AND B.3 Restore battery charger(s) to OPERABLE status.	2 hours Once per 12 hours 72 hours OR In accordance with the Risk Informed Completion Time Program
C. One Unit 1 DG DC electrical power subsystem inoperable for reasons other than Condition B. OR Swing DG DC electrical power subsystem inoperable for reasons other than Condition A or B.	C.1 Restore DG DC electrical power subsystem to OPERABLE status.	12 hours OR In accordance with the Risk Informed Completion Time Program

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. One or more required Unit 1 station service DC battery chargers on one subsystem inoperable.	D.1 Restore battery terminal voltage to greater than or equal to the minimum established float voltage.	2 hours
	AND	
	D.2 Verify battery float current is ≤ 20 amps.	Once per 12 hours
	AND	
	D.3 Restore battery charger(s) to OPERABLE status.	72 hours OR In accordance with the Risk Informed Completion Time Program
E. One Unit 1 station service DC electrical power subsystem inoperable for reasons other than Condition D.	E.1 Restore station service DC electrical power subsystem to OPERABLE status.	2 hours OR In accordance with the Risk Informed Completion Time Program
F. Required Action and Associated Completion Time of Condition A, B, C, D, or E not met.	F.1 ------------NOTE--------- LCO 3.0.4.a is not applicable when entering MODE 3. ------------------------------- Be in MODE 3.	12 hours
G. Two or more DC electrical power subsystems inoperable that result in a loss of function.	G.1 Enter LCO 3.0.3.	Immediately

3.8 ELECTRICAL POWER SYSTEMS

3.8.7 Distribution Systems - Operating

LCO 3.8.7 The following AC and DC electrical power distribution subsystems shall be OPERABLE:

a. Unit 1 AC and DC electrical power distribution subsystems comprised of:

1. 4160 V essential buses 1E, 1F, and 1G;
2. 600 V essential buses 1C and 1D;
3. 120/208 V essential cabinets 1A and 1B;
4. 120/208 V instrument buses 1A and 1B;
5. 125/250 V DC station service buses 1A and 1B;
6. DG DC electrical power distribution subsystems;
7. Critical Instrumentation Buses 1A and 1B; and

b. Unit 2 AC and DC electrical power distribution subsystems needed to support equipment required to be OPERABLE by LCO 3.6.4.3, "Standby Gas Treatment (SGT) System," and LCO 3.8.1, "AC Sources - Operating."

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required Unit 2 AC or DC electrical power distribution subsystems inoperable.	A.1 Restore required Unit 2 AC and DC subsystem(s) 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 or more (Unit 1 or swing bus) DG DC electrical power distribution subsystems inoperable.	B.1 Restore DG DC electrical power distribution subsystem to OPERABLE status.	12 hours OR In accordance with the Risk Informed Completion Time Program
C. One or more (Unit 1 or swing bus) AC electrical power distribution subsystems inoperable.	C.1 Restore AC electrical power distribution subsystem to OPERABLE status.	8 hours OR In accordance with the Risk Informed Completion Time Program
D. One Unit 1 station service DC electrical power distribution subsystem inoperable.	D.1 Restore Unit 1 station service DC electrical power distribution subsystem to OPERABLE status.	2 hours OR In accordance with the Risk Informed Completion Time Program
E. Required Action and associated Completion Time of Condition A, B, C, or D not met.	E.1 ------------NOTE----------- LCO 3.0.4.a is not applicable when entering MODE 3. ------------------------------- Be in MODE 3.	12 hours
F. Two or more electrical power distribution subsystems inoperable that result in a loss of function.	F.1 Enter LCO 3.0.3.	Immediately

5.5 Programs and Manuals

5.5.15 Battery Monitoring and Maintenance Program (continued)

4. In Regulatory Guide 1.129, Regulatory Position 3, Subsection 5.4.1, “State of Charge Indicator,” the following statements in paragraph (d) may be omitted: “When it has been recorded that the charging current has stabilized at the charging voltage for three consecutive hourly measurements, the battery is near full charge. These measurements shall be made after the initially high charging current decreases sharply and the battery voltage rises to approach the charger output voltage.”

5. In lieu of RG 1.129, Regulatory Position 7, Subsection 7.6, “Restoration”, the following may be used: “Following the test, record the float voltage of each cell of the string.”

b. The program shall include the following provisions:

1. Actions to restore battery cells with float voltage < 2.13 V;

2. Actions to determine whether the float voltage of the remaining battery cells is ≥ 2.13 V when the float voltage of a battery cell has been found to be < 2.13 V;

3. Actions to equalize and test battery cells that had been discovered with electrolyte level below the top of the plates;

4. Limits on average electrolyte temperature, battery connection resistance, and battery terminal voltage; and

5. A requirement to obtain specific gravity readings of all cells at each discharge test, consistent with manufacturer recommendations.

5.5.16 Risk Informed Completion Time Program

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

a. The RICT may not exceed 30 days;

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

(continued)

5.5 Programs and Manuals

5.5.16 Risk Informed Completion Time Program (continued)

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.

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 used to support this license amendment, 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.

1.3 Completion Times

EXAMPLES (continued)

EXAMPLE 1.3-8

ACTIONS

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

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

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

(continued)

1.3 Completion Times

EXAMPLES

EXAMPLE 1.3-8 (continued)

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

If the RICT expires or is recalculated to be less than the 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.

3.1 REACTIVITY CONTROL SYSTEMS

3.1.7 Standby Liquid Control (SLC) System

LCO 3.1.7 Two SLC subsystems shall be OPERABLE.

APPLICABILITY: MODES 1 and 2.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Sodium pentaborate solution not within Region A limits of Figure 3.1.7-1 or 3.1.7-2, but within the Region B limits.	A.1 Restore sodium pentaborate solution to within Region A limits.	72 hours
B. One SLC subsystem inoperable for reasons other than Condition A.	B.1 Restore SLC subsystem to OPERABLE status.	7 days OR In accordance with the Risk Informed Completion Time Program
C. Two SLC subsystems inoperable for reasons other than Condition A.	C.1 Restore one SLC subsystem to OPERABLE status.	8 hours
D. Required Action and associated Completion Time not met.	D.1 Be in MODE 3.	12 hours

3.3 INSTRUMENTATION

3.3.1.1 Reactor Protection System (RPS) Instrumentation

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

APPLICABILITY: According to Table 3.3.1.1-1.

ACTIONS

---NOTE---

Separate Condition entry is allowed for each channel.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required channels inoperable.	A.1 Place channel in trip. OR	12 hours OR ------------NOTE--------- Not applicable to Functions 7.a, 7.b, and 10. ----------------------------- In accordance with the Risk Informed Completion Time Program
		(continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.2 -----------NOTE------------ Not applicable for Functions 2.a, 2.b, 2.c, 2.d, and 2.f. ------------------------------- Place associated trip system in trip.	12 hours OR ------------NOTE--------- Not applicable to Functions 7.a, 7.b, and 10. ----------------------------- In accordance with the Risk Informed Completion Time Program
B. ---------------NOTE-------------- Not applicable for Functions 2.a, 2.b, 2.c, 2.d, and 2.f. ------------------------------------- One or more Functions with one or more required channels inoperable in both trip systems.	B.1 Place channel in one trip system in trip. OR	6 hours OR ------------NOTE--------- Not applicable to Functions 7.a, 7.b, and 10. ----------------------------- In accordance with the Risk Informed Completion Time Program

(continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. (continued)	B.2	Place one trip system in trip.	6 hours <u>OR</u> ------------NOTE--------- Not applicable to Functions 7.a, 7.b, and 10. ------------------------------ In accordance with the Risk Informed Completion Time Program
C. One or more Functions with RPS trip capability not maintained.	C.1	Restore RPS trip capability.	1 hour
D. Required Action and associated Completion Time of Condition A, B, or C not met.	D.1	Enter the Condition referenced in Table 3.3.1.1-1 for the channel.	Immediately
E. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	E.1	Reduce THERMAL POWER to < 27.6% RTP.	4 hours
F. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	F.1	Be in MODE 2.	6 hours
G. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	G.1	Be in MODE 3.	12 hours

(continued)

3.3 INSTRUMENTATION

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

LCO 3.3.4.1

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

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

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

OR

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

APPLICABILITY: THERMAL POWER ≥ 27.6% RTP.

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more channels inoperable.	A.1 Restore channel to OPERABLE status. OR	72 hours OR In accordance with the Risk Informed Completion Time Program (continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.2 ------------NOTE----------- Not applicable if inoperable channel is the result of an inoperable breaker. ------------------------------- Place channel in trip.	72 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program
B. One or more Functions with EOC-RPT trip capability not maintained. <u>AND</u> MCPR limit for inoperable EOC-RPT not made applicable.	B.1 Restore EOC-RPT trip capability. <u>OR</u> B.2 Apply the MCPR limit for inoperable EOC-RPT as specified in the COLR.	2 hours 2 hours
C. Required Action and associated Completion Time not met.	C.1 Remove the associated recirculation pump from service. <u>OR</u> C.2 Reduce THERMAL POWER to < 27.6% RTP.	4 hours 4 hours

3.3 INSTRUMENTATION

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

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

a. Reactor Vessel Water Level - ATWS-RPT Level; and

b. Reactor Steam Dome Pressure - High.

APPLICABILITY: MODE 1.

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more channels inoperable.	A.1 Restore channel to OPERABLE status. OR	14 days OR In accordance with the Risk Informed Completion Time Program (continued)

ACTIONS

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

ACTIONS

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

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. (continued)	C.2 Restore channel to OPERABLE status.	24 hours <u>OR</u> ------------NOTE--------- Not applicable to Function 3.c. ------------------------------ In accordance with the Risk Informed Completion Time Program
D. As required by Required Action A.1 and referenced in Table 3.3.5.1-1.	D.1 -----------NOTE----------- Only applicable if HPCI pump suction is not aligned to the suppression pool. ------------------------------ Declare HPCI System inoperable.	1 hour from discovery of loss of HPCI initiation capability
	<u>AND</u>	
	D.2.1 Place channel in trip.	24 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program
	<u>OR</u>	
	D.2.2 Align the HPCI pump suction to the suppression pool.	24 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. As required by Required Action A.1 and referenced in Table 3.3.5.1-1.	E.1 ----------NOTE----------- Only applicable for Functions 1.d and 2.g. -------------------------------- Declare supported feature(s) inoperable.	1 hour from discovery of loss of initiation capability for subsystems in both divisions
	<u>AND</u>	
	E.2 Restore channel to OPERABLE status.	7 days <u>OR</u> In accordance with the Risk Informed Completion Time Program

(continued)

3.3 INSTRUMENTATION

3.3.5.3 Reactor Core Isolation Cooling (RCIC) System Instrumentation

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

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

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more channels inoperable.	A.1 Enter the Condition referenced in Table 3.3.5.3-1 for the channel.	Immediately
B. As required by Required Action A.1 and referenced in Table 3.3.5.3-1.	B.1 Declare RCIC System inoperable. AND B.2 Place channel in trip.	1 hour from discovery of loss of RCIC initiation capability 24 hours OR In accordance with the Risk Informed Completion Time Program

(continued)

ACTIONS (continued)

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

3.3 INSTRUMENTATION

3.3.6.1 Primary Containment Isolation Instrumentation

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

APPLICABILITY: According to Table 3.3.6.1-1.

ACTIONS

---NOTES---

1. Penetration flow paths except for 18 inch purge valve penetration flow paths may be unisolated intermittently under administrative controls.
2. Separate Condition entry is allowed for each channel.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required channels inoperable.	A.1 ------------NOTE----------- Only applicable to Functions 2.a, 2.b, 6.b, 7.a, and 7.b. -------------------------------	
	Place channel in trip.	12 hours ~~for Functions 2.a, 2.b, 6.b, 7.a, and 7.b~~ ~~AND~~ ~~24 hours for Functions other than Functions 2.a, 2.b, 6.b, 7.a, and 7.b~~ OR ------------NOTE--------- Not applicable to Functions 6.b, 7.a, and 7.b. ------------------------------ In accordance with the Risk Informed Completion Time Program
	AND	

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
A.2 (continued)	A.2 ------------NOTE----------- Not applicable to Functions 2.a, 2.b, 6.b, 7.a, and 7.b. ------------------------------- Place channel in trip.	24 hours <u>OR</u> ------------NOTE--------- Not applicable to Functions 2.c, 2.d, 2.e, and 6.a. ------------------------------ In accordance with the Risk Informed Completion Time Program
B. --------------NOTE-------------- Not applicable for Function 5.c. ------------------------------------ One or more automatic Functions with isolation capability not maintained.	B.1 Restore isolation capability.	1 hour
C. Required Action and associated Completion Time of Condition A or B not met.	C.1 Enter the Condition referenced in Table 3.3.6.1-1 for the channel.	Immediately
D. As required by Required Action C.1 and referenced in Table 3.3.6.1-1.	D.1 Isolate associated main steam line (MSL).	12 hours
	<u>OR</u>	
	D.2.1 Be in MODE 3.	12 hours
	<u>AND</u>	
	D.2.2 Be in MODE 4.	36 hours

(continued)

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

3.5.1 ECCS - Operating

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

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

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One low pressure ECCS injection/spray subsystem inoperable. OR One LPCI pump in both LPCI subsystems inoperable.	A.1 Restore low pressure ECCS injection/spray subsystem(s) to OPERABLE status. ~~OR~~ ~~-----NOTES-----~~ ~~1. Only applicable during 2D RHR pump repair.~~ ~~2. Only applicable until May 1, 2021.~~ ~~----------~~	7 days OR In accordance with the Risk Informed Completion Time Program
	~~A.2.1 Establish compensatory measures as described in letter NL-21-0423, dated April 22, 2021.~~ ~~AND~~	~~7 days~~
	~~A.2.2 Restore low pressure ECCS injection/spray subsystem(s) to OPERABLE status.~~	~~15 days~~

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One LPCI pump in one subsystem or one LPCI pump in both LPCI subsystems inoperable. AND One CS subsystem inoperable.	C.1 Restore low pressure ECCS injection/spray subsystem(s) to OPERABLE status.	1 hour OR In accordance with the Risk Informed Completion Time Program
D. Required Action and associated Completion Time of Condition C not met.	D.1 Be in MODE 2. AND D.2 Be in MODE 3. AND D.3 Be in MODE 4.	6 hours 12 hours 36 hours
E~~C~~. HPCI System inoperable.	E~~C~~.1 Verify by administrative means RCIC System is OPERABLE. AND E~~C~~.2 Restore HPCI System to OPERABLE status.	1 hour 14 days OR In accordance with the Risk Informed Completion Time Program
F~~D~~. HPCI System inoperable. AND Condition A entered.	F~~D~~.1 Restore HPCI System to OPERABLE status. OR	72 hours OR In accordance with the Risk Informed Completion Time Program

(continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
F~~D~~. (continued)	F~~D~~.2 Restore low pressure ECCS injection/spray subsystem to OPERABLE status.	72 hours OR In accordance with the Risk Informed Completion Time Program
G~~E~~. Required Action and associated Completion Time of Condition E~~C~~ or F~~D~~ not met.	G~~E~~.1 ------------NOTE----------- LCO 3.0.4.a is not applicable when entering MODE 3. -------------------------------- Be in MODE 3.	 12 hours
H~~F~~. Two or more ADS valves inoperable.	H~~F~~.1 Be in MODE 3. AND H~~F~~.2 Reduce reactor steam dome pressure to ≤ 150 psig.	12 hours 36 hours
I~~G~~. Two or more low pressure ECCS injection/spray subsystems inoperable for reasons other than Condition A or C. OR HPCI System and two or more ADS valves inoperable.	I~~G~~.1 Enter LCO 3.0.3.	Immediately

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

3.5.3 RCIC System

LCO 3.5.3 The RCIC System shall be OPERABLE.

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

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. RCIC System inoperable.	A.1 Verify by administrative means high pressure coolant injection (HPCI) System is OPERABLE. AND A.2 Restore RCIC System to OPERABLE status.	1 hour 14 days OR In accordance with the Risk Informed Completion Time Program
B. Required Action and associated Completion Time not met.	B.1 ------------NOTE----------- LCO 3.0.4.a is not applicable when entering MODE 3. -------------------------------- Be in MODE 3.	12 hours

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. (continued)	B.3	------------NOTE------------ Air lock doors in high radiation areas or areas with limited access due to inerting may be verified locked closed by administrative means. -------------------------------- Verify an OPERABLE door is locked closed.	 Once per 31 days
C. Primary containment air lock inoperable for reasons other than Condition A or B.	C.1	Initiate action to evaluate primary containment overall leakage rate per LCO 3.6.1.1, using current air lock test results.	Immediately
	AND		
	C.2	Verify a door is closed.	1 hour
	AND		
	C.3	Restore air lock to OPERABLE status.	24 hours OR In accordance with the Risk Informed Completion Time Program
D. Required Action and associated Completion Time not met.	D.1	Be in MODE 3.	12 hours
	AND		
	D.2	Be in MODE 4.	36 hours

3.6 CONTAINMENT SYSTEMS

3.6.1.3 Primary Containment Isolation Valves (PCIVs)

LCO 3.6.1.3 Each PCIV, except reactor building-to-suppression chamber vacuum breakers, shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

--NOTES--

1. Penetration flow paths except for 18 inch purge valve penetration flow paths may be unisolated intermittently under administrative controls.

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

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

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. --------------NOTE--------------- Only applicable to penetration flow paths with two PCIVs. ------------------------------------- One or more penetration flow paths with one PCIV inoperable except due to leakage not within limit.	A.1 -------------NOTE----------- Not applicable to main steam line. -------------------------------- 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. AND	4 hours ~~except for main steam line~~ OR In accordance with the Risk Informed Completion Time Program ~~AND~~ ~~8 hours for main steam line~~

(continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. (continued)	A.2 -------------NOTE----------- Only applicable to main steam line. -------------------------------- 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.	8 hours ~~for main steam line~~ <u>OR</u> In accordance with the Risk Informed Completion Time Program
	<u>AND</u>	
	A.3~~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 administrative means. ----------------------------------- Verify the affected penetration flow path is isolated.	Once per 31 days following isolation for isolation devices outside primary containment <u>AND</u> Prior to entering MODE 2 or 3 from MODE 4 if primary containment was de-inerted while in MODE 4, if not performed within the previous 92 days, for isolation devices inside primary containment

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. --------------NOTE--------------- Only applicable to penetration flow paths with two PCIVs. ------------------------------------- One or more penetration flow paths with two PCIVs inoperable except due to leakage not within limit.	B.1 Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, or blind flange.	1 hour
C. --------------NOTE--------------- Only applicable to penetration flow paths with only one PCIV. ------------------------------------- One or more penetration flow paths with one PCIV inoperable except due to leakage not within limits.	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.	4 hours except for excess flow check valve (EFCV) line and penetrations with a closed system <u>AND</u> 72 hours for EFCV line and penetrations with a closed system
	<u>AND</u>	
	C.2 ----------NOTES----------- 1. Valves and blind flanges 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 administrative means. ------------------------------- Verify the affected penetration flow path is isolated.	Once per 31 days following isolation

3.6 CONTAINMENT SYSTEMS

3.6.2.3 Residual Heat Removal (RHR) Suppression Pool Cooling

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

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One RHR suppression pool cooling subsystem inoperable.	A.1 Restore RHR suppression pool cooling subsystem to OPERABLE status.	7 days OR In accordance with the Risk Informed Completion Time Program
B. Required Action and associated Completion Time of Condition A not met.	B.1 ------------NOTE--------- LCO 3.0.4.a is not applicable when entering MODE 3. -------------------------------- Be in MODE 3.	 12 hours
C. Two RHR suppression pool cooling subsystems inoperable.	C.1 Restore one RHR suppression pool cooling subsystem to OPERABLE status.	8 hours
D. Required Action and associated Completion Time of Condition C not met.	D.1 Be in MODE 3. AND D.2 Be in MODE 4.	12 hours 36 hours

3.6 CONTAINMENT SYSTEMS

3.6.2.4 Residual Heat Removal (RHR) Suppression Pool Spray

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

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One RHR suppression pool spray subsystem inoperable.	A.1 Restore RHR suppression pool spray subsystem to OPERABLE status.	7 days OR In accordance with the Risk Informed Completion Time Program
B. Two RHR suppression pool spray subsystems inoperable.	B.1 Restore one RHR suppression pool spray subsystem to OPERABLE status.	8 hours
C. Required Action and associated Completion Time not met.	C.1 ------------NOTE--------- LCO 3.0.4.a is not applicable when entering MODE 3. -------------------------------- Be in MODE 3.	12 hours

3.6 CONTAINMENT SYSTEMS

3.6.2.5 Residual Heat Removal (RHR) Drywell Spray

LCO 3.6.2.5 Two RHR drywell spray subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One RHR drywell spray subsystem inoperable.	A.1	Restore RHR drywell spray subsystem to OPERABLE status.	7 days <u>OR</u> In accordance with the Risk Informed Completion Time Program
B. Two RHR drywell spray subsystems inoperable.	B.1	Restore one RHR drywell spray subsystem to OPERABLE status.	8 hours
C. Required Action and associated Completion Time not met.	C.1	---------NOTE------- LCO 3.0.4.a is not applicable when entering MODE 3. ------------------------ Be in MODE 3.	12 hours

3.7 PLANT SYSTEMS

3.7.1 Residual Heat Removal Service Water (RHRSW) System

LCO 3.7.1 Two RHRSW subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One RHRSW pump inoperable.	A.1 Restore RHRSW pump to OPERABLE status.	30 days
B. One RHRSW pump in each subsystem inoperable.	B.1 Restore one RHRSW pump to OPERABLE status.	7 days <u>OR</u> In accordance with the Risk Informed Completion Time Program
C. One RHRSW subsystem inoperable for reasons other than Condition A.	------------------NOTE------------------ Enter applicable Conditions and Required Actions of LCO 3.4.7, "Residual Heat Removal (RHR) Shutdown Cooling System - Hot Shutdown," for RHR shutdown cooling made inoperable by RHRSW System. -- C.1 Restore RHRSW subsystem to OPERABLE status.	 7 days <u>OR</u> In accordance with the Risk Informed Completion Time Program

(continued)

3.7 PLANT SYSTEMS

3.7.2 Plant Service Water (PSW) System and Ultimate Heat Sink (UHS)

LCO 3.7.2 Two PSW subsystems and UHS shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One PSW pump inoperable.	A.1 Restore PSW pump to OPERABLE status.	30 days
B. One PSW turbine building isolation valve inoperable.	B.1 Restore PSW turbine building isolation valve to OPERABLE status.	30 days
C. One PSW pump in each subsystem inoperable.	C.1 Restore one PSW pump to OPERABLE status.	7 days <u>OR</u> In accordance with the Risk Informed Completion Time Program
D. One PSW turbine building isolation valve in each subsystem inoperable.	D.1 Restore one PSW turbine building isolation valve 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
E. Required Action and associated Completion Time of Condition A, B, C, or D not met.	E.1 ------------NOTE----------- LCO 3.0.4.a is not applicable when entering MODE 3. -------------------------------- Be in MODE 3.	 12 hours
F. One PSW subsystem inoperable for reasons other than Conditions A and B.	-----------------NOTES---------------- 1. Enter applicable Conditions and Required Actions of LCO 3.8.1, "AC Sources - Operating," for diesel generator made inoperable by PSW System. 2. Enter applicable Conditions and Required Actions of LCO 3.4.7, "Residual Heat Removal (RHR) Shutdown Cooling System - Hot Shutdown," for RHR shutdown cooling made inoperable by PSW System. --- F.1 Restore the PSW subsystem to OPERABLE status.	72 hours OR In accordance with the Risk Informed Completion Time Program

(continued)

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required offsite circuit inoperable.	A.1 Perform SR 3.8.1.1 for OPERABLE required offsite circuits.	1 hour <u>AND</u> Once per 8 hours thereafter
	<u>AND</u>	
	A.2 Declare required feature(s) with no offsite power available inoperable when the redundant required feature(s) are inoperable.	24 hours from discovery of no offsite power to one 4160 V ESF bus concurrent with inoperability of redundant required feature(s)
	<u>AND</u>	
	A.3 Restore required offsite circuit 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
B. One Unit 2 or the swing DG inoperable.	B.1	Perform SR 3.8.1.1 for OPERABLE required offsite circuit(s).	1 hour AND Once per 8 hours thereafter
	AND		
	B.2	Declare required feature(s), supported by the inoperable DG, inoperable when the redundant required feature(s) are inoperable.	4 hours from discovery of Condition B concurrent with inoperability of redundant required feature(s)
	AND		
	B.3.1	Determine OPERABLE DG(s) are not inoperable due to common cause failure.	24 hours
	OR		
	B.3.2	Perform SR 3.8.1.2.a for OPERABLE DG(s)	24 hours
	AND		
	B.4~~.1~~	Restore DG to OPERABLE status.	72 hours ~~for a Unit 2 DG with the swing DG not inhibited or maintenance restrictions not met~~ OR In accordance with the Risk Informed Completion Time Program

(continued)

~~CONDITION~~	~~REQUIRED ACTION~~	~~COMPLETION TIME~~
~~B. (continued)~~		~~AND~~ ~~14 days for a Unit 2 DG with the swing DG inhibited from automatically aligning to Unit 1 and maintenance restrictions met~~ ~~AND~~ ~~72 hours for the swing diesel with maintenance restrictions not met~~ ~~AND~~ ~~14 days for the swing diesel with maintenance restrictions met~~

~~(continued)~~

~~CONDITION~~	~~REQUIRED ACTION~~	~~COMPLETION TIME~~
~~B. (continued)~~	~~B.4.1 (continued)~~ ~~OR~~ ~~-----NOTES-----~~ ~~1. Only applicable during diesel engine cylinder liner replacement outage of Unit 1 DGs (i.e., DGs 1A and 1C) or swing DG (i.e., DG 1B).~~ ~~2. Only applicable to swing DG.~~ ~~3. Only applicable until June 30, 2021.~~	~~AND~~ ~~14 days for the swing diesel with maintenance restrictions met~~

	~~--~~	
	~~B.4.2.1 Establish compensatory and risk management controls for extended DG outage as specified in Attachment 5 of SNC letter NL-20-1000, dated August 23, 2020.~~	~~72 hours~~ ~~AND~~ ~~24 hours thereafter from discovery of compensatory or risk management control not met~~
	~~AND~~	
	~~B.4.2.2 Restore DG to OPERABLE status.~~	~~19 days~~

~~(continued)~~

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. One required Unit 1 DG inoperable.	C.1 Perform SR 3.8.1.1 for OPERABLE required offsite circuit(s).	1 hour <u>AND</u> Once per 8 hours thereafter
	<u>AND</u>	
	C.2 Declare required feature(s), supported by the inoperable DG, inoperable when the redundant required feature(s) are inoperable.	4 hours from discovery of Condition C concurrent with inoperability of redundant required feature(s)
	<u>AND</u>	
	C.3.1 Determine OPERABLE DG(s) are not inoperable due to common cause failure.	24 hours
	<u>OR</u>	
	C.3.2 Perform SR 3.8.1.2.a for OPERABLE DG(s).	24 hours
	<u>AND</u>	
	C.4 Restore required DG to OPERABLE status.	7 days ~~with the swing DG not inhibited or maintenance restrictions not met~~ <u>OR</u> In accordance with the Risk Informed Completion Time Program

(continued)

~~CONDITION~~	~~REQUIRED ACTION~~	~~COMPLETION TIME~~
~~C. (continued)~~		~~AND~~
	~~OR~~	~~14 days with the swing DG inhibited from automatically aligning to Unit 2 and maintenance restrictions met~~
	~~NOTES~~ ~~1. Only applicable during diesel engine cylinder liner replacement outage.~~ ~~2. Only applicable once per DG.~~ ~~3. Only applicable until June 30, 2021.~~	
	~~C.4.2.1 Establish compensatory and risk management controls for extended DG outage as specified in Attachment 5 of SNC letter NL-20-1000, dated August 23, 2020.~~	~~7 days~~
	~~AND~~	~~AND~~
	~~C.4.2.2 Inhibit swing DG from automatically aligning to Unit 2.~~	~~24 hours thereafter from discovery of compensatory or risk management control not met~~
	~~AND~~	
	~~C.4.2.3 Restore DG to OPERABLE status.~~	~~7 days~~
		~~19 days~~

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Two or more required offsite circuits inoperable.	D.1 Declare required feature(s) with no offsite power available inoperable when the redundant required feature(s) are inoperable. AND D.2 Restore all but one required offsite circuit to OPERABLE status.	12 hours from discovery of Condition D concurren with inoperability of redundant required feature(s) 24 hours OR In accordance with the Risk Informed Completion Time Program
E. One required offsite circuit inoperable. AND One required DG inoperable.	-------------------NOTE----------------- Enter applicable Conditions and Required Actions of LCO 3.8.7, "Distribution Systems - Operating," when Condition E is entered with no AC power source to one 4160 V ESF bus. -- E.1 Restore required offsite circuit to OPERABLE status. OR E.2 Restore required DG to OPERABLE status.	 12 hours OR In accordance with the Risk Informed Completion Time Program 12 hours OR In accordance with the Risk Informed Completion Time Program

(continued)

3.8 ELECTRICAL POWER SYSTEMS

3.8.4 DC Sources - Operating

LCO 3.8.4 The following DC electrical power subsystems shall be OPERABLE:

a. The Unit 2 Division 1 and Division 2 station service DC electrical power subsystems;

b. The Unit 2 and the swing DGs DC electrical power subsystems; and

c. The Unit 1 DG DC electrical power subsystems needed to support the equipment required to be OPERABLE by LCO 3.6.4.3, "Standby Gas Treatment (SGT) System"; LCO 3.7.4, "Main Control Room Environmental Control (MCREC) System"; LCO 3.7.5, "Control Room Air Conditioning (AC) System"; and LCO 3.8.1, "AC Sources - Operating."

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Swing DG DC electrical power subsystem inoperable due to performance of SR 3.8.4.3 or SR 3.8.6.6. OR One or more required Unit 1 DG DC electrical power subsystems inoperable.	A.1 Restore DG DC electrical power subsystem to OPERABLE status.	7 days OR In accordance with the Risk Informed Completion Time Program

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. Required Unit 2 DG DC battery charger on one subsystem inoperable. <u>OR</u> Required swing DG DC battery charger inoperable for reasons other than Condition A.	B.1 Restore battery terminal voltage to greater than or equal to the minimum established float voltage. <u>AND</u> B.2 Verify battery float current is ≤ 5 amps. <u>AND</u> B.3 Restore battery charger(s) to OPERABLE status.	2 hours Once per 12 hours 72 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program
C. One Unit 2 DG DC electrical power subsystem inoperable for reasons other than Condition B. <u>OR</u> Swing DG DC electrical power subsystem inoperable for reasons other than Condition A or B.	C.1 Restore DG DC electrical power subsystem to OPERABLE status.	12 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. One or more required Unit 2 station service DC battery chargers on one subsystem inoperable.	D.1 Restore battery terminal voltage to greater than or equal to the minimum established float voltage. AND D.2 Verify battery float current is ≤ 20 amps. AND D.3 Restore battery charger(s) to OPERABLE status.	2 hours Once per 12 hours 72 hours OR In accordance with the Risk Informed Completion Time Program
E. One Unit 2 station service DC electrical power subsystem inoperable for reasons other than Condition D.	E.1 Restore station service DC electrical power subsystem to OPERABLE status.	2 hours OR In accordance with the Risk Informed Completion Time Program
F. Required Action and Associated Completion Time of Condition A, B, C, D, or E not met.	F.1 ------------NOTE--------- LCO 3.0.4.a is not applicable when entering MODE 3. -------------------------------- Be in MODE 3.	 12 hours
G. Two or more DC electrical power subsystems inoperable that result in a loss of function.	G.1 Enter LCO 3.0.3.	Immediately

3.8 ELECTRICAL POWER SYSTEMS

3.8.7 Distribution Systems - Operating

LCO 3.8.7 The following AC and DC electrical power distribution subsystems shall be OPERABLE:

a. Unit 2 AC and DC electrical power distribution subsystems comprised of:

1. 4160 V essential buses 2E, 2F, and 2G;
2. 600 V essential buses 2C and 2D;
3. 120/208 V essential cabinets 2A and 2B;
4. 120/208 V instrument buses 2A and 2B;
5. 125/250 V DC station service buses 2A and 2B;
6. DG DC electrical power distribution subsystems;
7. Critical instrumentation Buses 2A and 2B; and

b. Unit 1 AC and DC electrical power distribution subsystems needed to support equipment required to be OPERABLE by LCO 3.6.4.3, "Standby Gas Treatment (SGT) System"; LCO 3.7.4, "Main Control Room Environmental Control (MCREC) System"; LCO 3.7.5, "Control Room Air Conditioning (AC) System"; and LCO 3.8.1, "AC Sources - Operating."

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required Unit 1 AC or DC electrical power distribution subsystems inoperable.	A.1 Restore required Unit 1 AC and DC subsystem(s) 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 or more (Unit 2 or swing bus) DG DC electrical power distribution subsystems inoperable.	B.1 Restore DG DC electrical power distribution subsystem to OPERABLE status.	12 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program
C. One or more (Unit 2 or swing bus) AC electrical power distribution subsystems inoperable.	C.1 Restore AC electrical power distribution subsystem to OPERABLE status.	8 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program
D. One Unit 2 station service DC electrical power distribution subsystem inoperable.	D.1 Restore Unit 2 station service DC electrical power distribution subsystem to OPERABLE status.	2 hours <u>OR</u> In accordance with the Risk Informed Completion Time Program
E. Required Action and associated Completion Time of Condition A, B, C, or D not met.	E.1 ------------NOTE--------- LCO 3.0.4.a is not applicable when entering MODE 3. -------------------------------- Be in MODE 3.	 12 hours
F. Two or more electrical power distribution subsystems inoperable that result in a loss of function.	F.1 Enter LCO 3.0.3.	Immediately

5.5 Programs and Manuals

5.5.15 Battery Monitoring and Maintenance Program (continued)

4. In Regulatory Guide 1.129, Regulatory Position 3, Subsection 5.4.1, "State of Charge Indicator," the following statements in paragraph (d) may be omitted: "When it has been recorded that the charging current has stabilized at the charging voltage for three consecutive hourly measurements, the battery is near full charge. These measurements shall be made after the initially high charging current decreases sharply and the battery voltage rises to approach the charger output voltage."

5. In lieu of RG 1.129, Regulatory Position 7, Subsection 7.6, "Restoration", the following may be used: "Following the test, record the float voltage of each cell of the string."

b. The program shall include the following provisions:

1. Actions to restore battery cells with float voltage < 2.13 V;

2. Actions to determine whether the float voltage of the remaining battery cells is ≥ 2.13 V when the float voltage of a battery cell has been found to be < 2.13 V;

3. Actions to equalize and test battery cells that had been discovered with electrolyte level below the top of the plates;

4. Limits on average electrolyte temperature, battery connection resistance, and battery terminal voltage; and

5. A requirement to obtain specific gravity readings of all cells at each discharge test, consistent with manufacturer recommendations.

5.5.16 Risk Informed Completion Time Program

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

a. The RICT may not exceed 30 days;

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

(continued)

5.5 Programs and Manuals

5.5.16 Risk Informed Completion Time Program (continued)

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.

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 used to support this license amendment, 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.

Edwin I. Hatch Nuclear Plant - Units 1 and 2
License Amendment Request to Revise Technical Specifications
to Adopt Risk Informed Completion Times TSTF-505, Revision 2,
"Provide Risk-Informed Extended Completion Times - RITSTF Initiative 4b"

Attachment 3

Proposed Technical Specification Bases Changes (Mark-Up) - For Information Only

BASES (continued)

ACTIONS

A.1

If the sodium pentaborate solution concentration is not within the 10 CFR 50.62 limits (not within Region A of Figure 3.1.7-1 or 3.1.7-2), but greater than original licensing basis limits (within Region B of Figure 3.1.7-1 or 3.1.7-2), the solution must be restored to within Region A limits in 72 hours. It should be noted that the lowest acceptable concentration in Region B is 5%. It is not necessary under these conditions to enter Condition C for both SLC subsystems inoperable, since the SLC subsystems are capable of performing their original design basis functions. Because of the low probability of an event and the fact that the SLC System capability still exists for vessel injection under these conditions, the allowed Completion Time of 72 hours is acceptable and provides adequate time to restore concentration to within limits.

B.1

If one SLC subsystem is inoperable for reasons other than Condition A, the inoperable subsystem must be restored to OPERABLE status within 7 days or in accordance with the Risk Informed Completion Time Program. In this condition, the remaining OPERABLE subsystem is adequate to perform the shutdown function and provide adequate buffering agent to the suppression pool. However, the overall reliability is reduced because a single failure in the remaining OPERABLE subsystem could result in reduced SLC System capability. The 7 day Completion Time is based on the availability of an OPERABLE subsystem capable of performing the

(continued)

BASES

ACTIONS (continued)

discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable RPS instrumentation channels provide appropriate compensatory measures for separate inoperable channels. As such, a Note has been provided that allows separate Condition entry for each inoperable RPS instrumentation channel.

A.1 and A.2

Because of the diversity of sensors available to provide trip signals and the redundancy of the RPS design, an allowable out of service time of 12 hours has been shown to be acceptable (Refs. 9, 12, and 16) to permit restoration of any inoperable channel to OPERABLE status. However, this out of service time is only acceptable provided the associated Function's inoperable channel is in one trip system and the Function still maintains RPS trip capability (refer to Required Actions B.1, B.2, and C.1 Bases). Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time (RICT) Program. The alternative Completion Times in Required Action A.1 and Required Action A.2 are modified by a Note which excludes use of the RICT Program for Functions 7.a, 7.b, and 10 since these functions are not modeled in the plant PRA.

If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel or the associated trip system must be placed in the tripped condition per Required Actions A.1 and A.2. Placing the inoperable channel in trip (or the associated trip system in trip) would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. Alternatively, if it is not desired to place the channel (or trip system) in trip (e.g., as in the case where placing the inoperable channel in trip would result in a full scram), Condition D must be entered and its Required Action taken.

As noted, Required Action A.2 is not applicable for APRM Functions 2.a, 2.b, 2.c, 2.d and 2.f. Inoperability of one required APRM channel affects both trip systems; thus, Required Action A.1 must be satisfied. This is the only action (other than restoring OPERABILITY) that will restore capability to accommodate a single failure. Inoperability of more than one required APRM channel of the same trip function results in loss of trip capability and entry into Condition C, as well as entry into Condition A for each channel.

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

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

Required Actions B.1 and B.2 limit the time the RPS scram logic, for any Function, would not accommodate single failure in both trip systems (e.g., one-out-of-one and one-out-of-one arrangement for a typical four channel Function). The reduced reliability of this logic arrangement was not evaluated in References 9, 12, and 16 for the 12 hour Completion Time. Within the 6 hour allowance, the associated Function will have all required channels OPERABLE or in trip (or any combination) in one trip system.

Completing one of these Required Actions restores RPS to a reliability level equivalent to that evaluated in References 9, 12, and 16 which justified a 12 hour allowable out of service time as presented in Condition A. The trip system in the more degraded state should be placed in trip or, alternatively, all the inoperable channels in that trip system should be placed in trip (e.g., a trip system with two inoperable channels could be in a more degraded state than a trip system with four inoperable channels if the two inoperable channels are in the same Function while the four inoperable channels are all in different Functions). The decision of which trip system is in the more degraded state should be based on prudent judgment and take into account current plant conditions (i.e., what MODE the plant is in). If this action would result in a scram or RPT, it is permissible to place the other trip system or its inoperable channels in trip.

The 6 hour Completion Time is judged acceptable based on the remaining capability to trip, the diversity of the sensors available to provide the trip signals, the low probability of extensive numbers of inoperabilities affecting all diverse Functions, and the low probability of an event requiring the initiation of a scram. Alternatively, a Completion Time can be determined in accordance with the RICT Program. The alternative Completion Times in Required Action B.1 and Required Action B.2 are modified by a Note which excludes use of the RICT Program for Functions 7.a, 7.b, and 10 since these functions are not modeled in the plant PRA.

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

(continued)

BASES (continued)

ACTIONS

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

A.1 and A.2

With one or more channels inoperable, but with EOC-RPT trip capability maintained (refer to Required Actions B.1 and B.2 Bases), the EOC-RPT System is capable of performing the intended function. However, the reliability and redundancy of the EOC-RPT instrumentation is reduced such that a single failure in the remaining trip system could result in the inability of the EOC-RPT System to perform the intended function. Therefore, only a limited time is allowed to restore compliance with the LCO. Because of the diversity of sensors available to provide trip signals, the low probability of extensive numbers of inoperabilities affecting all diverse Functions, and the low probability of an event requiring the initiation of an EOC-RPT, 72 hours is provided to restore the inoperable channels (Required Action A.1) or apply the EOC-RPT inoperable MCPR limit. Alternately, the inoperable channels may be placed in trip (Required Action A.2), since this would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. As noted, placing the channel in trip with no further restrictions is not allowed if the inoperable channel is the result of an inoperable breaker, since this may not adequately compensate for the inoperable breaker (e.g., the breaker may be inoperable such that it will not open). Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program. If it is not desired to place the channel in trip (e.g., as in the case where placing the inoperable channel in trip would result in an RPT, or if the inoperable channel is the result of an inoperable breaker), Condition C must be entered and its Required Actions taken.

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

trip system could result in the inability of the ATWS-RPT System to perform the intended function. Therefore, only a limited time is allowed to restore the inoperable channels to OPERABLE status. Because of the diversity of sensors available to provide trip signals, the low probability of extensive numbers of inoperabilities affecting all diverse Functions, and the low probability of an event requiring the initiation of ATWS-RPT, 14 days is provided to restore the inoperable channel (Required Action A.1). Alternately, the inoperable channel may be placed in trip (Required Action A.2), since this would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. As noted, placing the channel in trip with no further restrictions is not allowed if the inoperable channel is the result of an inoperable breaker, since this may not adequately compensate for the inoperable breaker (e.g., the breaker may be inoperable such that it will not open). Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program. If it is not desired to place the channel in trip (e.g., as in the case where placing the inoperable channel would result in an RPT), or if the inoperable channel is the result of an inoperable breaker, Condition D must be entered and its Required Actions taken.

B.1

Required Action B.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same Function result in the Function not maintaining ATWS-RPT trip capability. A Function is considered to be maintaining ATWS-RPT trip capability when sufficient channels are OPERABLE or in trip such that the ATWS-RPT System will generate a trip signal from the given Function on a valid signal, and both recirculation pumps can be tripped.

The 72 hour Completion Time is sufficient for the operator to take corrective action (e.g., restoration or tripping of channels) and takes into account the likelihood of an event requiring actuation of the ATWS-RPT instrumentation during this period and that one Function is still maintaining ATWS-RPT trip capability.

C.1

Required Action C.1 is intended to ensure that appropriate Actions are taken if multiple, inoperable, untripped channels within both Functions

(continued)

ACTIONS

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

Notes are also provided (the Note to Required Action B.1 and the Note to Required Action B.2) to delineate which Required Action is applicable for each Function that requires entry into Condition B if an associated channel is inoperable. This ensures that the proper loss of initiation capability check is performed. Required Action B.1 (the Required Action for certain inoperable channels in the low pressure ECCS subsystems) is not applicable to Function 2.e, since this Function provides backup to administrative controls ensuring that operators do not divert LPCI flow from injecting into the core when needed. Thus, a total loss of Function 2.e capability for 24 hours is allowed, since the LPCI subsystems remain capable of performing their intended function.

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." For Required Action B.1, the Completion Time only begins upon discovery that features in the same system (e.g., both CS subsystems) cannot be automatically initiated due to inoperable, untripped channels within the same Function as described in the paragraph above. For Required Action B.2, the Completion Time only begins upon discovery that the HPCI System cannot be automatically initiated due to inoperable, untripped channels for the associated Function as described in the paragraph above. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

Because of the diversity of sensors available to provide initiation signals and the redundancy of the ECCS design, an allowable out of service time of 24 hours has been shown to be acceptable (Ref. 5) to permit restoration of any inoperable channel to OPERABLE status. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program. The alternative Completion Time in Required Action B.3 is modified by a Note which excludes use of the RICT Program for Function 2.e since this function is not modeled in the plant PRA. If

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

The Note states that Required Action C.1 is only applicable for Functions 1.c, 2.c, 2.d, and 2.f. Required Action C.1 is not applicable to Function 3.c (which also requires entry into this Condition if a channel in this Function is inoperable), since the loss of one channel results in a loss of the Function (two-out-of-two logic). This loss was considered during the development of Reference 5 and considered acceptable for the 24 hours allowed by Required Action C.2.

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." For Required Action C.1, the Completion Time only begins upon discovery that the same feature in both subsystems (e.g., both CS subsystems) cannot be automatically initiated due to inoperable channels within the same Function as described in the paragraph above. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration of channels.

Because of the diversity of sensors available to provide initiation signals and the redundancy of the ECCS design, an allowable out of service time of 24 hours has been shown to be acceptable (Ref. 5) to permit restoration of any inoperable channel to OPERABLE status. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program. The alternative Completion Time in Required Action C.2 is modified by a Note which excludes use of the RICT Program for Function 3.c. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, Condition H must be entered and its Required Action taken. The Required Actions do not allow placing the channel in trip since this action would either cause the initiation or it would not necessarily result in a safe state for the channel in all events.

D.1, D.2.1, and D.2.2

Required Action D.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same Function result in a complete loss of automatic component initiation capability for the HPCI System. In this situation (loss of automatic

(continued)

ACTIONS

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

suction swap), the 24 hour allowance of Required Actions D.2.1 and D.2.2 is not appropriate and the HPCI System must be declared inoperable within 1 hour after discovery of loss of HPCI initiation capability. As noted, Required Action D.1 is only applicable if the HPCI pump suction is not aligned to the suppression pool, since, if aligned, the Function is already performed.

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." For Required Action D.1, the Completion Time only begins upon discovery that the HPCI System cannot be automatically aligned to the suppression pool due to inoperable, untripped channels in the same Function as described in the paragraph above. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

Because of the diversity of sensors available to provide initiation signals and the redundancy of the ECCS design, an allowable out of service time of 24 hours has been shown to be acceptable (Ref. 5) to permit restoration of any inoperable channel to OPERABLE status. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be placed in the tripped condition per Required Action D.2.1 or the suction source must be aligned to the suppression pool within 24 hours per Required Action D.2.2. Placing the inoperable channel in trip performs the intended function of the channel (shifting the suction source to the suppression pool). Performance of either of these two Required Actions will allow operation to continue. If Required Action D.2.1 or D.2.2 is performed, measures should be taken to ensure that the HPCI System piping remains filled with water. Alternately, if it is not desired to perform Required Actions D.2.1 and D.2.2 (e.g., as in the case where shifting the suction source could drain down the HPCI suction piping), Condition H must be entered and its Required Action taken.

E.1 and E.2

Required Action E.1 is intended to ensure that appropriate actions are taken if multiple, inoperable channels within the Core Spray and Low Pressure Coolant Injection Pump Discharge Flow - Low Bypass Functions result in automatic initiation capability being lost for the

(continued)

ACTIONS

E.1 and E.2 (continued)

same feature(s) in both divisions. For Required Action E.1, the features would be those that are initiated by Functions 1.d and 2.g (e.g., low pressure ECCS). Since each inoperable channel would have Required Action E.1 applied separately (refer to ACTIONS Note), each inoperable channel would only require the affected low pressure ECCS pump(s) to be declared inoperable. However, since channels for more than one low pressure ECCS pump are inoperable, and the Completion Times started concurrently for the channels of the low pressure ECCS pumps, this results in the affected low pressure ECCS pumps being concurrently declared inoperable.

In this situation (loss of minimum flow capability), the 7 day allowance of Required Action E.2 is not appropriate and the subsystem associated with each inoperable channel must be declared inoperable within 1 hour. A Note is also provided (the Note to Required Action E.1) to delineate that Required Action E.1 is only applicable to low pressure ECCS Functions. Required Action E.1 is not applicable to HPCI Function 3.f since the loss of one channel results in a loss of the Function (one-out-of-one logic). This loss was considered during the development of Reference 5 and considered acceptable for the 7 days allowed by Required Action E.2. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program.

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." For Required Action E.1, the Completion Time only begins upon discovery that the same feature in both subsystems (e.g., both CS subsystems) cannot be automatically initiated due to inoperable channels within the same Function as described in the paragraph above. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration of channels.

If the instrumentation that controls the pump minimum flow valve is inoperable, such that the valve will not automatically open, extended pump operation with no injection path available could lead to pump overheating and failure. If there were a failure of the instrumentation, such that the valve would not automatically close, a portion of the

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

Required Action B.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same Function result in a complete loss of automatic initiation capability for the RCIC System. In this situation (loss of automatic initiation capability), the 24 hour allowance of Required Action B.2 is not appropriate, and the RCIC System must be declared inoperable within 1 hour after discovery of loss of RCIC initiation capability.

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." For Required Action B.1, the Completion Time only begins upon discovery that the RCIC System cannot be automatically initiated due to inoperable, untripped Reactor Vessel Water Level - Low Low, Level 2 channels as described in the paragraph above. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

Because of the redundancy of sensors available to provide initiation signals and the fact that the RCIC System is not assumed in any accident or transient analysis, an allowable out of service time of 24 hours has been shown to be acceptable (Ref. 1) to permit restoration of any inoperable channel to OPERABLE status. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be placed in the tripped condition per Required Action B.2. Placing the inoperable channel in trip would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. Alternately, if it is not desired to place the channel in trip (e.g., as in the case where placing the inoperable channel in trip would result in an initiation), Condition E must be entered and its Required Action taken.

C.1

A risk based analysis was performed and determined that an allowable out of service time of 24 hours (Ref. 1) is acceptable to permit restoration of any inoperable channel to OPERABLE status (Required Action C.1). A Required Action (similar to Required Action B.1) limiting the allowable out of service time, if a loss of automatic RCIC initiation capability exists, is not required. This

(continued)

BASES

ACTIONS

C.1 (continued)

Condition applies to the Reactor Vessel Water Level - High, Level 8 Function whose logic is arranged such that any inoperable channel will result in a loss of automatic RCIC initiation capability (loss of high water level trip capability). As stated above, this loss of automatic RCIC initiation capability was analyzed and determined to be acceptable. The Required Action does not allow placing a channel in trip since this action would not necessarily result in a safe state for the channel in all events.

D.1, D.2.1, and D.2.2

Required Action D.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same Function result in automatic component initiation capability being lost for the feature(s). For Required Action D.1, the RCIC System is the only associated feature. In this situation (loss of automatic suction swap), the 24 hour allowance of Required Actions D.2.1 and D.2.2 is not appropriate, and the RCIC System must be declared inoperable within 1 hour from discovery of loss of RCIC initiation capability. As noted, Required Action D.1 is only applicable if the RCIC pump suction is not aligned to the suppression pool since, if aligned, the Function is already performed.

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." For Required Action D.1, the Completion Time only begins upon discovery that the RCIC System cannot be automatically aligned to the suppression pool due to inoperable, untripped channels in the same Function as described in the paragraph above. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

Because of the redundancy of sensors available to provide initiation signals and the fact that the RCIC System is not assumed in any accident or transient analysis, an allowable out of service time of 24 hours has been shown to be acceptable (Ref. 1) to permit restoration of any inoperable channel to OPERABLE status. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be placed in the tripped condition per Required Action D.2.1, which performs the intended function of the channel (shifting the suction source to the

(continued)

BASES

ACTIONS

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

suppression pool). Alternatively, Required Action D.2.2 allows the manual alignment of the RCIC suction to the suppression pool within 24 hours, which also performs the intended function. If Required Action D.2.1 or D.2.2 is performed, measures should be taken to ensure that the RCIC System piping remains filled with water. If it is not desired to perform Required Actions D.2.1 and D.2.2 (e.g., as in the case where shifting the suction source could drain down the RCIC suction piping), Condition E must be entered and its Required Action taken.

E.1

With any Required Action and associated Completion Time not met, the RCIC System may be incapable of performing the intended function, and the RCIC System must be declared inoperable immediately.

SURVEILLANCE REQUIREMENTS

As noted in the beginning of the SRs, the SRs for each RCIC System instrumentation Function are found in the SRs column of Table 3.3.5.3-1.

The Surveillances are modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed as follows: (a) for up to 6 hours for Function 2; and (b) for up to 6 hours for Functions 1, 3, and 4, provided the associated Function maintains trip capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the reliability analysis (Ref. 1) assumption of the average time required to perform channel surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that the RCIC will initiate when necessary.

SR 3.3.5.3.1

Performance of the CHANNEL CHECK ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a parameter on other similar channels. It is based on the assumption that

(continued)

BASES

ACTIONS (continued)

A.1 and A.2

Because of the diversity of sensors available to provide isolation signals and the redundancy of the isolation design, an allowable out of service time of 12 hours for Functions 2.a, 2.b, 6.b, 7.a, and ~~6~~7.b (as provided by a Note to Required Action A.1) and 24 hours for Functions other than Functions 2.a, 2.b, 6.b, 7.a, and ~~6~~7.b (as provided by a Note to Required Action A.2) has been shown to be acceptable (Refs. 4 and 5) to permit restoration of any inoperable channel to OPERABLE status. This out of service time is only acceptable provided the associated Function is still maintaining isolation capability (refer to Required Action B.1 Bases). Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time (RICT) Program. The alternative Completion Time in Required Action A.1 is modified by a Note which excludes use of the RICT Program for Functions 6.b, 7.a, and 7.b. Function 6.b is only applicable in MODE 3 and RICT is only applied in MODE 1. Function 7 is not modeled in the PRA. The alternative Completion Time in Required Action A.2 is modified by a Note which excludes use of the RICT Program for Functions 2.c, 2.d, 2.e, and 6.a, which are not modeled in the PRA.

If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be placed in the tripped condition per the Required Actions~~ A.1~~. Placing the inoperable channel in trip would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue with no further restrictions. Alternately, if it is not desired to place the channel in trip (e.g., as in the case where placing the inoperable channel in trip would result in an isolation), Condition C must be entered and its Required Action taken.

B.1

Required Action B.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same Function result in automatic isolation capability being lost for the associated penetration flow path(s). The MSL Isolation Functions are considered to be maintaining isolation capability when sufficient channels are OPERABLE or in trip, such that both trip systems will generate a trip signal from the given Function on a valid signal. The other isolation functions are considered to be maintaining isolation capability when sufficient channels are OPERABLE or in trip, such that one trip system will generate a trip signal from the given Function

(continued)

LCO
(continued)

subsystems and ADS must therefore be OPERABLE to satisfy the single failure criterion required by Reference 10. (References 8, 15, and 16 take no credit for HPCI.) HPCI must be OPERABLE due to risk consideration.

LPCI subsystems may be considered OPERABLE during alignment and operation for decay heat removal when below the actual RHR low pressure permissive pressure in MODE 3, if capable of being manually realigned (remote or local) to the LPCI mode and not otherwise inoperable. At these low pressures and decay heat levels, a reduced complement of ECCS subsystems should provide the required core cooling, thereby allowing operation of RHR shutdown cooling when necessary.

APPLICABILITY

All ECCS subsystems are required to be OPERABLE during MODES 1, 2, and 3, when there is considerable energy in the reactor core and core cooling would be required to prevent fuel damage in the event of a break in the primary system piping. In MODES 2 and 3, when reactor steam dome pressure is ≤ 150 psig, ADS and HPCI are not required to be OPERABLE because the low pressure ECCS subsystems can provide sufficient flow below this pressure. Requirements for MODES 4 and 5 are specified in LCO 3.5.2, "RPV Water Inventory Control."

ACTIONS

A Note prohibits the application of LCO 3.0.4.b to an inoperable HPCI subsystem. There is an increased risk associated with entering a MODE or other specified condition in the Applicability with an inoperable HPCI subsystem and the provisions of LCO 3.0.4.b, which allows entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

A.1

If any one low pressure ECCS injection/spray subsystem is inoperable, or if one LPCI pump in both LPCI subsystems is inoperable, the inoperable subsystem(s) must be restored to OPERABLE status within 7 days or in accordance with the Risk Informed Completion Time Program. In this condition, the remaining OPERABLE subsystems provide adequate core cooling during a LOCA. However, overall ECCS reliability is reduced, because a single failure in one of the remaining OPERABLE subsystems, concurrent with a LOCA, may result in the ECCS not being able to perform its intended safety function. The 7 day Completion Time is

(continued)

ACTIONS

A.1 (continued)

based on a reliability study (Ref. 11) that evaluated the impact on ECCS availability, assuming various components and subsystems were taken out of service. The results were used to calculate the average availability of ECCS equipment needed to mitigate the consequences of a LOCA as a function of allowed outage times (i.e., Completion Times).

B.1

If the inoperable low pressure ECCS subsystem cannot be restored to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which overall plant risk is minimized. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours. Remaining in the Applicability of the LCO is acceptable because the plant risk in MODE 3 is similar to or lower than the risk in MODE 4 (Ref. 15), because the time spent in MODE 3 to perform the necessary repairs to restore the system to OPERABLE status will be short. However, voluntary entry into MODE 4 may be made as it is also an acceptable low-risk state.

Required Action B.1 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 3. This Note prohibits the use of LCO 3.0.4.a to enter MODE 3 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 3, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit. The allowed Completion Time is reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

C.1

If one LPCI pump in one LPCI subsystem or one LPCI pump in both LPCI subsystems is inoperable and one CS subsystem is inoperable, the inoperable subsystem(s) must be restored to OPERABLE status within 1 hour or in accordance with the Risk Informed Completion Time (RICT) Program. In this condition, the remaining OPERABLE pumps within the subsystems provide adequate core cooling during a LOCA. However, overall ECCS reliability is reduced, because a single failure in one of the remaining OPERABLE pumps, concurrent with a LOCA, may result in the ECCS not being able to perform its

(continued)

BASES

ACTIONS

C.1 (continued)

intended safety function. The 1 hour Completion Time is allowed to prepare for an orderly shutdown or determine if a RICT is to be applied.

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

If the inoperable LPCI pump(s) or CS subsystem cannot be restored to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which overall plant risk is minimized. To achieve this status, the plant must be brought to at least MODE 2 in 6 hours, at least MODE 3 within 12 hours, and at least MODE 4 within 36 hours. The allowed Completion Times are reasonable and permit the shutdown to proceed in a controlled and orderly manner that is well within the specified maximum cooldown rate and within the capabilities of the unit, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

~~C~~E.1 and ~~C~~E.2

If the HPCI System is inoperable and the RCIC System is verified to be OPERABLE, the HPCI System must be restored to OPERABLE status within 14 days or in accordance with the RICT Program. In this condition, adequate core cooling is ensured by the OPERABILITY of the redundant and diverse low pressure ECCS injection/spray subsystems in conjunction with ADS. Also, the RCIC System will automatically provide makeup water at most reactor operating pressures. Verification of RCIC OPERABILITY within 1 hour is therefore required when HPCI is inoperable. This may be performed as an administrative check by

(continued)

ACTIONS

~~C~~E.1 and ~~C~~E.2 (continued)

examining logs or other information to determine if RCIC is out of service for maintenance or other reasons. It does not mean to perform the Surveillances needed to demonstrate the OPERABILITY of the RCIC System. If the OPERABILITY of the RCIC System cannot be verified, however, Condition E must be immediately entered. If a single active component fails concurrent with a design basis LOCA, there is a potential, depending on the specific failure, that the minimum required ECCS equipment will not be available. A 14 day Completion Time is based on a reliability study cited in Reference 11 and has been found to be acceptable through operating experience.

~~D~~F.1 and ~~D~~F.2

If any one low pressure ECCS injection/spray subsystem, or one LPCI pump in both LPCI subsystems, is inoperable in addition to an inoperable HPCI System, the inoperable low pressure ECCS injection/spray subsystem or the HPCI System must be restored to OPERABLE status within 72 hours or in accordance with the RICT Program. In this condition, adequate core cooling is ensured by the OPERABILITY of the ADS and the remaining low pressure ECCS subsystems. However, the overall ECCS reliability is significantly reduced because a single failure in one of the remaining OPERABLE subsystems concurrent with a design basis LOCA may result in the ECCS not being able to perform its intended safety function. Since both a high pressure system (HPCI) and a low pressure subsystem are inoperable, a more restrictive Completion Time of 72 hours is required to restore either the HPCI System or the low pressure ECCS injection/spray subsystem to OPERABLE status. This Completion Time is based on a reliability study cited in Reference 11 and has been found to be acceptable through operating experience.

~~E~~G.1

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

Remaining in the Applicability of the LCO is acceptable because the plant risk in MODE 3 is similar to or lower than the risk in MODE 4 (Ref. 15) and because the time spent in MODE 3 to perform the necessary repairs to restore the system to OPERABLE status will be short. However, voluntary entry into MODE 4 may be made as it is also an acceptable low-risk state.

(continued)

ACTIONS

~~E~~G.1 (continued)

Required Action ~~E~~G.1 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 3. This Note prohibits the use of LCO 3.0.4.a to enter MODE 3 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 3, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

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

~~F~~H.1 and ~~F~~H.2

With one ADS valve inoperable, no action is required, because an analysis demonstrated that the remaining six ADS valves are capable of providing the ADS function, per Reference 13.

If two or more ADS valves are inoperable, the plant must be brought to a condition in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and reactor steam dome pressure reduced to ≤ 150 psig within 36 hours. Entry into MODE 3 is not required if the reduction in reactor steam dome pressure to ≤ 150 psig results in exiting the Applicability for the Condition, and the ≤ 150 psig is achieved within the given 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

~~G~~I.1

When multiple ECCS subsystems are inoperable, as stated in Condition I~~G~~, the plant is in a condition outside of the accident analyses. Therefore, LCO 3.0.3 must be entered immediately.

(continued)

BASES

ACTIONS (continued)

A.1 and A.2

If the RCIC System is inoperable during MODE 1, or MODE 2 or 3 with reactor steam dome pressure > 150 psig, and the HPCI System is verified to be OPERABLE, the RCIC System must be restored to OPERABLE status within 14 days or in accordance with the Risk Informed Completion Time Program. In this condition, loss of the RCIC System will not affect the overall plant capability to provide makeup inventory at high reactor pressure since the HPCI System is the only high pressure system assumed to function during a loss of coolant accident (LOCA). OPERABILITY of HPCI is therefore verified within 1 hour when the RCIC System is inoperable. This may be performed as an administrative check, by examining logs or other information, to determine if HPCI is out of service for maintenance or other reasons. It does not mean it is necessary to perform the Surveillances needed to demonstrate the OPERABILITY of the HPCI System. If the OPERABILITY of the HPCI System cannot be verified, however, Condition B must be immediately entered. For non-LOCA events, RCIC (as opposed to HPCI) is the preferred source of makeup coolant because of its relatively small capacity, which allows easier control of the RPV water level. Therefore, a limited time is allowed to restore the inoperable RCIC to OPERABLE status.

The 14 day Completion Time is based on a reliability study (Ref. 3) that evaluated the impact on ECCS availability, assuming various components and subsystems were taken out of service. The results were used to calculate the average availability of ECCS equipment needed to mitigate the consequences of a LOCA as a function of allowed outage times (AOTs). Because of similar functions of HPCI and RCIC, the AOTs (i.e., Completion Times) determined for HPCI are also applied to RCIC.

B.1

If the RCIC System cannot be restored to OPERABLE status within the associated Completion Time, or if the HPCI System is simultaneously inoperable, the plant must be brought to a condition in which overall plant risk is minimized. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours.

Remaining in the Applicability of the LCO is acceptable because the plant risk in MODE 3 is similar to or lower than the risk in MODE 4 (Ref. 6) and because the time spent in MODE 3 to perform the necessary repairs to restore the system to OPERABLE status will be short. However, voluntary entry into MODE 4 may be made as it is also an acceptable low-risk state.

(continued)

BASES

ACTIONS

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

The Required Actions have been modified by two Notes. Note 1 ensures that only the Required Actions and associated Completion Times of Condition C are required if both doors in the air lock are inoperable. With both doors in the air lock inoperable, an OPERABLE door is not available to be closed. Required Actions C.1 and C.2 are the appropriate remedial actions. Note 2 allows entry into and exit from the primary containment under the control of a dedicated individual stationed at the air lock to ensure that only one door is opened at a time (i.e., the individual performs the function of the interlock).

Required Action B.3 is modified by a Note that applies to air lock doors located in high radiation areas or areas with limited access due to inerting and that allows these doors to be verified locked closed by use of administrative controls. Allowing verification by administrative controls is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment of the door, once it has been verified to be in the proper position, is small.

C.1, C.2, and C.3

If the air lock is inoperable for reasons other than those described in Condition A or B, Required Action C.1 requires action to be immediately initiated to evaluate containment overall leakage rates using current air lock leakage test results. An evaluation is acceptable since it is overly conservative to immediately declare the primary containment inoperable if both doors in the air lock have failed a seal test or if the overall air lock leakage is not within limits. In many instances (e.g., only one seal per door has failed), primary containment remains OPERABLE, yet only 1 hour (according to LCO 3.6.1.1) would be provided to restore the air lock door to OPERABLE status prior to requiring a plant shutdown. In addition, even with both doors failing the seal test, the overall containment leakage rate can still be within limits.

Required Action C.2 requires that one door in the primary containment air lock must be verified closed. This action must be completed within the 1 hour Completion Time. This specified time period is consistent with the ACTIONS of LCO 3.6.1.1, which require that primary containment be restored to OPERABLE status within 1 hour.

Additionally, the air lock must be restored to OPERABLE status within 24 hours or in accordance with the Risk Informed Completion Time

(continued)

BASES

ACTIONS

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

Program. The 24 hour Completion Time is reasonable for restoring an inoperable air lock to OPERABLE status considering that at least one door is maintained closed in the air lock.

D.1 and D.2

If the inoperable primary containment air lock cannot be restored to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.2.1

Maintaining primary containment air locks OPERABLE requires compliance with the leakage rate test requirements of the Primary Containment Leakage Rate Testing Program (Ref. 3). This SR reflects the leakage rate testing requirements with respect to air lock leakage (Type B leakage tests). The acceptance criteria were established as a small fraction of the total allowable containment leakage. The periodic testing requirements verify that the air lock leakage does not exceed the allowed fraction of the overall primary containment leakage rate. The Frequency is required by the Primary Containment Leakage Rate Testing Program.

The SR has been modified by two Notes. Note 1 states that an inoperable air lock door does not invalidate the previous successful performance of the overall air lock leakage test. This is considered reasonable since either air lock door is capable of providing a fission product barrier in the event of a DBA. Note 2 has been added to this SR, requiring the results to be evaluated against the acceptance criteria applicable to SR 3.6.1.1.1. This ensures that air lock leakage is properly accounted for in determining the combined Types B and C primary containment leakage.

(continued)

BASES

ACTIONS (continued)

A.1, A.2, and A.~~2~~3

With one or more penetration flow paths with one PCIV inoperable except for inoperability due to leakage not within a limit specified in an SR to this LCO, the affected penetration flow paths must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, a blind flange, and a check valve with flow through the valve secured.

For a penetration isolated in accordance with Required Action A.1 or A.2, the device used to isolate the penetration should be the closest available valve to the primary containment.

If a valve is inoperable due to isolation time not within limits or other condition that would not be expected to adversely affect leakage characteristics, the inoperable valve may be used to isolate the penetration.

~~The~~ Required Action A.1 must be completed within the 4 hour Completion Time ~~(8 hours for main steam lines)~~ or in accordance with the Risk Informed Completion Time Program. The Completion Time of 4 hours is reasonable considering the time required to isolate the penetration and the relative importance of supporting primary containment OPERABILITY during MODES 1, 2, and 3. For main steam lines, Required Action A.2 allows an 8 hour Completion Time ~~is allowed~~. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program. The Completion Time of 8 hours for the main steam lines allows a period of time to restore the MSIVs to OPERABLE status given the fact that MSIV closure will result in isolation of the main steam line(s) and a potential for plant shutdown.

For affected penetrations that have been isolated in accordance with Required Action A.1 or A.2, the affected penetration flow path must be verified to be isolated on a periodic basis. This is necessary to ensure that primary containment penetrations required to be isolated following an accident, and no longer capable of being automatically isolated, will be in the isolation position should an event occur. This Required Action does not require any testing or device manipulation. Rather, it involves verification that those devices outside containment

(continued)

BASES

ACTIONS

A.1, A.2, and A.3~~2~~ (continued)

and capable of potentially being mispositioned are in the correct position. The Completion Time of "Once per 31 days following isolation for isolation devices outside primary containment" is appropriate because the devices are operated under administrative controls and the probability of their misalignment is low. For the devices inside primary containment, the time period specified "Prior to entering MODE 2 or 3 from MODE 4, if primary containment was de-inerted while in MODE 4, if not performed within the previous 92 days" is based on engineering judgment and is considered reasonable in view of the inaccessibility of the devices and other administrative controls ensuring that device misalignment is an unlikely possibility.

Condition A is modified by a Note indicating that this Condition is only applicable to those penetration flow paths with two PCIVs. For penetration flow paths with one PCIV, Condition C provides the appropriate Required Actions.

Required Action A.2 is modified by two notes. Note 1 applies to isolation devices located in high radiation areas, and allows them to be verified by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Note 2 applies to isolation devices that are locked, sealed, or otherwise secured in position and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since the function of locking, sealing, or securing components is to ensure that these devices are not inadvertently repositioned. Therefore, the probability of misalignment, once they have been verified to be in the proper position, is low.

B.1

With one or more penetration flow paths with two PCIVs inoperable except due to leakage not within limits, either the inoperable PCIVs must be restored to OPERABLE status or the affected penetration flow path must be isolated within 1 hour. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, and a blind flange. A check valve may not be used to isolate the affected penetration.

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

The Completion Time of 4 hours for PCIVs other than those in penetrations with a closed system and EFCVs is reasonable considering the time required to isolate the penetration and the relative importance of supporting primary containment OPERABILITY in MODES 1, 2, and 3. The Completion Time of 72 hours for penetrations with a closed system is reasonable considering the relative stability of the closed system (hence, reliability) to act as a penetration isolation boundary. The closed system must meet the requirements of Reference 7. The Completion Time of 72 hours for EFCVs is also reasonable considering the instrument to act as a penetration isolation boundary and the small pipe diameter of the affected penetrations. In the event the affected penetration flow path is isolated in accordance with Required Action C.1, the affected penetration must be verified to be isolated on a periodic basis. This is necessary to ensure that primary containment penetrations required to be isolated following an accident are isolated.

The Completion Time of once per 31 days following isolation for verifying each affected penetration is isolated is appropriate because the valves are operated under administrative controls and the probability of their misalignment is low.

Condition C is modified by a Note indicating that this Condition is only applicable to penetration flow paths with only one PCIV. For penetration flow paths with two PCIVs, Conditions A and B provide the appropriate Required Actions.

Required Action C.2 is modified by two notes. Note 1 applies to valves and blind flanges located in high radiation areas and allows them to be verified by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Note 2 applies to isolation devices that are locked, sealed, or otherwise secured in position and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since the function of locking, sealing, or securing components is to ensure that these devices are not inadvertently repositioned. Therefore, the probability of misalignment of these valves, once they have been verified to be in the proper position, is low.

(continued)

BASES (continued)

LCO

During a DBA, a minimum of one RHR suppression pool cooling subsystem is required to maintain the primary containment peak pressure and temperature below design limits (Ref. 1). To ensure that these requirements are met, two RHR suppression pool cooling subsystems must be OPERABLE with power from two safety related independent power supplies. Therefore, in the event of an accident, at least one subsystem is OPERABLE assuming the worst case single active failure. An RHR suppression pool cooling subsystem is OPERABLE when one of the pumps, the heat exchanger, and associated piping, valves, instrumentation, and controls are OPERABLE. Management of gas voids is important to RHR Suppression Pool Cooling System OPERABILITY. Each RHR suppression pool cooling subsystem is supported by an independent subsystem of the Residual Heat Removal Service Water (RHRSW) System. Specifically, two OPERABLE RHRSW pumps and an OPERABLE flow path, as defined in the Bases for LCO 3.7.1, "Residual Heat Removal Service Water (RHRSW) System," are required to provide the necessary heat transfer from the heat exchanger and, thereby, support each suppression pool cooling subsystem.

APPLICABILITY

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

ACTIONS

A.1

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

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)	containment conditions within design limits. The time history for primary containment pressure is calculated to demonstrate that the maximum pressure remains below the design limit. The RHR Suppression Pool Spray System satisfies Criterion 3 of the NRC Policy Statement (Ref. 2).
LCO	In the event of a DBA, a minimum of one RHR suppression pool spray subsystem is required to mitigate potential bypass leakage paths and maintain the primary containment peak pressure below the design limits (Ref. 1). To ensure that these requirements are met, two RHR suppression pool spray subsystems must be OPERABLE with power from two safety related independent power supplies. Therefore, in the event of an accident, at least one subsystem is OPERABLE assuming the worst case single active failure. An RHR suppression pool spray subsystem is OPERABLE when one of the pumps, the heat exchanger, and associated piping, valves, instrumentation, and controls are OPERABLE. Management of gas voids is important to RHR Suppression Pool Spray System OPERABILITY. Each RHR suppression pool spray subsystem is supported by an independent subsystem of the Residual Heat Removal Service Water (RHRSW) System. Specifically, two OPERABLE RHRSW pumps and an OPERABLE flow path, as defined in the Bases for LCO 3.7.1, "Residual Heat Removal Service Water (RHRSW) System," are required to provide the necessary heat transfer from the heat exchanger and, thereby, support each suppression pool spray subsystem.
APPLICABILITY	In MODES 1, 2, and 3, a DBA could cause pressurization of primary containment. In MODES 4 and 5, the probability and consequences of these events are reduced due to the pressure and temperature limitations in these MODES. Therefore, maintaining RHR suppression pool spray subsystems OPERABLE is not required in MODE 4 or 5.
ACTIONS	<u>A.1</u> With one RHR suppression pool spray subsystem inoperable, the inoperable subsystem must be restored to OPERABLE status within 7 days or in accordance with the Risk Informed Completion Time Program. In this Condition, the remaining OPERABLE RHR suppression pool spray subsystem is adequate to perform the primary

(continued)

BASES (continued)

APPLICABILITY

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

ACTIONS

A.1

With one drywell spray subsystem inoperable, the inoperable subsystem must be restored to OPERABLE status within 7 days or in accordance with the Risk Informed Completion Time Program. In this condition, the remaining OPERABLE RHR drywell spray subsystem is adequate to perform the primary containment fission product scrubbing and temperature and pressure reduction functions.

However, the overall reliability is reduced because a single failure in the OPERABLE subsystem could result in the loss of the scrubbing and temperature and pressure reduction capabilities of the RHR drywell spray system. The 7 day Completion Time was chosen because of the capability of the redundant and OPERABLE RHR drywell spray subsystem and the low probability of a DBA occurring during this period.

B.1

With both RHR drywell spray subsystems inoperable, at least one subsystem must be restored to OPERABLE status within 8 hours. In this Condition, there is a substantial loss of the fission product scrubbing and temperature and pressure reduction functions of the RHR drywell spray system. The 8 hour Completion Time is based on the low probability of a DBA during this period.

C.1

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

(continued)

BASES

ACTIONS (continued)

B.1

With one RHRSW pump inoperable in each subsystem, if no additional failures occur in the RHRSW System, and the two OPERABLE pumps are aligned by opening the normally closed cross tie valves (i.e., after an event requiring operation of the RHRSW System), then the remaining OPERABLE pumps and flow paths provide adequate heat removal capacity following a design basis LOCA. However, capability for this alignment is not assumed in long term containment response analysis and an additional single failure in the RHRSW System could reduce the system capacity below that assumed in the safety analysis. Therefore, continued operation is permitted only for a limited time. One inoperable pump is required to be restored to OPERABLE status within 7 days or in accordance with the Risk Informed Completion Time Program. The 7 day Completion Time for restoring one inoperable RHRSW pump to OPERABLE status is based on engineering judgment, considering the level of redundancy provided.

C.1

Required Action C.1 is intended to handle the inoperability of one RHRSW subsystem for reasons other than Condition A. The Completion Time of 7 days is allowed to restore the RHRSW subsystem to OPERABLE status. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program. With the unit in this condition, the remaining OPERABLE RHRSW subsystem is adequate to perform the RHRSW heat removal function. However, the overall reliability is reduced because a single failure in the OPERABLE RHRSW subsystem could result in loss of RHRSW function. The Completion Time is based on the redundant RHRSW capabilities afforded by the OPERABLE subsystem and the low probability of an event occurring requiring RHRSW during this period.

The Required Action is modified by a Note indicating that the applicable conditions of LCO 3.4.7 be entered and Required Actions taken if the inoperable RHRSW subsystem results in an inoperable RHR shutdown cooling subsystem. This is an exception to LCO 3.0.6 and ensures the proper actions are taken for these components.

D.1

If one RHRSW subsystem is inoperable or one RHRSW pump in one or two subsystems is inoperable and not restored within the provided

(continued)

BASES

APPLICABILITY (continued)

The LCO for the PSW System and UHS is not applicable in MODES 4 and 5, and defueled. However, portions of the PSW System and UHS may be required to perform necessary support functions for OPERABILITY of the supported systems. Thus, the LCOs of the individual systems, which require portions of the PSW System and the UHS to be functional to support individual system OPERABILITY, will govern PSW System and UHS requirements during operation in MODES 4 and 5 and defueled.

ACTIONS

A.1

With one PSW pump inoperable, the inoperable pump must be restored to OPERABLE status within 30 days. With the unit in this condition, the remaining OPERABLE PSW pumps (even allowing for an additional single failure) are adequate to perform the PSW heat removal function; however, the overall reliability is reduced. The 30 day Completion Time is based on the remaining PSW heat removal capability to accommodate additional single failures, and the low probability of an event occurring during this time period.

~~A.2.1 and A.2.2~~

~~The Completion Time to restore one PSW pump to OPERABLE status to facilitate the 1C PSW pump repair may be extended to 45 days total, provided action is taken within 30 days to establish compensatory and risk management controls.~~

~~The A.2.1 and A.2.2 Required Actions are modified by two Notes. Note 1 ensures that the A.2.1 and A.2.2 Required Actions are only applied during the 1C PSW pump repair. Note 2 limits the time period the A.2.1 and A.2.2 Required Actions may be used.~~

~~The extended Completion Time is subject to additional compensatory controls specified in SNC letter NL-21-0862, dated September 23, 2021, that consist of controls that must be established and maintained during the extended Completion Time. These controls are based on procedural protection, operation of redundant functions, and recommended actions based on risk insights.~~

~~If Required Action A.2.1 is met, the allowed time to restore the PSW pump to OPERABLE status can be extended to 45 days from entry into Condition A. With the unit in this condition, the remaining OPERABLE PSW pumps (even allowing for an additional single~~

(continued)

BASES

ACTIONS

~~A.2.1 and A.2.2 (continued)~~

~~failure) are adequate to perform the PSW heat removal function; however, the overall reliability is reduced. The 45-day Completion Time is based on the remaining PSW heat removal capability to accommodate additional single failures, the low probability of an event occurring during this time period, and the established compensatory measures of SNC letter NL-21-0862.~~

B.1

With one PSW turbine building isolation valve inoperable, the inoperable valve must be restored to OPERABLE status within 30 days. With the unit in this condition, the remaining OPERABLE PSW turbine building isolation valve in the subsystem is adequate to isolate the non-essential loads, and, even allowing for an additional single failure, the other PSW subsystem is adequate to perform the PSW heat removal function; however, the overall reliability is reduced. The 30 day Completion Time is based on the remaining PSW heat removal capability to accommodate additional single failures, and the low probability of an event occurring during this time period.

(continued)

BASES

ACTIONS
(continued)

C.1

With one PSW pump inoperable in each subsystem, one inoperable pump must be restored to OPERABLE status within 7 days or in accordance with the Risk Informed Completion Time Program. With the unit in this condition, the remaining OPERABLE PSW pumps are adequate to perform the PSW heat removal function; however, the overall reliability is reduced. The 7 day Completion Time is based on the remaining PSW heat removal capability to accommodate an additional single failure and the low probability of an event occurring during this time period.

D.1

With one PSW turbine building isolation valve inoperable in each subsystem, one inoperable valve must be restored to OPERABLE status within 72 hours or in accordance with the Risk Informed Completion Time Program. With the unit in this condition, the remaining OPERABLE PSW valves are adequate to perform the PSW nonessential load isolation function; however, the overall reliability is reduced. The 72 hour Completion Time is based on the remaining PSW heat removal capability to accommodate an additional single failure and the low probability of an event occurring during this time period.

E.1

If one PSW pump in one or both subsystems is inoperable, or one PSW turbine building isolation valve in one or both subsystems is inoperable, and is not restored to OPERABLE status within the required Completion Times, the plant must be brought to a condition in which overall plant risk is minimized. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours.

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

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

(continued)

BASES

ACTIONS

E.1 (continued)

assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 3, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

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

F.1

With one PSW subsystem inoperable for reasons other than Condition A and Condition B (e.g., inoperable flow path, both pumps inoperable in a loop, or both turbine building isolation valves inoperable in a loop), the PSW subsystem must be restored to OPERABLE status within 72 hours or in accordance with the Risk Informed Completion Time Program. With the unit in this condition, the remaining OPERABLE PSW subsystem is adequate to perform the heat removal function. However, the overall reliability is reduced because a single failure in the OPERABLE PSW subsystem could result in loss of PSW function.

The 72 hour Completion Time is based on the redundant PSW System capabilities afforded by the OPERABLE subsystem, the low probability of an accident occurring during this time period, and is consistent with the allowed Completion Time for restoring an inoperable DG.

Required Action F.1 is modified by two Notes indicating that the applicable Conditions of LCO 3.8.1, "AC Sources - Operating," LCO 3.4.7, "Residual Heat Removal (RHR) Shutdown Cooling System - Hot Shutdown," be entered and Required Actions taken if the inoperable PSW subsystem results in an inoperable DG or RHR shutdown cooling subsystem, respectively. This is in accordance with LCO 3.0.6 and ensures the proper actions are taken for these components.

(continued)

BASES

ACTIONS

A.2 (continued)

The remaining OPERABLE offsite circuits and DGs are adequate to supply electrical power to the onsite Class 1E Distribution System. Thus, on a component basis, single failure protection may have been lost for the required feature's function; however, function is not lost. The 24 hour Completion Time takes into account the component OPERABILITY of the redundant counterpart to the inoperable required feature. Additionally, the 24 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

A.3

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition A for a period that should not exceed 72 hours. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program. With one required offsite circuit inoperable, the reliability of the offsite system is degraded, and the potential for a loss of offsite power is increased, with attendant potential for a challenge to the plant safety systems. In this condition, however, the remaining OPERABLE offsite circuit and DGs are adequate to supply electrical power to the onsite Class 1E Distribution System.

The 72 hour Completion Time takes into account the capacity and capability of the remaining AC sources, reasonable time for repairs, and the low probability of a DBA occurring during this period.

.

(continued)

BASES

ACTIONS

B.3.1 and B.3.2 (continued)

that would have prevented the DG from performing its specified safety function, a separate entry into Condition B is not required. The new DG problem should be addressed in accordance with the deficiency control program.

B.4

Regulatory Guide 1.93 (Ref. 6) provides guidance that operation in Condition B may continue for 72 hours. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time (RICT) Program. ~~A risk-informed, deterministic evaluation performed for Plant Hatch justifies operation in Condition B for 14 days, provided action is taken to ensure two DGs are dedicated to each Hatch unit. This is accomplished for an inoperable A or C DG by inhibiting the automatic alignment (on a LOCA or LOSP signal) of the swing DG to the other unit. If the inoperable DG is the swing DG, each unit has two dedicated DGs. For an inoperable swing DG, a 72 hour Completion Time applies unless the restrictions specified following this paragraph are satisfied. In Condition B for each defined Completion Time and restriction (if applicable), the remaining OPERABLE DGs and offsite circuits are adequate to supply electrical power to the onsite Unit 1 Class 1E Distribution System. The Completion Times take into account the capacity and capability of the remaining AC sources, reasonable time for maintenance and repairs, and low probability of a DBA occurring during this period. The 14 day Completion Time is also subject to additional restrictions for planned maintenance on other plant systems; these are controlled by NMP-GM-031. Use of the 14 day Completion time is permitted as follows :~~

- ~~For the Unit 1 DGs:~~

  ~~Once per DG per operating cycle for performing major overhaul of a DG.~~

  ~~As needed to complete unplanned maintenance. This time shall be minimized.~~

- ~~For the swing DG:~~

~~The additional restrictions apply prior to using a Completion Time of greater than 72 hours.~~

~~The 14 day Completion Time may be used once per Unit 1 operating cycle for performing a major overhaul of the swing DG.~~

~~The time may be used as needed to complete unplanned maintenance. This time shall be minimized.~~

(continued)

BASES

ACTIONS ~~B.4~~ (continued)

- ~~As needed for the swing DG when it is inhibited from automatically aligning to Unit 1 in order for the 14 day Completion Time to be used for a Unit 2 DG.~~

~~The "AND" connector between the 72 hour and 14 day Completion Times means that both Completion Times apply simultaneously. That is, the 14 day Completion Time for an A or C DG with the swing DG inhibited applies from the time of entry into Condition B, not from the time the swing DG is inhibited.~~

~~B.4.2.1, B.4.2.2, and B.4.2.3~~

~~The Completion Time to restore the DG to OPERABLE status may be extended to 19 days provided action is taken within 72 hours to: 1) for an inoperable Unit 1 DG, inhibit the swing DG from automatically aligning to the Unit 2 4.16 kV ESF bus, and 2) establish compensatory and risk management controls.~~

~~The B.4.2 Required Actions are modified by three Notes. Note 1 ensures that the B.4.2 Required Actions are only applied during the DG outage period that includes replacement of the engine cylinder liners. Note 2 specifies that the B.4.2 ACTIONS are only applicable one time for each DG because they are only approved for one-time use. Note 3 limits the time period the B.4.2 ACTIONS may be used.~~

~~The extended Completion Time is subject to additional defense-in-depth measures and risk management actions to ensure adequate electrical power sources and safety related equipment are available in the event of a loss of the offsite electrical power system during the extended DG outage period.~~

~~The compensatory controls specified in Attachment 5 of SNC letter NL-20-1000 (Ref. 16) consist of controls that must be established and maintained during the extended Completion Time period to preserve defense-in-depth. The requirement to establish and maintain features (i.e., systems, subsystems, and components) OPERABLE as a compensatory control may be performed as an administrative check, by examining logs or other information, to determine if the required features are out of service for maintenance or other reasons. It does not mean it is necessary to perform the Surveillances needed to demonstrate the OPERABILITY of the required features.~~

~~The risk evaluation performed, in accordance with RG 1.177 (Ref. 17), to extend the DG Completion Time to 19 days identified potentially high-risk configurations that could exist if equipment, in addition to the inoperable DG, were to be taken out of service simultaneously or~~

(continued)

~~BASES~~

~~ACTIONS~~ ~~B.4.2.1, B.4.2.2, and B.4.2.3 (continued)~~

~~other risk-significant operational factors, such as concurrent system or equipment testing. The risk management controls specified in Attachment 5 of SNC letter NL-20-1000 (Ref. 16) must be established and maintained, as applicable, during the extended Completion Time period to ensure appropriate restrictions on dominant risk-significant configurations associated with the extended Completion Time period are in place.~~

~~The 72 hour Completion Time of Required Action B.4.2.1 corresponds to the time required by Required Action B.4.1 to restore a unit DG or the swing DG to OPERABLE status with no additional restrictions or controls. If after the 72 hour Completion Time while applying the B.4.2 ACTIONS, it is discovered that these controls are not met, a Completion Time of 24 hours from discovery of the required controls not met is allowed to reestablish the compensatory and risk management controls. The Completion Time is intended to allow the operator time to evaluate and re-establish any discovered control not met. This Completion Time also allows for an exception to the normal "time zero" for beginning the Completion Time "clock." Following the initial 72 hours (while applying the B.4.2 ACTIONS) to establish the required controls, discovering one or more of the required controls not met results in starting the Completion Time for Required Action B.4.2.1. Twenty-four hours from the discovery of the required control(s) not met is acceptable because it minimizes risk while allowing time for re-establishing the control(s) before subjecting the unit to transients associated with shutdown while a DG is inoperable.~~

~~Required Action B.4.2.2 requires the swing DG to be inhibited from automatically aligning (on a LOCA or LOSP signal) to the other unit. This ensures two OPERABLE DGs are dedicated to each unit during a LOCA or LOSP event when a unit DG is inoperable. Required Action B 4.2.2 is modified by a Note that clarifies this action is only applicable when Condition B is entered due to DG 1A or 1C inoperable. When Condition B is entered due to the swing DG inoperable, this action is not applicable and is not needed since each unit has two dedicated OPERABLE DGs available in the event of a LOCA or LOSP event. The 72 hour Completion Time of Required Action B.4.2.2 corresponds to the time required by Required Action B.4.1 to restore a unit DG to OPERABLE status with no additional restrictions or controls.~~

~~Once Required Action B.4.2.1 and Required Action B.4.2.2 for the Unit 1 DGs, are performed, the DG can be restored to OPERABLE status within 19 days. The extended Completion Time of Required Action B.4.2.3 represents a balance between the risk associated with continued plant operation with less than the required system or~~

(continued)

~~BASES~~

~~ACTIONS~~ ~~B.4.2.1, B.4.2.2, and B.4.2.3 (continued)~~

~~component redundancy and the risk associated with initiating a plant transient while transitioning the unit based on the loss of redundancy. With compensatory and risk management controls established, the remaining OPERABLE DGs and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. The extended Completion Time takes into account the capacity and capability of the remaining AC sources, reasonable time for maintenance, and low probability of a DBA or an LOSP occurring during this period.~~

~~The Completion Time of Required Action B.4.2.3 is based on a defense-in-depth philosophy and risk informed using the plant PRA. The risk impact of the extended Completion Time has been evaluated pursuant to the risk assessment and management provisions of the Maintenance Rule, 10 CFR 50.65(a)(4), and the associated implementation guidance, Regulatory Guide 1.160, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." Regulatory Guide 1.160 endorses the guidance in Section 11 of NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." This guidance provides for the consideration of dynamic plant configuration issues, emergent conditions, and other aspects pertinent to plant operation with the DG inoperable for an extended period of time. These considerations may result in additional risk management and other compensatory actions being required during the extended period that the DG is inoperable.~~

C.1

To ensure a highly reliable power source remains with one required Unit 2 DG inoperable, it is necessary to verify the availability of the required offsite circuits on a more frequent basis. Since the Required Action only specifies "perform," a failure of SR 3.8.1.1 acceptance criteria does not result in a Required Action being not met. However, if a circuit fails to pass SR 3.8.1.1, it is inoperable. Upon offsite circuit inoperability, additional Conditions must then be entered.

C.2

Required Action C.2 is intended to provide assurance that a loss of offsite power, during the period that one required Unit 2 DG is inoperable, does not result in a complete loss of safety function of critical systems. These features are designed with redundant safety related divisions (i.e., single division systems are not included). Redundant required features failures consist of inoperable features associated with a division redundant to the division that has an inoperable DG.

(continued)

BASES

ACTIONS

C.3.1 and C.3.2 (continued)

DG cannot be confirmed not to exist on the remaining DG(s), performance of SR 3.8.1.2.a suffices to provide assurance of continued OPERABILITY of those DGs. In the event the inoperable DG is restored to OPERABLE status prior to completing either C.3.1 or C.3.2, the deficiency control program, as appropriate, will continue to evaluate the common cause possibility. This continued evaluation, however, is no longer under the 24 hour constraint imposed while in Condition C.

According to Generic Letter 84-15 (Ref. 7), 24 hours is a reasonable time to confirm that the OPERABLE DGs are not affected by the same problem as the inoperable DG.

C.4~~.1~~

In Condition C, the remaining OPERABLE offsite circuit is adequate to supply electrical power to the required onsite Unit 2 Class 1E Distribution System. The 7 day Completion Time is based on the shortest restoration time allowed for the systems affected by ~~-~~the inoperable DG in the individual system LCOs. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program.

~~A risk-informed, deterministic evaluation performed for Plant Hatch justifies operation in Condition C for 14 days, provided action is taken to ensure two DGs are dedicated to each Hatch unit. This is accomplished for an inoperable A or C DG by inhibiting the automatic alignment (on a LOCA or LOSP signal) of the swing DG to the other unit. The Completion Times take into account the capacity and capability of the remaining AC sources, reasonable time for maintenance, and low probability of a DBA occurring during this period. Use of the 14 day Completion Time, subject to additional restrictions controlled by NMP-GM-031, is permitted as follows:~~

- ~~Once per DG per operating cycle for performing a major overhaul of a DG.~~
- ~~As needed to complete unplanned maintenance. This time shall be minimized.~~

D.1 and D.2

Required Action D.1 addresses actions to be taken in the event of inoperability of redundant required features concurrent with

(continued)

BASES

ACTIONS

D.1 and D.2 (continued)

With two or more of the required offsite circuits inoperable, sufficient onsite AC sources are available to maintain the unit in a safe shutdown condition in the event of a DBA or transient. In fact, a simultaneous loss of offsite AC sources, a LOCA, and a worst case single failure were postulated as a part of the design basis in the safety analysis. Thus, the 24 hour Completion Time provides a period of time to effect restoration of one of the offsite circuits commensurate with the importance of maintaining an AC electrical power system capable of meeting its design criteria.

According to Regulatory Guide 1.93 (Ref. 6), with the available offsite AC sources two less than required by the LCO (which as stated earlier, generally corresponds to a total loss of the immediately accessible offsite power sources; this is the condition experienced by Plant Hatch when two or more required circuits are inoperable), operation may continue for 24 hours. If all required offsite sources are restored within 24 hours, unrestricted operation may continue. If all but one required offsite sources are restored within 24 hours, power operation continues in accordance with Condition A. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program.

E.1 and E.2

Pursuant to LCO 3.0.6, the Distribution System ACTIONS would not be entered even if all AC sources to it were inoperable, resulting in de-energization. Therefore, the Required Actions of Condition E are modified by a Note to indicate that when Condition E is entered with no AC source to any ESF bus, ACTIONS for LCO 3.8.7, "Distribution Systems - Operating," must be immediately entered. This allows Condition E to provide requirements for the loss of the offsite circuit and one DG without regard to whether a division is de-energized. LCO 3.8.7 provides the appropriate restrictions for a de-energized ESF bus.

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition E for a period that should not exceed 12 hours.

BASES

ACTIONS

E.1 and E.2 (continued)

In Condition E, individual redundancy is lost in both the offsite electrical power system and the onsite AC electrical power system. However, since power system redundancy is provided by two diverse sources of power, the reliability of the power systems in this Condition may appear higher than that in Condition D (loss of two or more

(continued)

required offsite circuits). This difference in reliability is offset by the susceptibility of this power system configuration to a single bus or switching failure.

The 12 hour Completion Time takes into account the capacity and capability of the remaining AC sources, reasonable time for repairs, and the low probability of a DBA occurring during this period. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program.

F.1

With two or more Unit 1 and swing DGs inoperable, with an assumed loss of offsite electrical power, insufficient standby AC sources are available to power the minimum required ESF functions. Since the offsite electrical power system is the only source of AC power for the majority of ESF equipment at this level of degradation, the risk associated with continued operation for a very short time could be less than that associated with an immediate controlled shutdown. (The immediate shutdown could cause grid instability, which could result in a total loss of AC power.) Since any inadvertent unit generator trip could also result in a total loss of offsite AC power, the time allowed for continued operation is severely restricted. The intent here is to avoid the risk associated with an immediate controlled shutdown and to minimize the risk associated with this level of degradation.

According to Regulatory Guide 1.93 (Ref. 6), with two or more DGs inoperable, operation may continue for a period that should not exceed 2 hours. (Regulatory Guide 1.93 assumed the unit has two DGs. Thus, a loss of both DGs results in a total loss of onsite power. Therefore, a loss of more than two DGs, in the Plant Hatch design, results in degradation no worse than that assumed in Regulatory Guide 1.93. In addition, the loss of a required Unit 2 DG concurrent with the loss of a Unit 1 or swing DG, is analogous to the loss of a single DG in the Regulatory Guide 1.93 assumptions; thus, entry into this Condition is not required in this case.)

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.19

Unit 2 DG and offsite circuit are governed by the Unit 2 Technical Specifications. Performance of the applicable Unit 2 Surveillances will satisfy both any Unit 2 requirements, as well as satisfying this Unit 1 SR. Several exceptions are noted to the Unit 2 SRs: SR 3.8.1.6 is excepted since only one Unit 2 circuit is required by the Unit 1 Specification (therefore, there is not necessarily a second circuit to transfer to); SRs 3.8.1.10, 15, and 17 are excepted since they relate to the DG response to a Unit 2 ECCS initiation signal, which is not a necessary function for support of the Unit 1 requirement for an OPERABLE Unit 2 DG.

The Frequency required by the applicable Unit 2 SR also governs performance of that SR for both Units.

REFERENCES

1. 10 CFR 50, Appendix A, GDC 17.
2. FSAR, Sections 8.3 and 8.4.
3. Not used.
4. Unit 2 FSAR, Section 6.2.3.
5. Unit 2 FSAR, Chapter 15.
6. Regulatory Guide 1.93, December 1974.
7. Generic Letter 84-15.
8. 10 CFR 50, Appendix A, GDC 18.
9. Regulatory Guide 1.9, March 1971.
10. Regulatory Guide 1.108, August 1977.
11. Regulatory Guide 1.137, October 1979.
12. IEEE Standard 387-1984.
13. IEEE Standard 308-1980.
14. NRC No. 93-102, "Final Policy Statement on Technical Specification Improvements," July 23, 1993.
15. NEDC-32988-A, Revision 2, Technical Justification to Support Risk-Informed Modification to Selected Required End States for BWR Plants, December 2002.
16. ~~Attachment 5, “Compensatory and Risk Management Controls for Hatch Nuclear Plant (HNP) Diesel Generator (DG) One-time 19-day Completion Time Allowance,” Letter NL-20-1000 from C.A. Gayheart (SNC) to the Document Control Desk (NRC), dated August 23, 2020.~~
17. ~~Regulatory Guide 1.177, May 2011.~~

BASES (continued)

ACTIONS

A.1

If one or more of the required Unit 2 DG DC electrical power subsystems is inoperable (e.g., inoperable battery, inoperable battery charger(s), or inoperable battery charger and associated inoperable battery), or if the swing DG DC electrical power subsystem is inoperable due to performance of SR 3.8.4.3 or SR 3.8.6.6, and a loss of function has not occurred as described in Condition G, the remaining DC electrical power subsystems have the capacity to support a safe shutdown and to mitigate an accident condition. In the case of an inoperable required Unit 2 DG DC electrical power subsystem, continued power operation should not exceed 7 days, since a subsequent postulated worst case single failure could result in the loss of certain safety functions (e.g., SGT System and LPCI valve load centers). The 7 day Completion Time takes into account the capacity and capability of the remaining DC sources, and is based on the shortest restoration time allowed for the systems affected by the inoperable DC source in the respective system Specification. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program.

In the case of an inoperable swing DG DC electrical power subsystem, since a subsequent postulated worst case single failure could result in the loss of minimum necessary DC electrical subsystems to mitigate a postulated worst case accident, continued power operation should also not exceed 7 days. The 7 day Completion Time is based upon the swing DG DC electrical power subsystem being inoperable due to performance of SR 3.8.4.3 or SR 3.8.6.6. Performance of these two SRs will result in inoperability of the DC battery. Since this battery is common to both units, more time is provided to restore the battery, if the battery is inoperable for performance of required Surveillances, to preclude the need to perform a dual unit shutdown to perform these Surveillances. The swing DG DC electrical power subsystem also does not provide power to the same type of equipment as the other DG DC sources (e.g., breaker control power for 4160 V loads is not provided by the swing DG battery). The Completion Time also takes into account the capacity and capability of the remaining DC sources. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program.

B.1, B.2, and B.3

Condition B represents one Unit 1 DG DC subsystem with a required battery charger inoperable (e.g., the voltage limit of SR 3.8.4.1 is not maintained), or the swing DG DC subsystem with a required battery charger inoperable for reasons other than Condition A. The

(continued)

ACTIONS

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

not less than or equal to 5 amps this indicates there may be additional battery problems and the battery must be declared inoperable.

Required Action B.3 limits the restoration time for the inoperable battery charger to 72 hours. This action is applicable if an alternate means of restoring battery terminal voltage to greater than or equal to the minimum established float voltage has been used (e.g., balance of plant non-Class 1E charger). The 72 hour Completion Time reflects a reasonable time to effect restoration of the qualified battery charger to OPERABLE status. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program.

C.1

If a Unit 1 DG DC electrical power subsystem is inoperable (for reasons other than Condition B), or if the swing DG DC electrical power subsystem is inoperable for reasons other than Condition A or B, (e.g., inoperable battery or inoperable battery charger and associated inoperable battery), the remaining DC electrical power subsystems have the capacity to support a safe shutdown and to mitigate an accident condition. Since a subsequent postulated worst case single failure could result in the loss of minimum necessary DC electrical subsystems to mitigate a postulated worst case accident, continued power operation should not exceed 12 hours. The 12 hour Completion Time provides a period of time to correct the problem commensurate with the importance of maintaining the DG DC electrical power subsystem OPERABLE. (The DG DC electrical power subsystem affects both the DG and the offsite circuit, as well as the breaker closure power for various 4160 VAC loads, but does not affect 125/250 VDC station service loads.) Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program.

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

Condition D represents one Unit 1 station service DC subsystem with a required battery charger inoperable (e.g., the voltage limit of SR 3.8.4.1 is not maintained). The ACTIONS provide a tiered response that focuses on returning the battery to the fully charged state and restoring a fully qualified charger to OPERABLE status in a reasonable time period. Required Action D.1 requires that the battery terminal voltage be restored to greater than or equal to the minimum established float voltage within 2 hours. This time provides for returning the inoperable charger to OPERABLE status or providing an alternate means of restoring battery terminal voltage to greater than or

(continued)

BASES

ACTIONS

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

A discharged battery having terminal voltage of at least the minimum established float voltage indicates that the battery is on the exponential charging current portion (the second part) of its recharge cycle. The time to return a battery to its fully charged state under this condition is simply a function of the amount of the previous discharge and the recharge characteristic of the battery. Thus there is good assurance of fully recharging the battery within 12 hours, avoiding a premature shutdown with its own attendant risk.

If established battery terminal float voltage cannot be restored to greater than or equal to the minimum established float voltage within 2 hours, and the charger is not operating in the current-limiting mode, a faulty charger is indicated. A faulty charger that is incapable of maintaining established battery terminal float voltage does not provide assurance that it can revert to and operate properly in the current limit mode that is necessary during the recovery period following a battery discharge event that the DC system is designed for.

If the charger is operating in the current limit mode after 2 hours, that is an indication that the battery is partially discharged and its capacity margins will be reduced. This time to return that battery to its fully charged condition in this case is a function of the battery charger capacity, the amount of loads on the associated DC system, the amount of the previous discharge, and the recharge characteristics of the battery. The charge time can be extensive, and there is not adequate assurance that it can be recharged within 12 hours (Required Action D.2).

Required Action D.2 requires that the battery float current be verified as less than or equal to 20 amps. This indicates that, if the battery had been discharged as the result of the inoperable battery charger, it is now fully capable of supplying the maximum expected load requirement. The 20 amp value is based on returning the battery to 95% charge and assumes a 5% design margin for the battery. If at the expiration of the initial 12 hour period the battery float current is not less than or equal to 20 amps this indicates there may be additional battery problems and the battery must be declared inoperable.

Required Action D.3 limits the restoration time for the inoperable battery charger to 72 hours. This action is applicable if an alternate means of restoring battery terminal voltage to greater than or equal to the minimum established float voltage has been used (e.g., balance of plant non-Class 1E charger). The 72 hour Completion Time reflects a reasonable time to effect restoration of the qualified battery charger to OPERABLE status. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program.

(continued)

ACTIONS

E.1

If one of the required Unit 1 station service DC electrical power subsystems is inoperable for reasons other than Condition D (e.g., inoperable battery or inoperable battery charger and associated inoperable battery), the remaining DC electrical power subsystems have the capacity to support a safe shutdown and to mitigate an accident condition. Since a subsequent postulated worst case single failure could result in the loss of minimum necessary DC electrical subsystems to mitigate a postulated worst case accident, continued power operation should not exceed 2 hours. The 2 hour Completion Time is based on Regulatory Guide 1.93 (Ref. 7) and reflects a reasonable time to assess unit status as a function of the inoperable DC electrical power subsystem and, if the DC electrical power subsystem is not restored to OPERABLE status, to prepare to effect an orderly and safe unit shutdown. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program.

F.1

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

Remaining in the Applicability of the LCO is acceptable because the plant risk in MODE 3 is similar to or lower than the risk in MODE 4 (Ref. 11) and because the time spent in MODE 3 to perform the necessary repairs to restore the system to OPERABLE status will be short. However, voluntary entry into MODE 4 may be made as it is also an acceptable low-risk state.

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

(continued)

BASES (continued)

ACTIONS

A.1

If one or more of the required Unit 2 AC or DC electrical power distribution subsystems are inoperable, and a loss of function has not occurred as described in Condition F, the remaining AC and DC electrical power distribution subsystems have the capacity to support a safe shutdown and to mitigate an accident condition. Since a subsequent postulated worst case single failure could, however, result in the loss of certain safety functions (e.g., SGT System and LPCI valve load centers), continued power operation should not exceed 7 days. The 7 day Completion Time takes into account the capacity and capability of the remaining AC and DC electrical power distribution subsystems, and is based on the shortest restoration time allowed for the systems affected by the inoperable AC and DC electrical power distribution subsystem in the respective system Specification. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program.

B.1

If a Unit 1 or swing DG DC electrical power distribution subsystem is inoperable, the remaining DC electrical power distribution subsystems have the capacity to support a safe shutdown and to mitigate an accident condition. Since a subsequent postulated worst case single failure could, however, result in the loss of minimum necessary DC electrical subsystems to mitigate a postulated worst case accident, continued power operation should not exceed 12 hours. The 12 hour Completion Time provides a period of time to correct the problem commensurate with the importance of maintaining the DG DC electrical power distribution subsystem OPERABLE. (The DG DC electrical power distribution subsystem affects both the DG and the offsite circuit, as well as the breaker closure power for various 4160 VAC loads, but does not affect 125/250 VDC station service loads). Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program.

The 12 hour time limit before requiring a unit shutdown in this Condition is acceptable because:

a. There is a potential for decreased safety if the unit operators' attention is diverted from the evaluations and actions necessary to restore power to the affected bus(es) to the actions associated with taking the unit to shutdown within this time limit.

b. The potential for an event in conjunction with a single failure of a redundant component in the division with AC power. [The

(continued)

BASES

ACTIONS (continued)

C.1

With one or more required Unit 1 or swing AC buses, load centers, motor control centers, or distribution panels in one subsystem inoperable, the remaining AC electrical power distribution subsystems are capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure. The overall reliability is reduced, however, because a single failure in the remaining power distribution subsystems could result in the minimum required ESF functions not being supported. Therefore, the required AC buses, load centers, motor control centers, and distribution panels must be restored to OPERABLE status within 8 hours. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program.

The Condition C postulated worst scenario is one 4160 V bus without AC power (i.e., no offsite power to the 4160 V bus and the associated DG inoperable). In this condition, the unit is more vulnerable to a complete loss of Unit 1 AC power. It is, therefore, imperative that the unit operators' attention be focused on minimizing the potential for loss of power to the remaining buses by stabilizing the unit, and on restoring power to the affected buses. The 8 hour time limit before requiring a unit shutdown in this Condition is acceptable because:

a. There is a potential for decreased safety if the unit operators' attention is diverted from the evaluations and actions necessary to restore power to the affected bus(es) to the actions associated with taking the unit to shutdown within this time limit.

b. The potential for an event in conjunction with a single failure of a redundant component in the division with AC power. [The redundant component is verified OPERABLE in accordance with Specification 5.5.10, "Safety Function Determination Program (SFDP)."]

D.1

With one Unit 1 station service DC bus inoperable, the remaining DC electrical power distribution subsystem is capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure. The overall reliability is reduced, however, because a single failure in the remaining DC electrical power distribution subsystems could result in the minimum required ESF functions not being supported. Therefore, the required Unit 1 DC buses must be restored to OPERABLE status within 2 hours by powering the bus from the associated battery or charger. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program.

(continued)

BASES

ACTIONS

A.1 (continued)

Figure 3.1.7-1 or 3.1.7-2), the solution must be restored to within Region A limits in 72 hours. It should be noted that the lowest acceptable concentration in Region is 5%. It is not necessary under these conditions to enter Condition C for both SLC subsystems inoperable, since the SLC subsystems are capable of performing their original design basis functions. Because of the low probability of an event and the fact that the SLC System capability still exists for vessel injection under these conditions, the allowed Completion Time of 72 hours is acceptable and provides adequate time to restore concentration to within limits.

B.1

If one SLC subsystem is inoperable for reasons other than Condition A, the inoperable subsystem must be restored to OPERABLE status within 7 days or in accordance with the Risk Informed Completion Time Program. In this condition, the remaining OPERABLE subsystem is adequate to perform the shutdown function and provide adequate buffering agent to the suppression pool. However, the overall reliability is reduced because a single failure in the remaining OPERABLE subsystem could result in reduced SLC System capability. The 7 day Completion Time is based on the availability of an OPERABLE subsystem capable of performing the intended SLC System functions and the low probability of a DBA or severe transient occurring requiring SLC injection.

(continued)

BASES

ACTIONS (continued)

discovered to be inoperable or not within limits, will not result in separate entry into the Condition. Section 1.3 also specifies that Required Actions of the Condition continue to apply for each additional failure, with Completion Times based on initial entry into the Condition. However, the Required Actions for inoperable RPS instrumentation channels provide appropriate compensatory measures for separate inoperable channels. As such, a Note has been provided that allows separate Condition entry for each inoperable RPS instrumentation channel.

A.1 and A.2

Because of the diversity of sensors available to provide trip signals and the redundancy of the RPS design, an allowable out of service time of 12 hours has been shown to be acceptable (Refs. 9, 13, and 17) to permit restoration of any inoperable channel to OPERABLE status. However, this out of service time is only acceptable provided the associated Function's inoperable channel is in one trip system and the Function still maintains RPS trip capability (refer to Required Actions B.1, B.2, and C.1 Bases). Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time (RICT) Program. The alternative Completion Times in Required Action A.1 and Required Action A.2 are modified by a Note which excludes use of the RICT Program for Functions 7.a, 7.b, and 10 since these functions are not modeled in the plant PRA.

If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel or the associated trip system must be placed in the tripped condition per Required Actions A.1 and A.2. Placing the inoperable channel in trip (or the associated trip system in trip) would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. Alternatively, if it is not desired to place the channel (or trip system) in trip (e.g., as in the case where placing the inoperable channel in trip would result in a full scram), Condition D must be entered and its Required Action taken.

As noted, Required Action A.2 is not applicable for APRM Functions 2.a, 2.b, 2.c, 2.d, and 2.f. Inoperability of one required APRM channel affects both trip systems; thus, Required Action A.1 must be satisfied. This is the only action (other than restoring OPERABILITY) that will restore capability to accommodate a single failure. Inoperability of more than one required APRM channel of the same trip function results in loss of trip capability and entry into Condition C, as well as entry into Condition A for each channel.

(continued)

ACTIONS

B.1 and B.2 (continued)

provided at least one channel per trip system is OPERABLE, the RPS still maintains trip capability for that Function, but cannot accommodate a single failure in either trip system.

Required Actions B.1 and B.2 limit the time the RPS scram logic, for any Function, would not accommodate single failure in both trip systems (e.g., one-out-of-one and one-out-of-one arrangement for a typical four channel Function). The reduced reliability of this logic arrangement was not evaluated in References 9, 13, and 17 for the 12 hour Completion Time. Within the 6 hour allowance, the associated Function will have all required channels OPERABLE or in trip (or any combination) in one trip system.

Completing one of these Required Actions restores RPS to a reliability level equivalent to that evaluated in References 9, 13, and 17 which justified a 12 hour allowable out of service time as presented in Condition A. The trip system in the more degraded state should be placed in trip or, alternatively, all the inoperable channels in that trip system should be placed in trip (e.g., a trip system with two inoperable channels could be in a more degraded state than a trip system with four inoperable channels if the two inoperable channels are in the same Function while the four inoperable channels are all in different Functions). The decision of which trip system is in the more degraded state should be based on prudent judgment and take into account current plant conditions (i.e., what MODE the plant is in). If this action would result in a scram or RPT, it is permissible to place the other trip system or its inoperable channels in trip.

The 6 hour Completion Time is judged acceptable based on the remaining capability to trip, the diversity of the sensors available to provide the trip signals, the low probability of extensive numbers of inoperabilities affecting all diverse Functions, and the low probability of an event requiring the initiation of a scram. Alternatively, a Completion Time can be determined in accordance with the RICT Program. The alternative Completion Times in Required Action B.1 and Required Action B.2 are modified by a Note which excludes use of the RICT Program for Functions 7.a, 7.b, and 10 since these functions are not modeled in the plant PRA.

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

As noted, Condition B is not applicable for APRM Functions 2.a, 2.b, 2.c, 2.d, and 2.f. Inoperability of an APRM channel affects both trip

(continued)

ACTIONS

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

A.1 and A.2

With one or more channels inoperable, but with EOC-RPT trip capability maintained (refer to Required Actions B.1 and B.2 Bases), the EOC-RPT System is capable of performing the intended function. However, the reliability and redundancy of the EOC-RPT instrumentation is reduced such that a single failure in the remaining trip system could result in the inability of the EOC-RPT System to perform the intended function. Therefore, only a limited time is allowed to restore compliance with the LCO. Because of the diversity of sensors available to provide trip signals, the low probability of extensive numbers of inoperabilities affecting all diverse Functions, and the low probability of an event requiring the initiation of an EOC-RPT, 72 hours is provided to restore the inoperable channels (Required Action A.1) or apply the EOC-RPT inoperable MCPR limit. Alternately, the inoperable channels may be placed in trip (Required Action A.2) since this would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. As noted, placing the channel in trip with no further restrictions is not allowed if the inoperable channel is the result of an inoperable breaker, since this may not adequately compensate for the inoperable breaker (e.g., the breaker may be inoperable such that it will not open). Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program. If it is not desired to place the channel in trip (e.g., as in the case where placing the inoperable channel in trip would result in an RPT, or if the inoperable channel is the result of an inoperable breaker), Condition C must be entered and its Required Actions taken.

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

trip system could result in the inability of the ATWS-RPT System to perform the intended function. Therefore, only a limited time is allowed to restore the inoperable channels to OPERABLE status. Because of the diversity of sensors available to provide trip signals, the low probability of extensive numbers of inoperabilities affecting all diverse Functions, and the low probability of an event requiring the initiation of ATWS-RPT, 14 days is provided to restore the inoperable channel (Required Action A.1). Alternately, the inoperable channel may be placed in trip (Required Action A.2), since this would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. As noted, placing the channel in trip with no further restrictions is not allowed if the inoperable channel is the result of an inoperable breaker, since this may not adequately compensate for the inoperable breaker (e.g., the breaker may be inoperable such that it will not open). Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program. If it is not desired to place the channel in trip (e.g., as in the case where placing the inoperable channel would result in an RPT), or if the inoperable channel is the result of an inoperable breaker, Condition D must be entered and its Required Actions taken.

B.1

Required Action B.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same Function result in the Function not maintaining ATWS-RPT trip capability. A Function is considered to be maintaining ATWS-RPT trip capability when sufficient channels are OPERABLE or in trip such that the ATWS-RPT System will generate a trip signal from the given Function on a valid signal, and both recirculation pumps can be tripped.

The 72 hour Completion Time is sufficient for the operator to take corrective action (e.g., restoration or tripping of channels) and takes into account the likelihood of an event requiring actuation of the ATWS-RPT instrumentation during this period and that one Function is still maintaining ATWS-RPT trip capability.

C.1

Required Action C.1 is intended to ensure that appropriate Actions are taken if multiple, inoperable, untripped channels within both Functions

(continued)

BASES

ACTIONS

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

Notes are also provided (the Note to Required Action B.1 and the Note to Required Action B.2) to delineate which Required Action is applicable for each Function that requires entry into Condition B if an associated channel is inoperable. This ensures that the proper loss of initiation capability check is performed. Required Action B.1 (the Required Action for certain inoperable channels in the low pressure ECCS subsystems) is not applicable to Function 2.e, since this Function provides backup to administrative controls ensuring that operators do not divert LPCI flow from injecting into the core when needed. Thus, a total loss of Function 2.e capability for 24 hours is allowed, since the LPCI subsystems remain capable of performing their intended function.

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." For Required Action B.1, the Completion Time only begins upon discovery that features in the same system (e.g., both CS subsystems) cannot be automatically initiated due to inoperable, untripped channels within the same Function as described in the paragraph above. For Required Action B.2, the Completion Time only begins upon discovery that the HPCI System cannot be automatically initiated due to inoperable, untripped channels for the associated Function as described in the paragraph above. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

Because of the diversity of sensors available to provide initiation signals and the redundancy of the ECCS design, an allowable out of service time of 24 hours has been shown to be acceptable (Ref. 5) to permit restoration of any inoperable channel to OPERABLE status. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program. The alternative Completion Time in Required Action B.3 is modified by a Note which excludes use of the RICT Program for Function 2.e since this function is not modeled in the plant PRA. If

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

The Note states that Required Action C.1 is only applicable for Functions 1.c, 2.c, 2.d, and 2.f. Required Action C.1 is not applicable to Function 3.c (which also requires entry into this Condition if a channel in this Function is inoperable), since the loss of one channel results in a loss of the Function (two-out-of-two logic). This loss was considered during the development of Reference 5 and considered acceptable for the 24 hours allowed by Required Action C.2.

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." For Required Action C.1, the Completion Time only begins upon discovery that the same feature in both subsystems (e.g., both CS subsystems) cannot be automatically initiated due to inoperable channels within the same Function as described in the paragraph above. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration of channels.

Because of the diversity of sensors available to provide initiation signals and the redundancy of the ECCS design, an allowable out of service time of 24 hours has been shown to be acceptable (Ref. 5) to permit restoration of any inoperable channel to OPERABLE status. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program. The alternative Completion Time in Required Action C.2 is modified by a Note which excludes use of the RICT Program for Function 3.c. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, Condition H must be entered and its Required Action taken. The Required Actions do not allow placing the channel in trip since this action would either cause the initiation or it would not necessarily result in a safe state for the channel in all events.

D.1, D.2.1, and D.2.2

Required Action D.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same Function result in a complete loss of automatic component initiation capability for the HPCI System. In this situation (loss of automatic

(continued)

BASES

ACTIONS

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

suction swap), the 24 hour allowance of Required Actions D.2.1 and D.2.2 is not appropriate and the HPCI System must be declared inoperable within 1 hour after discovery of loss of HPCI initiation capability. As noted, Required Action D.1 is only applicable if the HPCI pump suction is not aligned to the suppression pool, since, if aligned, the Function is already performed.

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." For Required Action D.1, the Completion Time only begins upon discovery that the HPCI System cannot be automatically aligned to the suppression pool due to inoperable, untripped channels in the same Function as described in the paragraph above. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

Because of the diversity of sensors available to provide initiation signals and the redundancy of the ECCS design, an allowable out of service time of 24 hours has been shown to be acceptable (Ref. 5) to permit restoration of any inoperable channel to OPERABLE status. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be placed in the tripped condition per Required Action D.2.1 or the suction source must be aligned to the suppression pool within 24 hours per Required Action D.2.2. Placing the inoperable channel in trip performs the intended function of the channel (shifting the suction source to the suppression pool). Performance of either of these two Required Actions will allow operation to continue. If Required Action D.2.1 or D.2.2 is performed, measures should be taken to ensure that the HPCI System piping remains filled with water. Alternately, if it is not desired to perform Required Actions D.2.1 and D.2.2 (e.g., as in the case where shifting the suction source could drain down the HPCI suction piping), Condition H must be entered and its Required Action taken.

E.1 and E.2

Required Action E.1 is intended to ensure that appropriate actions are taken if multiple, inoperable channels within the Core Spray and Low Pressure Coolant Injection Pump Discharge Flow - Low Bypass Functions result in automatic initiation capability being lost for the

(continued)

BASES

ACTIONS

E.1 and E.2 (continued)

same feature(s) in both divisions. For Required Action E.1, the features would be those that are initiated by Functions 1.d and 2.g (e.g., low pressure ECCS). Since each inoperable channel would have Required Action E.1 applied separately (refer to ACTIONS Note), each inoperable channel would only require the affected low pressure ECCS pump(s) to be declared inoperable. However, since channels for more than one low pressure ECCS pump are inoperable, and the Completion Times started concurrently for the channels of the low pressure ECCS pumps, this results in the affected low pressure ECCS pumps being concurrently declared inoperable.

In this situation (loss of minimum flow capability), the 7 day allowance of Required Action E.2 is not appropriate and the subsystem associated with each inoperable channel must be declared inoperable within 1 hour. A Note is also provided (the Note to Required Action E.1) to delineate that Required Action E.1 is only applicable to low pressure ECCS Functions. Required Action E.1 is not applicable to HPCI Function 3.f since the loss of one channel results in a loss of the Function (one-out-of-one logic). This loss was considered during the development of Reference 5 and considered acceptable for the 7 days allowed by Required Action E.2. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program.

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." For Required Action E.1, the Completion Time only begins upon discovery that the same feature in both subsystems (e.g., both CS subsystems) cannot be automatically initiated due to inoperable channels within the same Function as described in the paragraph above. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration of channels.

If the instrumentation that controls the pump minimum flow valve is inoperable, such that the valve will not automatically open, extended pump operation with no injection path available could lead to pump overheating and failure. If there were a failure of the instrumentation, such that the valve would not automatically close, a portion of the

(continued)

BASES

ACTIONS (continued)

B.1 and B.2

Required Action B.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same Function result in a complete loss of automatic initiation capability for the RCIC System. In this situation (loss of automatic initiation capability), the 24 hour allowance of Required Action B.2 is not appropriate, and the RCIC System must be declared inoperable within 1 hour after discovery of loss of RCIC initiation capability.

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." For Required Action B.1, the Completion Time only begins upon discovery that the RCIC System cannot be automatically initiated due to inoperable, untripped Reactor Vessel Water Level - Low Low, Level 2 channels as described in the paragraph above. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

Because of the redundancy of sensors available to provide initiation signals and the fact that the RCIC System is not assumed in any accident or transient analysis, an allowable out of service time of 24 hours has been shown to be acceptable (Ref. 1) to permit restoration of any inoperable channel to OPERABLE status. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be placed in the tripped condition per Required Action B.2. Placing the inoperable channel in trip would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. Alternately, if it is not desired to place the channel in trip (e.g., as in the case where placing the inoperable channel in trip would result in an initiation), Condition E must be entered and its Required Action taken.

C.1

A risk based analysis was performed and determined that an allowable out of service time of 24 hours (Ref. 1) is acceptable to permit restoration of any inoperable channel to OPERABLE status (Required Action C.1). A Required Action (similar to Required Action B.1) limiting the allowable out of service time, if a loss of automatic RCIC initiation capability exists, is not required. This

(continued)

BASES

ACTIONS

C.1 (continued)

Condition applies to the Reactor Vessel Water Level - High, Level 8 Function whose logic is arranged such that any inoperable channel will result ina loss of automatic RCIC initiation capability (loss of high water level trip capability). As stated above, this loss of automatic RCIC initiation capability was analyzed and determined to be acceptable. The Required Action does not allow placing a channel in trip since this action would not necessarily result in a safe state for the channel in all events.

D.1, D.2.1, and D.2.2

Required Action D.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same Function result in automatic component initiation capability being lost for the feature(s). For Required Action D.1, the RCIC System is the only associated feature. In this situation (loss of automatic suction swap), the 24 hour allowance of Required Actions D.2.1 and D.2.2 is not appropriate, and the RCIC System must be declared inoperable within 1 hour from discovery of loss of RCIC initiation capability. As noted, Required Action D.1 is only applicable if the RCIC pump suction is not aligned to the suppression pool since, if aligned, the Function is already performed.

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." For Required Action D.1, the Completion Time only begins upon discovery that the RCIC System cannot be automatically aligned to the suppression pool due to inoperable, untripped channels in the same Function as described in the paragraph above. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

Because of the redundancy of sensors available to provide initiation signals and the fact that the RCIC System is not assumed in any accident or transient analysis, an allowable out of service time of 24 hours has been shown to be acceptable (Ref. 1) to permit restoration of any inoperable channel to OPERABLE status. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be placed in the tripped condition per Required Action D.2.1, which performs the intended function of the channel (shifting the suction source to the

(continued)

BASES

ACTIONS

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

suppression pool). Alternatively, Required Action D.2.2 allows the manual alignment of the RCIC suction to the suppression pool within 24 hours, which also performs the intended function. If Required Action D.2.1 or D.2.2 is performed, measures should be taken to ensure that the RCIC System piping remains filled with water. If it is not desired to perform Required Actions D.2.1 and D.2.2 (e.g., as in the case where shifting the suction source could drain down the RCIC suction piping), Condition E must be entered and its Required Action taken.

E.1

With any Required Action and associated Completion Time not met, the RCIC System may be incapable of performing the intended function, and the RCIC System must be declared inoperable immediately.

SURVEILLANCE REQUIREMENTS

As noted in the beginning of the SRs, the SRs for each RCIC System instrumentation Function are found in the SRs column of Table 3.3.5.3-1.

The Surveillances are modified by a Note to indicate that when a channel is placed in an inoperable status solely for performance of required Surveillances, entry into associated Conditions and Required Actions may be delayed as follows: (a) for up to 6 hours for Function 2; and (b) for up to 6 hours for Functions 1, 3, and 4, provided the associated Function maintains trip capability. Upon completion of the Surveillance, or expiration of the 6 hour allowance, the channel must be returned to OPERABLE status or the applicable Condition entered and Required Actions taken. This Note is based on the reliability analysis (Ref. 1) assumption of the average time required to perform channel surveillance. That analysis demonstrated that the 6 hour testing allowance does not significantly reduce the probability that the RCIC will initiate when necessary.

SR 3.3.5.3.1

Performance of the CHANNEL CHECK ensures that a gross failure of instrumentation has not occurred. A CHANNEL CHECK is normally a comparison of the parameter indicated on one channel to a parameter on other similar channels. It is based on the assumption that

(continued)

BASES

ACTIONS (continued)

A.1 and A.2

Because of the diversity of sensors available to provide isolation signals and the redundancy of the isolation design, an allowable out of service time of 12 hours for Functions 2.a, 2.b, 6.b, 7.a, and ~~6~~7.b (as provided by a Note to Required Action A.1) and 24 hours for Functions other than Functions 2.a, 2.b, 6.b, 7.a, and ~~6~~7.b (as provided by a Note to Required Action A.2) has been shown to be acceptable (Refs. 4 and 5) to permit restoration of any inoperable channel to OPERABLE status. This out of service time is only acceptable provided the associated Function is still maintaining isolation capability (refer to Required Action B.1 Bases). Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time (RICT) Program. The alternative Completion Time in Required Action A.1 is modified by a Note which excludes use of the RICT Program for Functions 6.b, 7.a, and 7.b. Function 6.b is only applicable in MODE 3 and RICT is only applied in MODE 1. Function 7 is not modeled in the PRA. The alternative Completion Time in Required Action A.2 is modified by a Note which excludes use of the RICT Program for Functions 2.c, 2.d, 2.e, and 6.a, which are not modeled in the PRA.

If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be placed in the tripped condition per the Required Actions~~ A.1~~. Placing the inoperable channel in trip would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue with no further restrictions. Alternately, if it is not desired to place the channel in trip (e.g., as in the case where placing the inoperable channel in trip would result in an isolation), Condition C must be entered and its Required Action taken.

B.1

Required Action B.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same Function result in automatic isolation capability being lost for the associated penetration flow path(s). The MSL Isolation Functions are considered to be maintaining isolation capability when sufficient channels are OPERABLE or in trip, such that both trip systems will generate a trip signal from the given Function on a valid signal. The other isolation functions are considered to be maintaining isolation capability when sufficient channels are OPERABLE or in trip, such that one trip system will generate a trip signal from the given Function on a valid signal. This ensures that one of the two PCIVs in the associated penetration flow path can receive an isolation signal from the given Function. As noted, this Condition is not applicable for

(continued)

BASES

LCO (continued)

subsystems and ADS must therefore be OPERABLE to satisfy the single failure criterion required by Reference 11. (Reference 21 takes no credit for HPCI.) HPCI must be OPERABLE due to risk consideration.

LPCI subsystems may be considered OPERABLE during alignment and operation for decay heat removal when below the actual RHR low pressure permissive pressure in MODE 3, if capable of being manually realigned (remote or local) to the LPCI mode and not otherwise inoperable. At these low pressures and decay heat levels, a reduced complement of ECCS subsystems should provide the required core cooling, thereby allowing operation of RHR shutdown cooling when necessary.

APPLICABILITY

All ECCS subsystems are required to be OPERABLE during MODES 1, 2, and 3, when there is considerable energy in the reactor core and core cooling would be required to prevent fuel damage in the event of a break in the primary system piping. In MODES 2 and 3, when reactor steam dome pressure is ≤ 150 psig, ADS and HPCI are not required to be OPERABLE because the low pressure ECCS subsystems can provide sufficient flow below this pressure. Requirements for MODES 4 and 5 are specified in LCO 3.5.2, "RPV Water Inventory Control."

ACTIONS

A Note prohibits the application of LCO 3.0.4.b to an inoperable HPCI subsystem. There is an increased risk associated with entering a MODE or other specified condition in the Applicability with an inoperable HPCI subsystem and the provisions of LCO 3.0.4.b, which allows entry into a MODE or other specified condition in the Applicability with the LCO not met after performance of a risk assessment addressing inoperable systems and components, should not be applied in this circumstance.

A.1

If any one low pressure ECCS injection/spray subsystem is inoperable, or if one LPCI pump in both LPCI subsystems is inoperable, the inoperable subsystem(s) must be restored to OPERABLE status within 7 days or in accordance with the Risk Informed Completion Time Program. In this condition, the remaining OPERABLE subsystems provide adequate core cooling during a LOCA. However, overall ECCS reliability is reduced, because a single failure in one of the remaining OPERABLE subsystems, concurrent with a LOCA, may result in the ECCS not being able to perform its intended safety function. The 7 day Completion Time is

(continued)

ACTIONS

A.1 (continued)

based on a reliability study (Ref. 12) that evaluated the impact on ECCS availability, assuming various components and subsystems were taken out of service. The results were used to calculate the average availability of ECCS equipment needed to mitigate the consequences of a LOCA as a function of allowed outage times (i.e., Completion Times).

~~A.2.1 and A.2.2~~

~~The Completion Time to restore the low pressure ECCS injection/spray subsystem to OPERABLE status to facilitate the 2D RHR pump repair may be extended to 15 days, provided action is taken within 7 days to establish compensatory and risk management controls.~~

~~The A.2.1 and A.2.2 Required Actions are modified by two Notes. Note 1 ensures that the A.2.1 and A.2.2 Required Actions are only applied during the 2D RHR pump repair. Note 2 limits the time period the A.2.1 and A.2.2 Required Actions may be used.~~

~~The extended Completion Time is subject to additional compensatory controls specified in SNC letter NL-21-0423, dated April 22, 2021, that consists of controls that must be established and maintained during the extended Completion Time period to preserve defense-in-depth.~~

~~If Required Action A.2.1 is met, the allowed time to restore the ECCS injection/spray subsystem to OPERABLE status can be extended to 15 days from entry into Condition A. The extended Completion Time of Required Action A.2.2 represents a balance between the risk associated with continued plant operation with less than the required system or component redundancy and the risk associated with initiating a plant transient while transitioning the unit based on the loss of redundancy. With compensatory and risk management controls established, the remaining OPERABLE ECCS injection/spray subsystems are adequate to provide low pressure coolant injection to the reactor core. The extended Completion Time takes into account the low probability of a DBA or an LOSP occurring during this period.~~

~~The Completion Time of Required Action A.2.2 is based on a defense-in-depth philosophy, and is risk informed using the plant PRA. The risk impact of the extended Completion Time has been evaluated pursuant to the risk assessment and management provisions of the Maintenance Rule, 10 CFR 50.65(a)(4), and the associated implementation guidance, Regulatory Guide 1.160. Regulatory Guide 1.160 endorses the guidance in Section 11 of NUMARC 93-01. This guidance provides for the consideration of dynamic plant configuration~~

(continued)

ACTIONS

~~A.2.1 and A.2.2 (continued)~~

~~issues, emergent conditions, and other aspects pertinent to plant operation with the 2D RHR pump inoperable for an extended period of time. These considerations may result in additional risk management and other compensatory actions being required during the extended period that the 2D RHR pump is inoperable.~~

B.1

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

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

Required Action B.1 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 3. This Note prohibits the use of LCO 3.0.4.a to enter MODE 3 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 3, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

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

C.1

If one LPCI pump in one LPCI subsystem or one LPCI pump in both LPCI subsystems is inoperable and one CS subsystem is inoperable, the inoperable subsystem(s) must be restored to OPERABLE status within 1 hour or in accordance with the Risk Informed Completion

(continued)

BASES

ACTIONS

C.1 (continued)

Time (RICT) Program. In this condition, the remaining OPERABLE pumps within the subsystems provide adequate core cooling during a LOCA. However, overall ECCS reliability is reduced, because a single failure in one of the remaining OPERABLE pumps, concurrent with a LOCA, may result in the ECCS not being able to perform its intended safety function. The 1 hour Completion Time is allowed to prepare for an orderly shutdown or determine if a RICT is to be applied.

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

If the inoperable LPCI pump(s) or CS subsystem cannot be restored to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which overall plant risk is minimized. To achieve this status, the plant must be brought to at least MODE 2 in 6 hours, at least MODE 3 within 12 hours, and at least MODE 4 within 36 hours. The allowed Completion Times are reasonable and permit the shutdown to proceed in a controlled and orderly manner that is well within the specified maximum cooldown rate and within the capabilities of the unit, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

~~C~~E.1 and ~~C~~E.2

~~I~~f the HPCI System is inoperable and the RCIC System is verified to be OPERABLE, the HPCI System must be restored to OPERABLE

(continued)

ACTIONS

~~C~~E.1 and ~~C~~E.2 (continued)

status within 14 days or in accordance with the RICT Program. In this condition, adequate core cooling is ensured by the OPERABILITY of the redundant and diverse low pressure ECCS injection/spray subsystems in conjunction with ADS. Also, the RCIC System will automatically provide makeup water at most reactor operating pressures. Verification of RCIC OPERABILITY within 1 hour is therefore required when HPCI is inoperable. This may be performed as an administrative check by examining logs or other information to determine if RCIC is out of service for maintenance or other reasons. It does not mean to perform the Surveillances needed to demonstrate the OPERABILITY of the RCIC System. If the OPERABILITY of the RCIC System cannot be verified, however, Condition E must be immediately entered. If a single active component fails concurrent with a design basis LOCA, there is a potential, depending on the specific failure, that the minimum required ECCS equipment will not be available. A 14 day Completion Time is based on a reliability study cited in Reference 12 and has been found to be acceptable through operating experience.

~~D~~F.1 and ~~D~~F.2

If any one low pressure ECCS injection/spray subsystem, or one LPCI pump in both LPCI subsystems, is inoperable in addition to an inoperable HPCI System, the inoperable low pressure ECCS injection/spray subsystem or the HPCI System must be restored to OPERABLE status within 72 hours or in accordance with the RICT Program. In this condition, adequate core cooling is ensured by the OPERABILITY of the ADS and the remaining low pressure ECCS subsystems. However, the overall ECCS reliability is significantly reduced because a single failure in one of the remaining OPERABLE subsystems concurrent with a design basis LOCA may result in the ECCS not being able to perform its intended safety function. Since both a high pressure system (HPCI) and a low pressure subsystem are inoperable, a more restrictive Completion Time of 72 hours is required to restore either the HPCI System or the low pressure ECCS injection/spray subsystem to OPERABLE status. This Completion Time is based on a reliability study cited in Reference 12 and has been found to be acceptable through operating experience.

~~E~~G.1

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

(continued)

BASES (continued)

ACTIONS

~~E~~G.1 (continued)

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

Required Action ~~E~~G.1 is modified by a Note that states that LCO 3.0.4.a is not applicable when entering MODE 3. This Note prohibits the use of LCO 3.0.4.a to enter MODE 3 during startup with the LCO not met. However, there is no restriction on the use of LCO 3.0.4.b, if applicable, because LCO 3.0.4.b requires performance of a risk assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 3, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

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

~~F~~H.1 and ~~F~~H.2

With one ADS valve inoperable, no action is required, because an analysis demonstrated that the remaining six ADS valves are capable of providing the ADS function, per Reference 16.

If two or more ADS valves are inoperable, the plant must be brought to a condition in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and reactor steam dome pressure reduced to ≤ 150 psig within 36 hours. Entry into MODE 3 is not required if the reduction in reactor steam dome pressure to ≤ 150 psig results in exiting the Applicability for the Condition, and the ≤ 150 psig is achieved within the given 12 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

~~G~~I.1

When multiple ECCS subsystems are inoperable, as stated in Condition ~~G~~I, the plant is in a condition outside of the accident analyses. Therefore, LCO 3.0.3 must be entered immediately.

(continued)

ACTIONS (continued)

A.1 and A.2

If the RCIC System is inoperable during MODE 1, or MODE 2 or 3 with reactor steam dome pressure > 150 psig, and the HPCI System is verified to be OPERABLE, the RCIC System must be restored to OPERABLE status within 14 days or in accordance with the Risk Informed Completion Time Program. In this condition, loss of the RCIC System will not affect the overall plant capability to provide makeup inventory at high reactor pressure since the HPCI System is the only high pressure system assumed to function during a loss of coolant accident (LOCA). OPERABILITY of HPCI is therefore verified within 1 hour when the RCIC System is inoperable. This may be performed as an administrative check, by examining logs or other information, to determine if HPCI is out of service for maintenance or other reasons. It does not mean it is necessary to perform the Surveillances needed to demonstrate the OPERABILITY of the HPCI System. If the OPERABILITY of the HPCI System cannot be verified, however, Condition B must be immediately entered. For non-LOCA events, RCIC (as opposed to HPCI) is the preferred source of makeup coolant because of its relatively small capacity, which allows easier control of the RPV water level. Therefore, a limited time is allowed to restore the inoperable RCIC to OPERABLE status.

The 14 day Completion Time is based on a reliability study (Ref. 3) that evaluated the impact on ECCS availability, assuming various components and subsystems were taken out of service. The results were used to calculate the average availability of ECCS equipment needed to mitigate the consequences of a LOCA as a function of allowed outage times (AOTs). Because of similar functions of HPCI and RCIC, the AOTs (i.e., Completion Times) determined for HPCI are also applied to RCIC.

B.1

If the RCIC System cannot be restored to OPERABLE status within the associated Completion Time, or if the HPCI System is simultaneously inoperable, the plant must be brought to a condition in which overall plant risk is minimized. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours.

Remaining in the Applicability of the LCO is acceptable because the plant risk in MODE 3 is similar to or lower than the risk in MODE 4 (Ref. 6) and because the time spent in MODE 3 to perform the necessary repairs to restore the system to OPERABLE status will be short. However, voluntary entry into MODE 4 may be made as it is also an acceptable low-risk state.

(continued)

BASES

ACTIONS

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

The Required Actions have been modified by two Notes. Note 1 ensures that only the Required Actions and associated Completion Times of Condition C are required if both doors in the air lock are inoperable. With both doors in the air lock inoperable, an OPERABLE door is not available to be closed. Required Actions C.1 and C.2 are the appropriate remedial actions. Note 2 allows entry into and exit from the primary containment under the control of a dedicated individual stationed at the air lock to ensure that only one door is opened at a time (i.e., the individual performs the function of the interlock).

Required Action B.3 is modified by a Note that applies to air lock doors located in high radiation areas or areas with limited access due to inerting and that allows these doors to be verified locked closed by use of administrative controls. Allowing verification by administrative controls is considered acceptable, since access to these areas is typically restricted. Therefore, the probability of misalignment of the door, once it has been verified to be in the proper position, is small.

C.1, C.2, and C.3

If the air lock is inoperable for reasons other than those described in Condition A or B, Required Action C.1 requires action to be immediately initiated to evaluate containment overall leakage rates using current air lock leakage test results. An evaluation is acceptable since it is overly conservative to immediately declare the primary containment inoperable if both doors in the air lock have failed a seal test or if the overall air lock leakage is not within limits. In many instances (e.g., only one seal per door has failed), primary containment remains OPERABLE, yet only 1 hour (according to LCO 3.6.1.1) would be provided to restore the air lock door to OPERABLE status prior to requiring a plant shutdown. In addition, even with both doors failing the seal test, the overall containment leakage rate can still be within limits.

Required Action C.2 requires that one door in the primary containment air lock must be verified closed. This action must be completed within the 1 hour Completion Time. This specified time period is consistent with the ACTIONS of LCO 3.6.1.1, which require that primary containment be restored to OPERABLE status within 1 hour.

Additionally, the air lock must be restored to OPERABLE status within 24 hours or in accordance with the Risk Informed Completion Time

(continued)

BASES

ACTIONS

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

Program. The 24 hour Completion Time is reasonable for restoring an inoperable air lock to OPERABLE status considering that at least one door is maintained closed in the air lock.

D.1 and D.2

If the inoperable primary containment air lock cannot be restored to OPERABLE status within the associated Completion Time, the plant must be brought to a MODE in which the LCO does not apply. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours and to MODE 4 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required plant conditions from full power conditions in an orderly manner and without challenging plant systems.

SURVEILLANCE REQUIREMENTS

SR 3.6.1.2.1

Maintaining primary containment air locks OPERABLE requires compliance with the leakage rate test requirements of the Primary Containment Leakage Rate Testing Program (Ref. 3). This SR reflects the leakage rate testing requirements with respect to air lock leakage (Type B leakage tests). The acceptance criteria were established as a small fraction of the total allowable containment leakage. The periodic testing requirements verify that the air lock leakage does not exceed the allowed fraction of the overall primary containment leakage rate. The Frequency is required by the Primary Containment Leakage Rate Testing Program.

The SR has been modified by two Notes. Note 1 states that an inoperable air lock door does not invalidate the previous successful performance of the overall air lock leakage test. This is considered reasonable since either air lock door is capable of providing a fission product barrier in the event of a DBA. Note 2 has been added to this SR, requiring the results to be evaluated against the acceptance criteria applicable to SR 3.6.1.1.1. This ensures that air lock leakage is properly accounted for in determining the combined Type B and C primary containment leakage rate.

(continued)

BASES

ACTIONS (continued)

A.1, A.2, and A.3~~2~~

With one or more penetration flow paths with one PCIV inoperable except for inoperability due to leakage not within a limit specified in an SR to this LCO, the affected penetration flow paths must be isolated. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, a blind flange, and a check valve with flow through the valve secured.

For a penetration isolated in accordance with Required Action A.1 or A.2, the device used to isolate the penetration should be the closest available valve to the primary containment.

If a valve is inoperable due to isolation time not within limits or other condition that would not be expected to adversely affect leakage characteristics, the inoperable valve may be used to isolate the penetration.

~~The~~ Required Action A.1 must be completed within the 4 hour Completion Time ~~(8 hours for main steam lines)~~ or in accordance with the Risk Informed Completion Time Program. The Completion Time of 4 hours is reasonable considering the time required to isolate the penetration and the relative importance of supporting primary containment OPERABILITY during MODES 1, 2, and 3. For main steam lines, Required Action A.2 allows an 8 hour Completion Time ~~is allowed~~. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program. The Completion Time of 8 hours for the main steam lines allows a period of time to restore the MSIVs to OPERABLE status given the fact that MSIV closure will result in isolation of the main steam line(s) and a potential for plant shutdown.

For affected penetrations that have been isolated in accordance with Required Action A.1 or A.2, the affected penetration flow path must be verified to be isolated on a periodic basis. This is necessary to ensure that primary containment penetrations required to be isolated following an accident, and no longer capable of being automatically isolated, will be in the isolation position should an event occur. This Required Action does not require any testing or device manipulation. Rather, it involves verification that those devices outside containment

(continued)

BASES

ACTIONS

A.1, A.2, and A.3~~2~~ (continued)

and capable of potentially being mispositioned are in the correct position. The Completion Time of "Once per 31 days following isolation for isolation devices outside primary containment" is appropriate because the devices are operated under administrative controls and the probability of their misalignment is low. For the devices inside primary containment, the time period specified "Prior to entering MODE 2 or 3 from MODE 4, if primary containment was de-inerted while in MODE 4, if not performed within the previous 92 days" is based on engineering judgment and is considered reasonable in view of the inaccessibility of the devices and other administrative controls ensuring that device misalignment is an unlikely possibility.

Condition A is modified by a Note indicating that this Condition is only applicable to those penetration flow paths with two PCIVs. For penetration flow paths with one PCIV, Condition C provides the appropriate Required Actions.

Required Action A.2 is modified by two notes. Note 1 applies to isolation devices located in high radiation areas, and allows them to be verified by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Note 2 applies to isolation devices that are locked, sealed, or otherwise secured in position and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since the function of locking, sealing, or securing components is to ensure that these devices are not inadvertently repositioned. Therefore, the probability of misalignment, once they have been verified to be in the proper position, is low.

B.1

With one or more penetration flow paths with two PCIVs inoperable except due to leakage not within limits, either the inoperable PCIVs must be restored to OPERABLE status or the affected penetration flow path must be isolated within 1 hour. The method of isolation must include the use of at least one isolation barrier that cannot be adversely affected by a single active failure. Isolation barriers that meet this criterion are a closed and de-activated automatic valve, a closed manual valve, and a blind flange. A check valve may not be used to isolate the affected penetration.

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

The Completion Time of 4 hours for PCIVs other than those in penetrations with a closed system and EFCVs is reasonable considering the time required to isolate the penetration and the relative importance of supporting primary containment OPERABILITY in MODES 1, 2, and 3. The Completion Time of 72 hours for penetrations with a closed system is reasonable considering the relative stability of the closed system (hence, reliability) to act as a penetration isolation boundary. The closed system must meet the requirements of Reference 8. The Completion Time of 72 hours for EFCVs is also reasonable considering the instrument to act as a penetration isolation boundary and the small pipe diameter of the affected penetrations. In the event the affected penetration flow path is isolated in accordance with Required Action C.1, the affected penetration must be verified to be isolated on a periodic basis. This is necessary to ensure that primary containment penetrations required to be isolated following an accident are isolated.

The Completion Time of once per 31 days following isolation for verifying each affected penetration is isolated is appropriate because the valves are operated under administrative controls and the probability of their misalignment is low.

Condition C is modified by a Note indicating that this Condition is only applicable to penetration flow paths with only one PCIV. For penetration flow paths with two PCIVs, Conditions A and B provide the appropriate Required Actions.

Required Action C.2 is modified by two notes. Note 1 applies to valves and blind flanges located in high radiation areas and allows them to be verified by use of administrative means. Allowing verification by administrative means is considered acceptable, since access to these areas is typically restricted. Note 2 applies to isolation devices that are locked, sealed, or otherwise secured in position and allows these devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since the function of locking, sealing, or securing components is to ensure that these devices are not inadvertently repositioned. Therefore, the probability of misalignment of these valves, once they have been verified to be in the proper position, is low.

(continued)

BASES (continued)

LCO

During a DBA, a minimum of one RHR suppression pool cooling subsystem is required to maintain the primary containment peak pressure and temperature below design limits (Ref. 1). To ensure that these requirements are met, two RHR suppression pool cooling subsystems must be OPERABLE with power from two safety related independent power supplies. Therefore, in the event of an accident, at least one subsystem is OPERABLE assuming the worst case single active failure. An RHR suppression pool cooling subsystem is OPERABLE when one of the pumps, the heat exchanger, and associated piping, valves, instrumentation, and controls are OPERABLE. Management of gas voids is important to RHR Suppression Pool Cooling System OPERABILITY. Each RHR suppression pool cooling subsystem is supported by an independent subsystem of the Residual Heat Removal Service Water (RHRSW) System. Specifically, two OPERABLE RHRSW pumps and an OPERABLE flow path, as defined in the Bases for LCO 3.7.1, "Residual Heat Removal Service Water (RHRSW) System," are required to provide the necessary heat transfer from the heat exchanger and, thereby, support each suppression pool cooling subsystem.

APPLICABILITY

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

ACTIONS

A.1

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

(continued)

BASES

APPLICABLE SAFETY ANALYSES (continued)

containment conditions within design limits. The time history for primary containment pressure is calculated to demonstrate that the maximum pressure remains below the design limit.

The RHR Suppression Pool Spray System satisfies Criterion 3 of the NRC Policy Statement (Ref. 2).

LCO

In the event of a DBA, a minimum of one RHR suppression pool spray subsystem is required to mitigate potential bypass leakage paths and maintain the primary containment peak pressure below the design limits (Ref. 1). To ensure that these requirements are met, two RHR suppression pool spray subsystems must be OPERABLE with power from two safety related independent power supplies. Therefore, in the event of an accident, at least one subsystem is OPERABLE assuming the worst case single active failure. An RHR suppression pool spray subsystem is OPERABLE when one of the pumps, the heat exchanger, and associated piping, valves, instrumentation, and controls are OPERABLE. Management of gas voids is important to RHR Suppression Pool Spray System OPERABILITY. Each RHR suppression pool spray subsystem is supported by an independent subsystem of the Residual Heat Removal Service Water (RHRSW) System. Specifically, two OPERABLE RHRSW pumps and an OPERABLE flow path, as defined in the Bases for LCO 3.7.1, "Residual Heat Removal Service Water (RHRSW) System," are required to provide the necessary heat transfer from the heat exchanger and, thereby, support each suppression pool spray subsystem.

APPLICABILITY

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

ACTIONS

A.1

With one RHR suppression pool spray subsystem inoperable, the inoperable subsystem must be restored to OPERABLE status within 7 days or in accordance with the Risk Informed Completion Time Program. In this Condition, the remaining OPERABLE RHR suppression pool spray subsystem is adequate to perform the primary containment bypass leakage mitigation function.

(continued)

BASES (continued)

APPLICABILITY

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

ACTIONS

A.1

With one drywell spray subsystem inoperable, the inoperable subsystem must be restored to OPERABLE status within 7 days or in accordance with the Risk Informed Completion Time Program. In this condition, the remaining OPERABLE RHR drywell spray subsystem is adequate to perform the primary containment fission product scrubbing and temperature and pressure reduction functions.

However, the overall reliability is reduced because a single failure in the OPERABLE subsystem could result in the loss of the scrubbing and temperature and pressure reduction capabilities of the RHR drywell spray system. The 7 day Completion Time was chosen because of the capability of the redundant and OPERABLE RHR drywell spray subsystem and the low probability of a DBA occurring during this period.

B.1

With both RHR drywell spray subsystems inoperable, at least one subsystem must be restored to OPERABLE status within 8 hours. In this Condition, there is a substantial loss of the fission product scrubbing and temperature and pressure reduction functions of the RHR drywell spray system. The 8 hour Completion Time is based on the low probability of a DBA during this period.

C.1

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

(continued)

ACTIONS

A.1 (continued)

capability, including enhanced reliability afforded by manual cross connect capability, and the low probability of a DBA with concurrent worst case single failure.

B.1

With one RHRSW pump inoperable in each subsystem, if no additional failures occur in the RHRSW System, and the two OPERABLE pumps are aligned by opening the normally closed cross tie valves (i.e., after an event requiring operation of the RHRSW System), then the remaining OPERABLE pumps and flow paths provide adequate heat removal capacity following a design basis LOCA. However, capability for this alignment is not assumed in long term containment response analysis and an additional single failure in the RHRSW System could reduce the system capacity below that assumed in the safety analysis. Therefore, continued operation is permitted only for a limited time. One inoperable pump is required to be restored to OPERABLE status within 7 days or in accordance with the Risk Informed Completion Time Program. The 7 day Completion Time for restoring one inoperable RHRSW pump to OPERABLE status is based on engineering judgment, considering the level of redundancy provided.

C.1

Required Action C.1 is intended to handle the inoperability of one RHRSW subsystem for reasons other than Condition A. The Completion Time of 7 days is allowed to restore the RHRSW subsystem to OPERABLE status. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program. With the unit in this condition, the remaining OPERABLE RHRSW subsystem is adequate to perform the RHRSW heat removal function. However, the overall reliability is reduced because a single failure in the OPERABLE RHRSW subsystem could result in loss of RHRSW function. The Completion Time is based on the redundant RHRSW capabilities afforded by the OPERABLE subsystem and the low probability of an event occurring requiring RHRSW during this period.

The Required Action is modified by a Note indicating that the applicable Conditions of LCO 3.4.7 be entered and Required Actions taken if the inoperable RHRSW subsystem results in an inoperable RHR shutdown cooling subsystem. This is an exception to LCO 3.0.6 and ensures the proper actions are taken for these components.

(continued)

BASES

ACTIONS (continued)

C.1

With one PSW pump inoperable in each subsystem, one inoperable pump must be restored to OPERABLE status within 7 days or in accordance with the Risk Informed Completion Time Program. With the unit in this condition, the remaining OPERABLE PSW pumps are adequate to perform the PSW heat removal function; however, the overall reliability is reduced. The 7 day Completion Time is based on the remaining PSW heat removal capability to accommodate an additional single failure and the low probability of an event occurring during this time period.

D.1

With one PSW turbine building isolation valve inoperable in each subsystem, one inoperable valve must be restored to OPERABLE status within 72 hours or in accordance with the Risk Informed Completion Time Program. With the unit in this condition, the remaining OPERABLE PSW valves are adequate to perform the PSW non-essential load isolation function; however, the overall reliability is reduced. The 72 hour Completion Time is based on the remaining PSW heat removal capability to accommodate an additional single failure and the low probability of an event occurring during this time period.

E.1

If one PSW pump in one or both subsystems is inoperable, or one PSW turbine building isolation valve in one or both subsystems is inoperable, and is not restored to OPERABLE status within the required Completion Times, the plant must be brought to a condition in which overall plant risk is minimized. To achieve this status, the plant must be brought to at least MODE 3 within 12 hours.

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

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

(continued)

BASES

ACTIONS

E.1 (continued)

assessment addressing inoperable systems and components, consideration of the results, determination of the acceptability of entering MODE 3, and establishment of risk management actions, if appropriate. LCO 3.0.4 is not applicable to, and the Note does not preclude, changes in MODES or other specified conditions in the Applicability that are required to comply with ACTIONS or that are part of a shutdown of the unit.

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

F.1

With one PSW subsystem inoperable for reasons other than Condition A and Condition B (e.g., inoperable flow path, both pumps inoperable in a loop, or both turbine building isolation valves inoperable in a loop), the PSW subsystem must be restored to OPERABLE status within 72 hours or in accordance with the Risk Informed Completion Time Program. With the unit in this condition, the remaining OPERABLE PSW subsystem is adequate to perform the heat removal function. However, the overall reliability is reduced because a single failure in the OPERABLE PSW subsystem could result in loss of PSW function.

The 72 hour Completion Time is based on the redundant PSW System capabilities afforded by the OPERABLE subsystem, the low probability of an accident occurring during this time period, and is consistent with the allowed Completion Time for restoring an inoperable DG.

Required Action F.1 is modified by two Notes indicating that the applicable Conditions of LCO 3.8.1, "AC Sources - Operating," LCO 3.4.7, "Residual Heat Removal (RHR) Shutdown Cooling System - Hot Shutdown," be entered and Required Actions taken if the inoperable PSW subsystem results in an inoperable DG or RHR shutdown cooling subsystem, respectively. This is in accordance with LCO 3.0.6 and ensures the proper actions are taken for these components.

G.1 and G.2

If the Required Action and associated Completion Time of Condition F cannot be met, or both PSW subsystems are inoperable for reasons

(continued)

BASES

ACTIONS

A.2 (continued)

The remaining OPERABLE offsite circuits and DGs are adequate to supply electrical power to the onsite Class 1E Distribution System. Thus, on a component basis, single failure protection may have been lost for the required feature's function; however, function is not lost. The 24 hour Completion Time takes into account the component OPERABILITY of the redundant counterpart to the inoperable required feature. Additionally, the 24 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

A.3

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition A for a period that should not exceed 72 hours. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program. With one required offsite circuit inoperable, the reliability of the offsite system is degraded, and the potential for a loss of offsite power is increased, with attendant potential for a challenge to the plant safety systems. In this condition, however, the remaining OPERABLE offsite circuit and DGs are adequate to supply electrical power to the onsite Class 1E Distribution System.

The 72 hour Completion Time takes into account the capacity and capability of the remaining AC sources, reasonable time for repairs, and the low probability of a DBA occurring during this period.

(continued)

ACTIONS

B.3.1 and B.3.2 (continued)

function, a separate entry into Condition B is not required. The new DG problem should be addressed in accordance with the deficiency control program.

B.4~~.1~~

Regulatory Guide 1.93 (Ref. 6), provides guidance that operation in Condition B may continue for 72 hours. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time (RICT) Program.
~~A risk-informed, deterministic evaluation performed for Plant Hatch justifies operation in Condition B for 14 days, provided action is taken to ensure two DGs are dedicated to each Hatch unit. This is accomplished for an inoperable A or C DG by inhibiting the automatic alignment (on a LOCA or LOSP signal) of the swing DG to the other unit. If the inoperable DG is the swing DG, each unit has two dedicated DGs. For an inoperable swing DG, a 72 hour Completion Time applies unless the restrictions specified following this paragraph are satisfied. In Condition B for each defined Completion Time and restriction (if applicable), the remaining OPERABLE DGs and offsite circuits are adequate to supply electrical power to the onsite Unit 2 Class 1E Distribution System. The Completion Times take into account the capacity and capability of the remaining AC sources, reasonable time for maintenance, and low probability of a DBA occurring during this period. The 14 day Completion Time is also subject to additional restrictions for planned maintenance on other plant systems; these are controlled by NMP-GM-031. Use of the 14 day Completion time is permitted as follows:~~

- ~~For the Unit 2 DGs:~~

  ~~Once per DG per operating cycle for performing major overhaul of a DG.~~

  ~~As needed to complete unplanned maintenance. This time shall be minimized.~~

- ~~For the swing DG:~~

  ~~The additional restrictions apply prior to using a Completion Time of greater than 72 hours.~~

  ~~The 14 day Completion Time may be used once per Unit 1 operating cycle for performing a major overhaul of the swing~~

(continued)

~~DG.~~

BASES

ACTIONS ~~B.4~~ (continued)

~~The time may be used as needed to complete unplanned maintenance. This time shall be minimized.~~

- ~~As needed for the swing DG when it is inhibited from automatically aligning to Unit 2 in order for the 14 day Completion Time to be used for a Unit 1 DG.~~

~~The "AND" connector between the 72 hour and 14 day Completion Times means that both Completion Times apply simultaneously. That is, the 14 day Completion Time for an A or C DG with the swing DG inhibited applies from the time of entry into Condition B, not from the time the swing DG is inhibited.~~

~~B.4.2.1 and B.4.2.2~~

~~The Completion Time to restore the swing DG to OPERABLE status may be extended to 19 days provided action is taken within 72 hours to establish compensatory and risk management controls.~~

~~The B.4.2 Required Actions are modified by three Notes. Note 1 ensures that the B.4.2 Required Actions are only applied during the DG outage period that includes replacement of the engine cylinder liners of the Unit 1 DGs (i.e., DGs 1A and 1C) or the swing DG (i.e., DG 1B). Note 2 specifies that the B.4.2 ACTIONS are only applicable to the swing DG and, therefore, are not applicable when Condition B is entered due to the inoperability of a Unit 2 DG. Note 3 limits the time period the B.4.2 ACTIONS may be used.~~

~~The extended Completion Time is subject to additional defense-in-depth measures and risk management actions to ensure adequate electrical power sources and safety related equipment are available in the event of a loss of the offsite electrical power system during the extended DG outage period.~~

~~The compensatory controls specified in Attachment 5 of SNC letter NL-20-1000 (Ref. 15) consist of controls that must be established and maintained during the extended Completion Time period to preserve defense-in-depth. The requirement to establish and maintain features (i.e., systems, subsystems, and components) OPERABLE as a compensatory control may be performed as an administrative check, by examining logs or other information, to determine if the required features are out of service for maintenance or other reasons. It does not mean it is necessary to perform the Surveillances needed to demonstrate the OPERABILITY of the required features.~~

~~The risk evaluation performed, in accordance with RG 1.177 (Ref. 16),~~

(continued)

~~to extend the DG Completion Time to 19 days identified potentially~~

~~BASES~~

~~ACTIONS~~ ~~B.4.2.1 and B.4.2.2 (continued)~~

~~high-risk configurations that could exist if equipment, in addition to the inoperable DG, were to be taken out of service simultaneously or other risk-significant operational factors, such as concurrent system or equipment testing. The risk management control applicable to the swing DG (i.e., DG 1B) specified in Attachment 5 of SNC letter NL-20-1000 (Ref. 15) must be established and maintained during the extended Completion Time period to ensure appropriate restrictions on dominant risk-significant configurations associated with the extended Completion Time period are in place.~~

~~The 72 hour Completion Time of Required Action B.4.2.1 corresponds to the time required by Required Action B.4.1 to restore the swing DG to OPERABLE status with no additional restrictions or controls. If after the 72 hour Completion Time while applying the B.4.2 ACTIONS, it is discovered that these controls are not met, a Completion Time of 24 hours from discovery of the required controls not met is allowed to reestablish the compensatory and risk management controls. The Completion Time is intended to allow the operator time to evaluate and re-establish any discovered control not met. This Completion Time also allows for an exception to the normal "time zero" for beginning the Completion Time "clock." Following the initial 72 hours (while applying the B.4.2 ACTIONS) to establish the required controls, discovering one or more of the required controls not met results in starting the Completion Time for Required Action B.4.2.1. Twenty-four hours from the discovery of the required control(s) not met is acceptable because it minimizes risk while allowing time for re-establishing the control(s) before subjecting the unit to transients associated with shutdown while a DG is inoperable.~~

~~Once Required Action B.4.2.1 is performed, the swing DG can be restored to OPERABLE status within 19 days. The extended Completion Time of Required Action B.4.2.2 represents a balance between the risk associated with continued plant operation with less than the required system or component redundancy and the risk associated with initiating a plant transient while transitioning the unit based on the loss of redundancy. With compensatory and risk management controls established, the remaining OPERABLE DGs and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. The extended Completion Time takes into account the capacity and capability of the remaining AC sources, reasonable time for maintenance, and low probability of a DBA or an LOSP occurring during this period.~~

~~The Completion Time of Required Action B.4.2.2 is based on a defense-in-depth philosophy and risk informed using the plant PRA. The risk impact of the extended Completion Time has been evaluated~~

(continued)

~~pursuant to the risk assessment and management provisions of the~~

~~BASES~~

~~ACTIONS~~ ~~B.4.2.1 and B.4.2.2 (continued)~~

~~Maintenance Rule, 10 CFR 50.65(a)(4), and the associated implementation guidance, Regulatory Guide 1.160. Regulatory Guide 1.160 endorses the guidance in Section 11 of NUMARC 93-01. This guidance provides for the consideration of dynamic plant configuration issues, emergent conditions, and other aspects pertinent to plant operation with the swing DG inoperable for an extended period of time. These considerations may result in additional risk management and other compensatory actions being required during the extended period that the DG is inoperable.~~

C.1

To ensure a highly reliable power source remains with one required Unit 1 DG inoperable, it is necessary to verify the availability of the required offsite circuits on a more frequent basis. Since the Required Action only specifies "perform," a failure of SR 3.8.1.1 acceptance criteria does not result in a Required Action being not met. However, if a circuit fails to pass SR 3.8.1.1, it is inoperable. Upon offsite circuit inoperability, additional Conditions must then be entered.

C.2

Required Action C.2 is intended to provide assurance that a loss of offsite power, during the period that one required Unit 1 DG is inoperable, does not result in a complete loss of safety function of critical systems. These features are designed with redundant safety related divisions (i.e., single division systems are not included). Redundant required features failures consist of inoperable features associated with a division redundant to the division that has an inoperable DG.

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." In this Required Action the Completion Time only begins on discovery that both:

a. An inoperable required Unit 1 DG exists; and

b. A redundant required feature on the other division (Division 1 or 2), or divisions in the case of the Unit 1 and 2 SGT System, is inoperable.

If, at any time during the existence of this Condition (required Unit 1 DG inoperable), a redundant feature subsequently becomes inoperable, this Completion Time begins to be tracked.

(continued)

BASES

ACTIONS

C.2 (continued)

Discovering one required Unit 1 DG inoperable coincident with one or more inoperable redundant required support or supported features, or both, that are associated with the OPERABLE DGs results in starting the Completion Time for the Required Action. Four hours from the discovery of these events existing concurrently is acceptable because it minimizes risk while allowing time for restoration before subjecting the unit to transients associated with shutdown.

The remaining OPERABLE DGs and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. Thus, on a component basis, single failure protection for the required feature's function may have been lost; however, function has not been lost. The 4 hour Completion Time takes into account the component OPERABILITY of the redundant counterpart to the inoperable required feature. Additionally, the 4 hour Completion Time takes into account the capacity and capability of the remaining AC sources, reasonable time for repairs, and low probability of a DBA occurring during this period.

C.3.1 and C.3.2

Required Action C.3.1 provides an allowance to avoid unnecessary testing of OPERABLE DGs. If it can be determined that the cause of the inoperable DG does not exist on the OPERABLE DG, SR 3.8.1.2.a does not have to be performed. If the cause of inoperability exists on other DG(s), they are declared inoperable upon discovery, and Condition F of LCO 3.8.1 is entered. Once the failure is repaired, and the common cause failure no longer exists, Required Action C.3.1 is satisfied. If the cause of the initial inoperable DG cannot be confirmed not to exist on the remaining DG(s), performance of SR 3.8.1.2.a suffices to provide assurance of continued OPERABILITY of those DGs. In the event the inoperable DG is restored to OPERABLE status prior to completing either C.3.1 or C.3.2, the deficiency control program, as appropriate, will continue to evaluate the common cause possibility. This continued evaluation, however, is no longer under the 24 hour constraint imposed while in Condition C.

According to Generic Letter 84-15 (Ref. 7), 24 hours is a reasonable time to confirm that the OPERABLE DGs are not affected by the same problem as the inoperable DG.

(continued)

BASES

ACTIONS (continued)

C.4

In Condition C, the remaining OPERABLE offsite circuit is adequate to supply electrical power to the required onsite Unit 1 Class 1E Distribution System. The 7 day Completion Time is based on the shortest restoration time allowed for the systems affected by the inoperable DG in the individual system LCOs. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time (RICT) Program
~~A risk-informed, deterministic evaluation performed for Plant Hatch justifies operation in Condition C for 14 days, provided action is taken to ensure two DGs are dedicated to each Hatch unit. This is accomplished for an inoperable A or C DG by inhibiting the automatic alignment (on a LOCA or LOSP signal) of the swing DG to the other unit. The Completion Times take into account the capacity and capability of the remaining AC sources, reasonable time for maintenance, and low probability of a DBA occurring during this period. Use of the 14 day Completion Time, subject to additional restrictions controlled by NMP-GM-031, is permitted as follows:~~

- ~~Once per DG per operating cycle for performing a major overhaul of a DG.~~
- ~~As needed to complete unplanned maintenance. This time shall be minimized.~~

~~C.4.2.1, C.4.2.2, and C.4.2.3~~

~~The Completion Time to restore the required Unit 1 DG to OPERABLE status may be extended to 19 days provided action is taken within 7 days to: 1) inhibit the swing DG from automatically aligning to the Unit 2 4.16 kV ESF bus, and 2) establish compensatory and risk management controls.~~

~~The C.4.2 Required Actions are modified by three Notes. Note 1 ensures the C.4.2 Required Actions are only applied during the DG outage period that includes replacement of the engine cylinder liners. Note 2 specifies that the C.4.2 ACTIONS are only applicable one time for each DG because they are only approved for one time use. Note 3 limits the time period the C.4.2 ACTIONS may be used.~~

~~The extended Completion Time is subject to additional defense-in-depth measures and risk management actions to ensure adequate electrical power sources and safety related equipment are available in the event of a loss of the offsite electrical power system during the extended DG outage period.~~

~~The compensatory controls specified in Attachment 5 of SNC letter~~

(continued)

~~NL-20-1000 (Ref. 15) consist of controls that must be established and maintained during the extended Completion Time period to preserve defense-in-depth. The requirement to establish and maintain features~~

~~BASES~~

~~ACTIONS~~ ~~C.4.2.1, C.4.2.2, and C.4.2.3 (continued)~~

~~(i.e., systems, subsystems, and components) OPERABLE as a compensatory control may be performed as an administrative check, by examining logs or other information, to determine if the required features are out of service for maintenance or other reasons. It does not mean it is necessary to perform the Surveillances needed to demonstrate the OPERABILITY of the required features.~~

~~The risk evaluation performed, in accordance with RG 1.177 (Ref. 16), to extend the DG Completion Time to 19 days identified potentially high-risk configurations that could exist if equipment, in addition to the inoperable DG, were to be taken out of service simultaneously or other risk-significant operational factors, such as concurrent system or equipment testing. The risk management controls specified in Attachment 5 of SNC letter NL-20-1000 (Ref. 15) must be established and maintained, as applicable, during the extended Completion Time period to ensure appropriate restrictions on dominant risk-significant configurations associated with the extended Completion Time period are in place.~~

~~The 7 day Completion Time of Required Action C.4.2.1 corresponds to the time required by Required Action C.4.1 to restore the required Unit 1 DG to OPERABLE status with no additional restrictions or controls. If after the 7 day Completion Time while applying the C.4.2 ACTIONS, it is discovered that these controls are not met, a Completion Time of 24 hours from discovery of the required controls not met is allowed to reestablish the compensatory and risk management controls. The Completion Time is intended to allow the operator time to evaluate and re-establish any discovered control not met. This Completion Time also allows for an exception to the normal "time zero" for beginning the Completion Time "clock." Following the initial 7 days (while applying the C.4.2 ACTIONS) to establish the required controls, discovering one or more of the required controls not met results in starting the Completion Time for Required Action C.4.2.1. Twenty-four hours from the discovery of the required control(s) not met is acceptable because it minimizes risk while allowing time for re-establishing the control(s) before subjecting the unit to transients associated with shutdown while a DG is inoperable.~~

~~Required Action C.4.2.2 requires the swing DG to be inhibited from automatically aligning (on a LOCA or LOSP signal) to the other unit. This ensures two OPERABLE DGs are dedicated to each unit during a LOCA or LOSP event when a required Unit 1 DG is inoperable. The 7 day Completion Time of Required Action C.4.2.2 corresponds to the time required by Required Action C.4.1 to restore a required Unit 1~~

(continued)

~~DG to OPERABLE status with no additional restrictions or controls.~~

~~Once Required Actions C.4.2.1 and C.4.2.2 are performed, the DG~~

BASES

ACTIONS ~~C.4.2.1, C.4.2.2, and C.4.2.3~~ (continued)

~~can be restored to OPERABLE status within 19 days. The extended Completion Time of Required Action C.4.2.3 represents a balance between the risk associated with continued plant operation with less than the required system or component redundancy and the risk associated with initiating a plant transient while transitioning the unit based on the loss of redundancy. With compensatory and risk management controls established, the remaining OPERABLE DGs and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. The extended Completion Time takes into account the capacity and capability of the remaining AC sources, reasonable time for maintenance, and low probability of a DBA or an LOSP occurring during this period.~~

~~The Completion Time of Required Action C.4.2.3 is based on a defense-in-depth philosophy and risk informed using the plant PRA. The risk impact of the extended Completion Time has been evaluated pursuant to the risk assessment and management provisions of the Maintenance Rule, 10 CFR 50.65(a)(4), and the associated implementation guidance, Regulatory Guide 1.160. Regulatory Guide 1.160 endorses the guidance in Section 11 of NUMARC 93-01. This guidance provides for the consideration of dynamic plant configuration issues, emergent conditions, and other aspects pertinent to plant operation with the DG inoperable for an extended period of time. These considerations may result in additional risk management and other compensatory actions being required during the extended period that the DG is inoperable.~~

D.1 and D.2

Required Action D.1 addresses actions to be taken in the event of inoperability of redundant required features concurrent with inoperability of two or more required offsite circuits. Required Action D.1 reduces the vulnerability to a loss of function. The Completion Time for taking these actions is reduced to 12 hours from that allowed with one 4160 V ESF bus without offsite power (Required Action A.2). The rationale for the reduction to 12 hours is that Regulatory Guide 1.93 (Ref. 6) allows a Completion Time of 24 hours for two required offsite circuits inoperable, based upon the assumption that two complete safety divisions are OPERABLE. (While this ACTION allows more than two circuits to be inoperable, Regulatory Guide 1.93 assumed two circuits were all that were required by the LCO, and a loss of those two circuits resulted in a loss of all offsite power to the Class 1E AC Electrical Power Distribution System. Thus, with the Plant Hatch design, a loss of more than two required

(continued)

offsite circuits results in the same conditions assumed in Regulatory Guide 1.93.) When a concurrent redundant required feature failure exists, this assumption is not the case, and a shorter Completion Time

ACTIONS

D.1 and D.2 (continued)

of 12 hours is appropriate. These features are designed with redundant safety related divisions, (i.e., single division systems are not included in the list). Redundant required features failures consist of any of these features that are inoperable because any inoperability is on a division redundant to a division with inoperable offsite circuits.

The Completion Time for Required Action D.1 is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." In this Required Action, the Completion Time only begins on discovery that both:

a. All required offsite circuits are inoperable; and

b. A redundant required feature is inoperable.

If, at any time during the existence of this Condition (two or more required offsite circuits inoperable), a redundant required feature subsequently becomes inoperable, this Completion Time begins to be tracked.

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition D for a period that should not exceed 24 hours. This level of degradation means that the offsite electrical power system does not have the capability to effect a safe shutdown and to mitigate the effects of an accident; however, the onsite AC sources have not been degraded. This level of degradation generally corresponds to a total loss of the immediately accessible offsite power sources.

Because of the normally high availability of the offsite sources, this level of degradation may appear to be more severe than other combinations of two AC sources inoperable that involve one or more DGs inoperable. However, two factors tend to decrease the severity of this degradation level:

a. The configuration of the redundant AC electrical power system that remains available is not susceptible to a single bus or switching failure; and

b. The time required to detect and restore an unavailable offsite power source is generally much less than that required to detect and restore an unavailable onsite AC source.

With two or more of the required offsite circuits inoperable, sufficient

(continued)

onsite AC sources are available to maintain the unit in a safe shutdown condition in the event of a DBA or transient. In fact, a simultaneous loss of offsite AC sources, a LOCA, and a worst case

ACTIONS

D.1 and D.2 (continued)

single failure were postulated as a part of the design basis in the safety analysis. Thus, the 24 hour Completion Time provides a period of time to effect restoration of one of the offsite circuits commensurate with the importance of maintaining an AC electrical power system capable of meeting its design criteria.

According to Regulatory Guide 1.93 (Ref. 6), with the available offsite AC sources two less than required by the LCO (which as stated earlier, generally corresponds to a total loss of the immediately accessible offsite power sources; this is the condition experienced by Plant Hatch when two or more required circuits are inoperable), operation may continue for 24 hours. If all required offsite sources are restored within 24 hours, unrestricted operation may continue. If all but one required offsite sources are restored within 24 hours, power operation continues in accordance with Condition A. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program.

E.1 and E.2

Pursuant to LCO 3.0.6, the Distribution System ACTIONS would not be entered even if all AC sources to it were inoperable, resulting in de-energization. Therefore, the Required Actions of Condition E are modified by a Note to indicate that when Condition E is entered with no AC source to any ESF bus, ACTIONS for LCO 3.8.7, "Distribution Systems - Operating," must be immediately entered. This allows Condition E to provide requirements for the loss of the offsite circuit and one DG without regard to whether a division is de-energized. LCO 3.8.7 provides the appropriate restrictions for a de-energized ESF bus.

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition E for a period that should not exceed 12 hours. In Condition E, individual redundancy is lost in both the offsite electrical power system and the onsite AC electrical power system. However, since power system redundancy is provided by two diverse sources of power, the reliability of the power systems in this Condition may appear higher than that in Condition D (loss of two or more required offsite circuits). This difference in reliability is offset by the susceptibility of this power system configuration to a single bus or switching failure.

(continued)

The 12 hour Completion Time takes into account the capacity and capability of the remaining AC sources, reasonable time for repairs, and the low probability of a DBA occurring during this period. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program.

ACTIONS (continued)

F.1

With two or more Unit 2 and swing DGs inoperable, with an assumed loss of offsite electrical power, insufficient standby AC sources are available to power the minimum required ESF functions. Since the offsite electrical power system is the only source of AC power for the majority of ESF equipment at this level of degradation, the risk associated with continued operation for a very short time could be less than that associated with an immediate controlled shutdown. (The immediate shutdown could cause grid instability, which could result in a total loss of AC power.) Since any inadvertent unit generator trip could also result in a total loss of offsite AC power, the time allowed for continued operation is severely restricted. The intent here is to avoid the risk associated with an immediate controlled shutdown and to minimize the risk associated with this level of degradation.

According to Regulatory Guide 1.93 (Ref. 6), with two or more DGs inoperable, operation may continue for a period that should not exceed 2 hours. (Regulatory Guide 1.93 assumed the unit has two DGs. Thus, a loss of both DGs results in a total loss of onsite power. Therefore, a loss of more than two DGs, in the Plant Hatch design, results in degradation no worse than that assumed in Regulatory Guide 1.93. In addition, the loss of a required Unit 1 DG concurrent with the loss of a Unit 2 or swing DG, is analogous to the loss of a single DG in the Regulatory Guide 1.93 assumptions, thus, entry into this Condition is not required in this case.)

G.1

With both Unit 1 DGs and the swing DG inoperable (or otherwise incapable of supplying power to the LPCI valve load centers), and an assumed loss of offsite electrical power, insufficient standby AC sources are available to power the LPCI valve load centers. Since the offsite electrical power system is the only source of AC power for the LPCI valve load centers at this level of degradation, the risk associated with operation for a very short time could be less than that associated with an immediate controlled shutdown. (The immediate shutdown could cause grid instability, which could result in a total loss of AC power.) Since any inadvertent unit generator trip could also result in a total loss of offsite AC power, the time allowed for continued operation is severely restricted. The intent here is to avoid

(continued)

BASES (continued)

REFERENCES

1. 10 CFR 50, Appendix A, GDC 17.
2. FSAR, Sections 8.2 and 8.3.
3. Regulatory Guide 1.9, March 1971.
4. FSAR, Section 6.2.3.
5. FSAR, Chapter 15.
6. Regulatory Guide 1.93, December 1974.
7. Generic Letter 84-15.
8. 10 CFR 50, Appendix A, GDC 18.
9. Regulatory Guide 1.108, August 1977
10. Regulatory Guide 1.137, October 1979.
11. IEEE Standard 387-1984.
12. IEEE Standard 308-1980.
13. NRC No. 93-102, "Final Policy Statement on Technical Specification Improvements," July 23, 1993.
14. NEDC-32988-A, Revision 2, Technical Justification to Support Risk-Informed Modification to Selected Required End States for BWR Plants, December 2002.
15. ~~Attachment 5, “Compensatory and Risk Management Controls for Hatch Nuclear Plant (HNP) Diesel Generator (DG) One-time 19-day Completion Time Allowance,” Letter NL-20-1000 from C.A. Gayheart (SNC) to the Document Control Desk (NRC), dated August 23, 2020.~~
16. ~~Regulatory Guide 1.177, May 2011.~~

BASES (continued)

ACTIONS

A.1

If one or more of the required Unit 1 DG DC electrical power subsystems is inoperable (e.g., inoperable battery, inoperable battery charger(s), or inoperable battery charger and associated inoperable battery), or if the swing DG DC electrical power subsystem is inoperable due to performance of SR 3.8.4.3 or SR 3.8.6.6, and a loss of function has not occurred as described in Condition G, the remaining DC electrical power subsystems have the capacity to support a safe shutdown and to mitigate an accident condition. In the case of an inoperable required Unit 1 DG DC electrical power subsystem, continued power operation should not exceed 7 days since a subsequent postulated worst case single failure could result in the loss of certain safety functions (e.g., SGT System and LPCI valve load centers). The 7 day Completion Time takes into account the capacity and capability of the remaining DC sources, and is based on the shortest restoration time allowed for the systems affected by the inoperable DC source in the respective system Specification. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program.

In the case of an inoperable swing DG DC electrical power subsystem, since a subsequent postulated worst case single failure could result in the loss of minimum necessary DC electrical subsystems to mitigate a postulated worst case accident, continued power operation should also not exceed 7 days. The 7 day Completion Time is based upon the swing DG DC electrical power subsystem being inoperable due to performance of SR 3.8.4.7 or SR 3.8.6.6. Performance of these two SRs will result in inoperability of the DC battery. Since this battery is common to both units, more time is provided to restore the battery, if the battery is inoperable for performance of required Surveillances, to preclude the need to perform a dual unit shutdown to perform these Surveillances. The swing DG DC electrical power subsystem also does not provide power to the same type of equipment as the other DG DC sources (e.g., breaker control power for 4160 V loads is not provided by the swing DG battery). The Completion Time also takes into account the capacity and capability of the remaining DC sources. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program.

B.1, B.2, and B.3

Condition B represents one Unit 2 DG DC subsystem with a required battery charger inoperable (e.g., the voltage limit of SR 3.8.4.1 is not maintained), or the swing DG DC subsystem with a required battery charger inoperable for reasons other than Condition A. The

(continued)

BASES

ACTIONS

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

not less than or equal to 5 amps this indicates there may be additional battery problems and the battery must be declared inoperable.

Required Action B.3 limits the restoration time for the inoperable battery charger to 72 hours. This action is applicable if an alternate means of restoring battery terminal voltage to greater than or equal to the minimum established float voltage has been used (e.g., balance of plant non-Class 1E charger). The 72 hour Completion Time reflects a reasonable time to effect restoration of the qualified battery charger to OPERABLE status. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program.

C.1

If a Unit 2 DG DC electric power subsystem is inoperable (for reasons other than Condition B), or if the swing DG DC electrical power subsystem is inoperable for reasons other than Condition A or B, (e.g., inoperable battery or inoperable battery charger and associated inoperable battery), the remaining DC electrical power subsystems have the capacity to support a safe shutdown and to mitigate an accident condition. Since a subsequent postulated worst case single failure could result in the loss of minimum necessary DC electrical subsystems to mitigate a postulated worst case accident, continued power operation should not exceed 12 hours. The 12 hour Completion Time provides a period of time to correct the problem commensurate with the importance of maintaining the DG DC electrical power subsystem OPERABLE. (The DG DC electrical power subsystem affects both the DG and the offsite circuit, as well as the breaker closure power for various 4160 V AC loads, but does not affect 125/250 V DC station service loads.) Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program.

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

Condition D represents one Unit 2 station service DC subsystem with a required battery charger inoperable (e.g., the voltage limit of SR 3.8.4.1 is not maintained). The ACTIONS provide a tiered response that focuses on returning the battery to the fully charged state and restoring a fully qualified charger to OPERABLE status in a reasonable time period. Required Action D.1 requires that the battery terminal voltage be restored to greater than or equal to the minimum established float voltage within 2 hours. This time provides for returning the inoperable charger to OPERABLE status or providing an alternate means of restoring battery terminal voltage to greater than or

(continued)

BASES

ACTIONS

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

A discharged battery having terminal voltage of at least the minimum established float voltage indicates that the battery is on the exponential charging current portion (the second part) of its recharge cycle. The time to return a battery to its fully charged state under this condition is simply a function of the amount of the previous discharge and the recharge characteristic of the battery. Thus there is good assurance of fully recharging the battery within 12 hours, avoiding a premature shutdown with its own attendant risk.

If established battery terminal float voltage cannot be restored to greater than or equal to the minimum established float voltage within 2 hours, and the charger is not operating in the current-limiting mode, a faulty charger is indicated. A faulty charger that is incapable of maintaining established battery terminal float voltage does not provide assurance that it can revert to and operate properly in the current limit mode that is necessary during the recovery period following a battery discharge event that the DC system is designed for.

If the charger is operating in the current limit mode after 2 hours, that is an indication that the battery is partially discharged and its capacity margins will be reduced. The time to return the battery to its fully charged condition in this case is a function of the battery charger capacity, the amount of loads on the associated DC system, the amount of the previous discharge, and the recharge characteristics of the battery. The charge time can be extensive, and there is not adequate assurance that it can be recharged within 12 hours (Required Action D.2).

Required Action D.2 requires that the battery float current be verified as less than or equal to 20 amps. This indicates that, if the battery had been discharged as the result of the inoperable battery charger, it is now fully capable of supplying the maximum expected load requirement. The 20 amp value is based on returning the battery to 95% charge and assumes a 5% design margin for the battery. If at the expiration of the initial 12 hour period the battery float current is not less than or equal to 20 amps this indicates there may be additional battery problems and the battery must be declared inoperable.

Required Action D.3 limits the restoration time for the inoperable battery charger to 72 hours. This action is applicable if an alternate means of restoring battery terminal voltage to greater than or equal to the minimum established float voltage has been used (e.g., balance of plant non-Class 1E charger). The 72 hour Completion Time reflects a reasonable time to effect restoration of the qualified battery charger to OPERABLE status. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program.

(continued)

ACTIONS (continued)

E.1

If one of the required Unit 2 station service DC electrical power subsystems is inoperable for reasons other than Condition D (e.g., inoperable battery or inoperable battery charger and associated inoperable battery), the remaining DC electrical power subsystems have the capacity to support a safe shutdown and to mitigate an accident condition. Since a subsequent postulated worst case single failure could result in the loss of minimum necessary DC electrical subsystems to mitigate a postulated worst case accident, continued power operation should not exceed 2 hours. The 2 hour Completion Time is based on Regulatory Guide 1.93 (Ref. 7) and reflects a reasonable time to assess unit status as a function of the inoperable DC electrical power subsystem and, if the DC electrical power subsystem is not restored to OPERABLE status, to prepare to effect an orderly and safe unit shutdown. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program.

F.1

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

Remaining in the Applicability of the LCO is acceptable because the plant risk in MODE 3 is similar to or lower than the risk in MODE 4 (Ref. 11) and because the time spent in MODE 3 to perform the necessary repairs to restore the system to OPERABLE status will be short. However, voluntary entry into MODE 4 may be made as it is also an acceptable low-risk state.

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

(continued)

BASES

APPLICABILITY (continued)

b. Adequate core cooling is provided, and containment OPERABILITY and other vital functions are maintained in the event of a postulated DBA.

Electrical power distribution subsystem requirements for MODES 4 and 5, and other conditions in which AC and DC electrical power distribution subsystems are required, are covered in the Bases for LCO 3.8.8, "Distribution Systems - Shutdown."

ACTIONS

A.1

If one or more of the required Unit 1 AC or DC electrical power distribution subsystems are inoperable, and a loss of function has not occurred as described in Condition F, the remaining AC and DC electrical power distribution subsystems have the capacity to support a safe shutdown and to mitigate an accident condition. Since a subsequent postulated worst case single failure could, however, result in the loss of certain safety functions (e.g., SGT System and LPCI valve load centers), continued power operation should not exceed 7 days. The 7 day Completion Time takes into account the capacity and capability of the remaining AC and DC electrical power distribution subsystems, and is based on the shortest restoration time allowed for the systems affected by the inoperable AC and DC electrical power distribution subsystem in the respective system Specification. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program.

B.1

If a Unit 2 or swing DG DC electrical power distribution subsystem is inoperable, the remaining DC electrical power distribution subsystems have the capacity to support a safe shutdown and to mitigate an accident condition. Since a subsequent postulated worst case single failure could, however, result in the loss of minimum necessary DC electrical subsystems to mitigate a postulated worst case accident, continued power operation should not exceed 12 hours. The 12 hour Completion Time provides a period of time to correct the problem commensurate with the importance of maintaining the DG DC electrical power distribution subsystem OPERABLE.

(continued)

BASES

ACTIONS

B.1 (continued)

(The DG DC electrical power distribution subsystem affects both the DG and the offsite circuit, as well as the breaker closure power for various 4160 VAC loads, but does not affect 125/250 VDC station service loads). Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program.

The 12 hour time limit before requiring a unit shutdown in this Condition is acceptable because:

a. There is a potential for decreased safety if the unit operators' attention is diverted from the evaluations and actions necessary to restore power to the affected bus(es) to the actions associated with taking the unit to shutdown within this time limit.

b. The potential for an event in conjunction with a single failure of a redundant component in the division with AC power. [The redundant component is verified OPERABLE in accordance with Specification 5.5.10, "Safety Function Determination Program (SFDP)."]

C.1

With one or more required Unit 2 or swing AC buses, load centers, motor control centers, or distribution panels in one subsystem inoperable, the remaining AC electrical power distribution subsystems are capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure. The overall reliability is reduced, however, because a single failure in the remaining power distribution subsystems could result in the minimum required ESF functions not being supported. Therefore, the required AC buses, load centers, motor control centers, and distribution panels must be restored to OPERABLE status within 8 hours. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program.

The Condition C postulated worst scenario is one 4160 V bus without AC power (i.e., no offsite power to the 4160 V bus and the associated DG inoperable). In this condition, the unit is more vulnerable to a complete loss of Unit 2 AC power. It is, therefore, imperative that the unit operators' attention be focused on minimizing the potential for loss of power to the remaining buses by stabilizing the unit, and on restoring power to the affected buses. The 8 hour time limit before requiring a unit shutdown in this Condition is acceptable because:

(continued)

BASES

ACTIONS

C.1 (continued)

a. There is a potential for decreased safety if the unit operators' attention is diverted from the evaluations and actions necessary to restore power to the affected bus(es) to the actions associated with taking the unit to shutdown within this time limit.

b. The potential for an event in conjunction with a single failure of a redundant component in the division with AC power. [The redundant component is verified OPERABLE in accordance with Specification 5.5.10, "Safety Function Determination Program (SFDP)."]

D.1

With one Unit 2 station service DC bus inoperable, the remaining DC electrical power distribution subsystem is capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure. The overall reliability is reduced, however, because a single failure in the remaining DC electrical power distribution subsystems could result in the minimum required ESF functions not being supported. Therefore, the required Unit 2 DC buses must be restored to OPERABLE status within 2 hours by powering the bus from the associated battery or charger. Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time Program.

Condition D represents one Unit 2 division without adequate DC power, potentially with both the battery significantly degraded and the associated charger nonfunctioning. In this situation the plant is significantly more vulnerable to a complete loss of all Unit 2 station service DC power. It is, therefore, imperative that the operator's attention focus on stabilizing the plant, minimizing the potential for loss of power to the remaining division, and restoring power to the affected division.

This 2 hour limit is more conservative than Completion Times allowed for the majority of components that would be without power. Taking exception to LCO 3.0.2 for components without adequate DC power, which would have Required Action Completion Times shorter than 2 hours, is acceptable because of:

a. The potential for decreased safety when requiring a change in plant conditions (i.e., requiring a shutdown) while not allowing stable operations to continue;

(continued)

ENCLOSURE 1

Edwin I. Hatch Nuclear Plant - Units 1 and 2
License Amendment Request to Revise Technical Specifications
to Adopt Risk Informed Completion Times TSTF-505, Revision 2,
"Provide Risk-Informed Extended Completion Times - RITSTF Initiative 4b"

List of Revised Required Actions to Corresponding PRA Functions

ENCLOSURE 1
LIST OF REVISED REQUIRED ACTIONS TO CORRESPONDING PRA FUNCTIONS

1.0 INTRODUCTION

Section 4.0, Item 2 of the NRC's Safety Evaluation for Nuclear Energy Institute (NEI) Topical Report NEI 06-09, Revision 0-A (hereafter referred to as "NEI 06-09-A"), identifies the "Licensees should provide the following plant-specific information in support of their LAR.

(1) The LAR will include proposed changes to the Administrative Controls of Technical Specification (TS) to add a Configuration Risk Management Program (CRMP) in accordance with TR NEI 06-09, Revision 0.

(2) The LAR will provide identification of the TS limiting condition for operations (LCOs) and action requirements to which the Risk Managed Technical Specifications (RMTS) will apply, with a comparison of the TS functions to the PRA modeled functions of the SSCs subject to those LCO actions. The comparison should justify that the scope of the PRA model, including applicable success criteria such as number of SSCs required, flowrate, etc., are consistent licensing basis assumptions (i.e., 10 CFR 50.46 Emergency Core Cooling System [ECCS] flowrates) for each of the TS requirements, or an appropriate disposition or programmatic restriction will be provided.

This enclosure provides confirmation that the Edwin I. Hatch Nuclear Plant (HNP) - Units 1 and 2 PRA models include the necessary scope of SSCs and their functions to address each proposed application of the Risk-Informed Completion Time (RICT) Program to the proposed scope TS LCO Conditions, and provides the information requested for Section 4.0, Item 2 of the NRC Safety Evaluation. The scope of the comparison includes each of the TS LCO Conditions and associated Required Actions within the scope of the RICT Program. The HNP PRA model has the capability to either model directly or utilize a bounding surrogate to determine the risk impact of entering each of the TS LCOs in the scope of the RICT Program.

Table E1-1 lists each TS Condition to which the RICT Program is proposed to be applied and documents the following information regarding the TSs with the associated safety analyses, the analogous PRA functions and the results of the comparison. As noted in Attachment 1, the RICT is proposed to be applied only in MODE 1. The table also provides any required additional justification for inclusion in the RICT Program scope.

- The columns "Technical Specification (TS)" and "TS Condition" identifies the TS Conditions and Condition statements within the scope of the RICT Program.
- The column "SSCs Addressed by TS Condition" identifies the SSCs which could lead to entry into the TS Condition.
- The column "SSCs Modeled in PRA" indicates whether the SSCs addressed by the TS Condition are included in the PRA.
- The column "Function Covered by TS Condition" provides a summary of the required functions from the design basis analyses.

- The column "Design Success Criteria" provides a summary of the success criteria from the design basis analyses.
- The column "PRA Success Criteria" identifies the function success criteria modeled in the PRA.
- The column "Other Comments" provides the justification or resolution to address any inconsistencies between the TS and PRA functions regarding the scope of SSCs and the success criteria. Where the PRA scope of SSCs is not consistent with the TS, additional information is provided to describe how the TS Condition can be evaluated using appropriate surrogate events. Differences in the success criteria for TS functions are addressed to demonstrate that the PRA criteria provide a realistic estimate of the risk of the TS Condition as required by NEI 06-09-A.

The corresponding SSCs for each TS Condition and the associated TS functions are identified and compared to the PRA. This description also includes the design success criteria and the applicable PRA success criteria. Any differences between the scope or success criteria are identified in Table E1-1. Scope differences are justified by identifying appropriate surrogate events which permit a risk evaluation to be completed using the Configuration Risk Management Program (CRMP) tool. Differences in success criteria typically arise due to the requirement in the PRA standard to make PRAs realistic rather than bounding, whereas design basis criteria are necessarily conservative and bounding. The use of realistic success criteria is necessary to conform to capability Category II of the PRA standard as required by NEI 06-09-A.

For the purposes of the RICT program, the definition for “loss of function” or “loss of safety function” for the subject license amendment request is verbatim from TSTF-505, Revision 2. That is, “a loss of safety function exists when, assuming no concurrent single failure, no concurrent loss of offsite power, or no concurrent loss of onsite diesel generators, a safety function assumed in the accident analysis cannot be performed.”

For the purposes of the following information, the terms subsystem, train, loop, and division are considered interchangeable. Most TS Actions for systems required to be operable by the TS require more than one division, subsystem, or train of the system so that the system is capable of performing its specified safety function, even assuming a single failure disables one of the trains or subsystems. The LCO section of the TS Bases for each system defines the specific equipment which constitutes a division, loop, subsystem, or train for that system.

Table E1-1 describes whether the SSCs associated with instrumentation TS Actions are modeled in the PRA. For those instrumentation TS Actions where the SSCs are explicitly modeled, the instrumentation and control (I&C) equipment in the PRA consists of channels, relays, logic and transmitters, as appropriate. For those instrumentation TS Actions where the SSCs are not explicitly modeled, a conservative surrogate is chosen to represent the unavailability of that I&C equipment.

A system description and discussion of TS 3.8, "Electrical Power Systems," is provided below since the loading scheme is not uniform. Additional unit specific detail for both the AC and DC systems is provided in the Bases for TS 3.8.1, AC Sources – Operating,” and TS 3.8.4, “DC Sources – Operating,” for each unit.

Additionally, an overview of the AC power system design and operation is provided below (adopted from NL-20-0843, dated July 31, 2020, submittal of License Amendment Request to Revise the Required Actions of Technical Specification 3.8.1, AC Sources – Operating, for One-Time Extension of Completion Time for Unit 1 and Swing Emergency Diesel Generators).

The HNP offsite circuit design is robust and highly reliable. Offsite power is supplied to the station from the 230kV ring bus by five electrically and physically separate feeds through startup auxiliary transformers (SATs) 1C and 2C (via a common switchyard feed), 1D, 1E, 2D, and 2E, to the respective unit 4.16 kV engineered safety feature (ESF) buses E, F, and G. Each SAT provides the normal source of power to its respective ESF bus. If any 4.16 kV ESF bus loses power, an automatic transfer occurs from the normal offsite power source to its alternate offsite power source. By design, no single SAT can supply more than two 4.16 kV ESF buses simultaneously.

The SATs are sized to accommodate the simultaneous starting of all required ESF loads on receipt of an accident signal without the need for load sequencing. Only one SAT per unit is required to supply two 4.16 kV ESF buses, which are sufficient to provide the required safety functions and support unit shutdown and cooldown to cold conditions. As a result, only two SATs per unit are required to meet limiting condition for operation (LCO) 3.8.1 to support a single failure in the event of a loss of all onsite AC power sources (i.e., loss of all DGs).

Onsite standby emergency power is supplied by independent DGs, with 4.16 kV ESF Buses E and G each supplied by a dedicated unit DG and the 4.16 kV ESF Bus F on both units supplied by the swing DG (i.e., DG 1B). The swing DG cannot supply both F buses simultaneously. A simplified diagram of the HNP Class 1E electrical system is shown in Figure E1-1.

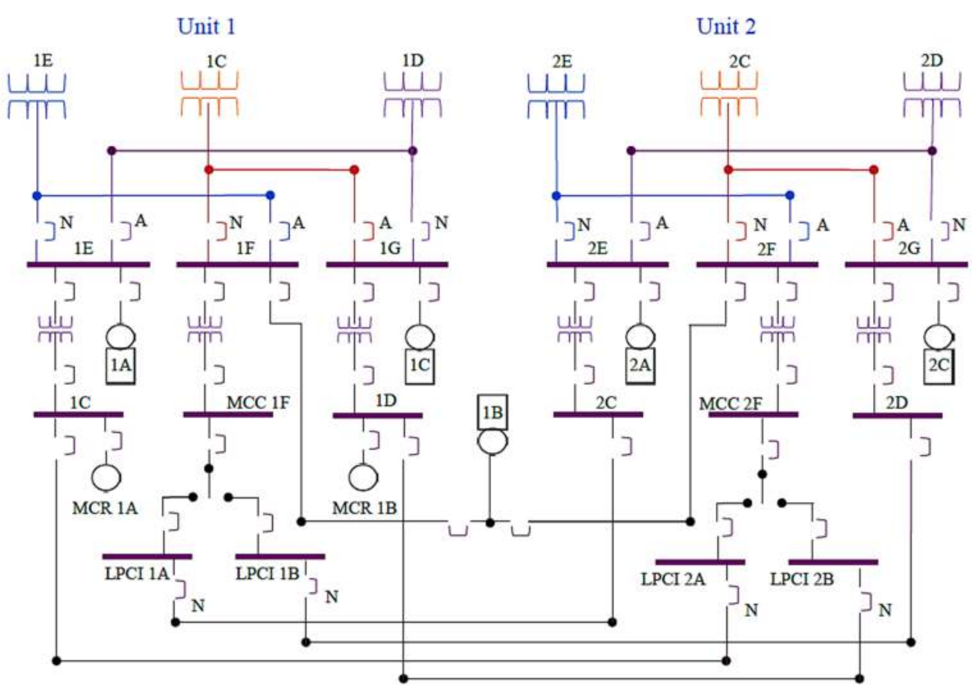

Figure E1-1, Simplified HNP Class 1E Electrical System

The DGs start automatically on a loss of coolant accident (LOCA) signal or on an ESF bus degraded voltage or undervoltage signal. After the DG has started, it automatically ties to its respective bus after offsite power is tripped as a consequence of ESF bus undervoltage or degraded voltage, independent of or coincident with a LOCA signal.

Each HNP unit is designed with three emergency 4.16 kV ESF buses (E, F, and G). The emergency portion of the 4.16 kV system is arranged into redundant electrical divisions. Each electrical division consists of the complement of safety-related equipment needed to achieve safe plant shutdown and to mitigate the consequences of a design basis accident (DBA). 4.16 kV ESF Buses E and G contain most of the redundant divisional equipment and 4.16 kV ESF Bus F bus contains some equipment from both electrical divisions (e.g., a residual heat removal (RHR) pump from each RHR loop). Two DGs per unit can fully provide the required safety functions to support a DBA and support unit shutdown and cooldown to cold conditions and remain in cold shutdown conditions for 30 days.

Per LCO 3.8.1, two of three qualified circuits between the offsite transmission network and the onsite AC distribution system provide availability of the required offsite power to shut down the reactor and maintain it in a safe shutdown condition after an anticipated operational occurrence (AOO) or a postulated DBA. In addition, some components are powered from opposite unit (e.g., Standby Gas Treatment (SGT) System, low pressure coolant injection (LPCI) valve load centers, and the Main Control Room Environmental Control (MCREC) System and Control Room Air Conditioning (AC) System are powered from Unit 1 only).

For the LPCI valve load centers, one qualified circuit between the offsite transmission network and the onsite Class 1E Electrical Distribution System capable of supplying power to each of the required LPCI valve load centers must be OPERABLE. The required circuits consist of a combination of the opposite unit circuits supplying the opposite unit E and G ESF buses and the circuit supplying the unit F ESF bus based on the LPCI valve load center alignment such that each LPCI valve load center is capable of being supplied.

With one required offsite circuit inoperable, the reliability of the offsite system is degraded, and the potential for a loss of offsite power is increased, with attendant potential for a challenge to the plant safety systems. In this condition, however, the remaining OPERABLE offsite circuit and DGs are adequate to supply electrical power to the onsite Class 1E Distribution System. With two or more of the required offsite circuits inoperable, sufficient onsite AC sources are available to maintain the unit in a safe shutdown condition in the event of a DBA or transient.

The onsite standby power source for 4.16 KV ESF buses E, F, and G consists of three DGs. DGs A and C are dedicated to ESF buses E and G, respectively. DG 1B (the swing DG) is a shared power source and can supply either Unit 1 ESF bus 1F or Unit 2 ESF bus 2F.

In the event of a loss of preferred power, the ESF electrical loads are automatically connected to the DGs in sufficient time to provide for safe reactor shutdown and to mitigate the consequences of a Design Basis Accident (DBA) such as a LOCA.

Per LCO 3.8.4, if one or more of the required opposite unit DG DC electrical power subsystems is inoperable (e.g., inoperable battery, inoperable battery charger(s), or inoperable battery charger and associated inoperable battery), or if the swing DG DC electrical power subsystem is inoperable due to performance of SR 3.8.4.3 or SR 3.8.6.6, and a loss of function has not occurred as described in Condition G, the remaining DC electrical power subsystems have the capacity to support a safe shutdown and to mitigate an accident condition.

In the case of an inoperable required opposite unit DG DC electrical power subsystem (for reasons other than an inoperable battery charger), the remaining DC electrical power subsystems have the capacity to support a safe shutdown and to mitigate an accident condition. However, continued power operation is limited since a subsequent postulated worst case single failure could result in the loss of certain safety functions (e.g., SGT System and LPCI valve load centers).

Each station service DC subsystem is energized by one 125/250 V station service battery (consisting of two 125 VDC batteries in series) and three 125 V battery chargers (two normally in-service chargers and one standby charger). Each battery is exclusively associated with a single 125/250 VDC switchgear, which then feeds divisional loads. Each set of battery chargers exclusively associated with a 125/250 VDC subsystem cannot be interconnected with any other 125/250 VDC subsystem. The diesel DC subsystems are energized by one 125 V battery and two 125 V chargers (one in-service and one standby charger) and supply power to the diesel control systems and associated 4kv bus and diesel supply breakers. The normal and backup chargers are supplied from the same AC load groups for which the associated DC subsystem supplies the control power. During normal operation, the DC loads are powered from the respective station service and DG battery chargers with the batteries floating on the system. In case of loss of normal power to any battery charger, the DC loads are automatically powered from the associated battery. There is no sharing between redundant Class 1E subsystems such as batteries, battery chargers, or distribution panels.

If one station service DC electrical power subsystems is inoperable for reasons other than an inoperable battery (or inoperable battery charger and associated inoperable battery), the remaining DC electrical power subsystems have the capacity to support a safe shutdown and to mitigate an accident condition. Since a subsequent postulated worst case single failure could result in the loss of minimum necessary DC electrical subsystems to mitigate a postulated worst case accident, continued power operation is limited.

Per LCO 3.8.7, the onsite Class 1E AC and DC electrical power distribution system is divided into redundant and independent AC and DC electrical power distribution subsystems. The primary AC distribution system consists of three 4.16 kV ESF buses. The secondary plant distribution system includes 600 VAC emergency buses 1(2)C and 1(2)D and associated load centers, and transformers. The 600 VAC busses 1(2)C and 1(2)D can be supplied from 4kv bus 1(2)F if the unit is offline. There are two independent 125/250 VDC station service electrical power distribution subsystems per unit and five independent 125 VDC DG electrical power distribution subsystems (two for each unit and one for the shared diesel) that support the necessary power for ESF functions.

Additionally, SNC held a presubmittal teleconference with the NRC on August 16, 2021 (ML21203A081). Subsequently, a series of clarification requests were posed by the NRC. These questions (*shown in italics*) and the SNC responses are provided below:

- *How do "Unit-specific PRAs" function in regard to swing DG and shared loads between units?*

For shared equipment in general, there would be a RICT evaluation for both units. If the 1B diesel is removed from service for a PM, there has to be a Unit 1 RICT and a Unit 2 RICT since there are Unit 1 and Unit 2 requirements. The RICT process does not evaluate the impact of initiating events but evaluates what mitigating equipment remains. The TS apply to both units for shared equipment, so both unit's PRA models will be run. The shared equipment is modeled in both unit's models. If the 1B diesel is locked to a unit because of a unit specific DG outage, the opposite unit is in a RICT for the 1B diesel.

The Hatch PRA models assume that a LOOP impacts both units. The shared diesel, by design, goes to the unit with a LOCA, no matter where the LOOP is. That logic is adjusted if a DG is inoperable for longer than 72 hours.

- *Based on electrical one line, it seems that Hatch has typical two DGs per unit that supply ESF loads with a swing DG available when necessary*

    - *Are buses 1E, 1F, and 1G for Unit 1 controlled shutdown (ESF) buses and similarly for Unit 2?*

      Yes.

    - *How many ESF buses per unit are required for normal shutdown and under combined LOOP and LOCA conditions for a unit?*

      Two ESF buses from that unit are required for shutdown under LOCA conditions. For example, Unit 1 would require either the 1E & 1F, 1E & 1G, or 1F & 1G buses. In addition, the LPCI valve load centers are supplied from either the opposite unit's E and G bus, or from its unit F bus. For example, the Unit 1 LPCI valve load centers are primarily supplied from the 2E and 2G buses, but either LPCI load center can also be supplied from the 1F bus. This is shown more clearly in the simplified figure from the presentation.

    - *What happens in non-accident unit for station LOOP if DG 1A(2A) or 1B(2B) is in RICT and there is a LOCA in the other unit at Hatch site?*

      With regard to PRA modeling, if a component on one unit is credited for the opposite unit, it is modeled in both PRA models. As an example, the DG 1A feeds the Unit 2 LPCI 2A MCC. Removing the DG 1A diesel from service requires putting the 2A LPCI MCC on alternate feed. Unit 2 LCO 3.8.1.f "Two DGs (any combination of Unit 1 DGs and the swing DG), each capable of supplying power to one Unit 2 low pressure coolant injection (LPCI) valve load center" would still be met based on the 1B and 1C DGs, however the risk impact of the alignment has to be assessed in the Unit 2 model to comply with 10 CFR 50.65(a)(4).

    - *Will LAR address non-accident unit or just provide design success criteria for accident unit since most PRAs cannot dynamically assess a dual unit response to an accident in one unit?*

The LAR is addressing application of RICT to an affected unit and the related TS 5.5.16 requirements imposing requirements associated with “any change to the plant configuration” and “emergent conditions.” Table E1-1 within this amendment request provides “design success criteria,” which is addressing only the affected unit.

With regard to PRA modeling, see above discussion.

2.0 TSTF VARIATIONS AND ADDITIONAL JUSTIFICATIONS

Table E1-2 provides a cross reference of the TSTF-505, Revision 2, TS and the HNP TS. As noted in Attachment 1, the RICT is proposed to be applied only in MODE 1. Variations are denoted within the table. TSTF-505, Revision 2, Table 1, “Conditions Requiring Additional Technical Justification,” contains a list of Required Actions from NUREG-1433, BWR/4 STS, that may be proposed for inclusion in a RICT Program, but which require additional technical justification to be provided by the licensee. Table E1-2 also provides the required additional justification related to not applying the RICT Program scope for a loss of function.

3.0 INSTRUMENTATION AND CONTROL SYSTEMS REDUNDANCY AND DIVERSITY

Information Supporting Instrumentation Redundancy and Diversity

Table E1-3 included list the Technical Specifications (TS) Section 3.3, Instrumentation, Limiting Conditions for Operation (LCO) Sections and associated trip or actuation Functions that have Risk Informed Completion Time (RICT) Program proposed changes applied to certain Required Action Completion Times (CTs), as described in Table E1-2. Each Function in the Tables provide the Final Safety Analysis Report (FSAR) reference for the transient or accident in which the Function is expected to trip/actuate. Each Table entry also indicates Redundant / Diverse signals available. As noted in Attachment 1, the RICT is proposed to be applied only in MODE 1.
The associate Event Type is also provided with the following abbreviations:

DBA – Design Bases Accident
AOO – Anticipated Operational Occurrence

Evaluation of Defense-in-Depth

The proposed change represents a robust technical approach that preserves a reasonable balance among redundant and diverse key safety functions that provide avoidance of core damage, avoidance of containment failure, and consequence mitigation. This approach to risk-informed TS CT changes provides additional assurance that defense-in-depth will not be significantly impacted by such changes to the licensing basis. The proposed change does not involve a change to the design of the plant or any operating parameter, introduce any new operating configurations, or modify the design basis. The effect of the proposed changes when implemented will be that the RICT Program 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 channel of a one-out-of-two taken-twice trip system is inoperable). A

RICT is not used if the trip system has lost the capability to perform its safety function(s). The restriction prohibiting utilization of the RICT Program when inoperability(ies) result in a loss of safety function, provides a reasonable balance such that defense-in-depth is maintained for protection of public health and safety.

While complying with the modified TS Actions, the redundancy of the function will be temporarily relaxed, and consequently, the system reliability will be reduced accordingly. However, under any given event evaluated in the FSAR, the affected instrumentation protective features maintain adequate defense-in-depth by the designed redundancy (i.e., sufficient redundant channel(s) remain available to perform the safety function). Furthermore, the designed instrumentation protection system diversity remains unaffected.

The proposed changes do not alter the protective instrumentation system designs. Consequently, the proposed changes do not alter the ways in which the instrumentation systems fail or introduce new common cause failure (CCF) modes, and the system independence is maintained. Some proposed changes allow the time of reduced redundancy (for specific conditions) to be prolonged, as such, this extension may reduce the level of defense against some CCFs. However, such extension of time of reduced redundancy and defense against CCFs is acceptable due to maintaining adequate defense-in-depth against a potential single failure during a RICT for the instrumentation systems.

Since system redundancy, independence, and diversity are adequately maintained, the defenses against potential CCFs are maintained and there is no potential for the introduction of new CCF mechanisms.

Since the capability to fulfill the safety function will be retained, any increase in unavailability because less equipment is available for a longer time is included in the RICT evaluation. Therefore, any reduction in margin of safety is considered by the implementation of the RICT Program.

As shown in Table E1-3, during the extended CTs at least one diverse actuation means is available, including manual actuations. These "manual actuations" are defined in plant operation procedures to which operators are trained. Select manual actions are modeled in the PRA. Those actions that are modeled incorporate appropriate human error probabilities. For manual actions that aren’t modeled, failure of the automatic function results in a failure of the function in the fault tree. This approach is consistent with the “not over-relying on programmatic activities as compensatory measures” principle.

4.0 EXAMPLES OF CALCULATED RISK INFORMED COMPLETION TIMES

Table E1-4 provides examples of calculated RICTs for each condition to which the RICT applies (assuming no other SSCs modeled in the PRA are unavailable). The RICTs presented in the table are based on a Unit 1 model calculation except where otherwise noted. Due to the close similarity between the Unit 1 and Unit 2 models, the Unit 1 RICTs not specifically related to electrical power are considered adequate examples for the Unit 2 RICTs. Following Initiative 4b implementation, the actual RICT values will be calculated on a unit-specific basis, using the actual plant configuration and the current revision of the PRA model representing the as-built, as-operated condition of the plant, as required by NEI 06-09-A and the NRC safety evaluation, and may differ from the RICTs presented as examples.

The example calculated RICT values in Table E1-4 are based upon current Internal Events, Internal Flooding, and Fire PRA models, with an added Seismic penalty factor. See Enclosure 4 of the LAR for treatment of excluded hazards and a description of how the Seismic penalty factor was derived.

Note also, that with the electrical system impacting both units, a RICT would be applied for each impacted unit.

Mapping of Technical Specification Conditions to PRA Functions

Table E1-1: Mapping of In-Scope TS Conditions to Corresponding PRA Functions

Technical Specification (TS)	TS Condition	SSCs Addressed by TS Condition	SSCs Modeled in PRA	Function Covered by TS Condition	Design Success Criteria	PRA Success Criteria	PRA Comments
3.1.7 Condition B	One SLC subsystem inoperable for reasons other than Condition A	Two Standby Liquid Control (SLC) subsystems	Yes	Capability to bring the reactor from full power to a cold, Xenon-free shutdown; also maintain suppression pool post-DBA pH >7	One of two subsystems	One SLC pump thru one squib valve	Function is modeled with two pumps, two squib valves, common injection path
3.3.1.1 Condition A	One or more required channels inoperable	Four Reactor Protection System (RPS) channels Functions 7.a, 7.b, and 10 excluded by Note	Partial Functions 7a, 7b, and 10 are not modeled	Provide reactor trip signal based on plant parameters	One-out-of-two twice logic; one of two channels in both trip systems	One channel in each trip system required to actuate for reactor scram. (A1 or A2) AND (B1 or B2)	RPS Functions are modeled with instrument inputs and channel relays. One of two channels in both trip systems A and B actuate to scram. Drywell High Pressure (Function 6) not directly modeled, surrogate event for channel failure will be used
3.3.1.1 Condition B	One or more Functions with one or more required channels inoperable in both trip systems	Same as TS 3.3.1.1 Condition A					

Table E1-1: Mapping of In-Scope TS Conditions to Corresponding PRA Functions

Technical Specification (TS)	TS Condition	SSCs Addressed by TS Condition	SSCs Modeled in PRA	Function Covered by TS Condition	Design Success Criteria	PRA Success Criteria	PRA Comments
3.3.4.1 Condition A	One or more channels inoperable	End of Cycle Recirculation Pump Trip (EOC-RPT) Instrumentation	Yes	Minimize reactor pressure increase by reduction in core flow after reactor trip	Two-out-of-two once logic for each Function; two of two channels in one of two trip systems trips both pumps	RPT trip requires two channels, one from each Trip System, A1 AND B1 or A2 AND B2	Two channels of trip signals per trip system, two trip systems, four RPT trip breakers, trip system A actuates inboard trip breakers for both recirc pumps, trip system B actuates outboard breakers for both pumps. Flag event is included in the logic to reflect that the EOC-RPT trip is bypassed at times during the run cycle
3.3.4.2 Condition A	One or more channels inoperable	Anticipated Transient Without Scram Recirculation Pump Trip (ATWS-RPT) Instrumentation	Yes	Reduction in core power in ATWS by reduction in core flow	Two-out-of-two once logic for each Function; two of two channels in one of two trip systems trips both pumps	RPT trip requires two channels, one from each Trip System, A1 AND B1 for trip system A or A2 AND B2 for trip system B	Trip system A or B trips both 4kv adjustable speed drive input breakers

Table E1-1: Mapping of In-Scope TS Conditions to Corresponding PRA Functions

Technical Specification (TS)	TS Condition	SSCs Addressed by TS Condition	SSCs Modeled in PRA	Function Covered by TS Condition	Design Success Criteria	PRA Success Criteria	PRA Comments
3.3.5.1 Condition B	One or more channels inoperable As required by Action A.1 and referenced in Table 3.3.5.1-1 – Functions 1a, 1b, 2a, 2b, 2e, 3a, 3b	Emergency Core Cooling System (ECCS) actuation instrumentation - Core Spray (CS), Low Pressure Coolant Injection (LPCI), and High Pressure Coolant Injection (HPCI) Function 2.e excluded by Note	Partial Function 2e not modeled Functions 1b, 2b, and 3b use surrogate	Initiate ECCS (CS, LPCI and HPCI)	One-out-of-two twice logic; one of two channels in both trip systems	Success is modeled as A1 or B1 AND A2 or B2	ECCS logic modeled at the instrument level. Drywell High Pressure instruments have placeholders for fire impacts that can be used as surrogate events
3.3.5.1 Condition C	One or more channels inoperable As required by Action A.1 and referenced in Table 3.3.5.1-1 – Functions 1c, 2c, 2d, 2f, 3c	ECCS permissive and trip instrumentation for CS, LPCI, and HPCI Function 3.c excluded by Note	Partial Functions 2d and 2f use surrogate	Initiate ECCS (CS, LPCI, and HPCI)	One-out-of-two twice logic; one of two channels in both trip systems	For 1c and 2c, success is modeled as A1 or B1 AND A2 or B2. Functions 2d and 2f are two channel systems	Functions 1c, 2c directly modeled. Functions 2d and 2f not modeled, but surrogate basic events for components actuated can be used
3.3.5.1 Condition D	One or more channels inoperable As required by Action A.1 and referenced in Table 3.3.5.1-1 – Functions 3d, 3e	ECCS suction source instrumentation for HPCI	Yes	Align HPCI suction source	One-out-of-two once logic; one of two channels	Two level instruments for each source, either initiates suction swap	All four instruments directly modeled

Table E1-1: Mapping of In-Scope TS Conditions to Corresponding PRA Functions

Technical Specification (TS)	TS Condition	SSCs Addressed by TS Condition	SSCs Modeled in PRA	Function Covered by TS Condition	Design Success Criteria	PRA Success Criteria	PRA Comments
3.3.5.1 Condition E	One or more channels inoperable As required by Action A.1 and referenced in Table 3.3.5.1-1 – Functions 1d, 2g, 3f	ECCS actuation instrumentation for CS, LPCI and HPCI (Pump discharge low flow bypass)	Partial	ECCS initiation of bypass on pump discharge low flow (CS, LPCI and HPCI) for pump minimum flow protection	One-out-of-one logic per subsystem for CS and LPCI; One-out-of-one logic for HPCI	One minimum flow valve per train for LPCI and CS, one valve for HPCI.	Minimum flow logic is not modeled separately from the valve. Minimum flow failing to open fails pumps. The valve failure to open events will be used as surrogate events for the logic. Minimum flow failing to close not included in the model due to restricting orifice downstream of valve limiting flow.
3.3.5.3 Condition B	One or more channels inoperable As required by Action A.1 and referenced in Table 3.3.5.3-1 – Function 1	Reactor Core Isolation Cooling (RCIC) instrumentation	Yes	RCIC Initiation on Low vessel level	One-out-of-two twice logic; one of two channels in both trip systems	A1 or B1 AND A2 or B2 initiates RCIC	Instruments, trip units, relays all modeled
3.3.5.3 Condition D	One or more channels inoperable As required by Action A.1 and referenced in Table 3.3.5.3-1 – Functions 3, 4	RCIC suction source instruments	Yes	Align RCIC suction sources	One-out-of-two logic	Two level instruments for each source; either initiates suction swap	All four instruments are modeled

Table E1-1: Mapping of In-Scope TS Conditions to Corresponding PRA Functions

Technical Specification (TS)	TS Condition	SSCs Addressed by TS Condition	SSCs Modeled in PRA	Function Covered by TS Condition	Design Success Criteria	PRA Success Criteria	PRA Comments
3.3.6.1 Condition A	One or more required channels inoperable	Primary Containment Isolation Instrumentation Functions 2.c, 2.d, 2.e, 6 and 7 excluded by Notes	Partial Functions 2.c, 2.d, 2.e, 6.a, and 7(a&b) are not modelled	Primary Containment integrity	F1, one-out-of-two twice logic except 1.c which is one-out-of-eight twice, and 1.e which is one-out-of-sixteen twice; F2.a & 2.b – two-out-of-two for inboard CIV trip system and two-out-of-two for outboard CIV trip system F3 & F4, one-out-of-one in one of two trip systems except 3.b and 3.c which are two-out-of-two in one of two trip systems; 5.a, one-out-of-three, 5.b, one-out-of-six, and 5.c, one-out-of-one logic 5.d, two-out-of-two trip systems	Containment isolation signals modeled by single composite events	Functions 2.c, 2.d, 2.e, 6.a, and 7(a&b) are not modelled in PRA The composite events can be used as surrogate events for the logic channels
3.5.1 Condition A	One low pressure ECCS injection/spray subsystem inoperable OR one LPCI pump in both LPCI subsystems inoperable	Emergency Core Cooling System Injection / Spray	Yes	To assure that the core is adequately cooled following a loss-of-coolant accident	One of two Core Spray subsystems and one LPCI pump in each LPCI subsystem	One low pressure injection system, one LPCI pump at 7000 GPM or one Core Spray pump at 4250 GPM	The PRA success criteria is based on safe shutdown analysis

Table E1-1: Mapping of In-Scope TS Conditions to Corresponding PRA Functions

Technical Specification (TS)	TS Condition	SSCs Addressed by TS Condition	SSCs Modeled in PRA	Function Covered by TS Condition	Design Success Criteria	PRA Success Criteria	PRA Comments
3.5.1 Condition C	One LPCI pump in one subsystem or one LPCI pump in both subsystems inoperable AND One CS subsystem inoperable	Emergency Core Cooling System Injection / Spray	Yes	To assure that the core is adequately cooled following a loss-of-coolant accident	One of two Core Spray subsystems and one LPCI pump in one LPCI subsystem	One low pressure injection system, one LPCI pump at 7000 GPM or one Core Spray pump at 4250 GPM	The PRA success criteria is based on safe shutdown analysis
3.5.1 Condition E	HPCI system inoperable	HPCI system	Yes	Reactor inventory control for small break LOCA	One train (not credited in LOCA safety analysis)	HPCI starts and injects at 4000 GPM	HPCI is modeled in detail and so can be directly evaluated in the CRMP tool for the RICT Program. The success criteria in the PRA are consistent with the design basis
3.5.1 Condition F	HPCI System inoperable AND Condition A entered	See LCO 3.5.1 Conditions A and E					
3.5.3 Condition A	RCIC system inoperable	Reactor Core Isolation Cooling (RCIC) system	Yes	Reactor inventory control when RPV isolated from main condenser and feedwater system	One train (not credited in safety analysis)	RCIC starts and injects at 360 GPM	RCIC is modeled in detail and so can be directly evaluated in the CRMP tool for the RICT Program. The success criteria in the PRA are consistent with the design basis

Table E1-1: Mapping of In-Scope TS Conditions to Corresponding PRA Functions

Technical Specification (TS)	TS Condition	SSCs Addressed by TS Condition	SSCs Modeled in PRA	Function Covered by TS Condition	Design Success Criteria	PRA Success Criteria	PRA Comments
3.6.1.2 Condition C	Primary containment air lock inoperable for reasons other than Condition A (door) or B (interlock mechanism)	Primary containment airlock	No	Containment Integrity	One of two containment air lock doors closed	Intact primary containment Boundary	This condition will be modeled as early containment isolation failure as a conservative surrogate in the PRA. [Compliance with the remaining portions of LCO Condition 3.6.1.2 ensure that there is a physical barrier (i.e., closed door) and an acceptable overall leakage from containment. Required Action C.1 of LCO Condition 3.6.1.2 requires the condition to be assessed in accordance with TS 3.6.1.1, "Primary Containment" (i.e., "Initiate action to evaluate primary containment overall leakage rate per LCO 3.6.1.1 using current air lock test results" with a Completion Time of Immediately). Thus, the function is still maintained]

Table E1-1: Mapping of In-Scope TS Conditions to Corresponding PRA Functions

Technical Specification (TS)	TS Condition	SSCs Addressed by TS Condition	SSCs Modeled in PRA	Function Covered by TS Condition	Design Success Criteria	PRA Success Criteria	PRA Comments
3.6.1.3 Condition A	One or more penetration flow paths with one PCIV inoperable except due to leakage not within limit (only applicable to penetrations with 2 PCIVs)	Primary Containment Isolation Valves (PCIVs)	Yes	Primary containment isolation	At least one isolation valve operable in each penetration flow path	At least one isolation valve operable in each penetration flow path. Lines smaller than two-inch are not considered a significant leakage path	Not all valves modeled. If specific valve is not modeled, a generic isolation failure event will be used as a surrogate for the RICT calculation Valves larger than 2 inches modeled in detail. Smaller valves grouped into single composite event
3.6.2.3 Condition A	One RHR suppression pool cooling subsystem Inoperable	Two Residual Heat Removal (RHR) subsystems of suppression pool cooling	Yes	Heat removal from the suppression pool	One subsystem with one pump and one heat exchanger	One pump at 7000 GPM and one heat exchanger	Suppression pool cooling is modeled in detail and so can be directly evaluated in the CRMP tool for the RICT Program.
3.6.2.4 Condition A	One RHR suppression pool spray subsystem inoperable	Two RHR suppression pool spray subsystems	No	Heat removal from the suppression pool chamber for temperature and pressure control	One subsystem with two pumps and one heat exchanger	Not modeled. Spray path provides no pool cooling	Because the flow path is shared with the suppression pool cooling path, the suppression pool cooling path will be used as surrogate events
3.6.2.5 Condition A	One RHR drywell spray subsystem inoperable	Two subsystems of drywell spray mode of RHR	Yes	Drywell temperature and pressure control and scrubbing for dose reduction	One subsystem with one pump and one heat exchanger	One pump at 7000 GPM and heat exchanger	PRA success criteria based on thermal-hydraulic runs

Table E1-1: Mapping of In-Scope TS Conditions to Corresponding PRA Functions

Technical Specification (TS)	TS Condition	SSCs Addressed by TS Condition	SSCs Modeled in PRA	Function Covered by TS Condition	Design Success Criteria	PRA Success Criteria	PRA Comments
3.7.1 Condition B	One RHRSW pump in each subsystem inoperable	Two subsystems of Residual Heat Removal Service Water (RHRSW)	Yes	Remove energy from reactor and containment	One pump in each of two subsystems (cross-tied) and one heat exchanger	One pump at 4000 GPM and heat exchanger	RHR Service Water is modeled in detail and so can be directly evaluated in the CRMP tool for the RICT Program
3.7.1 Condition C	One RHRSW subsystem inoperable for reasons other than Condition A	Two subsystems of Residual Heat Removal Service Water (RHRSW)	Yes	Remove energy from reactor and containment	One of two subsystems with two pumps and one heat exchanger	One pump at 4000 GPM and heat exchanger	RHR Service Water is modeled in detail and so can be directly evaluated in the CRMP tool for the RICT Program. The success criteria in the PRA are consistent with the design basis
3.7.2 Condition C	One PSW pump in each subsystem inoperable	Two Plant Service Water (PSW) subsystems and Ultimate Heat Sink (UHS)	Yes	Remove heat from equipment	One of two subsystems with one pump and the UHS	One PSW pump at 2400 GPM and UHS	One PSW pump at 2400 GPM provides sufficient cooling for one division loads
3.7.2 Condition D	One PSW turbine building isolation valve in each subsystem inoperable	Two Plant Service Water (PSW) subsystems and Ultimate Heat Sink (UHS)	Yes	Isolate non-safety PSW system in turbine building from safety-related systems	One valve in each subsystem isolates	One valve in each PSW division has to isolate or the division fails	All four valves modeled
3.7.2 Condition F	One PSW subsystem inoperable for reasons other than Condition A and B	Two Plant Service Water (PSW) subsystems and Ultimate Heat Sink (UHS)	Yes	Remove heat from equipment	One of two subsystems and the UHS	One PSW pump at 2400 GPM and UHS	One PSW pump at 2400 GPM provides sufficient cooling for one division loads

Table E1-1: Mapping of In-Scope TS Conditions to Corresponding PRA Functions

Technical Specification (TS)	**TS Condition**	**SSCs Addressed by TS Condition**	**SSCs Modeled in PRA**	**Function Covered by TS Condition**	**Design Success Criteria**	**PRA Success Criteria**	**PRA Comments**
3.8.1 Condition A	One required offsite circuit inoperable	Two qualified circuits between the offsite transmission network and the Unit onsite Class 1E AC Electrical Power Distribution (EPD) System AND One qualified circuit between the offsite transmission network and the opposite-unit onsite Class 1E AC EPD subsystem(s) needed to support select opposite-unit equipment AND One qualified circuit between the offsite transmission network and the applicable onsite Class 1E AC EPD subsystems needed to support each Unit LPCI valve load center	Yes	Provide power to safety related buses	The minimum DGs: One unit DG & the swing DG OR two unit DGs; AND One opposite unit DG capable of supplying power to one SGT subsystem; AND Two DGs (any combination of opposite unit DGs and the swing DG), each capable of supplying power to one unit LPCI valve load center	To prevent a 4KV bus from having to be supplied solely from a diesel, two of three startup transformers are required, however there is PRA success with no offsite power sources.	Three startup transformers per unit and all supporting transmission lines and breakers are modeled. No offsite power is needed for PRA success.

Table E1-1: Mapping of In-Scope TS Conditions to Corresponding PRA Functions

Technical Specification (TS)	TS Condition	SSCs Addressed by TS Condition	SSCs Modeled in PRA	Function Covered by TS Condition	Design Success Criteria	PRA Success Criteria	PRA Comments
3.8.1 Condition B	One Unit or the swing DG inoperable	Two Unit diesel generators (DGs) AND The swing DG AND One Unit opposite DG capable of supplying power to one Unit opposite Standby Gas Treatment (SGT) subsystem AND Two DGs (any combination of Unit opposite DGs and the swing DG), each capable of supplying power to one Unit LPCI valve load center	Yes	Provide power to safety related buses when offsite power to them is lost	The minimum DGs: One unit DG & the swing DG OR two unit DGs; AND One opposite unit DG capable of supplying power to one SGT subsystem; AND Two DGs (any combination of opposite unit DGs and the swing DG), each capable of supplying power to one unit LPCI valve load center	One unit specific diesel and either one opposite unit diesel or the swing diesel ESF bus aligned to the unit with only one diesel.	All five diesels are in both Unit 1 and Unit 2 PRA models.
3.8.1 Condition C	One required opposite-unit DG inoperable	See LCO Condition 3.8.1 Condition B					
3.8.1 Condition D	Two or more required offsite circuits inoperable	See TS 3.8.1 Condition A	Yes	Provide power to safety related buses when offsite power to them is lost	The required DGs: Two Unit DGs AND The swing DG AND One opposite unit DG capable of supplying power to one opposite unit SGT subsystem AND Two DGs (any combination of opposite unit DGs and the swing DG), each capable of supplying power to one Unit LPCI valve load center	To prevent a 4KV bus from having to be supplied solely from a diesel, two of three startup transformers are required, however there is PRA success with no offsite power sources.	Three startup transformers per unit and all supporting transmission lines and breakers are modeled. No offsite power is needed for PRA success.

Table E1-1: Mapping of In-Scope TS Conditions to Corresponding PRA Functions

Technical Specification (TS)	**TS Condition**	**SSCs Addressed by TS Condition**	**SSCs Modeled in PRA**	**Function Covered by TS Condition**	**Design Success Criteria**	**PRA Success Criteria**	**PRA Comments**
3.8.1 Condition E	One required offsite circuit inoperable AND one required DG inoperable	See TS 3.8.1 Conditions A & B	Yes	Provide power to safety related buses when offsite power to them is lost	See TS 3.8.1 Conditions A & B	One unit specific diesel and either one opposite unit diesel or the swing diesel ESF bus aligned to the unit with only one diesel.	All five diesels are in both Unit 1 and Unit 2 PRA models.
3.8.4 Condition A	Swing DG DC electrical power subsystem inoperable due to performance of SR 3.8.4.3 or SR 3.8.6.6. OR One or more required opposite unit DG DC electrical power subsystems inoperable.	The swing DGs DC electrical power subsystems; AND The opposite unit DG DC electrical power subsystems needed to support the required equipment	Yes	Provide normal and emergency DC electrical power for the required DGs to support DBA and transient analyses	One unit DG DC & the swing DG DC <u>OR</u> two unit DG DC; <u>AND</u> opposite unit DG DC capable of supplying power to support the required SGT (and for Unit 2, Unit 1 MCREC and Control Room AC) safety function and required DGs to support DBA and transient analyses	The diesel DC batteries associated with the diesels required in 3.8.1.	The Diesel DC panels do not power any motor operated valves; therefore they are modeled as requiring either the batteries or the charger to be functional
3.8.4 Condition B	Required Unit DG DC battery charger on one subsystem inoperable OR Required swing DG DC battery charger inoperable for reasons other than Condition A	Division 1 and Division 2 unit DG DC battery charger; AND swing DG DC battery charger	Yes	Provide normal and emergency DC electrical power for the required DGs to support DBA and transient analyses	One unit DG DC & the swing DG DC <u>OR</u> two unit DG DC; <u>AND</u> opposite unit DG DC capable of supplying power to support the required SGT (and for Unit 2, Unit 1 MCREC and Control Room AC) safety function and required DGs to support DBA and transient analyses	One of two battery chargers or the battery and the associated DC distribution panel can supply all diesel specific loads.	Both chargers associated with each battery are modeled, with alignment flags to select which is in service. MOVs cannot be powered by chargers alone

Table E1-1: Mapping of In-Scope TS Conditions to Corresponding PRA Functions

Technical Specification (TS)	TS Condition	SSCs Addressed by TS Condition	SSCs Modeled in PRA	Function Covered by TS Condition	Design Success Criteria	PRA Success Criteria	PRA Comments
3.8.4 Condition C	One Unit DG DC electrical power subsystem inoperable for reasons other than Condition B OR Swing DG DC electrical power subsystem inoperable for reasons other than Condition A or B	Division 1 and Division 2 unit DG DC electrical power subsystems; AND swing DGs DC electrical power subsystems	Yes	Provide normal and emergency DC electrical power for the required DGs to support DBA and transient analyses	One unit DG DC & the swing DG DC OR two unit DG DC; AND opposite unit DG DC capable of supplying power to support the required SGT (and for Unit 2, Unit 1 MCREC and Control Room AC) safety function and required DGs to support DBA and transient analyses	One of two battery chargers or the battery and the associated DC distribution panel can supply all diesel specific loads.	The Diesel DC panels do not power any motor operated valves; therefore they are modeled as requiring either the batteries or the charger to be functional
3.8.4 Condition D	One or more required Unit station service DC battery chargers on one subsystem inoperable	Division 1 and Division 2 unit station service DC electrical power subsystems	Yes	Provide normal and emergency DC electrical power for the required emergency auxiliaries and control and switching to support DBA and transient analyses	One Unit station service DC electrical power subsystem	The associated battery.	All three chargers modeled. Alignment flags allow selection of which two are in service. All DG DC systems contained in both unit models. The battery is required to operate larger DC MOVs due to the associated inrush current
3.8.4 Condition E	One Unit station service DC electrical power subsystem inoperable for reasons other than Condition D	Division 1 and Division 2 unit station service DC electrical power subsystems	Yes	Provide normal and emergency DC electrical power for the required emergency auxiliaries and control and switching to support DBA and transient analyses	One Unit station service DC electrical power subsystem	The battery is required to operate larger DC MOVs due to the associated inrush current. Two of three chargers can power the other DC loads	In the Unit 2 model, Unit 1 station service DC is modeled for support of MCREC systems

Table E1-1: Mapping of In-Scope TS Conditions to Corresponding PRA Functions

Technical Specification (TS)	TS Condition	SSCs Addressed by TS Condition	SSCs Modeled in PRA	Function Covered by TS Condition	Design Success Criteria	PRA Success Criteria	PRA Comments
3.8.7 Condition A	One or more required opposite unit AC or DC electrical power distribution subsystems inoperable	Opposite unit AC and DC electrical power distribution subsystems needed to support select equipment	Yes	Provide power to the onsite Class 1E loads.	Opposite unit AC and DC electrical power distribution subsystem(s) needed to support minimum required equipment	AC and DC switchgear and motor control centers to support equipment on the opposite unit, such as SGT.	All safety related AC and DC distribution systems for the unit are modeled, and any opposite unit systems required for shared components
3.8.7 Condition B	One or more (Unit or swing bus) DG DC electrical power distribution subsystems inoperable	Unit DG DC electrical power distribution subsystems	Yes	Provide power to required DG DC loads	One Unit or swing DG DC electrical power distribution subsystem	One DC switchgear and associated DC distribution panel and MCCs to support either HPCI or RCIC operation and provide DC logic control power to one train.	All safety related DC distribution systems for the unit are modeled, and any opposite unit systems required for shared components
3.8.7 Condition C	One or more (Unit or swing bus) AC electrical power distribution subsystems inoperable	Unit AC electrical power distribution subsystems	Yes	Provide power to the onsite Class 1E loads.	One Unit or swing AC electrical power subsystem	One 4KV ESF bus, the associated 600v ESF switchgear, and the train specific MCCs and distribution panels fed from the switchgear, to support one loop of RHR, Core Spray, PSW and RHRSW.	All safety related AC distribution systems for the unit are modeled, and any opposite unit systems required for shared components
3.8.7 Condition D	One Unit station service DC electrical power distribution subsystem inoperable	Unit DC electrical power distribution subsystem	Yes	Provide power to required DC loads	One Unit station service DC electrical power distribution subsystem	One DC switchgear and associated DC distribution panel and MCCs to support either HPCI or RCIC operation and provide DC logic control power to one train.	All safety related DC distribution systems for the unit are modeled, and any opposite unit systems required for shared components

Cross-Reference of TSTF-505 and HATCH Unit 1 and Unit 2 Technical Specifications

LCO ACTION TSTF-505/HATCH 1&2 TS	Add RICT?	DISCUSSION
Example 1.3-8 TSTF-505: [New example TS] HATCH 1&2: [New example TS]	N/A	
Standby Liquid Control (SLC) System TSTF-505: LCO 3.1.7, Required Action B.1 HATCH 1&2: LCO 3.1.7, Required Action B.1	YES	
Reactor Protection System (RPS) Instrumentation TSTF-505: LCO 3.3.1.1, Required Actions A.1 and A.2 HATCH 1&2: LCO 3.3.1.1, Required Actions A.1 and A.2	YES	VARIATION: Functions 7.a, 7.b, and 10 are not proposed to be included in the scope of the RICT Program (excluded by Note). This Condition allows one or more inoperable channels for the included Functions. Under certain circumstances, with more than one required channel inoperable, a loss of function may occur. However, a Note is not considered necessary since Condition C ("One or more Functions with RPS trip capability not maintained") addresses a loss of function and does not apply use of RICT. Condition C (without use of RICT) must be applied regardless, and thus, a loss of Function is adequately addressed without the need for additional Notes.
Reactor Protection System (RPS) Instrumentation TSTF-505: LCO 3.3.1.1, Required Actions B.1 and B.2 HATCH 1&2: LCO 3.3.1.1, Required Actions B.1 and B.2	YES	VARIATION: Functions 7.a, 7.b, and 10 are not proposed to be included in the scope of the RICT Program (excluded by Note). This Condition allows one or more inoperable channels for the included Functions. Under certain circumstances, with more than one required channel inoperable, a loss of function may occur. However, a Note is not considered necessary since Condition C ("One or more Functions with RPS trip capability not maintained") addresses a loss of function and does not apply use of RICT. Condition C (without use of RICT) must be applied regardless, and thus, a loss of Function is adequately addressed without the need for additional Notes.
Source Range Monitor (SRM) Instrumentation TSTF-505: LCO 3.3.1.2, Required Action A.1 HATCH 1&2: LCO 3.3.1.2, Required Action A.1	NO	VARIATION: This Action is not proposed to be in the scope of the RICT Program.
Feedwater and Main Turbine High Water Level Trip Instrumentation TSTF-505: LCO 3.3.2.2, Required Action A.1 Feedwater and Main Turbine Trip High Water Level Instrumentation HATCH 1&2: LCO 3.3.2.2, Required Action A.1	NO	VARIATION: This Action is not proposed to be in the scope of the RICT Program. VARIATION: TS title. Non-TSTF change included to make function title consistent with NUREG throughout the Specification.
Feedwater and Main Turbine High Water Level Trip Instrumentation TSTF-505: LCO 3.3.2.2, Required Action B.1 HATCH 1&2: LCO 3.3.2.2, Required Action B.1	NO	VARIATION: This Action is not proposed to be in the scope of the RICT Program.

LCO ACTION TSTF-505/HATCH 1&2 TS	Add RICT?	DISCUSSION
End of Cycle Recirculation Pump Trip (EOC-RPT) Instrumentation TSTF-505: LCO 3.3.4.1, Required Actions A.1 and A.2 HATCH 1&2: LCO 3.3.4.1, Required Actions A.1 and A.2	YES	TSTF Table 1 requests justification that one or more inoperable channels is not a condition in which all required trains or subsystems are inoperable or modify the Action to not apply a RICT when all required trains or subsystems are inoperable. Under certain circumstances, with more than one required channel inoperable, a loss of function may occur. However, a Note is not considered necessary since Condition B (“One or more Functions with EOC-RPT trip capability not maintained”) addresses a loss of function and does not apply use of RICT. Condition B (without use of RICT) must be applied regardless, and thus, a loss of Function is adequately addressed without the need for additional Notes. The TSTF also indicates that justification is required for the ability to calculate a RICT since the EOC-RPT function is not typically modeled in the PRA. As noted in Table E1-1, the PRA models the EOC-RPT function.
Anticipated Transient Without Scram Recirculation Pump Trip (ATWS-RPT) Instrumentation TSTF-505: LCO 3.3.4.2, Required Actions A.1 and A.2 HATCH 1&2: LCO 3.3.4.2, Required Actions A.1 and A.2	YES	This Condition allows one or more inoperable channels. Under certain circumstances, with more than one required channel inoperable, a loss of function may occur. However, a Note is not considered necessary since Condition B {“One Function with ATWS-RPT trip capability not maintained”} and Condition C {“Both Functions with ATWS-RPT trip capability not maintained”} addresses a loss of function and does not apply use of RICT. Conditions B and C (without use of RICT) must be applied regardless, and thus, a loss of Function is adequately addressed without the need for additional Notes.
Emergency Core Cooling System (ECCS) Instrumentation TSTF-505: LCO 3.3.5.1, Required Action B.3 HATCH 1&2: LCO 3.3.5.1, Required Action B.3	YES	This Condition allows one or more inoperable channels. Under certain circumstances, with more than one required channel inoperable, a loss of function may occur. However, a Note is not considered necessary since: a) Required Action B.1 (which must be applied “1 hour from discovery of loss of initiation capability for feature(s) in both divisions”) addresses loss of initiation function for Core Spray (Functions 1.a and 1.b) and LPCI (Functions 2.a and 2.b); b) Required Action B.2 (which must be applied “1 hour from discovery of loss of HPCI initiation capability”) addresses loss of initiation function for HPCI (Functions 3.a and 3.b); and c) Function 2.e, Reactor Vessel Shroud Level - Level 0, is excluded from RICT application by Note. Thus, a loss of Function is adequately addressed without the need for additional Notes.

LCO ACTION TSTF-505/HATCH 1&2 TS	Add RICT?	DISCUSSION
Emergency Core Cooling System (ECCS) Instrumentation TSTF-505: LCO 3.3.5.1, Required Action C.2 HATCH 1&2: LCO 3.3.5.1, Required Action C.2	YES	This Condition allows one or more inoperable channels. Under certain circumstances (i.e., for Core Spray (Function 1.c) and LPCI (Functions 2.c, 2.d and 2.f)), with more than one required channel inoperable, a loss of function may occur. However, a Note is not considered necessary since Required Action C.1 (which must be applied “1 hour from discovery of loss of initiation capability for feature(s) in both divisions”) addresses loss of initiation function. Thus, a loss of Function is adequately addressed for these Functions without the need for additional Notes. Function 3.c, Reactor Vessel Water Level – High, Level 8, is excluded from RICT application by Note.
Emergency Core Cooling System (ECCS) Instrumentation TSTF-505: LCO 3.3.5.1, Required Action D.2.1 HATCH 1&2: LCO 3.3.5.1, Required Action D.2.1	YES	This Condition allows one or more inoperable channels. Under certain circumstances, with more than one required channel inoperable, a loss of function may occur. However, a Note is not considered necessary since Required Action D.1 (which must be applied “1 hour from discovery of loss of HPCI initiation capability”) addresses loss of initiation function and does not apply use of RICT. Required Action D.1 (without use of RICT) must be applied regardless, and thus, a loss of Function is adequately addressed without the need for additional Notes (unless the function has already been fulfilled by aligning the HPCI pump suction to the suppression pool, and thus, a loss of Function is adequately addressed without the need for additional Notes).
Emergency Core Cooling System (ECCS) Instrumentation TSTF-505: LCO 3.3.5.1, Required Action E.2 HATCH 1&2: LCO 3.3.5.1, Required Action E.2	YES	This Condition allows one or more inoperable channels. Under certain circumstances (i.e., for Core Spray (Function 1.d) and LPCI (Function 2.g)), with more than one required channel inoperable, a loss of function may occur. However, a Note is not considered necessary since Required Action E.1 (which must be applied “1 hour from discovery of loss of initiation capability for feature(s) in both divisions”) addresses loss of initiation function. Function 3.f, HPCI Pump Discharge Flow – Low (Bypass), does not provide a HPCI actuation function and is not assumed in the accident and transient analyses, but is provided to protect the HPCI pump from overheating when the pump is operating and the associated injection valve is not fully open. A Note is not considered necessary since no assumed safety function is lost.
Emergency Core Cooling System (ECCS) Instrumentation TSTF-505: LCO 3.3.5.1, Required Action F.2 HATCH 1&2: LCO 3.3.5.1, Required Action F.2	NO	VARIATION: This Action is not proposed to be in the scope of the RICT Program.
Emergency Core Cooling System (ECCS) Instrumentation TSTF-505: LCO 3.3.5.1, Required Action G.2 HATCH 1&2: LCO 3.3.5.1, Required Action G.2	NO	VARIATION: This Action is not proposed to be in the scope of the RICT Program.

LCO ACTION TSTF-505/HATCH 1&2 TS	Add RICT?	DISCUSSION
Reactor Core Isolation Cooling (RCIC) System Instrumentation TSTF-505: LCO 3.3.5.2, Required Action B.2 HATCH 1&2: LCO 3.3.5.3, Required Action B.2	YES	VARIATION: TS numbering. This Condition allows one or more inoperable channels. Under certain circumstances, with more than one required channel inoperable, a loss of function may occur. However, a Note is not considered necessary since Required Action B.1 (which must be applied “1 hour from discovery of loss RCIC initiation capability”) addresses loss of RCIC initiation function. Required Action B.1 (without use of RICT) must be applied regardless, and thus, a loss of Function is adequately addressed without the need for additional Notes.
Reactor Core Isolation Cooling (RCIC) System Instrumentation TSTF-505: LCO 3.3.5.2, Required Action D.2.1 HATCH 1&2: LCO 3.3.5.3, Required Action D.2.1	YES	VARIATION: TS numbering. This Condition allows one or more inoperable channels. Under certain circumstances, with more than one required channel inoperable, a loss of function may occur. However, a Note is not considered necessary since Required Action D.1 (which must be applied “1 hour from discovery of loss RCIC initiation capability”) addresses loss of RCIC suction source swap function. Required Action D.1 (without use of RICT) must be applied regardless (unless the function has already been fulfilled by aligning the RCIC pump suction to the suppression pool, and thus, a loss of Function is adequately addressed without the need for additional Notes).
Primary Containment Isolation Instrumentation TSTF-505: LCO 3.3.6.1, Required Action A.1 HATCH 1&2: LCO 3.3.6.1, Required Action A.1 and A.2	YES	VARIATION: TS numbering. Format revised (similar to other precedent submittals) to avoid nested Completion Time logic which is only allowed in RA Column per Writer’s Guide. VARIATION: Functions 2.c, 2.d, 2.e, 6, and 7 are not proposed to be included in the scope of the RICT Program (excluded by Notes). This Condition allows one or more inoperable channels for the included Functions. Under certain circumstances (i.e., for all Functions except 5.c), with more than one required channel inoperable, a loss of function may occur. However, a Note is not considered necessary since Required Action B.1 (where the Condition is “One or more automatic Functions with isolation capability not maintained”) addresses loss of initiation function for all Functions without use of RICT. For Function 5.c, SLC initiation is a manual operator action and EOPs direct verification of RWCU isolation in conjunction with that manual action. Therefore, even if the automatic interlock to isolate RWCU is inoperable, RWCU will be manually isolated in conjunction with the manual initiation of SLC; as such, isolation function is maintained. The RWCU isolation safety function is maintained by plant procedures (to which operators are trained) governing this manual operator action. This manual action is modeled in the PRA, which incorporates appropriate human error probabilities. Thus, a loss of Function is adequately addressed without the need for additional Notes.

LCO ACTION TSTF-505/HATCH 1&2 TS	Add RICT?	DISCUSSION
Low-Low Set (LLS) Instrumentation TSTF-505: LCO 3.3.6.3, Required Action A.1 HATCH 1&2: LCO 3.3.6.3, Required Action A.1	NO	VARIATION: This Action is not proposed to be in the scope of the RICT Program.
Safety/Relief Valves (S/RVs) TSTF-505: LCO 3.4.3, Required Action A.1 HATCH 1&2: N/A	N/A	VARIATION: The TS do not have this Condition and Required Action.
ECCS – Operating TSTF-505: LCO 3.5.1, Required Action A.1 HATCH 1&2: LCO 3.5.1, Required Action A.1	YES	NOTE: Also included administrative change to remove no longer applicable Unit 2 Required Actions A.2.1 and A.2.2 as addressed in Attachment 1.
ECCS – Operating TSTF-505: N/A HATCH 1&2: LCO 3.5.1, Required Action C.1	YES	VARIATION: The TSTF does not have this new proposed Condition C. Corresponding new Condition D also proposed.
ECCS – Operating TSTF-505: LCO 3.5.1, Required Action C.2 HATCH 1&2: LCO 3.5.1, Required Action E.2	YES	VARIATION: TS numbering due to Included change to add new Conditions C and D which were not in TSTF.
ECCS – Operating TSTF-505: LCO 3.5.1, Required Actions D.1 and D.2 HATCH 1&2: LCO 3.5.1, Required Actions F.1 and F.2	YES	VARIATION: TS numbering due to Included change to add new Conditions C and D which were not in TSTF.
ECCS - Operating TSTF-505: LCO 3.5.1, Required Action E.1 HATCH 1&2: N/A	N/A	VARIATION: The TS do not have this Condition and RA.
ECCS - Operating TSTF-505: LCO 3.5.1, Required Action F.1 and F.2 HATCH 1&2: N/A	N/A	VARIATION: The TS do not have this Condition and RA.
Reactor Core Isolation Cooling (RCIC) System TSTF-505: LCO 3.5.3, Required Action A.2 HATCH 1&2: LCO 3.5.3, Required Action A.2	YES	
Primary Containment Air Lock TSTF-505: LCO 3.6.1.2, Required Action C.3 HATCH 1&2: LCO 3.6.1.2, Required Action C.3	YES	TSTF Table 1 requests justification that an inoperable containment airlock is not a condition in which all required trains or subsystems of a TS required system are inoperable. Required Action C.1 (without use of RICT) requires initiation of an evaluation of primary containment overall leakage rate per LCO 3.6.1.1 using the current air lock test results and excessive leakage would require an immediate plant shutdown under that TS, which is identified as an acceptable alternative in TSTF Table 1.
Primary Containment Isolation Valves (PCIVs) TSTF-505: LCO 3.6.1.3, Required Action A.1 HATCH 1&2: LCO 3.6.1.3, Required Action A.1 and A.2	YES	VARIATION: TS numbering. Format revised to avoid nested Completion Time logic which is only allowed in RA Column per Writer's Guide, resulting in a new RA A.2.

LCO ACTION TSTF-505/HATCH 1&2 TS	Add RICT?	DISCUSSION
Primary Containment Isolation Valves (PCIVs) TSTF-505: LCO 3.6.1.3, Required Action A.2 HATCH 1&2: LCO 3.6.1.3, Required Action A.3	NO	RICT not applied but TSTF change incorporated. VARIATION: TS numbering.
Primary Containment Isolation Valves (PCIVs) TSTF-505: LCO 3.6.1.3, Required Action C.2 HATCH 1&2: LCO 3.6.1.3, Required Action C.2	NO	RICT not applied but TSTF change incorporated.
Primary Containment Isolation Valves (PCIVs) TSTF-505: LCO 3.6.1.3, Required Action E.1, E.2 and E.3 HATCH 1&2: N/A	N/A	VARIATION: The TS do not have this Condition and RA.
Reactor Building-to-Suppression Chamber Vacuum Breakers TSTF-505: LCO 3.6.1.7, Required Action C.1 HATCH 1&2: LCO 3.6.1.7, Required Action C.1	NO	VARIATION: This Action is not proposed to be in the scope of the RICT Program.
Reactor Building-to-Suppression Chamber Vacuum Breakers TSTF-505: LCO 3.6.1.7, Required Action D.1 HATCH 1&2: LCO 3.6.1.7, Required Action E.1	NO	VARIATION: TS numbering. VARIATION: This Action is not proposed to be in the scope of the RICT Program.
Suppression Chamber-to-Drywell Vacuum Breakers TSTF-505: LCO 3.6.1.8, Required Action A.1 HATCH 1&2: LCO 3.6.1.8, Required Action A.1	NO	VARIATION: This Action is not proposed to be in the scope of the RICT Program.
Residual Heat Removal (RHR) Suppression Pool Cooling TSTF-505: LCO 3.6.2.3, Required Action A.1 HATCH 1&2: LCO 3.6.2.3, Required Action A.1	YES	
Residual Heat Removal (RHR) Suppression Pool Spray TSTF-505: LCO 3.6.2.4, Required Action A.1 HATCH 1&2: LCO 3.6.2.4, Required Action A.1	YES	
Residual Heat Removal (RHR) Drywell Spray TSTF-505: N/A HATCH 1&2: LCO 3.6.2.5, Required Action A.1	YES	VARIATION: The TSTF does not have this specification.
Drywell Cooling System Fans TSTF-505: LCO 3.6.3.1, Required Action B.2 HATCH 1: N/A HATCH 2: LCO 3.6.3.3, Required Action B.1	NO	VARIATION: This Action is not proposed to be in the scope of the RICT Program. VARIATION: The Unit 1 TS do not have this specification. VARIATION: Unit 2 TS numbering.
Residual Heat Removal Service Water (RHRSW) System TSTF-505: LCO 3.7.1, Required Action B.1 HATCH 1&2: LCO 3.7.1, Required Action B.1	YES	

LCO ACTION TSTF-505/HATCH 1&2 TS	Add RICT?	DISCUSSION
Residual Heat Removal Service Water (RHRSW) System TSTF-505: LCO 3.7.1, Required Action C.1 HATCH 1&2: LCO 3.7.1, Required Action C.1	YES	
Plant Service Water (SW) System and Ultimate Heat Sink (UHS) TSTF-505: LCO 3.7.2, Required Action B.1 HATCH 1&2: LCO 3.7.2, Required Action C.1	YES	
Plant Service Water (SW) System and Ultimate Heat Sink (UHS) TSTF-505: LCO 3.7.2, Required Action C.1 HATCH 1&2: N/A	N/A	VARIATION: The TS do not have this Condition and RA.
Plant Service Water (SW) System and Ultimate Heat Sink (UHS) TSTF-505: N/A HATCH 1&2: LCO 3.7.2, Required Action D.1	YES	VARIATION: The TSTF does not have this Condition and RA.
Plant Service Water (SW) System and Ultimate Heat Sink (UHS) TSTF-505: LCO 3.7.2, Required Action E.1 HATCH 1&2: LCO 3.7.2, Required Action F.1	YES	VARIATION: TS numbering.
Main Turbine Bypass System TSTF-505: LCO 3.7.7, Required Action A.1 HATCH 1&2: LCO 3.7.7, Required Action A.1	NO	VARIATION: This Action is not proposed to be in the scope of the RICT Program.
AC Sources - Operating TSTF-505: LCO 3.8.1, Required Action A.3 HATCH 1&2: LCO 3.8.1, Required Action A.3	YES	
AC Sources – Operating TSTF-505: LCO 3.8.1, Required Action B.4 HATCH 1&2: LCO 3.8.1, Required Action B.4	YES	VARIATION: Optional change/variation is discussed in Attachment 1 of the license amendment request. VARIATION: Existing risk-informed extended Completion Time replaced with RICT
AC Sources – Operating TSTF-505: LCO 3.8.1, Required Action B.4 HATCH 1&2: LCO 3.8.1, Required Action C.4	YES	VARIATION: Optional change/variation is discussed in Attachment 1 of the license amendment request. VARIATION: Existing risk-informed extended Completion Time replaced with RICT

LCO ACTION TSTF-505/HATCH 1&2 TS	Add RICT?	DISCUSSION
AC Sources – Operating TSTF-505: LCO 3.8.1, Required Action C.2 HATCH 1&2: LCO 3.8.1, Required Action D.2	YES	VARIATION: TS numbering. This Condition allows two or more inoperable required circuits. With two required offsite circuits inoperable, the TSTF indicates that the safety-related DGs must be available to utilize a RICT. This restriction is addressed by the second Condition for Action I, which would also be applied "immediately" if any required DG is inoperable. Required Action I.1 (without use of RICT) must be applied regardless, with two or more required circuits and any required DG inoperable.
AC Sources – Operating TSTF-505: LCO 3.8.1, Required Actions D.1 and D.2 HATCH 1&2: LCO 3.8.1, Required Actions E.1 and E.2	YES	VARIATION: TS numbering.
AC Sources – Operating TSTF-505: LCO 3.8.1, Required Action F.1 HATCH 1&2: N/A	N/A	VARIATION: The TS do not have this Condition and RA.
DC Sources – Operating TSTF-505: LCO 3.8.4, Required Action A.3 HATCH 1&2: LCO 3.8.4, Required Action B.3	YES	VARIATION: TS numbering. VARIATION: Optional change/variation is discussed in Attachment 1 of the license amendment request.
DC Sources – Operating TSTF-505: LCO 3.8.4, Required Action A.3 HATCH 1&2: LCO 3.8.4, Required Action D.3	YES	VARIATION: TS numbering. VARIATION: Optional change/variation is discussed in Attachment 1 of the license amendment request. This Condition allows one or more inoperable required unit station service DC battery chargers on one subsystem. Under certain circumstances, with more than one required unit station service DC battery chargers on one subsystem inoperable, a loss of function may occur. However, a Note is not considered necessary since Required Action G.1 (which must be applied "immediately") addresses loss of function. Required Action G.1 (without use of RICT) must be applied regardless, and thus, a loss of Function is adequately addressed without the need for additional Notes.

LCO ACTION TSTF-505/HATCH 1&2 TS	Add RICT?	DISCUSSION
DC Sources – Operating TSTF-505: LCO 3.8.4, Required Action B.1 HATCH 1&2: LCO 3.8.4, Required Action A.1	YES	VARIATION: TS numbering. VARIATION: Optional change/variation is discussed in Attachment 1 of the license amendment request. This Condition allows one or more inoperable required opposite unit DG DC electrical power subsystems. Under certain circumstances, with more than one required opposite unit DG DC electrical power subsystems inoperable, a loss of function may occur. However, a Note is not considered necessary since Required Action G.1 (which must be applied "immediately") addresses loss of function. Required Action G.1 (without use of RICT) must be applied regardless, and thus, a loss of Function is adequately addressed without the need for additional Notes.
DC Sources – Operating TSTF-505: LCO 3.8.4, Required Action B.1 HATCH 1&2: LCO 3.8.4, Required Action C.1	YES	VARIATION: TS numbering. VARIATION: Optional change/variation is discussed in Attachment 1 of the license amendment request.
DC Sources – Operating TSTF-505: LCO 3.8.4, Required Action C.1 HATCH 1&2: LCO 3.8.4, Required Action E.1	YES	VARIATION: TS numbering.
Inverters – Operating TSTF-505: LCO 3.8.7, Required Action A.1 HATCH 1&2: N/A	N/A	VARIATION: The TS do not have this Specification.
Distribution Systems - Operating TSTF-505: N/A HATCH 1&2: LCO 3.8.7, Required Action A.1	YES	VARIATION: TS numbering. VARIATION: Optional change/variation is discussed in Attachment 1 of the license amendment request. This Condition allows one or more inoperable required opposite unit AC or DC electrical power distribution subsystems. Under certain circumstances, with more than one required opposite unit AC or DC electrical power distribution subsystems inoperable, a loss of function may occur. However, a Note is not considered necessary since Required Action F.1 (which must be applied "immediately") addresses loss of function. Required Action F.1 (without use of RICT) must be applied regardless, and thus, a loss of Function is adequately addressed without the need for additional Notes.

LCO ACTION TSTF-505/HATCH 1&2 TS	Add RICT?	DISCUSSION
Distribution Systems - Operating TSTF-505: N/A HATCH 1&2: LCO 3.8.7, Required Action B.1	YES	VARIATION: TS numbering. VARIATION: Optional change/variation is discussed in Attachment 1 of the license amendment request. This Condition allows one or more inoperable required (unit or swing bus) DG DC electrical power distribution subsystems. Under certain circumstances, with more than one required unit or swing bus DG DC electrical power distribution subsystems inoperable, a loss of function may occur. However, a Note is not considered necessary since Required Action F.1 (which must be applied "immediately") addresses loss of function. Required Action F.1 (without use of RICT) must be applied regardless, and thus, a loss of Function is adequately addressed without the need for additional Notes).
Distribution Systems - Operating TSTF-505: LCO 3.8.9, Required Action A.1 HATCH 1&2: LCO 3.8.7, Required Action C.1	YES	VARIATION: TS numbering. This Condition allows one or more inoperable required (unit or swing bus) AC electrical power distribution subsystems. Under certain circumstances, with more than one required unit or swing bus AC electrical power distribution subsystems inoperable, a loss of function may occur. However, a Note is not considered necessary since Required Action F.1 (which must be applied "immediately") addresses loss of function. Required Action F.1 (without use of RICT) must be applied regardless, and thus, a loss of Function is adequately addressed without the need for additional Notes).
Distribution Systems - Operating TSTF-505: LCO 3.8.9, Required Action B.1 HATCH 1&2: N/A	N/A	VARIATION: The TS do not have a Condition and RA for one or more AC vital buses inoperable.
Distribution Systems - Operating TSTF-505: LCO 3.8.9, Required Action C.1 HATCH 1&2: LCO 3.8.7, Required Action D.1	YES	VARIATION: TS numbering.
Risk Informed Completion Time Program TSTF-505: [New Program TS 5.5.15] HATCH 1&2: [New Program TS 5.5.16]	N/A	VARIATION: TS numbering.

Reactor Protection System Instrumentation

RPS instrumentation and control initiates an automatic reactor shutdown (scram) if monitored system variables exceed pre-established limits. This action prevents fuel damage, limits system pressure, and thus, restricts the release of radioactive material.

Functional diversity is provided by monitoring a wide range of dependent and independent parameters. The input parameters to the scram logic are from instrumentation that monitors reactor vessel water level; reactor vessel pressure; neutron flux; main steam line isolation valve position; turbine control valve (TCV) fast closure, trip oil pressure; turbine stop valve (TSV) position; drywell pressure; and scram discharge volume (SDV) water level; as well as reactor mode switch in shutdown position and manual scram signals.

The RPS is comprised of two independent trip systems (A and B) with two logic channels in each trip system (logic channels A1 and A2; B1 and B2). The outputs of the logic channels in a trip system are combined in a one-out-of-two logic so that either channel can trip the associated trip system. The tripping of both trip systems will produce a reactor scram. This logic arrangement is referred to as a one-out-of-two taken twice logic.

Additionally, the alternate rod insertion (ARI) system depressurizes the CRD scram pilot valve air header through valves that are different from the RPS scram valves providing a parallel path for initiating control rod insertion. ARI is actuated on the same signals that trip the recirculation pumps (refer to TS 3.3.4.2, Anticipated Transient Without Scram Recirculation Pump Trip (ATWS-RPT) Instrumentation).

In the event of a significant Anticipated Transient Without Scram (ATWS) event, to limit the possibility of a Reactor Protection System (RPS) failure to scram the plant design is such that a minimum of two, and in some cases three or four, diverse and redundant RPS instrument setpoints are predicted to be exceeded.

Manual scram capability also provides diverse actuation for each automatic scram Function.

TS Table 3.3.1.1-1, Reactor Protection System Instrumentation

TS Table 3.3.1.1-1 Function	FSAR Reference	Transient/Accident	Redundant / Diverse Instrumentation	Event Type
2.b Average Power Range Monitor (APRM) Simulated Thermal Power – High & 2.d Average Power Range Monitor Inop & 2.e Average Power Range Monitor Two-out-of-Four Voter	15.2.1.1 15C.4.1.1.1 Fig. 15C-4	Loss of Feedwater Heating (Event 1)	Simulated Thermal Power – High Manual Reactor Mode Switch	AOO
	15.2.1.2 15C.4.1.1.2 Fig. 15C-5	Inadvertent Start of the HPCI Pump (Event 2)	Simulated Thermal Power – High Manual Reactor Mode Switch	AOO
	15.2.5.2 15C.4.1.5.2 Fig. 15C-20	Startup of Idle Recirculation Pump (Event 17)	Simulated Thermal Power – High APRM Neutron Flux – High Manual Reactor Mode Switch	AOO
2.c Average Power Range Monitor Neutron Flux – High & 2.d Average Power Range Monitor Inop & 2.e Average Power Range Monitor Two-out-of-Four Voter	15.2.5.2 15C.4.1.5.2 Fig. 15C-20	Startup of Idle Recirculation Pump (Event 17)	APRM Neutron Flux – High Simulated Thermal Power - High Manual Reactor Mode Switch	AOO
	15.2.3.8 15C.4.1.3.8 Fig. 15C-15	Pressure Regulator Failure - Closed (Event 12)	APRM Neutron Flux – High Reactor Vessel Steam Dome Pressure - High Manual Reactor Mode Switch	AOO

TS Table 3.3.1.1-1 Function	FSAR Reference	Transient/Accident	Redundant / Diverse Instrumentation	Event Type
2.c Average Power Range Monitor Neutron Flux – High (continued)	15.2.3.9	Loss of Stator Cooling (Event 57)	Average Power Range Monitor Neutron Flux – High Reactor Vessel Steam Dome Pressure - High Manual Reactor Mode Switch	AOO
	15.2.5.1 15C.4.1.5.1 Fig. 15C-19	Recirculation Flow Control Failure - Increasing Flow (Event 16)	APRM Neutron Flux – High Simulated Thermal Power – High Manual Reactor Mode Switch	AOO
	15.4.2 15C.4.3.2 Fig. 15C-37	Overpressure Protection (Event 42)	APRM Neutron Flux – High Main Steam Isolation Valve - Closure Reactor Vessel Steam Dome Pressure - High Manual Reactor Mode Switch	Special
	15.4.6 15C.4.3.6 Fig. 15C-41	Generator Load Rejection With Flux Scram and No Bypass or RPT (Event 46)	Average Power Range Monitor Neutron Flux – High Turbine Control Valve Fast Closure Reactor Vessel Steam Dome Pressure - High Manual Reactor Mode Switch	Special

TS Table 3.3.1.1-1 Function	FSAR Reference	Transient/Accident	Redundant / Diverse Instrumentation	Event Type
2.c Average Power Range Monitor Neutron Flux – High (continued)	15.4.7 15C.4.3.7 Fig. 15C-42	Turbine Trip With Flux Scram and No Bypass or RPT (Event 47)	APRM Neutron Flux – High Turbine Stop Valve – Closure Reactor Vessel Steam Dome Pressure - High	Special
2.f Average Power Range Monitor OPRM Upscale & 2.d Average Power Range Monitor Inop & 2.e Average Power Range Monitor Two-out-of-Four Voter	15.4.1 15C.4.3.1	Stability (Event 41)	APRM OPRM Upscale Manual Reactor Mode Switch	Special
3. Reactor Vessel Steam Dome Pressure - High	15.2.3.9	Loss of Stator Cooling (Event 57)	Reactor Vessel Steam Dome Pressure - High APRM Neutron Flux – High Manual Reactor Mode Switch	AOO
4. Reactor Vessel Water Level - Low, Level 3	15.2.8.4 15A.5.2.3 15C.4.1.8.4 Fig. 15C-28	Loss of Feedwater Flow (Event 25)	Reactor Vessel Water Level - Level 3 Main Steam Isolation Valve - Closure Manual Reactor Mode Switch	AOO
	15.3.3 15C.4.2.2 Fig. 15C-30	Loss of Coolant Accident (LOCA) (Event 32)	Reactor Vessel Water Level - Level 3 Drywell Pressure - High Manual Reactor Mode Switch	DBA

TS Table 3.3.1.1-1 Function	FSAR Reference	Transient/Accident	Redundant / Diverse Instrumentation	Event Type
4. Reactor Vessel Water Level - Low, Level 3 (continued)	15.3.4 15C.4.2.3 Fig. 15C-31	Main Steam Line Break Accident (MSLBA) (Event 33)	Reactor Vessel Water Level - Level 3 Main Steam Isolation Valve – Closure Turbine Stop Valve – Closure Turbine Control Valve Fast Closure, Trip Oil Pressure - Low Manual Reactor Mode Switch	DBA
	15.3.8 15C.4.2.7 Fig. 15C-35	Feedwater Line Break Accident (Event 37)	Reactor Vessel Water Level - Level 3 Main Steam Isolation Valve - Closure Manual Reactor Mode Switch	DBA
5. Main Steam Isolation Valve - Closure	15.2.3.6 15C.4.1.3.6 Fig. 15C-13	Closure of All MSIVs (Event 10)	Drywell Pressure - High APRM Neutron Flux – High Reactor Vessel Steam Dome Pressure - High Manual Reactor Mode Switch	AOO
	15.3.4 15C.4.2.3 Fig. 15C-31	Main Steam Line Break Accident (MSLBA) (Event 33)	Drywell Pressure - High Reactor Vessel Water Level - Level 3 Turbine Stop Valve – Closure Turbine Control Valve Fast Closure, Trip Oil Pressure - Low Manual Reactor Mode Switch	DBA

TS Table 3.3.1.1-1 Function	FSAR Reference	Transient/Accident	Redundant / Diverse Instrumentation	Event Type
6. Drywell Pressure - High	15.3.3 15C.4.2.2 Fig. 15C-30	Loss of Coolant Accident (LOCA) (Event 32)	Drywell Pressure - High Reactor Vessel Water Level - Level 3 Manual Reactor Mode Switch	DBA
8. Turbine Stop Valve – Closure	15.2.3.3 15C.4.1.3.3 Fig. 15C-10	Turbine Trip with No Bypass (Event 7)	Turbine Stop Valve – Closure APRM Neutron Flux – High Reactor Vessel Steam Dome Pressure - High Manual Reactor Mode Switch	AOO
	15.2.3.4 15C.4.1.3.4 Fig. 15C-11	Loss of Condenser Vacuum (Event 8)	Turbine Stop Valve – Closure APRM Neutron Flux – High Reactor Vessel Steam Dome Pressure - High Main Steam Isolation Valve – Closure Manual Reactor Mode Switch	AOO
	15.2.3.5 15C.4.1.3.5 Fig. 15C-12	Turbine Trip With Bypass (Event 9)	Turbine Stop Valve – Closure APRM Neutron Flux – High Reactor Vessel Steam Dome Pressure - High Manual Reactor Mode Switch	AOO

TS Table 3.3.1.1-1 Function	FSAR Reference	Transient/Accident	Redundant / Diverse Instrumentation	Event Type
8 Turbine Stop Valve – Closure (continued)	15.2.4.2 15C.4.1.4.2 Fig. 15C-17	Trip of Two Recirculation Pumps (Event 14)	Turbine Stop Valve – Closure Manual Reactor Mode Switch	AOO
	15.2.7.1 15C.4.1.7.1 Fig. 15C-24	Feedwater Controller Failure – Maximum Demand (Event 21)	Turbine Stop Valve – Closure APRM Neutron Flux – High Reactor Vessel Steam Dome Pressure - High Manual Reactor Mode Switch	AOO
	15.2.8.2 15C.4.1.8.2 Fig. 15C-26	Pressure Regulator Failure - Open (Event 23)	Turbine Stop Valve – Closure Main Steam Isolation Valve - Closure Manual Reactor Mode Switch	AOO
	15.2.8.3 15C.4.1.8.3 Fig. 15C-27	Loss of Auxiliary Power (Event 24)	Turbine Stop Valve – Closure APRM Neutron Flux – High Reactor Vessel Water Level - Level 3 Reactor Steam Dome Pressure Main Steam Isolation Valve - Closure Turbine Control Valve - Closure Manual Reactor Mode Switch	AOO

TS Table 3.3.1.1-1 Function	FSAR Reference	Transient/Accident	Redundant / Diverse Instrumentation	Event Type
8 Turbine Stop Valve – Closure (continued)	15.3.7 15C.4.2.6 Fig. 15C-34	Recirculation Pump Seizure (Event 36)	Turbine Stop Valve – Closure APRM Neutron Flux – High Reactor Vessel Steam Dome Pressure - High Manual Reactor Mode Switch	DBA
	15.4.8 15C.4.3.8 Fig. 15C-43	Loss of One dc System (Event 48)	Turbine Stop Valve – Closure APRM Neutron Flux – High Reactor Vessel Steam Dome Pressure - High Manual Reactor Mode Switch	Special
	15.4.16 15C.4.3.16 Fig. 15C-51	Station Blackout (SBO) (Event 56)	Turbine Stop Valve – Closure APRM Neutron Flux – High Reactor Vessel Steam Dome Pressure - High Reactor Vessel Water Level – Low 3 Main Steam Isolation Valve - Closure Turbine Control Valve Fast Closure Manual Reactor Mode Switch	Special

TS Table 3.3.1.1-1 Function	FSAR Reference	Transient/Accident	Redundant / Diverse Instrumentation	Event Type
9. Turbine Control Valve Fast Closure, Trip Oil Pressure - Low	15.2.3.1 15C.4.1.3.1 Fig. 15C-8	Generator Load Rejection with No Bypass (Event 5)	Turbine Control Valve Fast Closure, Trip Oil Pressure - Low APRM Neutron Flux – High Reactor Vessel Steam Dome Pressure - High Manual Reactor Mode Switch	AOO
	15.2.3.2 15C.4.1.3.2 Fig. 15C-9	Generator Load Rejection with Bypass (Event 6)	Turbine Control Valve Fast Closure APRM Neutron Flux – High Reactor Vessel Steam Dome Pressure - High Manual Reactor Mode Switch	AOO
9. Turbine Control Valve Fast Closure, Trip Oil Pressure – Low (continued)	15.2.8.3 15C.4.1.8.3 Fig. 15C-27	Loss of Auxiliary Power (Event 24)	Turbine Control Valve Fast Closure APRM Neutron Flux – High Turbine Stop Valve – Closure Reactor Vessel Water Level - Level 3 Reactor Steam Dome Pressure Main Steam Isolation Valve - Closure Manual Reactor Mode Switch	AOO

TS Table 3.3.1.1-1 Function	FSAR Reference	Transient/Accident	Redundant / Diverse Instrumentation	Event Type
9. Turbine Control Valve Fast Closure, Trip Oil Pressure – Low (continued)	15.4.16 15C.4.3.16 Fig. 15C-51	Station Blackout (SBO) (Event 56)	Turbine Control Valve Fast Closure APRM Neutron Flux – High Reactor Vessel Steam Dome Pressure - High Reactor Vessel Water Level – Low 3 Main Steam Isolation Valve - Closure Turbine Stop Valve – Closure Manual Reactor Mode Switch	Special
11. Manual Scram		Not specifically credited in accident analysis; retained for overall redundancy and diversity.	Manual Reactor Mode Switch - Shutdown Position	NA

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

The EOC-RPT instrumentation initiates a recirculation pump trip (RPT) to reduce the peak reactor pressure and power resulting from turbine trip or generator load rejection transients to provide additional margin to core thermal MCPR Safety Limits.

Each EOC-RPT trip system is a two-out-of-two logic for each Function; thus, either two TSV - Closure or two TCV Fast Closure, Trip Oil Pressure - Low signals are required for a trip system to actuate. If either trip system actuates, both recirculation pumps will trip. There are two EOC-RPT breakers in series per recirculation pump. One trip system trips one of the two EOC-RPT breakers for each recirculation pump, and the second trip system trips the other EOC-RPT breaker for each recirculation pump.

Manual RPT capability is provided as a diverse means to the automatic protective functions.

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

TS 3.3.4.1 Function	FSAR Reference	Transient/Accident	Redundant / Diverse Instrumentation	Event Type
a.1 Turbine Stop Valve - Closure	15.2.3.3 15C.4.1.3.3 Fig. 15C-10	Turbine Trip with No Bypass (Event 7)	Turbine Stop Valve – Closure Turbine Control Valve Fast Closure Manual	AOO
	15.2.3.4 15C.4.1.3.4 Fig. 15C-11	Loss of Condenser Vacuum (Event 8)	Turbine Stop Valve – Closure Turbine Control Valve Fast Closure Manual	AOO
	15.2.3.5 15C.4.1.3.5 Fig. 15C-12	Turbine Trip With Bypass (Event 9)	Turbine Stop Valve – Closure Turbine Control Valve Fast Closure Manual	AOO
	15.2.4.2 15C.4.1.4.2 Fig. 15C-17	Trip of Two Recirculation Pumps (Event 14)	Turbine Stop Valve – Closure Turbine Control Valve Fast Closure Manual	AOO

TS 3.3.4.1 Function	FSAR Reference	Transient/Accident	Redundant / Diverse Instrumentation	Event Type
a.1 Turbine Stop Valve – Closure (continued)	15.2.7.1 15C.4.1.7.1 Fig. 15C-24	Feedwater Controller Failure – Maximum Demand (Event 21)	Turbine Stop Valve – Closure Turbine Control Valve Fast Closure Manual	AOO
	15.2.8.2 15C.4.1.8.2 Fig. 15C-26	Pressure Regulator Failure - Open (Event 23)	Turbine Stop Valve – Closure Turbine Control Valve Fast Closure Manual	AOO
	15.2.8.3 15C.4.1.8.3 Fig. 15C-27	Loss of Auxiliary Power (Event 24)	Turbine Stop Valve – Closure Turbine Control Valve Fast Closure Manual	AOO
	15.3.7 15C.4.2.6 Fig. 15C-34	Recirculation Pump Seizure (Event 36)	Turbine Stop Valve – Closure Turbine Control Valve Fast Closure Manual	DBA
	15.4.8 15C.4.3.8 Fig. 15C-43	Loss of One dc System (Event 48)	Turbine Stop Valve – Closure Turbine Control Valve Fast Closure Manual	Special
	15.4.9 15C.4.3.9 Fig. 15C-44	Loss of Instrument Air (Event 49)	Turbine Stop Valve – Closure Turbine Control Valve Fast Closure Manual	Special
	15.4.16 15C.4.3.16 Fig. 15C-50	Gaseous Radwaste Tank Failure (Event 55)	Turbine Stop Valve – Closure Turbine Control Valve Fast Closure Manual	Special

TS 3.3.4.1 Function	FSAR Reference	Transient/Accident	Redundant / Diverse Instrumentation	Event Type
a.1 Turbine Stop Valve – Closure (continued)	15.4.16 15C.4.3.16 Fig. 15C-51	Station Blackout (SBO) (Event 56)	Turbine Stop Valve – Closure Turbine Control Valve Fast Closure Manual	Special
a.2 Turbine Control Valve Fast Closure, Trip Oil Pressure - Low	15.2.3.1 15C.4.1.3.1 Fig. 15C-8	Generator Load Rejection with No Bypass (Event 5)	Turbine Control Valve Fast Closure Turbine Stop Valve – Closure Manual	AOO
	15.2.3.2 15C.4.1.3.2 Fig. 15C-9	Generator Load Rejection with Bypass (Event 6)	Turbine Control Valve Fast Closure Turbine Stop Valve – Closure Manual	AOO
	15.2.8.3 15C.4.1.8.3 Fig. 15C-27	Loss of Auxiliary Power (Event 24)	Turbine Control Valve Fast Closure Turbine Stop Valve – Closure Manual	AOO
	15.4.16 15C.4.3.16 Fig. 15C-51	Station Blackout (SBO) (Event 56)	Turbine Control Valve Fast Closure Turbine Stop Valve – Closure Manual	Special

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

The ATWS-RPT System initiates an RPT, adding negative reactivity, following events in which a scram does not (but should) occur, to lessen the effects of an ATWS event. Tripping the recirculation pumps adds negative reactivity from the increase in steam voiding in the core area as core flow decreases.

The ATWS-RPT consists of two independent trip systems, with two channels of Reactor Steam Dome Pressure - High and two channels of Reactor Vessel Water Level - ATWS-RPT Level in each trip system. Each ATWS-RPT trip system is a two-out-of-two logic for each Function. Thus, either two Reactor Water Level - ATWS-RPT Level or two Reactor Pressure - High signals are needed to trip a trip system. The outputs of the channels in a trip system are combined in a logic so that either trip system will trip both recirculation pumps (by tripping the respective drive motor breakers). There is one drive motor breaker provided for each of the two recirculation pumps for a total of two breakers. The output of each trip system is provided to both recirculation pump breakers.

Manual RPT capability is provided as a diverse means to the automatic protective functions.

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

TS 3.3.4.2 Function	FSAR Reference	Transient/Accident	Redundant / Diverse Instrumentation	Event Type
a. Reactor Vessel Water Level - ATWS-RPT Level	15.4.5 15C.4.3.5 Fig. 15C-40	Anticipated Transient Without Scram (ATWS) (Event 45)	Reactor Vessel Water Level - ATWS-RPT Level Reactor Steam Dome Pressure - High Manual	Special
b. Reactor Steam Dome Pressure - High	15.4.5 15C.4.3.5 Fig. 15C-40	Anticipated Transient Without Scram (ATWS) (Event 45)	Reactor Vessel Water Level - ATWS-RPT Level Reactor Steam Dome Pressure – High Manual	Special

Emergency Core Cooling System (ECCS) Instrumentation

The ECCS instrumentation actuates core spray (CS), low pressure coolant injection (LPCI), high pressure coolant injection (HPCI), Automatic Depressurization System (ADS), and the diesel generators (DGs).

Core Spray System

The CS System may be initiated by automatic means. Automatic initiation occurs for conditions of Reactor Vessel Water Level – Low Low Low, Level 1 or Drywell Pressure - High. Each of these diverse variables send signals to two trip systems, with each trip system arranged in a one-out-of-two taken twice logic (each channel sends a signal to both trip systems). Each trip system can initiate both core spray pumps.

The CS pump discharge flow is monitored by a flow transmitter. When the pump is running and discharge flow is low enough so that pump overheating may occur, the minimum flow return line valve is opened (one -out-of-one logic for each pump). The valve is automatically closed if flow is above the minimum flow setpoint to allow the full system flow assumed in the accident analysis.

The CS System also monitors the pressure in the reactor to determine that, before the injection valves open, the reactor pressure has fallen to a value below the CS System's maximum design pressure. The channels are arranged in a one-out-of-two taken twice logic.

Low Pressure Coolant Injection System

Automatic initiation occurs for conditions of Reactor Vessel Water Level - Low Low Low, Level 1 or Drywell Pressure - High. Each of these diverse variables sends signals to two trip systems, with each trip system arranged in a one-out-of-two taken twice logic (each channel sends a signal to both trip systems). Each trip system can initiate all four LPCI pumps.

Upon receipt of an automatic initiation signal, all LPCI pumps will start immediately if power is provided by the primary feeds from Startup Auxiliary Transformers (SATs) 2C, 2D, and 2E. If power for either Bus 2E or Bus 2F is provided by the alternate feeds from the SATs or by the DGs, the engineered safety feature (ESF) Division I motors have a time delay. If power for either Bus 2F or Bus 2G is provided by the alternate feeds from the SATs or by the DGs, the ESF Division II motors have a time delay. If a time delay is active for the associated motor, LPCI pump C starts within 1 second when power is available, and the LPCI A, B, and D pumps are started after a 10 second delay.

Each LPCI subsystem's discharge flow is monitored by a flow transmitter (one-out-of-one logic). When a pump is running and discharge flow is low enough so that pump overheating may occur, the respective minimum flow return line valve is opened. If flow is above the minimum flow setpoint, the valve is automatically closed to allow the full system flow assumed in the analyses.

The LPCI System monitors reactor steam dome pressure to determine that, before an injection valve opens, the reactor pressure has fallen to a value below the LPCI System's maximum design pressure. The variable is monitored by four redundant transmitters, which are, in turn, connected to four trip units. The outputs of the trip units are connected to relays whose contacts are arranged in a one-out-of-two taken twice logic. Additional reactor steam dome pressure instruments are provided to close the recirculation pump discharge valves that LPCI flow does not bypass the core when it injects into the recirculation lines. The channels are arranged in a one-out-of-two taken twice logic.

Low reactor water level in the shroud is detected by two additional instruments to automatically isolate other modes of RHR (e.g., suppression pool cooling) when LPCI is required.

High Pressure Core Injection System

Automatic initiation occurs for conditions of Reactor Vessel Water Level – Low Low, Level 2 or Drywell Pressure - High. Each of these diverse variables is arranged in a one-out-of-two taken twice logic for each Function.

The HPCI pump discharge flow is monitored by a flow transmitter. When the pump is running and discharge flow is low enough so that pump overheating may occur, the minimum flow return line valve is opened. The valve is automatically closed if flow is above the minimum flow setpoint to allow the full system flow assumed in the accident analysis.

The HPCI System also monitors the water levels in the condensate storage tank (CST) and the suppression pool because these are the two sources of water for HPCI operation. Reactor grade water in the CST is the normal source. Upon receipt of a HPCI initiation signal, the CST suction valve is automatically signaled to open (it is normally in the open position) unless both suppression pool suction valves are open. If the water level in the CST falls below a preselected level, first the suppression pool suction valves automatically open, and then the CST suction valve automatically closes. Two level switches (one-out-of-two logic) are used to detect low water level in the CST. Either switch can cause the suppression pool suction valves to open and the CST suction valve to close. The suppression pool suction valves also automatically open and the CST suction valve closes if high water level is detected in the suppression pool (one-out-of-two logic similar to the CST water level logic). To prevent losing suction to the pump, the suction valves are interlocked so that one suction path must be open before the other automatically closes.

The HPCI provides makeup water to the reactor until the reactor vessel water level reaches the Reactor Vessel Water Level - High, Level 8 trip, at which time the HPCI turbine trips, which causes the turbine's stop valve and the injection valves to close. The logic is two-out-of-two to provide high reliability of the HPCI System.

Although the diversity means to actuate each function is the capability for manual actuation of each function, the ADS, LPCI, and CS systems can be used when the HPCI is unable to perform its functions. In addition, the LPCI and CS are diverse but both actuated by the same conditions.

TS Table 3.3.5.1-1, Emergency Core Cooling System Instrumentation

TS Table 3.3.5.1-1 Function	FSAR Reference	Transient/Accident	Redundant / Diverse Instrumentation	Event Type
1.a Core Spray System Reactor Vessel Water Level – Low Low Low, Level 1 & 1.c Reactor Steam Dome Pressure - Low (Injection Permissive) & 1.d Core Spray System Core Spray Pump Discharge Flow - Low (Bypass)	15.3.3 15C.4.2.2 Fig. 15C-30	Loss of Coolant Accident (LOCA) (Event 32)	Reactor Vessel Water Level – Level 1 Drywell Pressure - High Manual	DBA
	15.3.4 15C.4.2.3 Fig. 15C-31	Main Steam Line Break Accident (MSLBA) (Event 33)	Reactor Vessel Water Level – Level 1 Drywell Pressure - High Manual	DBA
	15.3.8 15C.4.2.7 Fig. 15C-35	Feedwater Line Break Accident (Event 37)	Reactor Vessel Water Level – Level 1 Drywell Pressure - High Manual	DBA
1.b Core Spray System Drywell Pressure - High & 1.c Reactor Steam Dome Pressure - Low (Injection Permissive) & 1.d Core Spray System Core Spray Pump Discharge Flow - Low (Bypass)	15.3.3 15C.4.2.2 Fig. 15C-30	Loss of Coolant Accident (LOCA) (Event 32)	Drywell Pressure - High Reactor Vessel Water Level – Level 1 Manual	DBA
	15.3.4 15C.4.2.3	Main Steam Line Break Accident (MSLBA) (Event 33)	Drywell Pressure - High Reactor Vessel Water Level – Level 1 Manual	DBA

TS Table 3.3.5.1-1 Function	FSAR Reference	Transient/Accident	Redundant / Diverse Instrumentation	Event Type
2.a LPCI System Reactor Vessel Water Level – Low Low Low, Level 1 & 2.c Reactor Steam Dome Pressure – Low (Injection Permissive) 2.d Reactor Steam Dome Pressure – Low & 2.fTime delay Relay & 2.f Low Pressure Coolant Injection Pump Start - Time Delay Relay & 2.g Low Pressure Coolant Injection Pump Discharge Flow - Low (Bypass)	15.3.3 15C.4.2.2 Fig. 15C-30	Loss of Coolant Accident (LOCA) (Event 32)	Reactor Vessel Water Level – Level 1 Drywell Pressure - High Manual	DBA
	15.3.4 15C.4.2.3 Fig. 15C-31	Main Steam Line Break Accident (MSLBA) (Event 33)	Reactor Vessel Water Level – Level 1 Drywell Pressure - High Manual	DBA
	15.3.8 15C.4.2.7 Fig. 15C-35	Feedwater Line Break Accident (Event 37)	Reactor Vessel Water Level – Level 1 Drywell Pressure - High Manual	DBA

TS Table 3.3.5.1-1 Function	FSAR Reference	Transient/Accident	Redundant / Diverse Instrumentation	Event Type
2.b LPCI System Drywell Pressure – High & 2.c Reactor Steam Dome Pressure – Low (Injection Permissive) 2.d Reactor Steam Dome Pressure – Low & 2.fTime delay Relay & 2.f Low Pressure Coolant Injection Pump Start - Time Delay Relay & 2.g Low Pressure Coolant Injection Pump Discharge Flow - Low (Bypass)	15.3.3 15C.4.2.2 Fig. 15C-30	Loss of Coolant Accident (LOCA) (Event 32)	Drywell Pressure – High Reactor Vessel Water Level – Level 1 Manual	DBA
3.a HPCI System Reactor Vessel Water Level - Low Low, Level 2 & 3.d Condensate Storage Tank Level - Low & 3.e Suppression Pool Water Level - High & 3.f High Pressure Coolant Injection Pump Discharge Flow – Low (Bypass)	15.2.2.1 15C.4.1.2.1 Fig. 15C-7	Loss of RHR Shutdown Cooling (Event 4)	Reactor Vessel Water Level - Level 2 Drywell Pressure - High Manual	AOO
	15.2.3.4 15C.4.1.3.4 Fig. 15C-11	Loss of Condenser Vacuum (Event 8)	Reactor Vessel Water Level - Level 2 Drywell Pressure - High Manual	AOO

TS Table 3.3.5.1-1 Function	FSAR Reference	Transient/Accident	Redundant / Diverse Instrumentation	Event Type
3.a HPCI System Reactor Vessel Water Level - Low Low, Level 2 (continued)	15.2.3.6 15C.4.1.3.6 Fig. 15C-13	Closure of All MSIVs (MSIVD) (Event 10)	Reactor Vessel Water Level - Level 2 Drywell Pressure - High Manual	AOO
	15.2.4.2 15C.4.1.4.2 Fig. 15C-17	Trip of Two Recirculation Pumps (Event 14)	Reactor Vessel Water Level - Level 2 Drywell Pressure - High Manual	AOO
	15.2.7.1 15C.4.1.7.1 Fig. 15C-24	Feedwater Controller Failure – Maximum Demand (Event 21)	Reactor Vessel Water Level - Level 2 Drywell Pressure - High Manual	AOO
	15.2.8.2 15C.4.1.8.2 Fig. 15C-26	Pressure Regulator Failure - Open (Event 23)	Reactor Vessel Water Level - Level 2 Drywell Pressure - High Manual	AOO
	15.2.8.3 15C.4.1.8.3 Fig. 15C-27	Loss of Auxiliary Power (Event 24)	Reactor Vessel Water Level - Level 2 Drywell Pressure - High Manual	AOO
	15.2.8.4 15C.4.1.8.4 Fig. 15C-28	Loss of Feedwater Flow (Event 25)	Reactor Vessel Water Level - Level 2 Drywell Pressure - High Manual	AOO

TS Table 3.3.5.1-1 Function	FSAR Reference	Transient/Accident	Redundant / Diverse Instrumentation	Event Type
3.a HPCI System Reactor Vessel Water Level - Low Low, Level 2 (continued)	15.3.2 15C.4.2.1 Fig. 15C-29	Control Rod Drop Accident (Event 31)	Reactor Vessel Water Level - Level 2 Drywell Pressure - High Manual	DBA
	15.3.3 15C.4.2.2 Fig. 15C-30	Loss of Coolant Accident (LOCA) (Event 32)	Reactor Vessel Water Level - Level 2 Drywell Pressure - High Manual	DBA
	15.3.4 15C.4.2.3 Fig. 15C-31	Main Steam Line Break Accident (MSLBA) (Event 33)	Reactor Vessel Water Level - Level 2 Drywell Pressure - High Manual	DBA
	15.3.7 15C.4.2.6 Fig. 15C-34	Recirculation Pump Seizure (Event 36)	Reactor Vessel Water Level - Level 2 Drywell Pressure - High Manual	DBA
	15.3.8 15C.4.2.7 Fig. 15C-35	Feedwater Line Break Accident (Event 37)	Reactor Vessel Water Level - Level 2 Drywell Pressure - High Manual	DBA
	15.4.5 15C.4.3.5 Fig. 15C-40	Anticipated Transient Without Scram (ATWS) (Event 45)	Reactor Vessel Water Level - Level 2 Drywell Pressure - High Manual	Special

TS Table 3.3.5.1-1 Function	FSAR Reference	Transient/Accident	Redundant / Diverse Instrumentation	Event Type
3.a HPCI System Reactor Vessel Water Level - Low Low, Level 2 (continued)	15.4.9 15C.4.3.9 Fig. 15C-44	Loss of Instrument Air (Event 49)	Reactor Vessel Water Level - Level 2 Drywell Pressure - High Manual	Special
	15.4.15 15C.4.3.15 Fig. 15C-50	Gaseous Radwaste Tank Failure (Event 55)	Reactor Vessel Water Level - Level 2 Drywell Pressure - High Manual	Special
	15.4.16 15C.4.3.16 Fig. 15C-51	Station Blackout (SBO) (Event 56)	Reactor Vessel Water Level - Level 2 Drywell Pressure - High Manual	Special
3.b HPCI System Drywell Pressure - High & 3.d Condensate Storage Tank Level - Low & 3.e Suppression Pool Water Level - High & 3.f High Pressure Coolant Injection Pump Discharge Flow – Low (Bypass)	15.3.3 15C.4.2.2 Fig. 15C-30	Loss of Coolant Accident (LOCA) (Event 32)	Drywell Pressure - High Reactor Vessel Water Level – Level 2 Manual	DBA

Reactor Core Isolation Cooling System

Reactor Core Isolation Cooling (RCIC) System instrumentation initiates actions to provide adequate core cooling when the reactor vessel is isolated from its primary heat sink (the main condenser) and normal coolant makeup flow from the Reactor Feedwater System is unavailable, such that RCIC System initiation occurs and maintains sufficient reactor water level such that initiation of the low pressure Emergency Core Cooling System (ECCS) pumps does not occur.

Automatic initiation occurs for conditions of Reactor Vessel Water Level – Low Low, Level 2. The variable is monitored by four channels that are arranged in a one-out-of-two taken twice logic.

The RCIC System also monitors the water levels in the condensate storage tank (CST) and the suppression pool since these are the two sources of water for RCIC operation. Reactor grade water in the CST is the normal source. Upon receipt of a RCIC initiation signal, the CST suction valve is automatically signaled to open (it is normally in the open position) unless the pump suction valves from the suppression pool are open. If the water level in the CST falls below a preselected level, first the suppression pool suction valves automatically open, and then the CST suction valve automatically closes. Two level switches (one-out-of-two logic) are used to detect low water level in the CST. Either switch can cause the suppression pool suction valves to open and the CST suction valve to close. The suppression pool suction valves also automatically open and the CST suction valve closes if high water level is detected in the suppression pool (one-out-of-two logic similar to the CST water level logic).

The RCIC System provides makeup water to the reactor until the (continued) reactor vessel water level reaches the high water level (Level 8) trip (two-out-of-two logic), at which time the RCIC steam supply, and cooling water supply valves close (the injection valve also closes due to the closure of the steam supply valves).

The RCIC System is not an Engineered Safety Feature System and no credit is taken in the safety analyses for RCIC System operation. Based on its contribution to the reduction of overall plant risk, however, the system, and therefore its instrumentation, meets Criterion 4 of the NRC Policy Statement.

TS Table 3.3.5.3-1, Reactor Core Isolation Cooling (RCIC) System Instrumentation

TS Table 3.3.5.3-1 Function	FSAR Reference	Transient/Accident	Redundant / Diverse Instrumentation	Event Type
1. Reactor Vessel Water Level - Low Low, Level 2 & 3. Condensate Storage Tank Level - Low & 4. Suppression Pool Water Level - High	15.2.1.2 15C.4.1.1.2 Fig. 15C-5	Inadvertent Start of a HPCI Pump (Event 2)	Reactor Vessel Water Level - Level 2 Manual	AOO
	15.2.2.1 15C.4.1.2.1 Fig. 15C-7	Loss of RHR Shutdown Cooling (Event 4)	Reactor Vessel Water Level - Level 2 Manual	AOO
	15.2.3.4 15C.4.1.3.4 Fig. 15C-11	Loss of Condenser Vacuum (Event 8)	Reactor Vessel Water Level - Level 2 Manual	AOO
	15.2.3.6 15C.4.1.3.6 Fig. 15C-13	Closure of All MSIVs (MSIVD) (Event 10)	Reactor Vessel Water Level - Level 2 Manual	AOO
	15.2.4.2 15C.4.1.4.2 Fig. 15C-17	Trip of Two Recirculation Pumps (Event 14)	Reactor Vessel Water Level - Level 2 Manual	AOO
	15.2.7.1 15C.4.1.7.1 Fig. 15C-24	Feedwater Controller Failure – Maximum Demand (Event 21)	Reactor Vessel Water Level - Level 2 Manual	AOO
	15.2.8.2 15C.4.1.8.2 Fig. 15C-26	Pressure Regulator Failure - Open (Event 23)	Reactor Vessel Water Level - Level 2 Manual	AOO

TS Table 3.3.5.3-1 Function	FSAR Reference	Transient/Accident	Redundant / Diverse Instrumentation	Event Type
1. Reactor Vessel Water Level - Low Low, Level 2 (continued)	15.2.8.3 15C.4.1.8.3 Fig. 15C-27	Loss of Auxiliary Power (Event 24)	Reactor Vessel Water Level - Level 2 Manual	AOO
	15.2.8.4 15C.4.1.8.4 Fig. 15C-28	Loss of Feedwater Flow (Event 25)	Reactor Vessel Water Level - Level 2 Manual	AOO
	15.3.2 15C.4.2.1 Fig. 15C-29	Control Rod Drop Accident (Event 31)	Reactor Vessel Water Level - Level 2 Manual	DBA
	15A.5.1.3	Main Steam Line Break Accident (MSLBA) (Event 33)	Reactor Vessel Water Level - Level 2 Drywell Pressure - High Manual	DBA
	15.3.7 15C.4.2.6 Fig. 15C-34	Recirculation Pump Seizure (Event 36)	Reactor Vessel Water Level - Level 2 Manual	DBA
	15.4.4 15C.4.3.4 Fig. 15C-39	MCR Uninhabitability (Event 44)	Reactor Vessel Water Level - Level 2 Manual	Special
	15.4.9 15C.4.3.9 Fig. 15C-44	Loss of Instrument Air (Event 49)	Reactor Vessel Water Level - Level 2 Manual	Special
	15.4.11 15C.4.3.11 Fig. 15C-46	Fire (Event 51)	Reactor Vessel Water Level - Level 2 Manual	Special

TS Table 3.3.5.3-1 Function	FSAR Reference	Transient/Accident	Redundant / Diverse Instrumentation	Event Type
1. Reactor Vessel Water Level - Low Low, Level 2 (continued)	15.4.15 15C.4.3.15 Fig. 15C-50	Gaseous Radwaste Tank Failure (Event 55)	Reactor Vessel Water Level - Level 2 Manual	Special
	15.4.16 15C.4.3.16 Fig. 15C-51	Station Blackout (SBO) (Event 56)	Reactor Vessel Water Level - Level 2 Manual	Special

Primary Containment Isolation Instrumentation

The primary containment isolation instrumentation automatically initiates closure of appropriate primary containment isolation valves (PCIVs) to limit fission product release during and following postulated Design Basis Accidents (DBAs). Functional diversity is provided by monitoring a wide range of independent parameters. Redundant sensor input signals from each parameter are provided for initiation of isolation. The only exception is SLC System initiation.

Main Steam Line Isolation Instrumentation

Most MSL Isolation Functions receive inputs from four channels. The outputs from these channels are combined in a one-out-of-two taken twice logic to initiate isolation of all main steam isolation valves (MSIVs). The outputs from the same channels are arranged into two two-out-of-two logic trip systems to isolate all MSL drain valves and reactor water sample valves. The MSL drain line has two isolation valves with one two-out-of-two logic system associated with each valve. Isolating either MSL drain valve and either reactor water sample valve accomplishes the safety function.

The exceptions to this arrangement are the Main Steam Line Flow - High Function and Area Temperature Functions. The Main Steam Line Flow - High Function uses 16 flow channels, four for each steam line. One channel from each steam line inputs to one of the four trip strings. Two trip strings make up each trip system and both trip systems must trip to cause an MSL isolation. Each trip string has four inputs (one per MSL), any one of which will trip the trip string. The trip strings are arranged in a one-out-of-two taken twice logic. This is effectively a one-out-of-eight taken twice logic arrangement to initiate isolation of the MSIVs. Similarly, the 16 flow channels are connected into two two-out-of-two logic trip systems (effectively, two one-out-of-four twice logic), with each trip system isolating one of the two MSL drain valves and one of the two reactor water sample valves.

The Main Steam Tunnel Temperature - High Function receives input from 16 channels. The logic is arranged similar to the Main Steam Line Flow - High Function. The Turbine Building Area Temperature - High Function receives input from 64 channels. Four channels from each steam line inputs to one of the four trip strings. Two trip strings make up each trip system and both trip systems must trip to cause an MSL isolation. Each trip string has 16 inputs (4 per MSL), any one of which will trip the trip string. The trip strings are arranged in a one-out-of-two taken twice logic. This is effectively a one-out-of-thirty-two taken twice logic trip system to isolate all MSIVs. Similarly, the inputs are arranged in two one-out-of-sixteen twice logic trip systems, with each trip system isolating one of the two MSL drain valves and one of the two reactor water sample valves.

High Pressure Coolant Injection System Isolation and Reactor Core Isolation Cooling System Isolation Instrumentation

Most Functions that isolate HPCI and RCIC receive input from two channels, with each channel in one trip system using a one-out-of-one logic. Each of the two trip systems in each isolation group is connected to one of the two valves on each associated penetration. The exceptions are the HPCI and RCIC Turbine Exhaust Diaphragm Pressure - High and Steam Supply Line Pressure - Low Functions. These Functions receive inputs from four turbine exhaust diaphragm pressure and four steam supply pressure channels for each system. The outputs from the turbine exhaust diaphragm pressure and steam supply pressure channels are each connected to two two-out-of-two trip systems. Additionally, each trip system of the Steam Line Flow - High Functions receives input from a low differential pressure channel. The low differential pressure channels are not required for OPERABILITY. Each trip system isolates one valve per associated penetration. Isolating either valve in the penetration accomplishes the safety function.

Reactor Water Cleanup System Isolation Instrumentation

The Reactor Vessel Water Level - Low Low, Level 2 Isolation Function channels are connected into two two-out-of-two trip systems. The Area Temperature - High Function receives input from six temperature monitors, three to each trip system. The Area Ventilation Differential Temperature - High Function receives input from six differential temperature monitors, three in each trip system. These are configured so that any one input will trip the associated trip system. Each of the two trip systems is connected to one of the two valves on the RWCU penetration. Isolating either valve in the penetration accomplishes the safety function. However, the SLC System Initiation Function only provides an input to one trip system, thus closes only one valve. For Function 5.c, SLC initiation is a manual operator action and EOPs direct verification of RWCU isolation in conjunction with that manual action. Therefore, even if the automatic interlock to isolate RWCU is inoperable, RWCU will be manually isolated in conjunction with the manual initiation of SLC; as such, isolation function is maintained. The RWCU isolation safety function is maintained by plant procedures (to which operators are trained) governing this manual operator action. This manual action is modeled in the PRA, which incorporates appropriate human error probabilities.

TS Table 3.3.6.1-1, Primary Containment Isolation Instrumentation

TS Table 3.3.6.1-1 Function	FSAR Reference	Transient/Accident	Redundant / Diverse Instrumentation	Event Type
1.a Main Steam Line Isolation Reactor Vessel Water Level - Low Low Low, Level 1	Table 5.2-8 7.3.2.2.6.A15.3.3 15C.4.2.2 Fig. 15C-30	Loss of Coolant Accident (LOCA) (Event 32)	Reactor Vessel Water Level – Level 1 Main Steam Line Pressure – Low Condenser Vacuum - Low Manual	DBA
	15.3.4 15C.4.2.3 Fig. 15C-31	Main Steam Line Break Accident (MSLBA) (Event 33)	Reactor Vessel Water Level – Level 1 Main Steam Line Pressure - Low Main Steam Line Flow – High Main Steam Tunnel Temperature Turbine Building Area Temperature Manual	DBA
	15.3.8 15C.4.2.7 Fig. 15C-35	Feedwater Line Break Accident (Event 37)	Reactor Vessel Water Level – Level 1 Manual	DBA
1.b Main Steam Line Isolation Main Steam Line Pressure - Low	7.3.2.2.6.E 15.3.3 15C.4.2.2 Fig. 15C-30	Loss of Coolant Accident (LOCA) (Event 32)	Main Steam Line Pressure - Low Reactor Vessel Water Level - Level 1 Condenser Vacuum - Low Manual	DBA

TS Table 3.3.6.1-1 Function	FSAR Reference	Transient/Accident	Redundant / Diverse Instrumentation	Event Type
1.c Main Steam Line Isolation Main Steam Line Flow - High	Table 5.2-8 7.3.2.2.6.C 15.3.4 15C.4.2.3 Fig. 15C-31	Main Steam Line Break Accident (MSLBA) (Event 33)	Main Steam Line Flow - High Reactor Vessel Water Level – Level 1 Main Steam Line Pressure - Low Main Steam Tunnel Temperature Turbine Building Area Temperature Manual	DBA
1.d Main Steam Line Isolation Condenser Vacuum - Low	15.2.3.4 15C.4.1.3.4 Fig. 15C-11	Loss of Condenser Vacuum (Event 8)	Condenser Vacuum – Low Manual	AOO
	15.3.3 15C.4.2.2 Fig. 15C-30	Loss of Coolant Accident (LOCA) (Event 32)	Condenser Vacuum – Low Reactor Vessel Water Level - Level 1 Main Steam Line Pressure - Low Manual	DBA
1.e Main Steam Line Isolation Main Steam Tunnel Temperature - High	7.3.2.2.6.D 15.3.4 15C.4.2.3 Fig. 15C-31	Main Steam Line Break Accident (MSLBA) (Event 33)	Main Steam Tunnel Temperature Reactor Vessel Water Level – Level 1 Main Steam Line Pressure - Low Main Steam Line Flow – High Turbine Building Area Temperature Manual	DBA

TS Table 3.3.6.1-1 Function	FSAR Reference	Transient/Accident	Redundant / Diverse Instrumentation	Event Type
1.f Main Steam Line Isolation Turbine Building Area Temperature - High	15.3.4 15C.4.2.3 Fig. 15C-31	Main Steam Line Break Accident (MSLBA) (Event 33)	Turbine Building Area Temperature Reactor Vessel Water Level – Level 1 Main Steam Line Pressure - Low Main Steam Line Flow – High Main Steam Tunnel Temperature Manual	DBA
2.a Reactor Vessel Water Level - Low, Level 3	7.3.2.2.6.A 15C.4.2.2 Table 15C-8 Figure 15C-30	Loss of Coolant Accident (LOCA) (Event 32)	Reactor Vessel Water Level – Level 3 Drywell Pressure – High Manual	DBA
	7.3.2.2.6.A 15C.4.1.8.4 Table 15C-8 Figure 15C-30	Loss of Feedwater Flow (Event 25)	Reactor Vessel Water Level – Level 3 Manual	AOO
	15.3.8 15C.4.2.7 Table 15C-8 Figure 15C-35	Feedwater Line Break (Event 37)	Reactor Vessel Water Level – Level 3 High Area Temperature Manual	DBA
2.b Drywell Pressure – High	7.3.2.2.6.F 15C.4.2.2 Table 15C-8 Figure 15C-30	Loss of Coolant Accident (LOCA) (Event 32)	Drywell Pressure – High Reactor Vessel Water Level – Level 3 Manual	DBA

TS Table 3.3.6.1-1 Function	FSAR Reference	Transient/Accident	Redundant / Diverse Instrumentation	Event Type
3.a HPCI System Isolation HPCI Steam Line Flow - High	Table 5.2-8 7.3.1.2.1.5.A.4 7.3.2.2.6.L 15A.5.3	HPCI Steam Line Break	HPCI Steam Line Flow - High HPCI Steam Supply Line Pressure – Low Manual	DBA
3.b HPCI System Isolation HPCI Steam Supply Line Pressure - Low	Table 5.2-8 7.3.1.2.1.5.A.7 7.3.2.2.6.M 15A.5.3	HPCI Steam Line Break	HPCI Steam Supply Line Pressure - Low HPCI Steam Line Flow – High Manual	DBA
3.c HPCI System Isolation HPCI Turbine Exhaust Diaphragm Pressure – High	7.3.1.2.1.5.A.6 7.3.2.2.2 7.3.2.2.6.N	Fracture of the rupture disk in the turbine exhaust vent line	Exhaust Diaphragm Pressure Manual	NA
3.d Drywell Pressure - High	7.3.2.2.6.F.16	Indirectly assumed in the FSAR accident analysis	Drywell Pressure - High Manual	DBA
3.e HPCI System Isolation HPCI Pipe Penetration Room Temperature - High	Table 5.2-8 7.3.1.2.1.5.A.1 15A.5.3	HPCI Steam Line Break	HPCI Pipe Penetration Room Temperature - High Manual	DBA
3.f HPCI System Isolation Suppression Pool Area Ambient Temperature – High & 3.g Suppression Pool Area Temperature - Time Delay Relays	Table 5.2-8 7.3.1.2.1.5.A.8 7.3.2.2.6.K 15A.5.3	HPCI Steam Line Break	Suppression Pool Area Ambient Temperature – High Manual	DBA
3.h HPCI System Isolation Suppression Pool Area Differential Temperature - High	Table 5.2-8 7.3.1.2.1.5.A.3 7.3.2.2.6.K 15A.5.3	HPCI Steam Line Break	Suppression Pool Area Differential Temperature – High Manual	DBA

TS Table 3.3.6.1-1 Function	FSAR Reference	Transient/Accident	Redundant / Diverse Instrumentation	Event Type
3.i HPCI System Isolation Emergency Area Cooler Temperature - High	7.3.1.2.1.5.A.2 7.3.2.2.6.K 7.6.9.3	HPCI Steam Line Break	Emergency Area Cooler Temperature – High Manual	DBA
4.a RCIC System Isolation RCIC Steam Line Flow - High	Table 5.2-8 7.3.2.2.6.H 15A.5.4	RCIC Steam Line Break	RCIC Steam Line Flow – High Manual	DBA
4.b RCIC System Isolation RCIC Steam Supply Line Pressure - Low	Table 5.2-8 7.3.2.2.6.I 15A.5.4	RCIC Steam Line Break	RCIC Steam Supply Line Pressure – Low Manual	DBA
4.c RCIC System Isolation RCIC Turbine Exhaust Diaphragm Pressure – High	7.3.2.2.2 7.3.2.2.6.J	Fracture of the rupture disk in the turbine exhaust vent line	RCIC Turbine Exhaust Diaphragm Pressure – High Manual	NA
4.d RCIC System Isolation Drywell Pressure - High	7.3.2.2.6.F.16	Indirectly assumed in the FSAR accident analysis	Drywell Pressure - High Manual	DBA
4.e RCIC System Isolation RCIC Suppression Pool Ambient Area Temperature - High	7.3.2.2.6.G 15.3.4 15A.5.4	RCIC Steam Line Break	RCIC Suppression Pool Ambient Area Temperature – High Manual	DBA
4.f RCIC System Isolation Suppression Pool Area Temperature - Time Delay Relays	7.3.2.2.6.G 15.3.4 15A.5.4	RCIC Steam Line Break	Suppression Pool Area Temperature - Time Delay Relays Manual	DBA
4.g RCIC System Isolation RCIC Suppression Pool Area Differential Temperature - High	7.3.2.2.6.G 15.3.4 15A.5.4	RCIC Steam Line Break	RCIC Suppression Pool Area Differential Temperature – High Manual	DBA

TS Table 3.3.6.1-1 Function	FSAR Reference	Transient/Accident	Redundant / Diverse Instrumentation	Event Type
4.h RCIC System Isolation Emergency Area Cooler Temperature - High	7.3.2.2.6.G 7.6.9.3 15.3.4 15A.5.4	RCIC Steam Line Break	Emergency Area Cooler Temperature – High Manual	DBA
5.a RWCU System Isolation Area Temperature - High	7.3.2.2.6.P&Q 15.3.4 15A.5.5	Reactor Water Cleanup Line Break	Area Temperature - High Reactor Water Cleanup High Differential Flow Manual	DBA
5.b RWCU System Isolation Area Ventilation Differential Temperature - High	7.3.2.2.6.P&Q 7.6.9.3 15.3.4 15A.5.5	Reactor Water Cleanup Line Break	Area Ventilation Differential Temperature - High Reactor Water Cleanup High Differential Flow Manual	DBA
5.c RWCU System Isolation SLC System Initiation	None	None	Manual	NA
5.d RWCU System Isolation Reactor Vessel Water Level - Low Low, Level 2	15.3.3 15C.4.2.2 Fig. 15C-30	Loss of Coolant Accident (LOCA) (Event 32)	Reactor Vessel Water Level - Level 2 Manual	DBA
	15.3.4 15C.4.2.3 Fig. 15C-31	Main Steam Line Break Accident (MSLBA) (Event 33)	Reactor Vessel Water Level - Level 2 Manual	DBA
	15.3.8 15C.4.2.7 Fig. 15C-35	Feedwater Line Break Accident (Event 37)	Reactor Vessel Water Level - Level 2 Manual	DBA

Enclosure 1-4 - Example Risk Informed Completion Times for HATCH Unit 1 and Unit 2 Technical Specifications

LCO ACTION TSTF-505/HATCH 1&2 TS	CONDITION	REQUIRED ACTION	EST RICT(1)(2)
Standby Liquid Control (SLC) System TSTF-505: LCO 3.1.7, Required Action B.1 HATCH 1&2: LCO 3.1.7, Required Action B.1	One SLC subsystem inoperable for reasons other than Condition A.	B.1 Restore SLC subsystem to OPERABLE status.	30d
Reactor Protection System (RPS) Instrumentation TSTF-505: LCO 3.3.1.1, Required Actions A.1 and A.2 HATCH 1&2: LCO 3.3.1.1, Required Actions A.1 and A.2	One or more required channels inoperable. Functions 7a, 7b and 10 are excluded from RICT.	A.1 Place channel in trip. OR A.2 Place associated trip system in trip.	30d
Reactor Protection System (RPS) Instrumentation TSTF-505: LCO 3.3.1.1, Required Actions B.1 and B.2 HATCH 1&2: LCO 3.3.1.1, Required Actions B.1 and B.2	One or more Functions with one or more required channels inoperable in both trip systems. Functions 7a, 7b and 10 are excluded.	B.1 Place channel in one trip system in trip. OR B.2 Place one trip system in trip.	30d
End of Cycle Recirculation Pump Trip (EOC-RPT) Instrumentation TSTF-505: LCO 3.3.4.1, Required Actions A.1 and A.2 HATCH 1&2: LCO 3.3.4.1, Required Actions A.1 and A.2	One or more channels inoperable.	A.1 Restore channel to OPERABLE status. OR A.2 Place channel in trip.	30d
Anticipated Transient Without Scram Recirculation Pump Trip (ATWS-RPT) Instrumentation TSTF-505: LCO 3.3.4.2, Required Actions A.1 and A.2 HATCH 1&2: LCO 3.3.4.2, Required Actions A.1 and A.2	One or more channels inoperable.	A.1 Restore channel to OPERABLE status. OR A.2 Place channel in trip.	30d
Emergency Core Cooling System (ECCS) Instrumentation TSTF-505: LCO 3.3.5.1, Required Action B.3 HATCH 1&2: LCO 3.3.5.1, Required Action B.3	As required by Required Action A.1 and referenced in Table 3.3.5.1-1. Functions 1a, 1b, 2a, 2b, 3a, 3b	B.3 Place channel in trip.	30d

LCO ACTION TSTF-505/HATCH 1&2 TS	CONDITION	REQUIRED ACTION	EST RICT(1)(2)
Emergency Core Cooling System (ECCS) Instrumentation TSTF-505: LCO 3.3.5.1, Required Action C.2 HATCH 1&2: LCO 3.3.5.1, Required Action C.2	As required by Required Action A.1 and referenced in Table 3.3.5.1-1. Functions 1c, 2c, 2d, 2f	C.2 Restore channel to OPERABLE status.	19d
Emergency Core Cooling System (ECCS) Instrumentation TSTF-505: LCO 3.3.5.1, Required Action D.2.1 HATCH 1&2: LCO 3.3.5.1, Required Action D.2.1	As required by Required Action A.1 and referenced in Table 3.3.5.1-1. Functions 3d and 3e	D.2.1 Place channel in trip.	30d
Emergency Core Cooling System (ECCS) Instrumentation TSTF-505: LCO 3.3.5.1, Required Action E.2 HATCH 1&2: LCO 3.3.5.1, Required Action E.2	As required by Required Action A.1 and referenced in Table 3.3.5.1-1. Functions 1d, 2g, 3f	E.2 Restore channel to OPERABLE status.	30d
Reactor Core Isolation Cooling (RCIC) System Instrumentation TSTF-505: LCO 3.3.5.2, Required Action B.2 HATCH 1&2: LCO 3.3.5.3, Required Action B.2	As required by Required Action A.1 and referenced in Table 3.3.5.3-1. Function 1	B.2 Place channel in trip.	30d
Reactor Core Isolation Cooling (RCIC) System Instrumentation TSTF-505: LCO 3.3.5.2, Required Action D.2.1 HATCH 1&2: LCO 3.3.5.3, Required Action D.2.1	As required by Required Action A.1 and referenced in Table 3.3.5.3-1. Functions 3 and 4	D.2.1 Place channel in trip.	30d
Primary Containment Isolation Instrumentation TSTF-505: LCO 3.3.6.1, Required Action A.1 HATCH 1&2: LCO 3.3.6.1, Required Action A.1 and A.2	One or more required channels inoperable. Functions 2c, 2d, 2e, 6 and 7.	A.1 Place channel in trip. AND A.2 Place channel in trip.	30d
ECCS – Operating TSTF-505: LCO 3.5.1, Required Action A.1 HATCH 1&2: LCO 3.5.1, Required Action A.1	One low pressure ECCS injection/spray subsystem inoperable. OR One LPCI pump in both LPCI subsystems inoperable.	A.1 Restore low pressure ECCS injection/spray subsystem to OPERABLE status.	23.4d

LCO ACTION TSTF-505/HATCH 1&2 TS	CONDITION	REQUIRED ACTION	EST RICT[(1)(2)]
ECCS – Operating TSTF-505: N/A HATCH 1&2: LCO 3.5.1, Required Action C.1	One LPCI pump in one or both LPCI subsystems inoperable. AND One CS subsystem inoperable.	C.1 Restore low pressure ECCS injection/spray subsystem(s) to OPERABLE status.	27.3d
ECCS – Operating TSTF-505: LCO 3.5.1, Required Action C.2 HATCH 1&2: LCO 3.5.1, Required Action E.2	HPCI System inoperable.	E.2 Restore HPCI System to OPERABLE status.	30d
ECCS - Operating TSTF-505: LCO 3.5.1, Required Actions D.1 and D.2 HATCH 1&2: LCO 3.5.1, Required Actions F.1 and F.2	HPCI System inoperable. AND Condition A entered.	F.1 Restore HPCI System to OPERABLE status. OR F.2 Restore low pressure ECCS injection/spray subsystem to OPERABLE status.	24.5d
Reactor Core Isolation Cooling (RCIC) System TSTF-505: LCO 3.5.3, Required Action A.2 HATCH 1&2: LCO 3.5.3, Required Action A.2	RCIC System inoperable.	A.2 Restore RCIC System to OPERABLE status.	30d
Primary Containment Air Lock TSTF-505: LCO 3.6.1.2, Required Action C.3 HATCH 1&2: LCO 3.6.1.2, Required Action C.3	Primary containment air lock inoperable for reasons other than Condition A or B.	C.3 Restore air lock to OPERABLE status.	10.8d
Primary Containment Isolation Valves (PCIVs) TSTF-505: LCO 3.6.1.3, Required Action A.1 HATCH 1&2: LCO 3.6.1.3, Required Action A.1 and A.2	One or more penetration flow paths with one PCIV inoperable except due to leakage not within limit.	A.1 Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, blind flange, or check valve with flow through the valve secured. AND A.2 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.	30d
Residual Heat Removal (RHR) Suppression Pool Cooling TSTF-505: LCO 3.6.2.3, Required Action A.1 HATCH 1&2: LCO 3.6.2.3, Required Action A.1	One RHR suppression pool cooling subsystem inoperable.	A.1 Restore RHR suppression pool cooling subsystem to OPERABLE status.	30d

LCO ACTION TSTF-505/HATCH 1&2 TS	CONDITION	REQUIRED ACTION	EST RICT[(1)(2)]
Residual Heat Removal (RHR) Suppression Pool Spray TSTF-505: LCO 3.6.2.4, Required Action A.1 HATCH 1&2: LCO 3.6.2.4, Required Action A.1	One RHR suppression pool spray subsystem inoperable.	A.1 Restore RHR suppression pool spray subsystem to OPERABLE status.	30d
Residual Heat Removal (RHR) Drywell Spray TSTF-505: N/A HATCH 1&2: LCO 3.6.2.5, Required Action A.1	A. One RHR drywell spray subsystem inoperable.	A.1 Restore RHR drywell spray subsystem to OPERABLE status.	30d
Residual Heat Removal Service Water (RHRSW) System TSTF-505: LCO 3.7.1, Required Action B.1 HATCH 1&2: LCO 3.7.1, Required Action B.1	One RHRSW pump in each subsystem inoperable.	B.1 Restore one RHRSW pump to OPERABLE status	30d
Residual Heat Removal Service Water (RHRSW) System TSTF-505: LCO 3.7.1, Required Action C.1 HATCH 1&2: LCO 3.7.1, Required Action C.1	One RHRSW subsystem inoperable for reasons other than Condition A.	C.1 Restore RHRSW subsystem to OPERABLE status.	30d
Plant Service Water (SW) System and Ultimate Heat Sink (UHS) TSTF-505: LCO 3.7.2, Required Action B.1 HATCH 1&2: LCO 3.7.2, Required Action C.1	One PSW pump in each subsystem inoperable.	C.1 Restore one PSW pump to OPERABLE status.	13d
Plant Service Water (SW) System and Ultimate Heat Sink (UHS) TSTF-505: N/A HATCH 1&2: LCO 3.7.2, Required Action D.1	One PSW turbine building isolation valve in each subsystem inoperable.	D.1 Restore one PSW turbine building isolation valve to OPERABLE status.	30d
Plant Service Water (SW) System and Ultimate Heat Sink (UHS) TSTF-505: LCO 3.7.2, Required Action E.1 HATCH 1&2: LCO 3.7.2, Required Action F.1	One PSW subsystem inoperable for reasons other than Conditions A and B.	F.1 Restore the PSW subsystem to OPERABLE status.	28.8d
AC Sources – Operating TSTF-505: LCO 3.8.1, Required Action A.3 HATCH 1&2: LCO 3.8.1, Required Action A.3	One required offsite circuit inoperable.	A.3 Restore required offsite circuit to OPERABLE status.	30d

LCO ACTION TSTF-505/HATCH 1&2 TS	CONDITION	REQUIRED ACTION	EST RICT[(1)(2)]
AC Sources – Operating TSTF-505: LCO 3.8.1, Required Action B.4 HATCH 1&2: LCO 3.8.1, Required Action B.4	One {same unit} or the swing DG inoperable.	B.4 Restore DG to OPERABLE status.	30d
AC Sources – Operating TSTF-505: LCO 3.8.1, Required Action B.4 HATCH 1&2: LCO 3.8.1, Required Action C.4	One required {other unit} DG inoperable.	C.4 Restore required DG to OPERABLE status.	30d
AC Sources – Operating TSTF-505: LCO 3.8.1, Required Action C.2 HATCH 1&2: LCO 3.8.1, Required Action D.2	Two or more required offsite circuits inoperable.	D.2 Restore all but one required offsite circuit to OPERABLE status.	5.4d
AC Sources – Operating TSTF-505: LCO 3.8.1, Required Actions D.1 and D.2 HATCH 1&2: LCO 3.8.1, Required Actions E.1 and E.2	One required offsite circuit inoperable. AND One required DG inoperable.	E.1 Restore required offsite circuit to OPERABLE status. OR E.2 Restore required DG to OPERABLE status.	0 [(3)] 19.2H for emergent RICT
DC Sources – Operating TSTF-505: LCO 3.8.4, Required Action A.3 HATCH 1&2: LCO 3.8.4, Required Action B.3	Required {same unit} DG DC battery charger on one subsystem inoperable. OR Required swing DG DC battery charger inoperable for reasons other than Condition A.	B.3 Restore battery charger(s) to OPERABLE status.	30d
DC Sources – Operating TSTF-505: LCO 3.8.4, Required Action A.3 HATCH 1&2: LCO 3.8.4, Required Action D.3	One or more required {same unit} station service DC battery chargers on one subsystem inoperable.	D.3 Restore battery charger(s) to OPERABLE status.	30d
DC Sources – Operating TSTF-505: LCO 3.8.4, Required Action B.1 HATCH 1&2: LCO 3.8.4, Required Action A.1	Swing DG DC electrical power subsystem inoperable due to performance of SR 3.8.4.3 or SR 3.8.6.6. OR One or more required {other unit} DG DC electrical power subsystems inoperable.	A.1 Restore DG DC electrical power subsystem to OPERABLE status.	30d

LCO ACTION TSTF-505/HATCH 1&2 TS	CONDITION	REQUIRED ACTION	EST RICT(1)(2)
DC Sources – Operating TSTF-505: LCO 3.8.4, Required Action B.1 HATCH 1&2: LCO 3.8.4, Required Action C.1	One {same unit} DG DC electrical power subsystem inoperable for reasons other than Condition B. OR Swing DG DC electrical power subsystem inoperable for reasons other than Condition A or B.	C.1 Restore DG DC electrical power subsystem to OPERABLE status.	30d
DC Sources - Operating TSTF-505: LCO 3.8.4, Required Action C.1 HATCH 1&2: LCO 3.8.4, Required Action E.1	One {same unit} station service DC electrical power subsystem inoperable for reasons other than Condition D.	E.1 Restore station service DC electrical power subsystem to OPERABLE status.	14.1d
Distribution Systems - Operating TSTF-505: N/A HATCH 1&2: LCO 3.8.7, Required Action A.1	One or more required {other unit} AC or DC electrical power distribution subsystems inoperable.	A.1 Restore required {other unit} AC and DC subsystem(s) to OPERABLE status.	13.2d
Distribution Systems - Operating TSTF-505: N/A HATCH 1&2: LCO 3.8.7, Required Action B.1	One or more ({same unit} or swing bus) DG DC electrical power distribution subsystems inoperable.	B.1 Restore DG DC electrical power distribution subsystem to OPERABLE status.	0 (3) 62 H for emergent RICT
Distribution Systems - Operating TSTF-505: LCO 3.8.9, Required Action A.1 HATCH 1&2: LCO 3.8.7, Required Actions A.1 and C.1	[Condition A addressed above] One or more ({same unit} or swing bus) AC electrical power distribution subsystems inoperable.	[Required Action A.1 addressed above] C.1 Restore AC electrical power distribution subsystem to OPERABLE status.	0 (3) 45.1H for emergent RICT
Distribution Systems - Operating TSTF-505: LCO 3.8.9, Required Action C.1 HATCH 1&2: LCO 3.8.7, Required Actions A.1, B.1 and D.1	[Conditions A and B addressed above] One {same unit} station service DC electrical power distribution subsystem inoperable.	[Required Actions A.1 and B.1 addressed above] D.1 Restore {same unit} station service DC electrical power distribution subsystem to OPERABLE status.	0 (3) 39.4H for emergent RICT

Note 1: The RICT estimate in this table represents the most limiting RICT calculation based on the most limiting component in the most limiting unit. In accordance with NEI 06-09-A, depending upon the specific inoperable SSC which causes the TS LCO to be not met, the level of risk calculated varies, and a different RICT may be calculated for different inoperable SSCs within the Action.

Note 2: RICTs calculated to be greater than 30 days are capped at 30 days in accordance with NEI 06-09-A, Revision 0-A.

Note 3: By current calculation, the use of the RICT Program on this Action for planned equipment outages is precluded by the instantaneous CDF or LERF limits of 1E-03 or 1E-04, respectively. A RICT may still be entered for this action in the event of an unplanned equipment failure in accordance with NEI 06-09 guidance.

ENCLOSURE 2

Edwin I. Hatch Nuclear Plant – Units 1 and 2
License Amendment Request to Revise Technical Specifications
to Adopt Risk Informed Completion Times TSTF-505, Revision 2,
"Provide Risk-Informed Extended Completion Times - RITSTF Initiative 4b"

Information Supporting Consistency
With Regulatory Guide 1.200, Revision 2

1 Introduction

This enclosure provides information on the technical adequacy of the Edwin I. Hatch Nuclear Plant (Hatch) Probabilistic Risk Assessment (PRA) internal events model, internal flooding model, and the Fire PRA model in support of the license amendment request to revise Technical Specifications to implement NEI 06-09, Revision 0-A, "Risk-Informed Technical Specifications Initiative 4b, Risk-Managed Technical Specifications (RMTS) Guidelines" (Reference [1]).

Topical Report NEI 06-09, Revision 0-A (Reference [1]), as clarified by the Nuclear Regulatory Commission (NRC) final safety evaluation (Reference [2]), defines the technical attributes of a PRA model and its associated Configuration Risk Management Program (CRMP) tool required to implement this risk-informed application. Meeting these requirements satisfies Regulatory Guide (RG) 1.174 (Reference [3]) requirements for risk informed plant-specific changes to a plant's licensing basis.

SNC employs a multi-faceted approach to establish and maintain the technical adequacy and fidelity of probabilistic risk assessment (PRA) models for all operating SNC nuclear generation sites. This approach includes both a proceduralized PRA maintenance and update process and the use of self-assessments and independent peer reviews. The following information describes this approach as it applies to the Hatch PRA.

Section 2 of this enclosure describes requirements related to the scope of the Hatch PRA internal events, internal flooding, and fire models. Section 3 addresses the technical adequacy of the internal events PRA for this application. Section 4 addresses the technical adequacy of the internal flooding PRA for this application. Section 5 similarly addresses the technical adequacy of the Fire PRA for this application. Section 6 provides details to support the technical adequacy of the models. Section 7 lists references used in the development of this enclosure.

All of the PRA models described below have been peer reviewed, and the finding-level Facts and Observations (F&Os) from the peer review have been independently evaluated to confirm that the associated model changes address the finding. Sections 3, 4, and 5 summarize the peer reviews and F&O finding closure reviews of the Hatch internal events PRA, internal flooding PRA, and Fire PRA models, respectively.

2 Requirements Related to Scope of Hatch PRA Models

Hatch internal events PRA model, internal flooding PRA model, Fire PRA model are at-power models (i.e., they directly address plant configurations during plant mode 1 of reactor operation). The models include core damage frequency (CDF) and large early release frequency (LERF).

Note that this portion of the Hatch PRA model does not incorporate the risk impacts of external events. The treatment of seismic risk and other external hazards for this application are discussed in Enclosure 4.

3 Scope and Technical Adequacy of Hatch Internal Events PRA Model

Topical Report NEI 06-09, Revision 0-A [1] requires that the PRA be reviewed to the guidance of RG 1.200 (Reference [4]) for a PRA which meets Capability Category (CC) II for the supporting requirements of the American Society of Mechanical Engineers (ASME) / American Nuclear Society (ANS) internal events at power PRA standard, ASME/ANS RA-Sa-2009 (Reference [5]). It also requires that deviations from these CCs relative to the Risk Informed Completion Time (RICT) Program be justified and documented.

The full scope peer review of the Plant Hatch Full-Power Internal Events (including Internal Flooding) (FPIE) Probabilistic Risk Assessment (PRA) was performed in November 2009. The peer review team issued a total of 25 unique findings. In April 2017, an Appendix X Fact and Observation (F&O) Closure Independent Assessment (IA) was performed to review SNC's disposition of the finding-level F&Os received from the November 2009 peer review. This closure review was performed in accordance with the requirements described in NEI 05-04 [6], and in particular, Appendix X of this report [7]. The NEI methodology for performing F&O closure reviews was accepted by the US Nuclear Regulatory Commission [8] [9], with a number of clarifications and specific documentation expectations noted. Upon completion of the IA, of the 25 total reviewed findings, only 3 were left OPEN and 1 left "Partially Closed". Two F&Os were specific to internal flooding technical element and are discussed in the next section. The other two F&Os relate to the accident sequence and human reliability technical elements. These two findings have since been resolved by performing the recommendations from the IA team. See Table E2-1 for the disposition of these findings with respect to this application.

The other 21 reviewed findings were considered to be closed by the IA team. Given the resolution of the remaining findings, the Hatch Internal Events PRA is of adequate technical capability to support the TSTF-505 program.

4 Scope and Technical Adequacy of Hatch Internal Flooding PRA Model

As mentioned in Section 3, the Hatch Internal Flooding PRA was the subject of a full scope peer review in November 2009. A subsequent Appendix X F&O closure was also performed to address open F&Os in April 2017. Two F&Os related to internal flooding technical element remained, one open and one partially closed. In response to the resolution of these two F&Os, SNC determined that a focused scope peer review (FSPR) was triggered due to significant changes in risk insight as a result of internal flooding PRA model update A FSPR was performed in October 2019 to address the supporting requirements that are associated with the responses to these two findings. As a result of the FSPR, no finding-level F&Os were generated.

Given there are no remaining open finding-level F&Os, the Hatch Internal Flooding PRA is of adequate technical capability to support the TSTF-505 program.

5 Scope and Technical Adequacy of Hatch Fire PRA Model

The Hatch Fire PRA (FPRA) full scope peer review was performed in May 2016 using the NEI 07-12 Fire PRA peer review process (Reference [10]), the ASME PRA Standard, ASME/ANS RA-Sa-2009 (Reference [5]) and Regulatory Guide 1.200, Rev. 2. A total of 61 finding-level F&Os were issued. In October 2017, an Appendix X Fact and Observation (F&O) Closure Independent Assessment (IA) was performed to review SNC's disposition of the finding-level F&Os received from the May 2016 peer review.

The IA Team determined that disposition of all 61 Finding level F&Os was satisfactory; therefore, all F&Os were closed out. The IA Team also determined that resolution of one F&O constituted PRA Upgrade. As a result, a concurrent focused-scope peer review (FSPR) was performed to review a method that calculated time to cable damage due to exposure of a fire environment. The IA Team determined that the method was technically sound and provided a reasonable and realistic method for estimating time to cable damage due to exposure of a fire environment. No additional F&Os were issued as a result of the FSPR.

Given there are no remaining open finding-level F&Os, the Hatch Fire PRA is of adequate technical capability to support the TSTF-505 program.

6 Details to Support Technical Adequacy of Hatch PRA Models

Table E2-1 provides the open Peer Review F&O Findings for the FPIE model. These two findings have been resolved by performing the recommendations from the IA team. There are no open Peer Review F&O Findings for the Internal Flooding and Fire PRA models.

Internal Events, Internal Flooding, and Fire PRA models credit only permanently installed FLEX equipment, since they are similar to other installed equipment and operated the same. The modeling of FLEX was reviewed in the Safety Evaluation related to Hatch 10 CFR 50.69 submittal [11]. Portable FLEX equipment was credited only in the Hatch Seismic PRA (SPRA) model. The Hatch SPRA is not used as the direct basis for this risk application but rather is used to provide selected inputs into the calculation of the SCDF and SLERF seismic penalty values discussed in Enclosure 4.

Table E2-1
Peer Review F&Os Not Closed

Supporting Requirement(s)	Finding	Disposition	Impact to TSTF-505 Implementation
AS-B3, AS-C2	Reviewed the AS Notebook. Generally, the discussion of the accident sequence modeling is adequate. However, the following information was not present: (1) Discussion of environmental conditions associated with sequences. (2) Interface between accident sequences and plant damage states. <u>Basis</u>: SR AS-83 requires the identification of phenomenological conditions expected from each accident sequence. <u>Possible Resolution</u>: Include additional detail for each accident sequence. Particularly, there was no mention of the generation of harsh environments affecting temperature, pressure, debris, water levels or humidity that could impact the success of the system. <u>Per 2017 App. X Finding Closure Review</u>: The detail required by this finding has been added to the accident sequence notebook. The sequence descriptions have a discussion of Environmental Conditions. However, no information has been provided on why no environmental impact. One Accident Sequence that does have an adverse impact, is based upon an assumption of equipment qualifications. No listing of Environmental considerations is provided for SBO sequences with uses of Fire Water. No discussion about access or other issues.	Original F&O Disposition: In AS Notebook Subsections 3.#.3, Environmental Conditions have been evaluated for each accident sequence. In subsections 3.#.5, each sequence has a detailed description of the characteristics, which also describes the interface between accident sequences and the plant damage states. 2017 Appendix X Finding Closure Disposition: In AS Notebook Section 3.0, a discussion was added that the Hatch PRA does not typically rely on equipment or operator actions in an area where a severe environment is expected. A discussion on environmental considerations for the SBO sequence where fire water is used was added to the documentation.	Based on the Hatch Equipment Qualification Program, equipment located in potentially harsh environment conditions, including inside containment, are expected to perform its safety function when exposed to normal, abnormal, and accident environment. For all other areas, the models do not credit use of equipment in the area for events that cause adverse environmental events, such as ISLOCA events and steam line breaks outside containment. The Internal flooding analysis evaluates the susceptibility of components to spray and flooding separately. This finding is a documentation issue; therefore, there is no impact to the implementation of TSTF-505.

Table E2-1
Peer Review F&Os Not Closed

Supporting Requirement(s)	Finding	Disposition	Impact to TSTF-505 Implementation
HR-G6	Consistency check did not include comparison of HEPs in regards to scenario context, plant history, procedures, operational practices, and experience. Basis: Section 8.3 of the HRA notebook evaluated consistency of HEPs based on the ratio of execution time and recovery time to check the reasonableness of the derived probability. This checks the reasonableness of the derivation of the probability. However, there was no check of consistency based on scenario context, plant history, procedures. Possible Resolution: Compare HEPs and determine if the HEP values, relative to each other, are representative of applicable scenario context, plant history, procedures, operational practices, and experience. Per 2017 App. X Finding Closure Review: Reviewed Hatch Human Reliability Analysis Update dated Oct. 26, 2009. The evidence presented in the HRA notebook does not appear to be adequate, comparing with the documentation for a similar BWR plant. The model owner at the time of the Peer Review felt that the brief comparison of action versus overall timing in Section 8.3 of the HRA notebook was adequate to comply with HR-G6 and that no additional information needed to be added. Because of this approach there were no revisions made to the HRA notebook after the peer review and there are no added words or amplifying discussion to further support this view in the calculation.	The internal events HRA documentation was revised to incorporate a better consistency analysis. A discussion on requirements from NUREG-1792 and feasibility requirements from NUREG-1921 to be used for internal events HFEs were added to the HRA notebook. HFEs and their HEP were reviewed relative to each other to check their reasonableness given the scenario context including plant procedures, plant history, operational practices and experiences and documented in the HRA notebook.	The documentation associated with this issue has been revised. There is no impact to the implementation of TSTF-505.

7 References

[1] Nuclear Energy Institute (NEI) Topical Report (TR) NEI 06-09, "Risk-Informed Technical Specifications Initiative 4b, Risk-Managed Technical Specifications (RMTS) Guidelines," Revision 0-A, October 12, 2012 (ADAMS Accession No. ML 12286A322).

[2] Letter from Jennifer M. Golder (NRC) to Biff Bradley (NEI), "Final Safety Evaluation for Nuclear Energy Institute (NEI) Topical Report (TR) NEI 06-09, “Risk-Informed Technical Specifications Initiative 4b, Risk-Managed Technical Specifications (RMTS) Guidelines," May 17, 2007 (ADAMS Accession No. ML071200238).

[3] Regulatory Guide (RG) 1.174, *"An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," Revision 3,* January 2018.

[4] Regulatory Guide (RG) 1.200, *"An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities," Revision 2,* March 2009.

[5] ASME/ANS RA-Sa-2009, "Standard for Level 1/Large Early Release Frequency Probabilistic Risk Assessment for Nuclear Power Plant Applications," Addendum A to RAS-2008, ASME, New York, NY, American Nuclear Society, La Grange Park, Illinois, February 2009.

[6] Nuclear Energy Institue NEI 05-04, *"Process for Performing Internal Events PRA Peer Reviews Using the ASME/ANS PRA Standard," Revision 3,* November 2009.

[7] Nuclear Energy Institue NEI 05-04/07-12/12-06 Appendix X, *“Close Out of Facts and Observations (F&Os)",* February 2017.

[8] Letter from J. Giitter and M.J. Ross-Lee (US NRC) to G. Krueger (NEI), *“U.S. Nuclear Regulatory Commission Acceptance On Nuclear Energy Institute Appendix X To Guidance 05-04, 07-12, And 12-13, Close-Out Of Facts And Observations (F&Os)”,* May 2017.

[9] Memorandum from NRC Risk-Informed Steering Committee (US NRC) to S. Rosenberg (US NRC), *“U.S. Nuclear Regulatory Commission Staff Expectations For An Industry Facts And Observations Independent Assessment Process",* May 2017.

[10] Nuclear Energy Institue NEI 07-12, *"Fire Probabilistic Risk Assessment (FPRA) Peer Review Process Guidelines," Revision 1,* June 2010.

[11] Edwin I. Hatch Nuclear Plant, Unit Nos. 1 and 2 - Issuance of Amendment Nos. 305 and 250, Regarding Adoption of 10 CFR 50.69, "Risk-Informed Categorization and Treatment of Structures, Systems, and Components for Nuclear Power Reactors", June 26, 2020 (ADAMS Accession No. ML20077J704).

ENCLOSURE 4

Edwin I. Hatch Nuclear Plant – Units 1 and 2
License Amendment Request to Revise Technical Specifications
to Adopt Risk Informed Completion Times TSTF-505, Revision 2,
"Provide Risk-Informed Extended Completion Times - RITSTF Initiative 4b"

Information Supporting Justification of Excluding
Sources of Risk Not Addressed by the PRA Models

1 Introduction and Scope

Topical Report NEI 06-09, Revision 0-A (Reference [1]), as clarified by the Nuclear Regulatory Commission (NRC) final safety evaluation (Reference [2]), requires that the License Amendment Request (LAR) provide a justification for exclusion of risk sources from the Probabilistic Risk Assessment (PRA) model based on their insignificance to the calculation of configuration risk as well as discuss conservative or bounding analyses applied to the configuration risk calculation. This enclosure addresses this requirement by discussing the overall generic methodology to identify and disposition such risk sources. This enclosure also provides the Edwin I. Hatch Nuclear Plant (Hatch) specific results of the application of the generic methodology and the disposition of impacts on the Hatch Risk Informed Completion Time (RICT) Programs. Section 3 of this Enclosure presents the plant-specific analysis of the extreme wind hazard. Section 4 presents the plant-specific analysis of external flooding hazard. Section 5 presents the plant-specific analysis of the seismic hazard. Section 6 of this enclosure presents the plant-specific analysis of the other external hazards.

Topical Report NEI 06-09 does not provide a specific list of hazards to be considered in a RICT Program. However, non-mandatory Appendix 6-A in the ASME/ANS PRA Standard (Reference [3]) provides a guide for identification of most of the possible external events for a plant site. Additionally, NUREG-1855 [4] provides a discussion of hazards that should be evaluated to assess uncertainties in plant PRAs and support the risk-informed decision-making process. This information was reviewed for the Hatch site and augmented with a review of information on the site region and plant design to identify the set of external events to be considered. The information in the FSAR regarding the geologic, seismologic, hydrologic, and meteorological characteristics of the site region as well as present and projected industrial activities in the vicinity of the plant were also reviewed for this purpose. No new site-specific and plant-unique external hazards were identified through this review. The list of hazards in Appendix 6-A of the PRA Standard were considered for Hatch as summarized in Table E4-4.

The scope of this enclosure is consideration of the hazards in Table E4-4 for Hatch. As explained in subsequent sections of this enclosure, risk contribution from seismic events is evaluated quantitatively, and the other listed external hazards are evaluated and screened as having low risk.

2 Technical Approach

The guidance contained in NEI 06-09 states that hazards that contribute significantly to incremental risk of a configuration must be quantitatively addressed in the implementation of the RICT Program. The following approach focuses on the risk implications of specific external hazards in the determination of the risk management action time (RMAT) and RICT for the Technical Specification (TS) Limiting Conditions for Operation (LCOs) selected to be part of the RICT Program.

Consistent with NUREG-1855 (Reference [4]), external hazards may be addressed by:

1) Screening the hazard based on a low frequency of occurrence,
2) Bounding the potential impact and including it in the decision-making, or
3) Developing a PRA model to be used in the RMAT/RICT calculation.

The overall process for addressing external hazards considers two aspects of the external hazard contribution to risk.

- The first is the contribution from the occurrence of beyond design basis conditions, e.g., winds greater than design, seismic events greater than the design-basis earthquake (DBE), etc. These beyond design basis conditions challenge the capability of the SSCs to maintain functionality and support safe shutdown of the plant.

- The second aspect addressed is the challenges caused by external conditions that are within the design basis, but still require some plant response to assure safe shutdown, e.g., high winds or seismic events causing loss of offsite power, etc. While the plant design basis assures that the safety related equipment necessary to respond to these challenges are protected, the occurrence of these conditions nevertheless causes a demand on these systems that present a risk.

Hazard Screening

The first step in the evaluation of an external hazard is screening based on an estimation of a bounding core damage frequency (CDF) for beyond design basis hazard conditions. An example of this type of screening is reliance on the NRC's 1975 Standard Review Plan (SRP) (Reference [5]), which is acknowledged in the NRC's Individual Plant Examination of External Events (IPEEE) procedural guidance (Reference [6]) as assuring a bounding CDF of less than 1E-6/yr for each hazard. The bounding CDF estimate is often characterized by the likelihood of the site being exposed to conditions that are beyond the design basis limits and an estimate of the bounding conditional core damage probability (CCDP) for those conditions. If the bounding CDF for the hazard can be shown to be less than 1E-6/yr, then beyond design basis challenges from that hazard can be screened out and do not need to be addressed quantitatively in the RICT Program.

The basis for this is as follows:

- The overall calculation of the RICT is limited to an incremental core damage probability (ICDP) of 1E-5.
- The maximum time interval allowed for this RICT is 30 days.
- If the maximum CDF contribution from a hazard is <1E-6/yr, then the maximum ICDP from the hazard is <1E-7 (1E-6/yr * 30 days/365 days/yr).
- Thus, the bounding ICDP contribution from the hazard is shown to be less than 1% of the permissible ICDP in the bounding time for the condition. Such a minimal contribution is not significant to the decision in computing a RICT.

The Hatch IPEEE hazard screening analysis (Reference [7]), has been updated to reflect current Hatch site conditions (Reference [8]). The results are discussed in Section 6 and show that all the events listed in Table E4-4 can be screened except seismic events for Hatch.

Hazard Analysis - CDF and LERF

There are two options in cases where the CDF for the external hazard cannot be shown to be less than 1E-6/yr. The first option is to develop a PRA model that explicitly models the challenges created by the hazard and the role of the SSCs included in the RICT Program in mitigating those challenges. The second option for addressing an external hazard is to compute a conservative CDF contribution for the hazard. Section 5 describes the method used to calculate a conservative seismic CDF and LERF to be used in the calculation of RICT. This seismic “penalty” will be added to the internal events and fire ΔCDF and ΔLERF to calculate the RICT; the seismic “penalty” will apply to all RICT configurations.

Risks from Hazard Challenges

Sections 3 and 4 of this enclosure provides detailed analyses of the HNP extreme winds and external flooding hazards, respectively. Section 5 describes the seismic analysis used to determine the seismic risk for inclusion in the RICT calculations. Section 6 provides an analysis of all other external hazards for HNP.

3 Extreme Winds Analysis

The Hatch design bases for extreme winds and tornadoes are described in the Hatch Units 1 and 2 FSARs (Reference [9]). Components needed for safe shutdown of the plant are protected by reinforced concrete or located underground.

Wind Loadings

The above ground Seismic Category I structures are designed for tornado loadings from a 300-mph tornado. Failure of Category II structures do not affect the ability of Seismic Category I structures to perform their function. The design tornado wind speeds bound straight winds (e.g., from thunderstorms).

Missile Loadings

The FSARs discuss the protection of Seismic Category I structures against design basis tornado missiles. In response to Regulatory Issue Summary 2015-06, a Tornado Missile Vulnerability Evaluation was performed (RER SNC826314 (Reference [10]) to verify compliance to the existing tornado missile license basis requirements. Attachment 1 of Reference [10] describes the design basis tornado missile protection for both units. The evaluation identified two non-conformances which were subsequently resolved, one by adding physical protection (SNC799744 (Reference [11])) and one by engineering calculations showing non-vulnerability due to inherent robustness (SNCH-16-042 (Reference [12])), and the site now fully complies with the license basis.

Tornado wind speed hazard curve information for Hatch (as well as other U.S. nuclear sites) is provided in Table 6-1 of NUREG/CR-4461 (Reference [13]). The NUREG/CR-4461 tornado hazard estimation methodologies include accepted practices and consider uncertainties. The 1E-6 annual probability using the Fujita Scale for Hatch is 228 mph and the 1E-7 wind speed is 278 mph. Using the more recent Enhanced Fujita Scale, the 1E-6 annual probability is 181 mph and the 1E-7 wind speed is 213 mph. NUREG/CR-7005 (Reference [14]) provides peak-gust wind speeds for hurricanes; Figure 3-2a shows that the wind speed with 1E-7 annual exceedance probability in the vicinity of Hatch is approximately 180 mph. Therefore, the frequency of extreme winds impacting the site that exceed the plant design basis is less than 1E-7/yr.

Conclusion

Since Hatch Unit 1 and 2 safety-related systems and components necessary for safe shutdown are protected within Seismic Category I structures, buried underground, or otherwise shown to be able to withstand the design basis tornado hazard, and the Seismic Category I structures provide adequate physical protection from extreme winds, tornados and associated missiles, this hazard screens from PRA modeling in this application based on Criterion C1, "*Event* *damage potential is less than events for which the plant is designed."* Furthermore, the design basis tornado wind speeds at Hatch (300 mph) have a frequency less than 1E-7/yr.

This hazard is also screened for plant configurations associated with LCOs in the RICT program. During configurations with SSCs unavailable, tornado missile risk is not affected since the SSCs needed for safe shutdown are protected against tornado missiles as discussed above. Any potential increase in risk from a high wind event during an LCO configuration would be reflected in the internal events PRA (i.e., for severe weather LOOP scenarios). Therefore, the extreme winds and tornado hazard also screens for configurations.

4 External Flooding Assessment

The external flood hazard and each of the mechanisms that could potentially impact the plant were screened at Hatch using criterion C1, *"Event damage potential is less than events for which the plant is designed."*

The justification for use of C1 is based on the results of a series of calculations and analyses performed in response to Near Term Task Force recommendation 2.1, which were developed in accordance with NEI 16-05, Revision 1 (ML16165A178), and NUREG/CR-7046 (Reference [15]). The Hatch Unit 1 and 2 Flood Hazard Reevaluation Report (FHRR) (ML14069A054, as supplemented by ML14219A570, ML15154B601, and ML16069A088) examined the external flooding hazard in detail, including the following mechanisms which were not bounded by the existing design basis flood height:

- Local Intense Precipitation (LIP)
- Combined effects flooding (Probable Maximum Flood (PMF) with upstream overtopping dam failure with wind-induced waves)
- Flooding in rivers and streams (all season Probable Maximum Flood (PMF) with a 1/2 PMF antecedent storm)
- Seismic upstream dam failure
- PMF with upstream overtopping dam failure

The final NRC staff assessment of the FHRR was issued in ML16237A095.

In the follow-up evaluation documented in the Hatch Mitigating Strategies Assessment (MSA, ML16351A087) and NRC's assessment letter (ML17069A234), SNC determined that three (listed below) of the five previously identified flooding mechanisms have maximum flooding elevations that remain below the 111 ft. Geodetic Vertical Datum of 1929 (NGVD 29) elevation and did not require further analyses.

- Flooding in rivers and streams (all season Probable Maximum Flood (PMF) with a 1/2 PMF antecedent storm)
- Seismic upstream dam failure
- PMF with upstream overtopping dam failure

The elevation of 111 ft. NGVD 29 is the elevation of the lowest floor of the intake structure; this is also lower than the power block, which sits at approximately 130 ft. NGVD 29. Therefore, these mechanisms cannot cause damage to key SSCs and are therefore screened under C1.

Only LIP and the combined effects flooding required further evaluation due to potential to exceed the 111 ft. NGVD 29 elevation. The Flooding Focused Evaluation (SCNH-16-007, ML17173A777) was developed to assess LIP and combined effects flooding and the NRC response has been documented (ML18030B076). The underlying SNC calculation was audited by the NRC (ML17192A452) and a Staff Assessment (ML18030B076) was issued for the

Flooding Focused Evaluation. The following discussion summarizes the LIP and combined effects conclusions and applicability to the screening evaluation.

Local Intense Precipitation

The LIP analysis utilized a 1-hour/1-square mile Probable Maximum Precipitation (PMP) approach to determine local flood levels across a grid. Some doors were identified where the maximum LIP exterior water surface elevation would be greater than the finished floor elevation (both based on NGVD 29) for a given duration. These doors are all normally closed exterior doors that do not require manual action to close or provide additional flood protection.

Calculations show that the water ingress from the LIP event through normally closed exterior doors is insufficient to damage key SSCs. SNC used conservative assumptions in the calculation of water ingress and available physical margin. For example, it was assumed that there was no water leakage during the time of inundation; this means the maximum exterior surface water elevation, and therefore maximum head, was used in calculations of ingress under doors. Additionally, storm drains were not credited in the computation of water heights at the exterior doors.

There are no manual actions required to be implemented to screen this mechanism and its flooding scenario using criterion C1.

Combined Effects Flooding

The analysis was documented in the Flooding Focused Evaluation (SCNH-16-007, ML17173A777) and in the NRC response (ML18030B076) for Combined Effects flooding. The Combined Effects flood is a beyond design basis event, requiring a combination of probable maximum flooding, dam overtopping failure, and wind-driven wave. Combined, the surface water elevation does not reach the main power block buildings; they are located at an elevation (approximately 130 ft. NGVD 29) that provides enough available physical margin to prevent damage to SSCs within those structures.

At the intake structure, the fixed floor elevation of 111 ft. NGVD 29 would not be reached by PMF with dam overtopping failure only; however, with the addition of the wind-driven wave the fixed floor elevation is exceeded. The calculations show that the intake structure walls would withstand both hydrostatic and hydrodynamic loads, and that the doors would withstand hydrodynamic loads (SCNH-16-007, ML17173A777). The doors would not be subject to hydrostatic loading.

Due to the bathymetry of the site, the intake structure would not be directly impacted by waves because the waves would break prior to impact. The hydrostatic loading at the doors was computed as if waves were normally incident to the doors; however, this is conservative because the doors have a labyrinth geometry and the waves could not be normally incident; also, the doors have weather stripping which aids in prevention of water ingress. Additionally, grating south of the intake structure would drain waves to the valve pit below; this was not credited in the calculations. Furthermore, there are grates within the structure that would allow drainage of water ingress from a wave, were it to occur, prior to reaching key SSCs.

There are no manual actions required to be implemented to screen this mechanism and its flooding scenario using criterion C1. There are no plant configurations that would result in an unscreened mechanism or scenario.

Plant Response to Flooding

Hatch does not rely on any personnel actions to respond to the design basis or beyond design basis flooding mechanisms. The NRC staff previously concluded that Hatch has demonstrated that effective flood protection exists and that an "Integrated Assessment" based on the NRC's JLD-ISG-2016-01 document was not necessary (ML16090A140). Therefore, only passive features (exterior doors in their normally closed positions) are credited in the screening of the hazard.

While the site does not rely on any personnel actions for external hazards, Hatch does have a "Naturally-Occurring Phenomena" procedure (34AB-Y22-002-0, Reference [16]) that directs the site to take actions based on Altamaha River elevation or expected elevation. Based on the time required for the maximum probable flood to develop, and the time required for flooding water from a dam failure to reach the site, there is adequate time to perform these proceduralized actions. None of these actions are required for screening the external flood hazard per Criterion C1.

Conclusion

The flood hazard and all associated flood causing mechanisms were screened from this evaluation based on criterion C1, *"Event damage potential is less than events for which the plant is designed."* There are no plant configurations that would result in unscreened scenarios or the hazard.

5 Seismic Assessment

Introduction

The TSTF-505 program requires accounting for seismic risk contribution in calculating extended risk informed technical specification (TS) completion times (CT, also referred to as Allowed Outage Time, AOT).

A seismic PRA (SPRA) was not developed for the Hatch IPEEE (Individual Plant Examination for External Events) (Reference [7]). An SPRA for the Hatch plant has been developed and maintained in recent years; however, the HNP SPRA is not used as the direct basis for this risk application but rather is used to provide selected inputs into the calculation of the SCDF and SLERF seismic penalty values.

The approach taken for the estimation of the SCDF penalty value is a mathematical convolution calculation of the current HNP seismic hazard curve with an estimate of the HNP plant-level seismic fragility. Such convolution approaches are cited in various industry references (e.g., Part 10-B of Reference [3]) and used in various industry programs (e.g., GI-199 risk assessment, Reference [34]), including utility TSTF-505 seismic penalty calculations. Such calculations are often performed using spreadsheets; discussions of the mechanics of such calculations can be found in, among other sources, Appendix A of GI-199 risk assessment (Reference [31]) and are summarized in the ensuing discussions of this section.

The approach taken for the estimation of the SLERF penalty value is to multiply the estimated SCDF by a Seismic Conditional Large Early Release Probability (SCLERP) based on information from the HNP SPRA.

Input and Assumptions

<u>Hazard Curve</u>:

The HNP seismic hazard is defined by the seismic hazard curve that was used in the HNP seismic hazard screening report response to Near Term Task Force (NTTF) Recommendation 2.1, as well as in the development of the recent HNP SPRA (Reference [22]).

<u>PGA Metric</u>:

The ground motion metric used to define the seismic hazard in this analysis is peak ground acceleration (PGA). Other spectral frequency (Hz) curves are considered and discussed.

Plant-Level Seismic Fragility:

The assumed limiting plant level seismic capacity used in the Hatch seismic penalty calculation has a high confidence of low probability of failure (HCLPF) value of 0.30g PGA. The basis for this value is the HNP IPEEE (Reference [7]) seismic analysis. The HNP IPEEE assessed HNP structures, systems and components (SSCs) associated with HNP SMA (seismic margins analysis) success paths to a review level earthquake (RLE) value of 0.30g PGA in accordance with NRC guidance NUREG-1407 (Reference [6]). The Electric Power Research Institute (EPRI) NP-6041 seismic margin assessment methodology (Reference [29]) was used for the Hatch IPEEE seismic analysis.

The uncertainty parameter for seismic capacity is represented by a composite beta factor (βc). Past LAR seismic penalty calculations have often used the estimated Bc cited in Reference [32] by the NRC in Table C-2 of the GI-199 risk assessment (such as Bc=0.4 cited for the Hatch plant in Reference [32]). The Hatch TSTF-505 seismic penalty calculation uses a Bc=0.3 based on insights from the Hatch IPEEE SMA and recommendations from NEI 12-06, Table H.1 (Reference [30]) that state Bc=0.3 is a reasonable lower bound value for use in simplified SCDF estimations and is reflective of relay chatter, block walls and other brittle seismic induced failure modes. The Bc=0.3 value produces a higher convolved SCDF than would use of the Bc=0.4 cited in Table C-2 of Reference [32].

Convolution to Determine SCDF:

The estimation of SCDF in this calculation is performed by a mathematical convolution of the PGA based seismic hazard curve and the HNP PGA based plant level fragility from Reference [7]. This convolution estimation approach is a common analysis in approximating an SCDF for use in risk-informed decision making as well as is common in TSTF-505 LARs.

SLERF:

The HNP SLERF for this risk evaluation is obtained by multiplying the calculated SCDF by a seismic conditional large early release probability (SCLERP). The SCLERP is estimated using information from the HNP SPRA (Reference [22]).

Calculations

The general approach to estimation of the SCDF is to use the plant level HCLPF and convolve the corresponding failure probabilities as a function of seismic hazard level with the seismic hazard curve frequencies of occurrence. SCLERP information from the HNP SPRA is used to calculate the SLERF estimate. The key elements of the SCDF and SLERF seismic penalty calculations are discussed below.

The SCDF from the HNP SPRA (Reference [22]) is provided as additional information to show the reasonableness of the SCDF produced by the plant HCLPF convolution calculation.

Seismic Hazard and Intervals

The data points of the seismic hazard curve in units of g (PGA) from Reference [22] are shown in Table E4-1. The mean fractile occurrence frequencies of Table E4-1 are used in the calculations. Since past industry seismic penalty calculations have used the PGA hazard curve and the majority of SPRAs (including the HNP SPRA) use PGA, the PGA seismic hazard curve was selected for use in the seismic penalty calculations. EPRI SPRA guidelines [26] and the ASME/ANS PRA Standard [17] appropriately allow use of either PGA or other frequencies (Hz) to characterize the seismic hazard input to seismic risk calculations. The PGA metric was also identified as the controlling frequency Hz curve for the Hatch plant in Table D-1 of the NRC GI-199 risk assessment (Reference [33]). The effect on the SCDF convolution result from using different spectral hazard curves is examined later in this section and PGA is concluded to remain reasonable for use in the seismic penalty calculation.

To facilitate calculation of the HNP fragility probability at each seismic hazard interval, a representative g-level is calculated for each interval. The representative g-level for the seismic hazard intervals is calculated using a geometric mean approach (i.e., the square root of the product of the g-level values at the beginning and end of a given interval). For the final open-ended seismic interval, the representative g-level is estimated by multiplying the final g-level by a factor of 1.1. However, the precision of the representative magnitude used for the final open-ended seismic interval in the SCDF convolution is immaterial given that the calculated conditional failure probability of the preceding intervals is already 1.0 and the contribution from the final interval has a minor contribution to the overall SCDF estimate (refer to final rows in Table E4-3).

The seismic hazard interval annual initiating event frequency is calculated (except for the final interval) by subtracting the mean exceedance frequency associated with the g-interval (high) end point from the mean exceedance frequency associated with the g-interval beginning point. The frequency of the last seismic hazard interval is the exceedance frequency at the beginning point of that interval.

The portion of the HNP seismic hazard frequency below the 0.075g point for the start of the first interval, which is consistent with the HNP operating basis earthquake (OBE), is a non-significant contribution to the calculated SCDF and SLERF.

Table E4-1 - Seismic Hazard Data for HNP Used in SCDF Penalty Calculation
(from Reference [22] Table 2-1)

PGA (g)	0.16	0.50	Mean	0.84
0.0724	6.06E-05	1.68E-04	3.36E-04	5.48E-04
0.1059	2.16E-05	6.36E-05	1.47E-04	2.33E-04
0.1549	7.14E-06	2.28E-05	5.69E-05	8.72E-05
0.2100	2.23E-06	9.69E-06	2.41E-05	3.02E-05
0.3071	6.30E-07	3.17E-06	7.25E-06	9.65E-06
0.4162	2.06E-07	1.22E-06	2.54E-06	3.61E-06
0.5229	8.28E-08	5.63E-07	1.11E-06	1.67E-06
0.6088	4.40E-08	3.29E-07	6.30E-07	9.88E-07
0.7087	2.29E-08	1.89E-07	3.57E-07	5.82E-07
0.8251	1.17E-08	1.07E-07	2.03E-07	3.42E-07
0.8903	5.93E-09	6.02E-08	1.53E-07	2.63E-07
1.0365	2.94E-09	3.37E-08	8.79E-08	1.55E-07
1.1184	2.06E-09	2.52E-08	6.69E-08	1.19E-07
1.2067	1.43E-09	1.88E-08	5.11E-08	9.18E-08
1.3020	9.90E-10	1.41E-08	3.90E-08	7.07E-08
1.4049	6.79E-10	1.05E-08	2.98E-08	5.45E-08
1.5158	4.62E-10	7.77E-09	2.28E-08	4.20E-08
1.6356	3.12E-10	5.75E-09	1.74E-08	3.23E-08
1.7648	2.08E-10	4.23E-09	1.33E-08	2.48E-08
1.9042	1.37E-10	3.09E-09	1.01E-08	1.90E-08
2.0546	8.95E-11	2.24E-09	7.61E-09	1.44E-08
2.2169	5.75E-11	1.61E-09	5.71E-09	8.25E-09
2.3920	3.65E-11	1.15E-09	4.26E-09	6.18E-09
2.5809	2.28E-11	8.05E-10	3.14E-09	4.58E-09
2.7848	1.40E-11	5.60E-10	2.30E-09	3.37E-09
3.0048	8.45E-12	3.84E-10	1.66E-09	2.46E-09

Seismic Failure Probabilities

The seismic failure probability of the HNP limiting plant level fragility for each hazard interval is calculated using the following equations:

Fragility (i.e., failure probability) = Φ [ln(A/Am)/ßc], where:

- Φ is the standard lognormal distribution function
- A is the g level in question
- Am is the median seismic capacity

HCLPF and Am are related as follows: Am = HCLPF / exp (-2.33 x ßc)

The above fragility relationships are used to determine the plant level seismic-induced failure probability as a function of seismic hazard interval. Table E4-2 shows the HNP limiting plant level seismic fragility statistics.

Table E4-2
HNP Limiting Plant Level Seismic Fragility Parameters

Source	HCLPF	Am	ßc
Hatch 1996 IPEEE SMA	0.30g PGA	0.60	0.30

Seismic Core Damage Frequency

The SCDF for each hazard interval is computed as the product of the hazard interval initiating event frequency (/yr) and the plant level seismic fragility failure probability for that same hazard interval. The results per hazard interval are then straight summed to produce the overall total SCDF across the hazard curve. The SCDF convolution calculation is summarized in Table E4-3, which shows the total estimated SCDF is 1.18E-06/yr.

Table E4-3 - Convolution Summary of HNP Seismic CDF

Peak Ground Acceleration (g)	Mean Exceedance Frequency (/yr)	Hazard Interval Representative Magnitude (geo. mean, g PGA)	Hazard Interval Fragility (Mean)	Hazard Interval Occurrence Frequency (/yr)	Convolved Frequency (/yr)
0.0724	3.36E-04	0.0876	6.18E-11	1.89E-04	1.17E-14
0.1059	1.47E-04	0.1281	1.19E-07	9.01E-05	1.07E-11
0.1549	5.69E-05	0.1804	2.84E-05	3.28E-05	9.30E-10
0.2100	2.41E-05	0.2540	1.95E-03	1.69E-05	3.29E-08
0.3071	7.25E-06	0.3575	4.05E-02	4.71E-06	1.91E-07
0.4162	2.54E-06	0.4665	1.95E-01	1.43E-06	2.79E-07
0.5229	1.11E-06	0.5642	4.11E-01	4.80E-07	1.97E-07
0.6088	6.30E-07	0.6569	6.11E-01	2.73E-07	1.67E-07
0.7087	3.57E-07	0.7647	7.85E-01	1.54E-07	1.21E-07
0.8251	2.03E-07	0.8571	8.79E-01	5.00E-08	4.39E-08
0.8903	1.53E-07	0.9606	9.39E-01	6.51E-08	6.12E-08
1.0365	8.79E-08	1.0767	9.73E-01	2.10E-08	2.04E-08
1.1184	6.69E-08	1.1617	9.85E-01	1.58E-08	1.56E-08
1.2067	5.11E-08	1.2534	9.93E-01	1.21E-08	1.20E-08
1.3020	3.90E-08	1.3525	9.96E-01	9.20E-09	9.17E-09
1.4049	2.98E-08	1.4593	9.98E-01	7.00E-09	6.99E-09
1.5158	2.28E-08	1.5746	9.99E-01	5.40E-09	5.40E-09
1.6356	1.74E-08	1.6990	1.00E+00	4.10E-09	4.10E-09
1.7648	1.33E-08	1.8332	1.00E+00	3.20E-09	3.20E-09
1.9042	1.01E-08	1.9780	1.00E+00	2.49E-09	2.49E-09
2.0546	7.61E-09	2.1342	1.00E+00	1.90E-09	1.90E-09
2.2169	5.71E-09	2.3028	1.00E+00	1.45E-09	1.45E-09
2.3920	4.26E-09	2.4847	1.00E+00	1.12E-09	1.12E-09
2.5809	3.14E-09	2.6809	1.00E+00	8.40E-10	8.40E-10
2.7848	2.30E-09	2.8927	1.00E+00	6.40E-10	6.40E-10
3.0048	1.66E-09	3.3053	1.00E+00	1.66E-09	1.66E-09
Total Convolved SCDF Across PGA Hazard Curve (1/yr): **1.18E-06**					

Comparison to HNP SPRA SCDF

The seismic PRA performed for HNP shows that the point estimate mean seismic CDF is 6.8E-07/yr for Unit 1 and 5.6E-07/yr for Unit 2 (Reference [22]). The estimated SCDF from the Unit 1 HNP SPRA (6.8E07/yr) is less than the estimated SCDF shown in Table E4-3 (1.18E06/yr) when using the convolution methodology. This comparison shows that the simple convolution method using the plant level seismic fragility determined from the HNP IPEEE SMA methodology produces a reasonable and conservative (in comparison to a realistic SPRA) estimate of SCDF.

To evaluate the effect of using the different available hazard curves from the HNP PSHA [23], the seismic penalty calculation has been re-performed with different hazard curves in the 2.5 Hz to 10 Hz range (i.e., the range of spectral values that would be used in an SPRA as an alternative to PGA). The plant-level fragility HCLPF value is adjusted per the Hatch IPEEE seismic margins earthquake (SME) ground response spectra curve (Figure 3.1-11 of Reference [7]) for each convolution sensitivity case (keeping Bc=0.3 for each case). The SCDF from each case is summarized below:

	PGA	10 Hz	5 Hz	2.5 Hz
Plant-Level Fragility (Am):	0.60	1.27	1.27	1.27
Convolved SCDF:	**1.18E-6**	**1.36E-6**	**1.37E-6**	**1.34E-6**

As can be seen, the resulting convolved SCDFs from the above sensitivity cases are very similar (differing by approximately 15%). If the ground motion response spectra (GMRS) from the 2014 HNP PSHA [23] were used, the difference in the calculated SCDFs would be even lower (<10%). As such, the seismic penalty SCDF (1.18E-6/yr) associated with the 100 Hz (PGA) range is reasonable and will be used in RICT calculations.

Seismic Large Early Release Frequency

The HNP SLERF for the TSTF-505 program is obtained by multiplying the estimated SCDF shown in Table E4-3 (1.18E-06/yr) by a seismic conditional large early release probability (SCLERP). This SCLERP is an averaged value covering the spectrum of SCDF accident sequence types (different accident sequence types have different individual CLERP values). An estimate of the SCLERP is obtained based on the results from the HNP SPRA (Reference [22]). The HNP SPRA is judged to be of adequate technical quality to serve as the basis for a reasonable estimate for SCLERP. A peer review of the HNP SPRA (Reference [25]) has been performed as well as an F&O Closure Review (Reference [28]) to ensure the technical quality of the model. Following the F&O Closure Review, all Finding-level F&Os were evaluated to be closed.

The HNP SPRA shows that the point estimate mean seismic LERF is 1.4E-07/yr for both Unit 1 and Unit 2. The limiting seismic LERF of 1.4E-07/yr is approximately 25% of the Unit 2 seismic CDF of 5.6E-07/yr; that is,

$$\text{Seismic CLERP} = (1.4\text{E-07} \div 5.6\text{E-07}) = 0.25$$

Based on the information from the HNP SPRA, an SCLERP value of 0.25 is chosen to support the HNP TSTF-505 program. Structural failure of containment and containment isolation failure are included in this SCLERP value. Such SSCs were screened out from the IPEEE SMA as sufficiently rugged (e.g., PCIV seismic HCLPF capacities are significantly higher than the 0.3g SMA RLE). In addition, both random and seismic induced failures of the containment isolation function are inherent in the calculation of this SCLERP value from the HNP SPRA results.

Therefore, the estimate of SLERF to support the HNP TSTF-505 program is:

$$\text{SLERF} = [1.18\text{E-6/yr } (\text{SCDF}_{\text{Table E4-3}}) \times 0.25 \text{ (SCLERP)}] = 2.95\text{E-7/yr}$$

The above estimated SLERF will be used for the base case SLERF value for RICT calculations that apply when the primary containment is inerted. If a RICT is being entered during a period when the primary containment is de-inerted, a different SLERF penalty of 1.18E-06/yr (SCDF = SLERF, SCLERP = 1.0) will be applied to address the increased potential for hydrogen deflagration events in the primary containment. This is deemed conservative since the Hatch Level 2 FPIE PRA [27] credits steam inerting with an estimated 0.5 probability (basic event BCZPH-STMINRTF--) that the steam inerting would fail to mitigate the hydrogen deflagration event. Therefore, a CLERP of ~0.5 could apply for de-inerted conditions. Given the uncertainty in the steam inerting value of 0.5 and the small timeframe for potential de-inerted conditions, a conservative assumption for SCLERP of 1.0 will apply when the primary containment is de-inerted.

To summarize:

- SCLERP of 0.25 will apply when the primary containment is inerted.
- SCLERP of 1.0 will apply when the primary containment is de-inerted.

Application of SLERF in RICT Calculations

The SLERF estimate documented above is conservatively used in the RICT process. Conservatism in the RICT process derives from the proposed approach to apply the total estimated annual seismic LERF as a delta SLERF in each RICT calculation, regardless of the duration of the completion time. The total estimated annual seismic CDF and LERF will be applied starting at time zero for each RICT calculation.

Summary

Estimates of SCDF and SLERF have been derived for use in the HNP TSTF-505 program. Since the estimates are intended to be treated as conservative values in the RICT calculations for that program, the results for the case of plant level HCLPF = 0.30g PGA with ßc = 0.3 will be used.

Seismic CDF = 1.18E-6/yr

Seismic LERF = 2.95E-7/yr (inerted containment)

Seismic LERF = 1.18E-6/yr (de-inerted containment)

6 Evaluation of External Event Challenges and IPEEE Update Results

This Section provides an evaluation of other external hazards. The results of the assessment of these hazards is provided in Table E4-4. Table E4-5 provides the summary criteria for screening of the hazards listed in Table E4-4.

Hazard Screening

The IPEEE for Hatch Units 1 and 2 provides an assessment of the risk to Hatch associated with other external hazards. Additional analyses have been performed since the IPEEE to provide updated risk assessments of various hazards, such as aircraft impacts, industrial facilities and pipelines, and external flooding. Appendix 6-A of the PRA Standard (Reference [17]) and EPRI 3002010357 (Reference [18]) were used as sources for the list of hazards. These analyses are documented in the FSAR and H-RIE-OEE-U00, “Hatch Other External Events PRA Screening” (Reference [8]).

Table E4-4 reviews and provides the bases for the screening of external hazards, identifies any challenges posed, and identifies any additional treatment of these challenges, if required. The conclusions of the assessment, as documented in Table E4-4, assure that the hazard either does not present a design-basis challenge to Hatch or is adequately addressed in the PRA.

Impacts to RICT

In the application of Risk-Informed Completion Times, a significant consideration in the screening of external hazards is whether particular plant configurations could impact the decision on whether a particular hazard that screens under the normal plant configuration and the base risk profile would still screen given the particular configuration. The external hazards screening evaluation for Hatch has been performed accounting for such configuration-specific impacts. This evaluation involves several steps.

As a first step in this screening process, hazards that screen for one or more of the following criteria (as defined in Table E4-5) still screen regardless of the configuration, as these criteria are not dependent on the plant configuration.

- The occurrence of the event is of sufficiently low frequency that its impact on plant risk does not appreciably impact CDF or LERF. (Criterion C2)
- The event cannot occur close enough to the plant to affect it. (Criterion C3)
- The event which subsumes the external hazard is still applicable and bounds the hazard for other configurations (Criterion C4)
- The event develops slowly, allowing adequate time to eliminate or mitigate the hazard or its impact on the plant. (Criterion C5)

The next step in the screening process is to consider the remaining hazards (i.e., those not screened per the above criteria) to consider the impact of the hazard on the plant given particular configurations for which a RICT is allowed. For hazards for which the ability to achieve safe shutdown may be impacted by one or more such plant configurations, the impact of the hazard to particular SSCs is assessed and a basis for the screening decision applicable to configurations impacting those SSCs is provided.

As noted above, the configurations to be evaluated are those involving unavailable SSCs whose LCOs are included in the RICT program.

Table E4-4: Evaluation of Other External Hazards				
Hazard	**Definition**	**Screened (Y/N)**	**Screening Criterion**	**Hatch Response**
Aircraft impacts	A direct or indirect (i.e. skidding impact) collision of a portion of or an entire aircraft with one or more structures at or in the area surrounding the plant site.	Y	PS2, PS4	There are no airports within 10 miles of the plant. There are no military facilities or military training routes close to the plant. Airports nearby (all greater than 10 miles from the plant) are small municipal fields not used for scheduled commercial service (Section 2.2.2.5, Reference [9]). This was also confirmed using the most recent airfield data (Reference [19]). Based on the low likelihood of aircraft crash at the site, the CDF is estimated to be less than 1E-6/yr. Based on this review, the Aircraft impacts hazard can be considered to be negligible. There are no configuration-specific considerations for this hazard. This hazard can be excluded from the RICT program evaluation.
Avalanche	A rapid flow of a large mass of accumulated frozen precipitation down a sloped surface.	Y	C3	Topography is such that no avalanche is possible. Based on this review, the Avalanche hazard can be considered to be negligible. There are no configuration-specific considerations for this hazard. This hazard can be excluded from the RICT program evaluation.
Biological events	The accumulation or deposition of vegetation or organisms (e.g., zebra	Y	C5	Hazard is slow to develop and there is sufficient time to eliminate the source of the threat or to provide an adequate response.

Table E4-4: Evaluation of Other External Hazards				
Hazard	**Definition**	**Screened (Y/N)**	**Screening Criterion**	**Hatch Response**
	mussels, clams, fish) on an intake structure or internal to a system that uses an intake structure.			Based on this review, the Biological Events hazard can be considered to be negligible. There are no configuration-specific considerations for this hazard. This hazard can be excluded from the RICT program evaluation.
Coastal erosion	The wearing away of a shoreline due to wave action, tidal currents, wave currents, drainage, or winds.	Y	C3	Not applicable to the site because of inland location. Based on this review, the Coastal Erosion hazard can be considered to be negligible. There are no configuration-specific considerations for this hazard. This hazard can be excluded from the RICT program evaluation.
Drought	An extended period of months or years when a region experiences a deficiency in its surface or underground water supply	Y	C1, C5	The main concern with drought at Hatch is low river flow. Section 2.4.11 of the FSAR (Reference [9]) describes considerations for low river flow at Hatch, including river stages and historical data. Technical specifciations and procedures exist to monitor and mitigate the effects of a drought (References [16] and [20]). Also see Low Lake Level or River Stage. Based on this review, the Drought hazard can be considered to be negligible. There are no configuration-specific considerations for this hazard. This hazard can be excluded from the RICT program evaluation.

Table E4-4: Evaluation of Other External Hazards				
Hazard	**Definition**	**Screened (Y/N)**	**Screening Criterion**	**Hatch Response**
External Flooding	Accumulation of excessive water on the station grounds from various sources including Local Intense Precipitation and Snow Accumulation	Y	C1	See Section 4 of this enclosure for a detailed evaluation of this hazard. The flooding hazard was reevaluated following present-day guidance in response to the Near Term Task Force (NTTF) Recommendation 2.1 for flooding. The calculations demonstrate that Hatch Unit 1 and 2 safety related SSCs do not experience impacts from any of the external flood causing mechanisms. The Flooding Focused Evaluation (ML17173A777) demonstrates adequate available physical margin between any safety-related SSCs and the effects of an external flood at the site. The NRC staff performed an audit on the evaluation then subsequently issued a Staff Assessment (ML18030B076) confirming no further actions were necessary for the external flood response to NTTF Rec. 2.1. Based on this review, the External Flooding hazard can be considered to be negligible. There are no configuration-specific considerations for this hazard. This hazard can be excluded from the RICT program evaluation.

Table E4-4: Evaluation of Other External Hazards				
Hazard	**Definition**	**Screened (Y/N)**	**Screening Criterion**	**Hatch Response**
Extreme Wind or Tornado	Excessive winds, straight-line or tornadic	Y	C1	See Section 3 for the results of the screening evaluation for this hazard. The design of the plant provides protection for components necessary for safe shutdown against extreme winds (including hurricanes), tornados, and associated missiles. Based on this review, the Extreme Wind or Tornado hazard can be considered to be negligible. There are no configuration-specific considerations for this hazard. This hazard can be excluded from the RICT program evaluation.
Fog	Water droplets suspended in the atmosphere at or near the Earth's surface that limit visibility.	Y	C1, C4	There is negligible impact on the plant for this hazard. It may affect the frequency of other events (aircraft or other transportation accidents) and is accounted for in those hazards. Based on this review, the Fog hazard can be considered to be negligible. There are no configuration-specific considerations for this hazard. This hazard can be excluded from the RICT program evaluation.
Forest or Range Fire	Fires originating from outside the plant site boundary that are caused by the uncontrolled	Y	C1, C3	FSAR Section 2.2.3.1 (Reference [9]) states that the terrain and ground cover surrounding Hatch are such that they are not conducive to forest or brush fires.

Table E4-4: Evaluation of Other External Hazards				
Hazard	**Definition**	**Screened (Y/N)**	**Screening Criterion**	**Hatch Response**
	combustion of vegetation (e. g. , trees, grasses, brush, etc.)			Based on this review, the Forest or Range Fire hazard can be considered to be negligible. There are no configuration-specific considerations for this hazard. This hazard can be excluded from the RICT program evaluation.
Frost	A thin layer of ice crystals that form on the ground or the surface of an earthbound object when the temperature of the ground or surface of the object falls below freezing.	Y	C1	There is negligible impact on the plant due to frost. Snow and ice cover bounds this hazard. Based on this review, the Frost hazard can be considered to be negligible. There are no configuration-specific considerations for this hazard. This hazard can be excluded from the RICT program evaluation.
Hail	Showery precipitation in the form of irregular pellets or balls of ice.	Y	C1	Hail is bounded by other events for which the plant is designed. Tornado missile protection features, structural walls and roofs are adequate to withstand the impact of hail. Based on this review, the Hail hazard can be considered to be negligible. There are no configuration-specific considerations for this hazard. This hazard can be excluded from the RICT program evaluation.

Table E4-4: Evaluation of Other External Hazards

Hazard	Definition	Screened (Y/N)	Screening Criterion	Hatch Response
High summer temperature	High abnormal ambient temperatures.	Y	C1, C5	At Savannah, the record maximum was 105°F in July 1879. At Macon a record maximum temperature of 106°F was recorded in June 1954 (Section 2.3.2.2 of Reference [9]). The HVAC systems are designed to maintain prescribed building temperatures during outside temperature variations between 20°F and 95°F (FSAR Section 9.4). Even if the maximum temperature exceeds the design limits for HVAC systems, such exceedance lasts only for a brief period, and given the thermal inertia of the concrete structures where safety-related equipment is located, equipment functionality is maintained. High summer temperatures are of negligible impact on the plant. This phenomenon provides large amount of time for preparation (weather forecast) with time for implementation of appropriate mitigation actions (e.g. plant power reduction or shutdown). Based on this review, the High Summer Temperature hazard can be considered to be negligible. There are no configuration-specific considerations for this hazard. This hazard can be excluded from the RICT program evaluation.

Table E4-4: Evaluation of Other External Hazards

Hazard	Definition	Screened (Y/N)	Screening Criterion	Hatch Response
High tide, Lake Level, or River Stage	The periodic maximum rise of sea level resulting from the combined effects of the tidal gravitational forces exerted by the Moon and Sun and the rotation of the Earth.	Y	C1, C3	The site is located inland on the Altamaha River, so high tide or lake level do not apply to Hatch. See the External Flooding evaluation which includes river flooding. Based on this review, the High Tide, Lake Level, or River Stage hazard can be considered to be negligible. There are no configuration-specific considerations for this hazard. This hazard can be excluded from the RICT program evaluation.
Hurricane	An extremely large, powerful, and destructive storm resulting in strong winds, excessive rainfall, high waves, storm surge, and tornados.	Y	C1, C3	The site is located inland, more than 60 miles from the coast. Any flooding associated with the hurricane is addressed in External Flooding. See the Extreme Winds evaluation for hurricane wind effects. Based on this review, the Hurricane hazard can be considered to be negligible. There are no configuration-specific considerations for this hazard. This hazard can be excluded from the RICT program evaluation.
Ice cover	The accumulation of frozen water on bodies of water (e.g., lakes, rivers, etc.) or on structures, systems, and components.	Y	C3	Icing does not normally occur on the Altamaha River at Hatch. Based on this review, the Ice Cover hazard can be considered to be negligible.

Table E4-4: Evaluation of Other External Hazards				
Hazard	**Definition**	**Screened (Y/N)**	**Screening Criterion**	**Hatch Response**
				There are no configuration-specific considerations for this hazard. This hazard can be excluded from the RICT program evaluation.
Industrial or military facility accident	An accident at an offsite industrial or military facility such as a release of toxic gases, a release of combustion products, a release of radioactivity, an explosion, or the generation of missiles.	Y	C3	The FSAR Section 2.2.2.1 (Reference [9]) states that within a 5-mile radius of Hatch, there are no manufacturing plants, chemical plants, refineries, storage facilities, mining and quarrying operations, military bases, missile sites, transportation facilities, oil and gas wells, or underground gas storage facilities. Also, there are no known military firing or bombing ranges or aircraft low-level flight holding or landing patterns near the site area. Based on this review, the Industrial or Military Facility Accident hazard can be considered to be negligible. There are no configuration-specific considerations for this hazard. This hazard can be excluded from the RICT program evaluation.
Internal Flooding	Excessive water accumulation internal to the station buildings	N	Detailed PRA	The Hatch internal events PRA includes evaluation of risk from internal flooding events.
Internal Fire	Fire events that are internal to the station buildings	N	Detailed PRA	The Hatch Fire PRA addresses risk from internal fire events.

Table E4-4: Evaluation of Other External Hazards				
Hazard	**Definition**	**Screened (Y/N)**	**Screening Criterion**	**Hatch Response**
Landslide	A rapid flow of a large mass of earth, rock, or material other than accumulated frozen precipitation down a sloped surface.	Y	C3	There are no steep hills in the vicinity of the plant. Based on this review, the Landslide hazard can be considered to be negligible. There are no configuration-specific considerations for this hazard. This hazard can be excluded from the RICT program evaluation.
Lightning	An electrical discharge from a cloud to the ground or Earth-bound object.	Y	C1, C4	Lightning protection is provided as part of the plant design. Although lightning strikes may result in loss of offsite power or plant trip, these events are included in the Hatch internal events PRA. Based on this review, the Lightning hazard can be considered to be negligible. There are no configuration-specific considerations for this hazard. This hazard can be excluded from the RICT program evaluation.
Low Lake Level or River Stage	A decrease in the water level of the lake or river used for power generation.	Y	C1, C5	Section 2.4.11 of the FSAR (Reference [9]) describes considerations for low river flow at Hatch, including river stages and historical data. Technical Specifications and operational procedures are in place to monitor and mitigate this hazard (References [16] and [20]). If the river level becomes too low, the ultimate heat sink (UHS) is declared inoperable and the requirements of Tech Spec 3.7.2.F apply (Reference [16]).

Table E4-4: Evaluation of Other External Hazards

Hazard	Definition	Screened (Y/N)	Screening Criterion	Hatch Response
				Based on this review, the Low Lake Level or River Stage hazard can be considered to be negligible. There are no configuration-specific considerations for this hazard. This hazard can be excluded from the RICT program evaluation.
Low winter temperature	Low abnormal ambient temperatures.	Y	C1, C5	At Savannah, the record minimum temperature was 8°F in February 1899. At Macon a record low of 3°F occurred in January 1966 (Section 2.3.2.2 of Reference [9]). The HVAC systems are designed to maintain prescribed building temperatures during outside temperature variations between 20°F and 95°F (FSAR Section 9.4). Even if the minimum temperature exceeds the design limits for HVAC systems, such exceedance lasts only for a brief period, and given the thermal inertia of the concrete structures where safety-related equipment is located, equipment functionality is maintained. Based on this review, the Low Winter Temperature hazard can be considered to be negligible. There are no configuration-specific considerations for this hazard. This hazard can be excluded from the RICT program evaluation.

Table E4-4: Evaluation of Other External Hazards				
Hazard	**Definition**	**Screened (Y/N)**	**Screening Criterion**	**Hatch Response**
Meteorite or Satellite Impact	A meteoroid or artificial satellite that releases energy due to its disintegration in the atmosphere above the Earth's surface, direct impact with the Earth's surface, or a combination of these effects.	Y	PS4	This hazard is of negligible likelihood of impact to the site (very low event frequency). Based on this review, the Meteorite or Satellite impact hazard can be considered to be negligible. There are no configuration-specific considerations for this hazard. This hazard can be excluded from the RICT program evaluation.
Pipeline accident	An accident involving the rupture of a pipeline carrying hazardous materials or toxic gases.	Y	C3	Per Section 2.2.2.3 of the FSAR (Reference [9]), a Southern Natural Gas Company pipeline is located within approximately 4-1/2 miles of Hatch. The pipeline is sufficiently distant from Hatch such that any potential leak or detonation would not affect Hatch. Based on this review, the Pipeline Accident hazard can be considered to be negligible. There are no configuration-specific considerations for this hazard. This hazard can be excluded from the RICT program evaluation.
Release of Chemicals in Onsite Storage	An onsite accident involving the storage or handling of hazardous materials such as a release of toxic gases, a release of combustion products, a release of	Y	PS2	FSAR Section 2.2.3.1 describes the storage and handling of toxic chemicals on the site (Reference [9]). The most recent periodic re-evaluation perfomed for Plant Hatch (Reference [21]) determined that the chemicals stored onsite do not pose a threat to main control room habitability.

Table E4-4: Evaluation of Other External Hazards

Hazard	Definition	Screened (Y/N)	Screening Criterion	Hatch Response
	radioactivity, an explosion, or the generation of missiles. In this context, an onsite release of radioactivity is assumed to be associated with low-level radioactive waste.			Based on this review, the Release of Chemicals in Onsite Storage hazard can be considered to be negligible. There are no configuration-specific considerations for this hazard. This hazard can be excluded from the RICT program evaluation.
River diversion	The redirection of all or a portion of river flow by natural causes (e.g. a riverine embankment landslide) or intentionally (e.g. power production, irrigation, etc.).	Y	C5	FSAR Section 2.4.9 (Reference [9]) states that the river channel is relatively straight for a distance of 1.5 miles below US Highway No. 1 and that there are no meanders at the plant site which could cut across and divert the flow. The US No 1 bridge and highway fill serve to control the channel alignment to its present location. No major changes have occurred since the river was surveyed in 1900. Any change in the river's course would be slow, allowing time to respond. Based on this review, the River Diversion hazard can be considered to be negligible. There are no configuration-specific considerations for this hazard. This hazard can be excluded from the RICT program evaluation.

Table E4-4: Evaluation of Other External Hazards				
Hazard	**Definition**	**Screened (Y/N)**	**Screening Criterion**	**Hatch Response**
Sand or Dust Storm	A strong wind storm with airborne particles of sand and dust.	Y	C3	The plant site not located near any large sources of small airborne particles. Based on this review, the Sand or Dust Storm hazard can be considered to be negligible. There are no configuration-specific considerations for this hazard. This hazard can be excluded from the RICT program evaluation.
Seiche	An oscillation of the surface of a landlocked body of water, such as a lake, that can vary in period from minutes to several hours.	Y	C3	There is no large body of water close the site for this event. Based on this review, the Seiche hazard can be considered to be negligible. There are no configuration-specific considerations for this hazard. This hazard can be excluded from the RICT program evaluation.
Seismic activity	A sudden release of energy from the Earth's crust resulting in strong ground motion.	N	N/A	See information in Section 5 of this Enclosure.
Snow	The accumulation of snow on structures, systems, and components	Y	C1	The 50 year snow load is estimated as less than 5 pounds per square foot (psf) (Reference [8]). The design basis roof live load for seismic Category I structures is 20 psf per FSAR Table 3.8-13 (Reference [9]). Based on this review, the Snow hazard can be considered to be negligible.

Table E4-4: Evaluation of Other External Hazards				
Hazard	**Definition**	**Screened (Y/N)**	**Screening Criterion**	**Hatch Response**
				There are no configuration-specific considerations for this hazard. This hazard can be excluded from the RICT program evaluation.
Soil shrink-swell	The relative change in volume of the soil as a result of the type of soil and the amount of moisture.	Y	C1, C5	Sections 2.5 and 2A of the FSAR describe the site soil and foundations. Section 2A.5.3 describes the building settlement monitoring that was in place from 1980 to 2006. It was determined in January 2007 that settlement curves were essentially flat and had been for 25 years (Reference [9]). Based on this review, the Soil Shrink-Swell hazard can be considered to be negligible. There are no configuration-specific considerations for this hazard. This hazard can be excluded from the RICT program evaluation.
Storm surge	An abnormal rise in sea level accompanying a hurricane or other intense storm, whose height is the difference between the observed level of the sea surface and the level that would have occurred in the absence of the intense storm.	Y	C3	The site is located inland, more than 60 miles from the coast. Based on this review, the Storm Surge hazard can be considered to be negligible. There are no configuration-specific considerations for this hazard. This hazard can be excluded from the RICT program evaluation.

Table E4-4: Evaluation of Other External Hazards				
Hazard	**Definition**	**Screened (Y/N)**	**Screening Criterion**	**Hatch Response**
Toxic Gas	An onsite accident involving the storage or handling of hazardous materials such as a release of toxic gases, a release of combustion products, a release of radioactivity, an explosion, or the generation of missiles. In this context, an onsite release of radioactivity is assumed to be associated with low-level radioactive waste.	Y	C4	Toxic gas is covered under release of chemicals in onsite storage, industrial or military facility accident, and transportation accident. Based on this review, the Toxic Gas hazard can be considered to be negligible. There are no configuration-specific considerations for this hazard. This hazard can be excluded from the RICT program evaluation.
Transportation accidents	An accident involving damage to a land-based or marine vehicle transporting hazardous materials that may result in a release of toxic gases, a release of combustion products, or an explosion.	Y	C3	Section 2.2.3.1 of the FSAR discusses postulated accidents on the transportation routes near the site (U.S. Highway No. 1 approximately 3400 ft from plant buildings, railroad line approximately 10 miles from the site, and the Athamaha River). Potential accidents on Highway 1 are far enough from the plant to preclude damage to the plant from explosions or the presence of hazardous levels of toxic fumes. There is no commercial barge traffic on the Athamaha River. Based on this review, the Transportation Accident hazard can be considered to be negligible.

Table E4-4: Evaluation of Other External Hazards				
Hazard	**Definition**	**Screened (Y/N)**	**Screening Criterion**	**Hatch Response**
				There are no configuration-specific considerations for this hazard. This hazard can be excluded from the RICT program evaluation.
Tsunami	A sea wave of local or distant origin that results from large-scale seafloor displacements associated with large earthquakes or major submarine slides or landslides.	Y	C3	The site is located inland, more than 60 miles from the coast. Based on this review, the Tsunami hazard can be considered to be negligible. There are no configuration-specific considerations for this hazard. This hazard can be excluded from the RICT program evaluation.
Turbine-generated missiles	The generation of a high-energy missile that is ejected from the turbine casing resulting from failure of a steam turbine. The turbine-generated missile may be ejected either upward (i.e., high-trajectory missile) which may result in damage to safety-related structures, systems, and components (SSCs) from the falling missile or it may be ejected directly toward safety-related SSCs (i.e., low-trajectory missiles).	Y	PS4	The FSAR Section 10.2.3 (Reference [9]) documents a probabilistic analysis for postulated failures of the main turbines. The annual probability of unacceptable damage resulting from a turbine missile is less than the NRC accepted value of 1E-7. Based on this review, the Turbine-Generated Missiles' hazard can be considered to be negligible. There are no configuration-specific considerations for this hazard. This hazard can be excluded from the RICT program evaluation.

Table E4-4: Evaluation of Other External Hazards				
Hazard	**Definition**	**Screened (Y/N)**	**Screening Criterion**	**Hatch Response**
Volcanic activity	The extrusion of magma from beneath the earth's crust that may be accompanied by the flow of lava and explosion of fragmented material (pulverized pieces of rock, bits of chilled magma), and releases of volcanic ash and dust as well as gases and steam.	Y	C3	The site is not close to any active volcanoes. Based on this review, the Volcanic Activity hazard can be considered to be negligible. There are no configuration-specific considerations for this hazard. This hazard can be excluded from the RICT program evaluation.
Waves	An area of moving water that is raised above the main surface of an ocean, a lake, etc. as a result of the wind blowing over an area of fluid surface.	Y	C1, C4	Waves are included in the external flooding analysis and are not considered a separate hazard. See External Flooding. Based on this review, the Waves hazard can be considered to be negligible. There are no configuration-specific considerations for this hazard. This hazard can be excluded from the RICT program evaluation.

Table E4-5: Progressive Screening Approach for Addressing External Hazards			
Event Analysis	**Criterion**	**Source**	**Comments**
Initial Preliminary Screening	C1. Event damage potential is < events for which plant is designed.	NUREG/CR-2300 and ASME/ANS Standard RA-Sa-2009	
	C2. Event has lower mean frequency and no worse consequences than other events analyzed.	NUREG/CR-2300 and ASME/ANS Standard RA-Sa-2009	
	C3. Event cannot occur close enough to the plant to affect it.	NUREG/CR-2300 and ASME/ANS Standard RA-Sa-2009	
	C4. Event is included in the definition of another event.	NUREG/CR-2300 and ASME/ANS Standard RA-Sa-2009	Not used to screen. Used only to include within another event.
	C5. Event develops slowly, allowing adequate time to eliminate or mitigate the threat.	ASME/ANS Standard RA-Sa-2009	
Progressive Screening	PS1. Design basis hazard cannot cause a core damage accident.	ASME/ANS Standard RA-Sa-2009	
	PS2. Design basis for the event meets the criteria in the NRC 1975 Standard Review Plan (SRP).	NUREG-1407 and ASME/ANS Standard RA-Sa-2009	
	PS3. Design basis event mean frequency is < 1E-5/y and the mean conditional core damage probability is < 0.1.	NUREG-1407 as modified in ASME/ANS Standard RA-Sa-2009	
	PS4. Bounding mean CDF is < 1E-6/y.	NUREG-1407 and ASME/ANS Standard RA-Sa-2009	
Detailed PRA	Screening not successful. PRA needs to meet requirements in the ASME/ANS PRA Standard.	NUREG-1407 and ASME/ANS Standard RA-Sa-2009	

7 Conclusions

Based on this analysis of external hazards for Hatch Units 1 and 2, no additional external hazards other than seismic events need to be added to the existing PRA model. The evaluation concluded that the hazards either do not present a design-basis challenge to Hatch, the challenge is adequately addressed in the PRA, or the hazard has a negligible impact on the calculated RICT and can be excluded. Hatch will apply a seismic "penalty" in the risk evaluations performed as part of the process to calculate a Risk Informed Completion Time (RICT).

The ICDP/ILERP acceptance criteria of 1E-5/1E-6 will be used within the Phoenix Risk Monitor to calculate the resulting RICT and RMAT based on the total configuration-specific delta CDF/LERF attributed to internal events and internal fire, internal flooding, plus the seismic delta CDF/LERF values.

8 References

[1] Nuclear Energy Institute (NEI) Topical Report (TR) NEI 06-09, "Risk-Informed Technical Specifications Initiative 4b, Risk-Managed Technical Specifications (RMTS) Guidelines," Revision 0-A, October 12, 2012 (ADAMS Accession No. ML 12286A322).

[2] Letter from Jennifer M. Golder (NRC) to Biff Bradley (NEI), "Final Safety Evaluation for Nuclear Energy Institute (NEI) Topical Report (TR) NEI 06-09, “Risk-Informed Technical Specifications Initiative 4b, Risk-Managed Technical Specifications (RMTS) Guidelines," May 17, 2007 (ADAMS Accession No. ML071200238).

[3] ASME/ANS RA-Sa-2009, "Standard for Level 1/Large Early Release Frequency Probabilistic Risk Assessment for Nuclear Power Plant Applications," Addendum A to RAS-2008, ASME, New York, NY, American Nuclear Society, La Grange Park, Illinois, February 2009.

[4] NUREG-1855, "Guidance on the Treatment of Uncertainties Associated with PRAs in Risk-Informed Decision Making," Revision 1, March 2017.

[5] NUREG-75/087, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants, LWR Edition," 1975.

[6] NUREG-1407, "Procedural and Submittal Guidance for the Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities," June 1991.

[7] Individual Plant Examination for External Events (IPEEE), Edwin I. Hatch Nuclear Plant, Units 1 and 2, January 26, 1996.

[8] Hatch Nuclear Plant, Calculation Number H-RIE-OEE-U00, "Evaluation of Other External Hazards," Version 2.0, June 26, 2019.

[9] Hatch Unit 1 & 2 Final Safety Analysis Report (FSAR), Rev. 39, May 2021.

[10] Southern Nuclear, SNC826314, "Plant Hatch Tornado Missile Project (TMP) Summary Report," Version 1, August 2018.

[11] Southern Nuclear, SNC799744, "Missile Protection for EDG Fuel Oil Storage Tank Vent Lines".

[12] Southern Nuclear, SNCH-16-042, "PSW Discharge Piping Tornado Missile Evaluation," Version 1.0, December 2016.

[13] NUREG/CR-4461, "Tornado Climatology of the Contiguous United States," Revision 2, February 2007.

[14] NUREG/CR-7005, "Technical Basis for Regulatory Guidance on Design-Basis Hurricane Wind Speeds for Nuclear Power Plants," November 2011.

[15] U.S. Nuclear Regulatory Commission, NUREG/CR-7046, "Design-Basis Flood Estimate for Site Characterization at Nuclear Power Plants in the United States of America," November 2011.

[16] Southern Nuclear Company, Hatch Unit C, 34AB-Y22-002-0, "Naturally Occurring Phenomena," Version 19.1, March 17, 2020.

[17] ASME/ANS RA-Sb-2013, "Addenda to ASME/ANS RA-S-2008, Standard for Level 1/Large Early Release Frequency Probabilistic Risk Assessment for Nuclear Power Plant Applications", September 30, 2013.

[18] Electric Power Research Institute, “External Hazards: Information Compilation and Analysis—2016 New Information Report.” EPRI, Palo Alto, CA: 2017, 3002010357..

[19] Pilot Aviation Information, www.airnav.com.

[20] 40AC-ENG-004-0, "Plant Hatch Drought Contingency Actions," Version 1.1, May 2014.

[21] Southern Nuclear Design Calculation SMNH-13-014, "Control Room Habitability Following Hazardous Chemical Spill," Version 2.0, September 2017.

[22] H-RIE-SEIS-U00-001-002, Seismic Probabilistic Risk Assessment Quantification Report, Revision 5, June 2020.

[23] Edwin I. Hatch Nuclear Plant - Units 1 and 2 Seismic Hazard Reevaluation and Screening for Risk Evaluation, March 31, 2014 (ML14092A017).

[24] Generic Issue 199, "Implications of Updated Probabilistic Seismic Hazard Estimates in Central and Eastern United States on Existing Plants," U.S. NRC Information Notice (IN) 2010-18, September 2, 2010, NRC ADAMS Accession # ML101970221.

[25] H-RIE-SEIS-U00-010-001, Seismic PRA Peer Review Report Using ASME/ANS PRA Standard Requirements.

[26] Electric Power Research Institute (EPRI) TR 3002000709, "Final Report, Seismic Probabilistic Risk Assessment Implementation Guide," December 2013.

[27] H-RIE-IEIF-U01-010, Revision 2, Hatch Unit 1 Level 2 PRA Model, November 2015.

[28] H-RIE-SEIS-U00-010-002, PRA Finding Level and Observation Technical Review & Focused-Scope Peer Review, Revision 1, August 2017.

[29] Electric Power Research Institute (EPRI) NP-6041-SL, A Methodology for Assessment of Nuclear Power Plant Seismic Margin (Revision 1), August 1991.

[30] NEI 12-06, Diverse and Flexible Coping Strategies (FLEX) Implementation Guide, Revision 4, December 2016.

[31] Appendix A, “Seismic Core-Damage Frequency Estimates,” Generic Issue 199 Risk Assessment, August 2010, NRC ADAMS Assession # ML100270664.

[32] Appendix C, “Plant-Level Fragility Data,” Generic Issue 199 Risk Assement, August 2010, NRC ADAMS Assession # ML100270731.

[33] Appendix D, “Seismic Core-Damage Frequencies,” Generic Issue 199 Risk Assessment, August 2010, NRC ADAMS Assession # ML100270756.

[34] Generic Issue 199 Safety/Risk Assessment, “Implications of Updated Probabilistic Seismic Hazard Estimates in Central and Eastern United States on Existing Plants,” August 2020, NRC ADAMS Assession # ML100270639.

ENCLOSURE 5

Edwin I. Hatch Nuclear Plant - Units 1 and 2
License Amendment Request to Revise Technical Specifications
to Adopt Risk Informed Completion Times TSTF-505, Revision 2,
"Provide Risk-Informed Extended Completion Times - RITSTF Initiative 4b"

Baseline CDF and LERF

The purpose of this enclosure is to demonstrate that the total Core Damage Frequency (CDF) and total Large Early Release Frequency (LERF) are below the limits established in Regulatory Guide (RG) 1.174 (Reference 1), which are 1E-04/year for CDF and 1E-05/year for LERF. These limits allow for the risk metrics of NEI 06-09 (Reference 2) to be applied to the Hatch Nuclear Plant (HNP) Risk Informed Completion Time (RICT) Program.

Table E5-1 reflects the Unit 1 and Unit 2 CDF and LERF values that resulted from a quantification of the baseline internal events, internal flooding, and fire Probabilistic Risk Assessment (PRA) average annual models (Reference 3). This table also includes an estimate of the seismic contribution to CDF and LERF based on the methodology detailed in Enclosure 4. Other external hazards, as discussed in Enclosure 4, are below accepted screening criteria and therefore do not contribute significantly to the totals.

Table E5-1
Total Baseline Average Annual CDF/ LERF

Unit 1		
Source	CDF	LERF
Internal Events PRA	4.26E-06	3.03E-07
Fire PRA	5.65E-05	3.66E-06
Flood	3.94E-07	1.04E-08
Seismic	1.18E-06	2.95E-07
Other External Events	Screened Out	
Total Unit 1	6.23E-05	4.27E-06

Unit 2		
Source	CDF	LERF
Internal Events PRA	4.88E-06	2.99E-07
Fire PRA	4.98E-05	3.54E-06
Flood	2.12E-07	6.99E-09
Seismic	1.18E-06	2.95E-07
Other External Events	Screened Out	
Total Unit 2	5.61E-05	4.14E-06

Table E5-2 reflects the Unit 1 and Unit 2 CDF and LERF mean values (Reference 3). The mean values referred to are the means of the probability distributions that result from the propagation of the uncertainties on the PRA input parameters and model uncertainties explicitly reelected in the PRA models.

Table E5-2
Total Mean Value CDF/ LERF

Unit 1		
Source	CDF	LERF
Internal Events PRA	4.54E-06	4.44E-07
Fire PRA	5.65E-05	3.66E-06
Flood	3.97E-07	1.05E-08
Seismic	1.18E-06	2.95E-07
Other External Events	Screened Out	
Total Unit 1	6.26E-05	4.41E-06

Unit 2		
Source	CDF	LERF
Internal Events PRA	4.93E-06	3.00E-07
Fire PRA	4.98E-05	3.54E-06
Flood	2.13E-07	7.08E-09
Seismic	1.18E-06	2.95E-07
Other External Events	Screened Out	
Total Unit 2	5.61E-05	4.14E-06

As demonstrated in Table E5-1 and Table E5-2, the total CDF and total LERF for each unit are within the limits set forth in RG 1.174, which permit small changes in risk that may occur during entries into the RICT Program. Therefore, the HNP RICT Program is consistent with NEI 06-09 guidance.

The values shown in Table E5-1 and Table E5-2 are a snapshot in time and are subject to change based on the on-record PRA models that support the RICT Program. The RICT Program will monitor these values to ensure that annual average CDF and LERF are reasonably within RG 1.174 limits of 1E-04 and 1E-05 as a condition of program implementation requirement. Enclosure 11 provides additional information on the RICT Program monitoring process.

References

1. U.S. Nuclear Regulatory Commission, Regulatory Guide 1.174, Revision 3, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing basis," January 2018 (ADAMS Accession No. ML17317A256).

2. NEI 06-09, "Risk-Informed Technical Specifications Initiative 4b, Risk-Managed Technical Specifications (RMTS) Guidelines," Nuclear Energy Institute, Revision 0-A, October 2012 (ADAMS Accession No. ML122860402).

3. SNC Risk Based Assessment RBA-21-006-H, "Hatch RICT LAR Enclosure 5 Values," Rev 1.

ENCLOSURE 7

Edwin I. Hatch Nuclear Plant – Units 1 and 2
License Amendment Request to Revise Technical Specifications
to Adopt Risk Informed Completion Times TSTF-505, Revision 2,
"Provide Risk-Informed Extended Completion Times - RITSTF Initiative 4b"

PRA Model Update Process

1 PRA Model Update Process

The SNC risk management process ensures that the applicable PRA models used in this application continue to reflect the as-built and as-operated plant for each of the Hatch units. The process delineates the responsibilities and guidelines for updating the PRA models, and includes criteria for both regularly scheduled and interim PRA model updates. The process includes provisions for monitoring potential areas affecting the PRA models (e.g., due to changes in the plant, errors or limitations identified in the model, industry operational experience) for assessing the risk impact of unincorporated changes, and for controlling the model and associated computer files. The process assesses the impact of these changes on the plant PRA model in a timely manner but no longer than once every two refueling outages. If a quantitatively significant change cannot be implemented in the PRA model such that it could adversely affect RICT calculations, alternatives including bounding analyses or restrictions on the use of the RICT program are put in place until the PRA model can be changed.

The SNC PRA procedures include a requirement to maintain the total CDF and LERF mean values from all quantified sources documented in the LAR, including impact of changes to fire ignition frequency updates, within reasonable limits of the RG 1.174 risk acceptance guidelines.

1. Plant Changes (including both physical modifications to the facility and changes to procedures or operating practices) are reviewed as follows:

    a. Modifications to the physical plant are reviewed for changes to maintain the PRA consistent with the as-designed plant. The review of design changes, e.g., Design Change Packages (DCP), Minor Design Changes (MDC), etc., is performed on an on-going basis. All design changes expected to impact or result in a need to change the baseline PRA model are identified in the PRA change log.

    b. Modifications to plant procedures, Technical Specifications, and other licensing documents are reviewed to maintain the PRA consistent with the as-operated plant. The review is performed on an on-going basis. Licensing Document Change Requests (LDCR) expected to significantly impact or change the baseline PRA model are identified in the PRA model change log.

    c. Consideration of reliability data, unavailability data, initiating events frequency data, human reliability data, and other such PRA inputs are included in the scope of the scheduled PRA model maintenance at least every two fuel cycles to maintain the PRA consistent with the as-operated plant.

2. If a quantitatively significant change to the PRA model is identified, it is accounted for in the model prior to the implementation of that plant change, including a physical modification, a procedure change, or other changes as noted in Item (1).

3. Following the scheduled PRA model maintenance performed at least every two fuel cycles, the PRA is reviewed to account for cumulative changes identified by the analysis.

4. If PRA model errors are discovered, they are reviewed to determine the quantitative impact on PRA results. Errors that result in quantitatively significant changes to the PRA model are corrected as soon as possible.

5. The process reviews the results of periodic and interim updates of the plant PRA that may affect the real time risk model and the subsequent risk calculations which support the RICT Program. If the results are affected, but cannot be immediately implemented:

    a. Interim analyses to address the expected risk impact of the change will be performed. In such a case, these interim analyses become part of the RICT Program calculation process until the plant changes are incorporated into the PRA model during the next update. The use of such bounding analyses is consistent with the guidance of NEI 06-09.

    OR

    b. Appropriate administrative restrictions on the use of the RICT Program for extended Completion Times are put in place until the model changes are completed, consistent with the guidance of NEI 06-09.

2 References

[1] Nuclear Energy Institute (NEI) Topical Report (TR) NEI 06-09, "Risk-Informed Technical Specifications Initiative 4b, Risk-Managed Technical Specifications (RMTS) Guidelines," Revision 0-A, October 12, 2012 (ADAMS Accession No. ML 12286A322).

[2] Letter from Jennifer M. Golder (NRC) to Biff Bradley (NEI), "Final Safety Evaluation for Nuclear Energy Institute (NEI) Topical Report (TR) NEI 06-09, “Risk-Informed Technical Specifications Initiative 4b, Risk-Managed Technical Specifications (RMTS) Guidelines," May 17, 2007 (ADAMS Accession No. ML071200238).

[3] Regulatory Guide (RG) 1.174, *"An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," Revision 3,* January 2018.

[4] Southern Nuclear Company RIE-001, *"Generation and Maintenance of Probabilistic Risk Assessment Models and Associated Updates," Version 11.0,* September 2020.

[5] Southern Nuclear Company RIE-005, *"Generation and Maintenance of Configuration Risk Management Tools," Version 6.1,* April 2020.

[6] Southern Nuclear Company RIE-012, *"Risk Informed Applications," Version 7.0,* March 2020.

ENCLOSURE 8

Edwin I. Hatch Nuclear Plant - Units 1 and 2
License Amendment Request to Revise Technical Specifications
to Adopt Risk Informed Completion Times TSTF-505, Revision 2,
"Provide Risk-Informed Extended Completion Times - RITSTF Initiative 4b"

<u>Attributes of the Real-Time Model</u>

Table of Contents

1.0 Introduction

This enclosure documents the process for adapting the peer-reviewed baseline Probabilistic Risk Assessment (PRA) models for use in the Configuration Risk Management Program (CRMP) software to support the Risk Informed Completion Time (RICT) Program. Hatch Nuclear Plant (HNP) intends to employ a CRMP software tool which provides for real time recalculation of Core Damage Frequency (CDF) and Large Early Release Frequency (LERF) for configuration risk. The baseline PRA models are separate internal events, internal flooding, and internal fires, which calculate average annual risk. The CRMP model used in the RICT Program must integrate results for the modeled hazard groups and determine CDF and LERF for actual plant conditions which exist at the time. The process employed to adapt the baseline models for CRMP use is demonstrated 1) to preserve the CDF and LERF quantitative results, 2) to maintain the quality of the peer-reviewed PRA models, and 3) to correctly accommodate changes in risk as required due to time-of-year, time-of-cycle and configuration-specific considerations as required. As indicated in Enclosure 1, the representative RICT values reported in Enclosure 1 are calculated using separate zero-maintenance annual average PRA models which include the internal events PRA models, the internal flooding PRA models, the internal fire events PRA models, and the seismic bounding delta CDF/LERF penalty values. The Hatch Maintenance Rule a(4) CRMP model that reflects the as-built and as-operated plant will be modified (similar in scope to the currently implemented VEGP 4B CRMP model) prior to implementation of the Hatch RICT Program. Quality controls and training programs applicable for the CRMP tool are also discussed in this enclosure. The seismic bounding delta CDF/LERF penalty values are subject to replacement with updated values as the model is updated.

2.0 Process

The baseline PRA models for internal events, internal flooding, and internal fires are peer-reviewed models, updated to incorporate resolution of relevant peer review findings and to incorporate plant changes that reflect the as-built and as-operated plant. These models will then be modified using the following process to create a single top CRMP model, which also includes changes needed to facilitate configuration-specific risk calculations.

Each step in the process is documented using, as required, separate reports or calculations, which provide for necessary reviews and approvals of the changes being applied. The significant steps of the process are described below:

Step 1: This step represents the model for internal events which was subjected to the peer review process.

Step 2: This step represents the model for internal flooding which was subjected to the peer review process.

Step 3: This step represents the model for internal fires which was subjected to the peer review process.

Step 4: This step represents the modification of the internal events models to resolve peer review findings determined to be relevant to the use of the models in the RICT Program, as well as updates to address plant changes.

Step 5: This step represents the modification of the internal flooding models to resolve peer review findings determined to be relevant to the use of the models in the RICT Program, as well as updates to address plant changes

Step 6: This step represents the modification of the internal fires models to resolve peer review findings determined to be relevant to the use of the models in the RICT Program, as well as updates to address plant changes.

Step 7: This step makes changes to the internal events, internal flooding, and fire PRA models to include systems, structures, and components (SSCs) that are in the scope of the RICT Program, but which are not part of the baseline PRA models. An evaluation of the RICT Program scope against the baseline PRA model scope is performed to identify SSCs which are not part of the baseline model and which need to be included to support configuration risk evaluations for LCOs in the scope of the RICT Program. It is expected that future revisions to the baseline PRA model will incorporate those SSCs that support configuration risk evaluations for the RICT program.

The changes being made to the existing baseline PRA models do not involve new methods; as such, there is no need for any focused scope peer review. The associated LCOs are documented in Enclosure 1.

Step 8: This step integrates the baseline PRA models, following steps 4, 5, 6, and 7 into a single top fault tree model for calculation of CDF and LERF. The single top model is capable of calculating and combining the numerical risk results for use in the CRMP. At this step, the single top risk model calculates the total average annual CDF and LERF from internal events, internal floods, and internal fires.

The results obtained from the integrated model are validated against the baseline model results to ensure the single-top model is properly calculating CDF and LERF. The single top model accommodates such comparisons because it permits quantification of the initiating events, or a selection of initiating events, which facilitates comparisons to the baseline PRA models.

At the completion of step 8, the PRA baseline models are integrated, and the single top model is verified to provide quantitative results consistent with the baseline models.

Step 9: This step optimizes, if required, the single top model to improve quantification time and is an intermediate step.

At the conclusion of step 9, the quantified results from the optimized model are benchmarked to ensure the optimization process did not significantly alter the numerical results from the baseline PRA models.

Step 10: This step changes the model logic to account for variations in system success criteria based on the time of year or the time in the operating cycle as required. It also accounts for other specific changes needed to properly account for configuration- specific issues as required, which are either not evaluated in the baseline average annual model or are evaluated based on average conditions encountered during a typical operating cycle. The CRMP model used for the RICT Program is required to either conservatively model these variations or include the capability to account for the variations.

The types of changes implemented in the CRMP model are described in Table E8-1. System alignments are not shown but would be reflected in the CRMP model based on the configuration-specific equipment alignments in effect at the time of a RICT calculation if system alignment is determined to impact the calculated RICT time.

Table E8-1
Changes Made During Translation to CRMP Model

Description	Basis for Change
Seismic Bounding Risk Penalty	Seismic risk is not included in the baseline PRA models. As justified in Enclosure 4 of this LAR, bounding seismic CDF and LERF penalty values are calculated and included in the delta risk calculation for each RICT assessment.
Plant Availability (PAV) Event	The baseline PRA models account for the time the reactor operates at power by using a plant availability factor. This is appropriate for determining the average annual (time based) risk, but the factor is not applicable to configuration-specific risk calculated for the RICT Program. Therefore, the probability of the PAV event is set to 1.0 in the CRMP model. This change is necessary to adjust the modeled initiating event frequencies from a per year to per reactor year basis for use in the CRMP.
Maintenance Event Probabilities	Maintenance events in the baseline PRA models have probabilities based on the fraction of the year the equipment is unavailable. For the CRMP model, the actual configuration of equipment is known, so the maintenance event probabilities are set to 0. When components are in maintenance, these events (or equivalent events) are set to 1 or TRUE.

3.0 Administrative Controls

Departmental procedures and their sub-tier instructions and guidelines provide high level guidance and requirements for creating and maintaining the CRMP model for implementing the RICT Program at HNP. The procedures collectively implement the following requirements of NEI 06-09, Revision 0-A (Reference 1), consistent with RG 1.177 (Reference 2) guidance, for the CRMP model:

- A process for evaluation and disposition of proposed facility changes shall be established for items impacting the CRMP model (Section 2.3.4, Item 7.2).
- The CRMP model shall accurately reflect the as-built, as-operated plant consistent with RG 1200 guidance for PRA capability category II (Section 2.3.5, Item 9 and Section 4.1).
- The CRMP model shall be updated to reflect the as-built and as-operated plant on a periodic basis not to exceed two refueling cycles (Section 2.3.5, Item 9.1).

Common cause treatment, as applied in the CRMP model, shall be consistent with the PRA model and Risk Managed Technical Specification (RMTS) guidance. If a component is out-of-service for planned maintenance, there is no justification for changing the common cause failure (CCF) factors. If an emergent failure occurs, the "extent of condition" evaluation performed by Operations will either address the situation or provide assurance that a CCF is not occurring, so no changes in CCF modeling are necessary. However, optionally if an “extent of condition” evaluation cannot establish with a high degree of confidence that there is no common cause failure mechanism, the probability that the redundant component is failed from a common cause failure mechanism will be modified numerically, consistent with the guidance in RG 1.177 while calculating the RICT. If, for either option, it is determined that a common cause failure mechanism exists, the redundant SSC will be declared inoperable and cannot be considered available for a PRA functionality assessment. Specifically, the treatment of CCF in the CRM tool will be as described below:

- Planned Configurations:
    - For planned configurations the RICT calculations will be performed consistent with NEI 06-09, Section 3.3.6, “Common Cause Failure Consideration,” guidance on the treatment of CCF, as follows:

      “For all RICT assessments of planned configurations, the treatment of common cause failures in the quantitative CRM Tools may be performed by considering only the removal of the planned equipment and not adjusting common cause failure terms.”

    - This approach will result in slightly shorter completion times than if RICTs were calculated using the RG 1.177 approach (i.e., it is conservative), and it will prevent deviation from NEI 06-09.

- Emergent Configurations

    - For emergent configurations, the RICT program will abide by NEI 06-09, Section 3.3.6, "Common cause Failure Consideration" guidance on the treatment of CCF, as follows:

      "For RICT assessments involving unplanned or emergent conditions, the potential for common cause failure is considered during the operability determination process. This assessment is more accurately described as an 'extent of condition' assessment."

      "In addition to a determination of operability on the affected component, the operator should make a judgement with regard to whether the operability of similar or redundant components might be affected."

      "The components are considered functional in the PRA unless the operability evaluations determine otherwise."

    - An "extent of condition" evaluation together with an operability evaluation will provide an assessment of the vulnerability of the operable redundant components to any common cause failure potential. The RICT determination process for an emergent configuration will be consistent with the following guidance provided in the NRC SER for NEI 06-09:

      *"**Emergent Failures.** During the time when a RICT is in effect and risk is being assessed and managed, it is possible that emergent failures of SSCs may occur, and these must be assessed to determine the impact on the RICT. If a failed component is one of two or more redundant components in separate trains of a system, then there is potential for a common cause failure mechanism. Licensees must continue to assess the remaining redundant components to determine there is reasonable assurance of their continued operability, and this is not changed by implementation of the RMTS. If a licensee concludes that the redundant components remain operable, then these components are functional for purposes of the RICT. However, the licensee is required to consider and implement additional risk management actions (RMAs), due to the potential for increased risks from common cause failure of similar equipment. The staff interprets TR NEI 06-09, Revision 0, as requiring consideration of such RMAs whenever the redundant components are considered to remain operable, but the licensee has not completed the extent of condition evaluations…"*

    - In keeping with the above NRC guidance, if it is determined that redundant components remain operable, these components are considered PRA functional for purpose of RICT determinations. However, HNP will consider and implement additional RMAs, due to the potential for increased risks from common cause failure of similar equipment, whenever the redundant components are considered to remain operable, but an extent of condition evaluation has not yet been completed. The consideration and implementation of additional RMAs, according to the NRC SER on NEI 06-09, is considered to be consistent with the guidance of RG 1.177 regarding the treatment of increased risks from common cause failures.

- Criteria shall exist to require CRMP model updates concurrent with implementation of facility changes that significantly impact RICT calculations (Section 2.3.5, Item 9.2).

- Initiating event models in the CRMP shall accurately include external conditions and effects of out-of-service equipment (Section 2.3.5, Item 1).

- The impacts of out-of-service equipment shall be properly reflected in the CRMP model initiating event models, as well as system response models. For example, if a certain component being declared inoperable and placed in a maintenance status is modeled in the PRA, the entry of that equipment status into the CRMP model must accommodate risk quantification to include both initiating event and system response impact (Section 4.2, Item 1).

- The CRMP model fault trees shall be traceable to the PRA (Section 2.3.5, Item 3).

- Changes to the CRMP model and data shall correctly reflect configuration-specific risk (Section 4.2, Item 3).

- In order for human recovery actions as modeled in the PRA to be credited in the RICT Program, such actions shall be performed via approved station procedures with the implementing personnel trained in their performance (Section 4.2, Item 4).

- The baseline PRA models assess average annual risk. However, some risk is not consistent throughout the year, and the CRMP tool needs to properly assess change in risk for the existing plant configuration. The departmental procedure process requires that time averaging features of the baseline PRA shall be excluded from the CRMP model (specific items discussed in Table E8-1) (Section 2.3.4, Item 5).

- Benchmarking of the CRMP model against the baseline PRA will be performed and documented to demonstrate consistency (Section 2.3.5., Item 3).

4.0 Quality Requirements

Southern Nuclear Operating Company (SNC) employs a multi-faceted approach to establishing and maintaining the quality of the PRA models, including the CRMP models, for the operating SNC nuclear generation sites. This approach includes both a proceduralized PRA maintenance and update process (documented in Enclosure 7) and the use of self-assessments and independent peer reviews (documented in Enclosure 2). The information documented in Enclosure 2 demonstrates that the HNP at-power internal events PRA model, internal flooding PRA model, and, internal fire PRA model are consistent with RG 1.200, Revision 2 (Reference 3), requirements. This information provides a robust basis for concluding that the PRA is of sufficient quality for use in risk-informed licensing actions.

For maintenance of an existing CRMP model, changes made to the baseline PRA model in translation to the CRMP model, and changes made to the CRMP configuration files, are controlled and documented by departmental procedures. Those procedures specify an acceptance test to be performed after every CRMP model update. This testing verifies proper translation of the baseline PRA models and acceptance of the changes made to the baseline PRA models pursuant to translation to the CRMP model. This testing also verifies correct mapping of plant components included in CRMP to the correct basic events in the CRMP model.

Prior to the implementation of the RICT Program, results of the acceptance testing for the integrated single top model (Step 8), the optimized single top model if developed (Step 9), and the CRMP model, which is used for configuration specific calculations (Step 10) are compared with the models produced in Step 7 to ascertain fidelity of the CRMP model. The results are documented in the model development reports and/or calculations.

The model development reports will discuss the results and justify variations in the CDF and LERF results. The primary variations in the CDF and LERF results typically arise from using average maintenance models in Step 7 and zero-maintenance models in Step 10.

5.0 Training and Qualification

The training for personnel developing the CRMP model used to support RICT Program implementation is developed based on SNC procedures as documented in Enclosure 10. The qualification of personnel developing and using the CRMP model is controlled by SNC qualification and training programs based on the Institute of Nuclear Power Operation (INPO) Accreditation (ACAD) requirements. SNC fleet-wide procedures establish the responsibilities and requirements for the training and qualification of personnel who perform engineering activities. The following discussion provides an overview of general accountabilities and aspects of HNP training programs applicable to plant staff involved with the CRMP tool development and use.

The Southern Nuclear Fleet Operations Training Manager is accountable for the performance and use of Training procedures. Site Functional Area Managers are responsible for the following:

- Governance and oversight of any site-specific sub-tiered instructions, guidelines, and forms and the overall administration of and performance of the continuing training program
- Conducting courses to support the training and qualification of individuals in the engineering population.
- Ensuring that training and qualification records are processed in accordance with procedures.

The SNC Training Manager is responsible for conducting courses to support the training and qualification of individuals in the Engineering population and for processing Training and Qualification records in accordance with SNC fleet-wide procedures and applicable site procedures.

The Engineering Fleet Training Program Committee (TPC) is composed of the four Engineering TPC Chairs, one Training Manager, and the Vice President of Engineering. This group is responsible individually and collectively to drive training program performance to levels of excellence and leverage training to drive station performance to levels of excellence. They are responsible for the following:

- Training program performance issues are identified and resolved.
- Student performance shortfalls (in training and in-plant) are identified and resolved.
- Training is a core business and addresses needs through annual, biennial and long-range planning.
- Overall training program health remains strong and meets station needs and provides workers the knowledge and skills necessary for job performance.
- Approving position-specific qualifications that are designated for common fleet Engineering duties and activities.

HNP Site and Corporate Department Managers with personnel performing Job Performance Requirements (JPRs) that are covered by the Training program are responsible for the following:

- Ensuring that individuals are evaluated for inclusion in, or exclusion from, the Engineering Training program population based on their job assignment.
- Ensuring that personnel in their department complete qualifications and training in accordance with procedural requirements.

- Maintaining and reviewing the qualification requirements in the Learning Management System (LMS).

- Administering the Engineering Training Population Determination Form for Supervisors who perform engineering activities independently or who perform the Final Technical Review of engineering activities. This applies regardless of inclusion in or exclusion from the Engineer population.

- Ensuring that only qualified individuals perform engineering activities independently or perform the Final Technical Review of engineering activities. This applies to individuals regardless of inclusion in or exclusion from the Engineer population.

- Designating one or more individuals as Department Training Coordinator(s) to ensure effective use of LMS.

- Designating personnel to be Technical Mentors.

- Participating in Engineering Training Committees, which oversee the Engineering Support Personnel Accredited Training Program.

- Coordinating the scheduling of assignments.

Each Supervisor with personnel performing JPRs covered by the Training program is responsible for the following:

- Checking employee qualifications prior to assigning work, to ensure that the assigned personnel are qualified for the work being assigned

- Ensuring items and qualifications are assigned, as needed, to assigned personnel

- Participating in Engineering Training Committees, which oversee the Engineering Support Personnel Accredited Training Program.

Personnel performing Engineering JPRs that are covered by the training program are responsible for the following:

- Verifying they are qualified in the Learning Management System (LMS) prior to independently performing the work, whether or not they are in the accredited program population.

- Ensuring that completion of qualifications and training is done in accordance with procedural requirements.

As stated above, the qualification of personnel developing and using the CRMP model is controlled by the SNC qualification and training programs, which are based on INPO ACAD requirements.

6.0 References

1. NEI 06-09, "Risk-Informed Technical Specifications Initiative 4b, Risk-Managed Technical Specifications (RMTS) Guidelines," Nuclear Energy Institute, Revision 0-A, October 2012 (ADAMS Accession No. ML 122860402).

2. Regulatory Guide 1.177, "Plant-Specific, Risk-Informed Decision making: Technical Specifications," Revision 2, January 2021 (ADAMS Accession No. ML20164A034).

3. Regulatory Guide 1.200, "An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities," Revision 2, March 2009 (ADAMS Accession No. ML090410014).

ENCLOSURE 9

Edwin I. Hatch Nuclear Plant – Units 1 and 2
License Amendment Request Revise Technical Specifications
to Adopt Risk Informed Completion Times TSTF-505, Revision 2,
"Provide Risk-Informed Extended Completion Times - RITSTF Initiative 4b"

Key Assumptions and Sources of Uncertainty

1. Introduction

The purpose of this enclosure is to disposition the impact of Probabilistic Risk Assessment (PRA) modeling epistemic uncertainty for the Risk Informed Completion Time (RICT) Program. Topical Report NEI 06-09-A (Reference 1), Section 2.3.4, item 10 requires an evaluation to determine insights that will be used to develop risk management actions (RMAs) to address these uncertainties. The baseline Internal Events, Internal Flooding, and Fire PRA models document assumptions and sources of uncertainty and these were reviewed during the model peer reviews. The approach taken is, therefore, to review these documents to identify the items which may be directly relevant to the RICT Program calculations, to perform sensitivity analyses where appropriate, to discuss the results and to document dispositions for the RICT Program.

The epistemic uncertainty analysis approach described below applies to the Internal Events and Internal Flooding PRAs and any epistemic uncertainty impacts that are unique to Fire PRA. In addition, Topical Report NEI 06-09-A requires that the uncertainty be addressed in RICT Program Configuration Risk Management Program (CRMP), tools by consideration of the translation from the PRA model to the CRMP model. The CRMP model discussed in Enclosure 8 includes internal events, internal flooding events, and fire events. The model translation uncertainties evaluation and impact assessment are limited to new uncertainties that could be introduced by application of the CRMP tool during RICT Program calculations.

2. Process

The process defined in NUREG-1855 (Reference 2) and Electric Power Research Institute (EPRI) Technical Reports 1016737 (Reference 3) and 1026511 (Reference 4) was used to evaluate model uncertainties in the Internal Events, Internal Flooding, and Fire PRAs. This systematic review included the following:

- Identification of internal events / internal flooding PRA model plant-specific sources of uncertainty, and generic sources of uncertainty, per EPRI 1016737.
- Consideration of parameter and completeness uncertainties.
- Identification of internal Fire PRA model plant-specific sources of uncertainty, and generic sources of uncertainty, per Appendix B of EPRI 1026511.
- Consideration of generic Level 2 model sources of uncertainty per Appendix E of EPRI 1026511, as applicable to Large Early Release Frequency (LERF).

As stated in Section 1.5 of NUREG 1855:

> *"Although the guidance in this report does not currently address all sources of uncertainty, the guidance provided on the uncertainty identification and characterization process and on the process of factoring the results into the decision making is generic and independent of the specific source of uncertainty. Consequently, the guidance is applicable for sources of uncertainty in PRAs that address at-power and low power and shutdown operating conditions, and both internal and external hazards."*

NUREG-1855 also describes an approach for addressing sources of model uncertainty and related assumptions. It states:

> *"A source of model uncertainty exists when (1) a credible assumption (decision or judgment) is made regarding the choice of the data, approach, or model used to address an issue because there is no consensus and (2) the choice of alternative data, approaches or models is known to have an impact on the PRA model and results. An impact on the PRA model could include the introduction of a new basic event, changes to basic event probabilities, change in success criteria, or introduction of a new initiating event. A credible assumption is one submitted by relevant experts and which has a sound technical basis. Relevant experts include those individuals with explicit knowledge and experience for the given issue. An example of an assumption related to a source of model uncertainty is battery depletion time. In calculating the depletion time, the analyst may not have any data on the time required to shed loads and thus may assume (based on analyses) that the operator is able to shed certain electrical loads in a specified time."*

Assessment of potential sources that are key to the respective applications for Internal Events, Internal Flooding, and / or Fire, and disposition / treatment for the application is not explicitly included in this enclosure. Only the results of the review are included in this enclosure.

The systematic review of PRA sources of uncertainty utilized the process outlined in Stage E ("Assessing Model Uncertainty") of NUREG-1855, as endorsed by Reg. Guide 1.200 (Reference 5). The Stage E process is summarized below:

- **Step E-1: Identify any potential model uncertainties and determine their significance.**
  - **Step E-1.1: Identify sources of model uncertainty and related assumptions**
    1) Tables A-1 and A-2 of EPRI 1016737 were used to identify potential sources of model uncertainty from the Internal Events and Internal Flooding PRA models.
    2) Appendix B of EPRI 1026511 was used to identify potential sources of model uncertainty from the Fire PRA model.
    3) Appendix E of EPRI 1026511 was used to identify potential sources of model uncertainty from the Level 2 PRA models used for Internal Events, Internal Flooding, and Fire PRA hazards.
    4) Finally, plant-specific sources of model uncertainty and assumptions were also considered in the identification process of the uncertainty evaluation.
  - **Step E-1.2: Identify relevant sources of model uncertainty and related assumptions**

    This step allows for screening of potential sources of model uncertainty based on the parts of the model used for the applications. No specific potential sources of model uncertainty were screened out during the performance of this step.
  - **Step E-1.3: Characterize sources of model uncertainty and related assumptions**

    Per the guidance in NUREG-1855 and the associated EPRI reports, the characterization process involves identifying:
    1) The part of the PRA model affected,
    2) The modeling approach or assumptions utilized in the model,
    3) The impact on the PRA model, and
    4) Representation of conservative bias (if applicable)

    These considerations were included in the evaluation of potential sources of model uncertainty.
  - **Step E-1.4: Qualitative screening of source of model uncertainty and related assumptions**

    This step allows for screening out potential sources of model uncertainty by referencing consensus model approaches. The evaluation process included identifying the approach utilized (e.g., consensus approach or other applicable guidance), and the level of detailed included in the PRA.

    Section 2.1.3 of NUREG-1855 defines a consensus model as:

    "A consensus model is a model that has a publicly available

published basis and has been peer reviewed and widely adopted by an appropriate stakeholder group. In addition, widely accepted PRA practices may be regarded as consensus models. Examples of the latter include the use of the constant probability of failure on demand model for standby components and the Poisson model for initiating events. For risk-informed regulatory decisions, the consensus model approach is one that the NRC has used or accepted for the specific risk-informed application for which it is proposed."

These two considerations were used as a means of qualitatively screening potential impacts on the risk-informed applications.

- **Step E-1.5: Identify and characterize relevant sources of model uncertainty and related assumptions associated with model changes**

  The implementation of the TSTF-505 RICT program utilizes the base PRA models. As such, no new sources of model uncertainty have been introduced for the application.

- **Step E-2: Identify sources of model uncertainty key to the application.**

  As described in NUREG-1855, only the relevant sources of model uncertainty and related assumptions with the potential to challenge the application's acceptance guidelines were considered key sources of uncertainty that were further evaluated. Also, per NUREG-1855, if any sources of model uncertainty do challenge the acceptance guidelines, then appropriate compensatory measures or performance monitoring should be identified to help minimize the risk.

  In the case of TSTF-505 RICT, appropriate compensatory measures will be in place prior to the completion time being exceeded and for the remaining duration of the configuration. Risk Management Actions (RMAs) will be developed as described in Enclosure 12 of the LAR using insights from the PRA models and other good practices (e.g., minimizing durations of maintenance activities and minimizing work on redundant trains of equipment). Additionally, Enclosure 11 of the LAR describes the performance monitoring that will be associated with the TSTF-505 RICT program.

  As such, the overall TSTF-505 RICT program implementation is consistent with Step E-2 of NUREG-1855.

For those topics identified as potential sources of uncertainty for the TSTF-505 RICT application (i.e., not screened out using the NUREG-1855 methodology previously discussed), sensitivity analyses were performed, and the results of the sensitivity analyses are documented in this enclosure.

If the results of the sensitivity analysis demonstrated a significant impact on the TSTF-505 RICT calculations (e.g., >10% change), then the importance measures of the base case and the sensitivity case were reviewed in order to determine if the top risk-significant operator actions change, thus requiring a different set of Risk Management Actions (RMAs) for the configuration. If the top risk-significant operator actions remain unchanged, then the proposed RMAs for the configuration would also remain unchanged, thus supporting the conclusion that the source of uncertainty does not impact the TSTF-505 RICT calculations.

3. Assessment of Internal Events PRA Epistemic Uncertainty Impacts

The Internal Events and Internal Flooding PRA model uncertainties were evaluated using the NUREG-1855 guidance discussed in Section 2 of this enclosure. As described in NUREG-1855, sources of uncertainty include “parametric” uncertainties, “modeling” uncertainties, and “completeness” (or scope and level of detail) uncertainties.

Parametric uncertainty was addressed as part of the Edwin I. Hatch Nuclear Plant (Hatch) PRA model quantification. The parametric uncertainty evaluation for the Internal Events PRA model is documented in the Full Power Internal Events (FPIE) and Internal Flooding Uncertainty Analysis Calculation (Reference 7). As summarized in the calculation, both traditional Monte Carlo and Latin Hypercube sampling methods were examined for 10,000 simulations for both units, with little difference indicated between the uncertainty results. Overall, the parametric mean and point-estimate values for Internal Events and Internal Flooding CDF and LERF were in fairly close agreement and the values conform with the Reg. Guide 1.174 (Reference 6) risk acceptance guidance when combined with all other applicable hazards (i.e., CDF < 1E-04 and LERF < 1E-05 per year).

Modeling uncertainties are considered in both the base PRA and in specific risk-informed applications. Assumptions are made during the PRA development to address modeling uncertainties because there is not a single definitive approach. Plant-specific assumptions made for each of the Hatch Internal Events & Internal Flooding PRA technical elements are noted in the individual notebooks and summarized in Reference 7. The Internal Events and Internal Flooding PRA model uncertainties evaluation considers the modeling uncertainties for the base PRA by identifying assumptions, determining if those assumptions are related to a source of modeling uncertainty and characterizing that uncertainty, as necessary. EPRI compiled a listing of generic sources of modeling uncertainty to be considered for each PRA technical element (Reference 3), and the evaluation performed for Hatch considered each of the generic sources of modeling uncertainty as well as the plant-specific sources.

Completeness uncertainty addresses scope and level of detail. Uncertainties associated with scope and level of detail are documented in the PRA but are only considered for their impact on a specific application. No specific issues of PRA completeness have been identified relative to the TSTF-505 application, based on the results of the Internal Events and Internal Flooding PRA peer reviews.

Additionally, an evaluation of Level 2 Internal Events PRA model uncertainty was performed, based on the guidance in NUREG-1855 (Reference 2) and Electric Power Research Institute (EPRI) 1026511 (Reference 4). The potential sources of model uncertainty in the Hatch PRA model were evaluated for the 32 Level 2 PRA topics outlined in EPRI 1026511.

A detailed review of the generic and plant-specific sources of Internal Events and Internal Flooding model uncertainties was performed and are not documented in this enclosure. The purpose of this enclosure is to summarize the key sources of uncertainty that could potentially impact the RICT calculations. In order to assess the potential impact on RICT calculations, sensitivity analyses were performed for the key sources of uncertainty and the insights from the sensitivity analyses are summarized in Table E9-1 for the Internal Events and Internal Flooding PRA models.

The key sources of uncertainty identified in Table E9-1 do not present a significant impact on the Hatch RICT calculations and therefore, the Internal Events and Internal Flooding PRA models can produce accurate RICT calculations. Note that RMAs will be developed when appropriate using insights from the PRA model results specific to the configuration.

TABLE E9-1

SUMMARY OF KEY SOURCES OF UNCERTAINTY IN THE INTERNAL EVENTS & INTERNAL FLOODING PRA MODELS FOR RICT APPLICATION

Source of Uncertainty and Assumptions	RICT Program Impact	Model Sensitivity and Disposition
HRA Dependency Analysis – Minimum JHEP		
For the human failure event (HFE) dependencies included in the PRA, a joint human error probability (JHEP) was calculated using the THERP methodology and included in the quantification via a set of recovery rules. A minimum / floor JHEP value was used. A minimum JHEP value of 1E-05 was used in the Fire PRA and 1E-06 was used in the Internal Events and Internal Flooding PRA.	Although this treatment is realistic and consistent with industry consensus approaches, there is the potential that the RICT calculations could be sensitive to the lower (1E-06) minimum JHEP value. Therefore, this assumption was identified as a candidate source of model uncertainty and was further evaluated with various sensitivity analyses.	For this source of model uncertainty, sensitivity analyses were performed for a select sample of technical specifications within scope of the RICT application. For this sensitivity case, the minimum JHEP value was escalated to 1E-05 for all applicable combinations. Due to the negligible impact demonstrated by the sensitivity analyses, this topic does not represent a significant source of model uncertainty to the TSTF-505 RICT application.
Open Phase Condition		
The open phase condition (OPC) described in NRC Bulletin 12-01 has been screened from inclusion in the PRA model, based on the conservative delta risk evaluation performed per NEI 19-02.	Off normal alignments might impact the assumptions in the OPC analysis that lead to the very low risk screening conclusion.	The Open Phase condition only applies to Internal Events. Fire is not impacted since the trip circuit is not connected, only the alarm circuit. The OPC assessment included sensitivity analysis of the various event and operator response probabilities. It also evaluated configurations for the emergency busses on alternate power sources instead of on normal sources. These studies indicate that the OPC condition is a very small risk contributor and thus is not a source of uncertainty for offsite power and emergency bus evaluations.

4. Assessment of Translation (CRMP Model) Uncertainty Impacts

Incorporation of the baseline PRA models into the Configuration Risk Management Program (CRMP) model used for RICT Program calculations may introduce new sources of model uncertainty. Table E9-2 provides a description of the relevant model changes and dispositions of whether any of the changes made represent possible new sources of model uncertainty that must be addressed. Refer to Enclosure 8 for additional discussion on the CRMP model.

TABLE E9-2

ASSESSMENT OF TRANSLATION UNCERTAINTY IMPACTS

CRMP Model Change and Assumptions	Part of Model Affected	Impact on Model	Disposition
PRA model logic structure is optimized to increase solution speed.	Basic events with a 1.0 value are set to logical TRUE and compressed out of the model.	The restructured model, if is logically equivalent and produces results comparable to the baseline PRA logic model.	Since the restructured model produces comparable numerical results, this is not a source of uncertainty for the RICT program.
Incorporation of seismic risk bias (Enclosure 4) to support RICT Program risk calculations. A conservative value for the seismic delta CDF is applicable.	Calculation of RICT and Risk Management Action Threshold (RMAT) within CRMP.	The addition of bounding impacts for seismic events has no impact on baseline PRA or CRMP model. Impact is reflected in calculation of all RICTs and RMATs.	Since this is a bounding approach for addressing seismic risk in the RICT Program, it is not a source of translation uncertainty and RICT Program calculations are not impacted, so no mandatory Risk Management Actions (RMAs) are required.
Set plant availability (Reactor Critical Years Factor) basic event to 1.0.	Basic Event: HATCHAVAIL	Since the CRMP model evaluates specific configurations during at-power conditions, the use of a plant availability factor less than 1.0 is not appropriate. This change allows the CRMP model to produce appropriate results for specific at-power configurations.	This change is consistent with CRMP tool practice; therefore, this change does not represent a source of uncertainty, and RICT program calculations are not impacted, so no mandatory RMAs are required.
Set maintenance events to logical FALSE.	Basic Events with the following prefix: MNUN* and TTUN*	Since the CRMP model evaluates specific configurations during at-power conditions, the use of average maintenance probabilities is not appropriate. This change allows the CRMP model to produce appropriate results for specific at-power configurations.	This change is consistent with CRMP tool practice; therefore, this change does not represent a source of uncertainty, and RICT program calculations are not impacted, so no mandatory RMAs are required.

5. Assessment of Supplementary Fire PRA Epistemic Uncertainty Impacts

The Fire PRA includes various sources of uncertainty that exist because there are both inherent randomness in elements that comprise the Fire PRA and because the state of knowledge in these elements continues to evolve. The Hatch Fire PRA was developed using consensus modeling approaches described within NUREG/CR-6850 (Reference 10).

The Fire PRA model uncertainties were evaluated using the NUREG-1855 guidance discussed in Section 2 of this enclosure. As described in NUREG-1855, sources of uncertainty include "parametric" uncertainties, "modeling" uncertainties, and "completeness" (or scope and level of detail) uncertainties.

Parametric uncertainty was addressed as part of the Hatch Fire PRA model quantification. The parametric uncertainty evaluation for the Fire PRA model is documented in Hatch Fire PRA Task 15, Uncertainty & Sensitivity Analysis Calculation (Reference 8) and Hatch Fire PRA ABAO Uncertainty Calculation (Reference 9) (this calculation supports the "as-built-as-operated" Fire PRA model). As summarized in the calculations, the parametric uncertainty analysis considered uncertainties associated with (1) fire ignition frequencies, (2) severity factors, (3) non-suppression probabilities, and (4) spurious probabilities (along with the traditional sources of uncertainty assessed in the Internal Events model that are applicable to the Fire PRA model). A Monte Carlo sampling method was examined for 50,000 simulations for both units. Overall, the parametric mean and point-estimate values for Fire PRA CDF and LERF were in fairly close agreement and the values conform with the Reg. Guide 1.174 (Reference 6) risk acceptance guidance when combined with all other applicable hazards (i.e., CDF < 1E-04 and LERF < 1E-05 per year).

Modeling uncertainties are considered in both the base Fire PRA and in specific risk-informed applications. Assumptions are made during the Fire PRA development to address modeling uncertainties because there is not a single definitive approach. Plant-specific assumptions made for each of the Hatch Fire PRA technical elements are noted in the individual notebooks and summarized in Reference 8 and Reference 9. The Fire PRA model uncertainties evaluation considers the modeling uncertainties for the base Fire PRA by identifying assumptions, determining if those assumptions are related to a source of modeling uncertainty and characterizing that uncertainty, as necessary. EPRI compiled a listing of generic sources of modeling uncertainty to be considered for each Fire PRA technical element (Reference 4), and the evaluation performed for Hatch considered each of the generic sources of modeling uncertainty as well as the plant-specific sources.

Completeness uncertainty addresses scope and level of detail. Uncertainties associated with scope and level of detail are documented in the Fire PRA but are only considered for their impact on a specific application. No specific issues of Fire PRA completeness have been identified relative to the TSTF-505 application, based on the conclusions of the Fire PRA peer reviews.

The plant-specific assumptions in the Hatch Fire PRA and the 71 generic sources of uncertainty identified in EPRI 1026511 were evaluated for their potential impact on the RICT application. This guideline organizes the uncertainties in Topic Areas like those outlined in NUREG/CR-6850 and was used to evaluate the baseline Fire PRA epistemic uncertainty and evaluate the impact of this uncertainty on RICT Program calculations.

A detailed review of the generic and plant-specific sources of internal fire model uncertainties was performed and are not documented in this enclosure. The purpose of this enclosure is to summarize the key sources of uncertainty that could potentially impact the RICT calculations. In order to assess the potential impact on RICT calculations, sensitivity analyses were performed for the key sources of uncertainty and the insights from the sensitivity analyses are summarized in Table E9-3 for the internal fire model (organized by NUREG/CR-6850 tasks).

As noted above, the Hatch Fire PRA was developed using consensus methods outlined in NUREG/CR-6850 and interpretations of technical approaches as required by NRC. Fire PRA methods were based on NUREG/CR-6850, other more recent NUREGs and published "frequently asked questions" (FAQs).

The key sources of uncertainty identified in Table E9-3 do not present a significant impact on the Hatch RICT calculations and therefore, the Fire PRA model can produce accurate RICT calculations. Note that RMAs will be developed when appropriate using insights from the Fire PRA model results specific to the configuration.

TABLE E9-3

ASSESSMENT OF FIRE PRA EPISTEMIC UNCERTAINTY FOR RICT APPLICATION

Task #	Description	Sources of Uncertainty	Disposition for RICT Application
1	Analysis boundary and partitioning	This task establishes the overall spatial scope of the analysis and provides a framework for organizing the data for the analysis. The partitioning features credited are required to satisfy established industry standards.	Based on a review of the assumptions and potential sources of sources of uncertainly associated with this element, it is concluded that the methodology for the Analysis Boundary and Partitioning task does not introduce any epistemic uncertainties that would affect the RICT calculation. Therefore, RICT Program calculations are not impacted, and no RMAs are required to address this item.
2	Component Selection	This task involves the selection of components to be treated in the analysis in the context of initiating events and mitigation. The potential sources of uncertainty include those inherent in the internal events PRA model as that model provides the foundation for the Fire PRA.	The uncertainty associated with this task is related to the identification of all components that should be credited/linked in the Fire PRA. This source of uncertainty is reduced as a result of multiple overlapping tasks including the MSO expert panel, reviews of FPIE screened initiating events, screened containment penetrations, and screened ISLOCA scenarios. Additional internal reviews of analysis results further reduce the uncertainty associated with this task. Based on a review of the assumptions and potential sources of uncertainty related to this element and the discussion above, it is concluded that the methodology for the Component Selection task does not introduce any epistemic uncertainties that would affect the RICT calculation. Therefore, RICT Program calculations are not impacted, and no RMAs are required to address this item.

TABLE E9-3

ASSESSMENT OF FIRE PRA EPISTEMIC UNCERTAINTY FOR RICT APPLICATION

Task #	Description	Sources of Uncertainty	Disposition for RICT Application
3	Cable Selection	The selection of cables to be considered in the analysis is identified using industry guidance documents. The overall process is essentially the same as that used to perform the analyses to demonstrate compliance with 10 CFR 50.48.	Additionally, as part of the Fire PRA, some components were conservatively assumed to be failed based on lack of cable data. Components in this category are referred to as Unknown Location (UNL) components because specific cables were not identified for the components. For this source of model uncertainty, sensitivity analyses were performed for a select sample of technical specifications within scope of the RICT application. For this sensitivity case, all UNL component failures were removed from the fire scenarios (i.e., fire-induced failure of UNL components are no longer included in the target sets). Based on the results of this sensitivity analysis, the UNL methodology does not introduce significant conservatisms into the base Fire PRA model and is assessed to be appropriate to avoid overly conservative results that mask key risk insights. Based on a review of the assumptions and potential sources of uncertainty related to this element it is concluded that the methodology for the Cable Selection task does not introduce any epistemic uncertainties that would affect the RICT calculation. Therefore, RICT Program calculations are not impacted, and no RMAs are required to address this item.

TABLE E9-3

ASSESSMENT OF FIRE PRA EPISTEMIC UNCERTAINTY FOR RICT APPLICATION

Task #	Description	Sources of Uncertainty	Disposition for RICT Application
4	Qualitative Screening	Qualitative screening was performed; however, some structures (locations) were eliminated from the global analysis boundary and ignition sources deemed to have no impact on the Fire PRA (based on industry guidance and criteria) were excluded from the quantification based on qualitative screening criteria. The only criterion subject to uncertainty is the potential for plant trip. However, such locations would not contain any features (equipment or cables identified in the prior two tasks) and consequently are expected to have a low risk contribution.	In the event a structure (location) which could result in a plant trip was incorrectly excluded, its contribution to CDF would be small (with a CCDP commensurate with base risk). Such a location would have a negligible risk contribution to the overall Fire PRA. Based on a review of the assumptions and potential sources of uncertainty related to this element and the discussion above, it is concluded that the methodology for the Qualitative Screening task does not introduce any epistemic uncertainties that would affect the RICT calculation. Therefore, RICT Program calculations are not impacted, and no RMAs are required to address this item.
5	Fire-Induced Risk Model	The internal events PRA model was updated to add fire specific initiating event structure as well as additional system logic. The methodology used is consistent with that used for the internal events PRA model development as was subjected to industry Peer Review. The developed model is applied in such a fashion that all postulated fires are assumed to generate a plant trip. This represents a source of uncertainty, as it is not necessarily clear that fires would result in a trip. In the event the fire results in damage to cables and/or equipment identified in Task 2, the PRA model includes structure to translate them into the appropriate induced initiator.	The identified source of uncertainty could result in the over-estimation of fire risk. In general, the Fire PRA development process would have reviewed significant fire initiating events and performed supplemental assessments to address this possible source of uncertainty. Based on a review of the assumptions and potential sources of uncertainty related to this element and the discussion above, it is concluded that the methodology for the Fire-Induced Risk Model task does not introduce any epistemic uncertainties that would affect the RICT calculation. Therefore, RICT Program calculations are not impacted, and no RMAs are required to address this item.

TABLE E9-3

ASSESSMENT OF FIRE PRA EPISTEMIC UNCERTAINTY FOR RICT APPLICATION

Task #	Description	Sources of Uncertainty	Disposition for RICT Application
6	Fire Ignition Frequency	Fire ignition frequency is an area with inherent uncertainty. Part of this uncertainty arises due to the counting and related partitioning methodology. However, the resulting frequency is not particularly sensitive to changes in ignition source counts. The primary source of uncertainty for this task is associated with the industry generic frequency values used for the Fire PRA. This is because there is no specific treatment for variability among plants along with some significant conservatism in defining the frequencies, and their associated heat release rates.	The Fire PRA utilized the bin frequencies from NUREG/CR-2169 (Reference 13), which represents the most current approved source for bin frequencies. As such, some of the inherent conservatism associated with bin frequencies from NUREG/CR-6850 was removed. A parametric uncertainty analysis using the Money Carlo method is documented in the Uncertainty and Sensitivity Analysis Calculation (Reference 8). Consensus approaches are employed in the model. Based on a review of the assumptions and potential sources of uncertainty related to this element it is concluded that the methodology for the Fire Ignition Frequency task does not introduce any epistemic uncertainties that would affect the RICT calculation. Therefore, RICT Program calculations are not impacted, and no RMAs are required to address this item.
7	Quantitative Screening	Other than screening out potentially risk significant scenarios (ignition sources), this task is not a source of uncertainty.	Quantitative screening criteria was defined for the Hatch Fire PRA as the CDF / LERF contribution of zero, such that all quantified fire scenarios are retained. All of the results were retained in the cumulative CDF / LERF; therefore, no uncertainty was introduced as a result of this task. Based on the discussion above, it is concluded that the methodology for the Quantitative Screening task does not introduce any epistemic uncertainties that would affect the RICT calculation. Therefore, RICT Program calculations are not impacted, and no RMAs are required to address this item.
8	Scoping Fire Modeling	The framework of NUREG/CR-6850 includes two tasks related to fire scenario development (Tasks 8 and 11). The discussion of uncertainty for both tasks is provided in the discussion for Task 11.	See Task 11 discussion.

TABLE E9-3

ASSESSMENT OF FIRE PRA EPISTEMIC UNCERTAINTY FOR RICT APPLICATION

Task #	Description	Sources of Uncertainty	Disposition for RICT Application
9	Detailed Circuit Failure Analysis	The circuit analysis is performed using standard electrical engineering principles. However, the behavior of electrical insulation properties and the response of electrical circuits to fire induced failures is a potential source of uncertainty. This uncertainty is associated with the dynamics of fire and the inability to ascertain the relative timing of circuit failures. The analysis methodology assumes failures would occur in the worst possible configuration, or if multiple circuits are involved, at whatever relative timing is required to cause a bounding worst-case outcome. This results in a skewing of the risk estimates such that they are over-estimated.	Circuit analysis was performed as part of the deterministic post fire safe shutdown analysis. Refinements in the application of the circuit analysis results to the Fire PRA were performed on a case-by-case basis where the scenario risk quantification was large enough to warrant further detailed analysis. Hot short probabilities and hot short duration probabilities as defined in NUREG-7150, Volume 2, based on actual fire test data, were used in the FPRA. The uncertainty (conservatism) which may remain in the Fire PRA is associated with scenarios that do not contribute significantly to the overall fire risk. Based on a review of the assumptions and potential sources of uncertainty related to this element and the discussion above, it is concluded that the methodology for the Detailed Circuit Failure Analysis task does not introduce any epistemic uncertainties that would affect the RICT calculation. Therefore, RICT Program calculations are not impacted, and no RMAs are required to address this item.
10	Circuit Failure Mode Likelihood Analysis	One of the failure modes for a circuit (cable) given fire induced failure is a hot short. A conditional probability and a hot short duration probability are assigned using industry guidance published in NUREG 7150, Volume 2. The uncertainty values specified in NUREG-7150, Volume 2 are based on fire test data.	The use of hot short failure probability and duration probability is based on fire test data and associated consensus methodology published in NUREG-7150, Volume 2. Based on a review of the assumptions and potential sources of uncertainty related to this element and the discussion above, it is concluded that the methodology for the Circuit Failure Mode Likelihood Analysis task does not introduce any epistemic uncertainties that would affect the RICT calculation. Therefore, RICT Program calculations are not impacted, and no RMAs are required to address this item.

TABLE E9-3

ASSESSMENT OF FIRE PRA EPISTEMIC UNCERTAINTY FOR RICT APPLICATION

Task #	Description	Sources of Uncertainty	Disposition for RICT Application
11	Detailed Fire Modeling	The application of fire modeling technology is used in the Fire PRA to translate a fire initiating event into a set of consequences (fire-induced failures). The performance of the analysis requires a number of key input parameters. These input parameters include the heat release rate (HRR) for the fire, the growth rate, the damage threshold for the targets, and response of plant staff (detection, fire control, fire suppression). The fire modeling methodology itself is largely empirical in some respects and consequently is another source of uncertainty. For a given set of input parameters, the fire modeling results (temperatures as a function of distance from the fire) are characterized as having some distribution (aleatory uncertainty). The epistemic uncertainty arises from the selection of the input parameters (specifically the HRR and growth rate) and how the parameters are related to the fire initiating event. While industry guidance is available, that guidance is derived from laboratory tests and may not necessarily be representative of randomly occurring events. The fire modeling results using these input parameters are used to identify a zone of influence (ZOI) for the fire and cables/equipment within that ZOI are assumed to be damaged. In general, the guidance provided for the treatment of fires is conservative and the application of that guidance retains that conservatism. The resulting risk estimates are also conservative.	Consensus modeling approach is used for Detailed Fire Modeling and it is concluded that the methodology for the Detailed Fire Modeling task does not introduce any epistemic uncertainties that would require sensitivity treatment. Therefore, RICT Program calculations are not impacted, and no additional RMAs are required to address this item.

TABLE E9-3

ASSESSMENT OF FIRE PRA EPISTEMIC UNCERTAINTY FOR RICT APPLICATION

Task #	Description	Sources of Uncertainty	Disposition for RICT Application
12	Post-Fire Human Reliability Analysis	The human error probabilities (HEPs) used in the Fire PRA were adjusted to consider the additional challenges that may be present given a fire. The HEPs were obtained using the EPRI HRA Calculator (HRAC) and included the consideration of degradation or loss of necessary cues due to fire. Given the methodology used, the impact of any remaining uncertainties is expected to be small.	The HEPs include the consideration of degradation or loss of necessary cues due to fire. The fire risk importance measures indicate that the results are somewhat sensitive to HRA model and parameter values. The Fire PRA model HRA is based on industry consensus modeling approaches for its HEP calculations, so this is not considered a significant source of epistemic uncertainty. However, a sensitivity analysis was performed to evaluate the potential impact of the minimum joint human error probability (JHEP) on the RICT calculations. This sensitivity utilized the same approach as the analysis conducted for the Internal Events and Internal Flooding PRA models, as summarized in Table E9-1 of this enclosure. Based on the results of this sensitivity analysis, the minimum JHEP methodology (floor JHEP of 1E-05) does not introduce significant conservatisms into the base Fire PRA model and is assessed to be appropriate to avoid overly conservative results that mask key risk insights. The TSTF-505 procedure will require appropriate Risk Management Action (RMA) focus on human performance for RICT entry (e.g., including an operator briefing on the significant human actions in the PRA that are pertinent to the configuration). It is concluded that the methodology for the Post-Fire Human Reliability Analysis task does not introduce any epistemic uncertainties that would require sensitivity treatment. Therefore, RICT Program calculations are not impacted, and no additional RMAs are required to address this item.

TABLE E9-3

ASSESSMENT OF FIRE PRA EPISTEMIC UNCERTAINTY FOR RICT APPLICATION

Task #	Description	Sources of Uncertainty	Disposition for RICT Application
13	Seismic-Fire Interactions Assessment	Since this is a qualitative evaluation, there is no quantitative impact with respect to the uncertainty of this task.	The qualitative assessment of seismic-induced fires should not be a source of model uncertainty as it is not expected to provide changes to the quantified Fire PRA model. A conservative seismic hazard penalty is already applied to all RICT calculations to account for seismic risk impact. Based on the discussion above, it is concluded that the methodology for the Seismic-Fire Interactions Assessment task does not introduce any epistemic uncertainties that affect the RICT calculation. Therefore, RICT Program calculations are not impacted, and no RMAs are required to address this item.
14	Fire Risk Quantification	As the culmination of other tasks, most of the uncertainty associated with quantification has already been addressed. The other source of uncertainty is the selection of the truncation limit. However, the selected truncation was confirmed to be consistent with the requirements of the PRA Standard (Reference 11).	The selected truncation was confirmed to be consistent with the requirements of the PRA Standard (Reference 11). Based on a review of the assumptions and potential sources of uncertainty related to this element and the discussion above, it is concluded that the methodology for the Fire Risk Quantification task does not introduce any epistemic uncertainties that would affect the RICT calculation. Therefore, RICT Program calculations are not impacted, and no RMAs are required to address this item.
15	Uncertainty and Sensitivity Analyses	This task does not introduce any new uncertainties. This task is intended to address how the fire risk assessment could be impacted by the various sources of uncertainty.	This task does not introduce any new uncertainties. This task is intended to address how the fire risk assessment could be impacted by the various sources of uncertainty. Based on the discussion above, it is concluded that the methodology for the Uncertainty and Sensitivity Analyses task does not introduce any epistemic uncertainties that would affect the RICT calculation. Therefore, RICT Program calculations are not impacted, and no RMAs are required to address this item.

TABLE E9-3

ASSESSMENT OF FIRE PRA EPISTEMIC UNCERTAINTY FOR RICT APPLICATION

Task #	Description	Sources of Uncertainty	Disposition for RICT Application
16	Fire PRA Documentation	This task does not introduce any new uncertainties to the fire risk.	This task does not introduce any new uncertainties to the fire risk as it outlines documentation requirements. Based on the discussion above, it is concluded that the methodology for the Fire PRA documentation task does not introduce any epistemic uncertainties that would affect the RICT calculation. Therefore, RICT Program calculations are not impacted, and no RMAs are required to address this item.

6. References

1. Nuclear Energy Institute (NEI) Topical Report (TR) NEI 06-09, "Risk-Informed Technical Specifications Initiative 4b, Risk-Managed Technical Specifications (RMTS) Guidelines," Revision 0-A, October 2012 (ADAMS Accession No. ML12286A322).
2. NUREG-1855, Guidance on the Treatment of Uncertainties Associated with PRAs in Risk-Informed Decision Making, Revision 1, March 2017.
3. EPRI 1016737, Treatment of Parameter and Model Uncertainty for Probabilistic Risk Assessments, December 2008.
4. EPRI 1026511, Practical Guidance on the Use of Probabilstic Risk Assessment in Risk-Informed Applications with a Focus on the Treatment of Uncertainty, December 2012.
5. NRC Regulatory Guide 1.200, Acceptability of Probabilistic Risk Assessment Results for Risk-Informed Activities, Revision 2, March 2009.
6. NRC Regulatory Guide 1.174, An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis, Revision 3, January 2018.
7. H-RIE-IEIF-U00-011, Hatch Full Power Internal Events and Internal Flooding Uncertainty Analysis, Revision 3, June 2020.
8. H-RIE-FIREPRA-U00-015, Hatch Fire PRA Task 15, Uncertainty and Sensitivity Analysis, Revision 3, December 2019.
9. H-RIE-FIREPRA-ABAO-U00-015, Hatch Fire PRA ABAO Uncertainty, Revision 2, June 2020.
10. NUREG/CR-6850 (also EPRI 1011989), “Fire PRA Methodology for Nuclear Power Facilities,” September 2005, with Supplement 1 (EPRI 1019259), September 2010.
11. ASME/ANS RA-Sa-2009, “Standard for Level 1/Large Early Release Frequency Probabilistic Risk Assessment for Nuclear Power Plant Applications,” Addendum A to RAS-2008, ASME, New York, NY, American Nuclear Society, La Grange Park, Illinois, February 2009.
12. NUREG/CR-6595, An Approach for Estimating the Frequencies of Various Containment Failure Modes and Bypass Events, Rev. 1, October 2004.
13. NUREG-2169 / EPRI 300200936, Nuclear Power Plant Fire Ignition Frequency and Non-Suppression Probability Estimation Using the Updated Fire Events Database, Rev. 0, January 2015.
14. PRA-BC-H-19-004, Hatch Open Phase Risk Evaluation, Revision 1, January 2020.

ENCLOSURE 10

Edwin I. Hatch Nuclear Plant - Units 1 and 2
License Amendment Request to Revise Technical Specifications
to Adopt Risk Informed Completion Times TSTF-505, Revision 2,
"Provide Risk-Informed Extended Completion Times - RITSTF Initiative 4b"

Program Implementation

Table of Contents

1.0 Introduction

This enclosure provides a description of the implementing programs and procedures regarding the plant staff responsibilities for the Risk Informed Completion Time (RICT) Program including training of the personnel required for implementation of the RICT Program. Several procedures and processes are detailed in Enclosures 7, 11, and 12; those discussions are not repeated as part of this enclosure. Those topics include Probabilistic Risk Assessment (PRA) Maintenance and Update process (Enclosure 7), Cumulative Risk Assessment and Performance Monitoring Program (Enclosure 11), and Risk Management Actions (Enclosure 12).

2.0 RICT Program Procedures

The procedures discussed below were developed for implementing the RICT Program for the SNC fleet and are currently in effect for Farley Nuclear Plant (FNP) and Vogtle Electric Generating Plant (VEGP). They will be adopted for use in implementing the Hatch Nuclear Plant (HNP) RICT program. They provide guidance to the appropriate SNC personnel on the following topics:

- <u>On-Line Configuration Risk Management Program (CRMP, Reference 2):</u>

  This procedure provides requirements for Implementation of the RICT program while in Mode 1. In addition, it provides requirements for outlining planning and scheduling strategies to minimize risk (in terms of core damage frequency (CDF, ICDP) and large early release frequency (LERF, ILERP)), and meeting requirements necessary for maintaining and retaining a chronological history of configuration changes and their risk impacts (in terms of CDF, ICDP, LERF, and ILERP) throughout the operating cycle

- <u>Risk Management Actions (RMAs) for the RICT Program (Reference 3):</u>

  This instruction provides requirements for development and implementation of RMAs for the RICT program.

- <u>Calculation of RMAT and RICT for the RICT Program (Reference 4):</u>

  This procedure provides detailed requirements and limitations of the RICT Program at Southern Nuclear Company. It includes the calculation of RICT and RISK MANAGEMENT ACTION TIMES (RMAT). This procedure is applicable to sites that have an approved license amendment to use the RICT Program.

- <u>PRA Functionality Determination (Reference 5):</u>

  This procedure provides requirements for determining whether structures, systems and components (SSCs) that are declared inoperable can be considered PRA FUNCTIONAL in RICT calculations.

- <u>Recording Limiting Conditions for Operation (Reference 6):</u>

  This procedure provides instructions to the control room operator for logging RICTs, entering the out of service components into the CRM, documenting RMAs and requirements for common cause evaluations. .

The procedures discussed above may be revised or supplemented by other procedures, as deemed necessary to implement the RICT Program effectively at HNP Units 1 and 2. They are described in more detail below.

2.1 On-Line Configuration Risk Management Program

This procedure (Reference 2) describes, in general terms, the CRMP, as it pertains to the RICT Program as well as parts of the 10 CFR 50.65(a)(4) program. It is the parent procedure for both these programs.

With respect to the RICT Program, this procedure has the following attributes:

- Identifies the plant management individual with the authority to approve entry into the RICT Program.
- Details the plant conditions under which the RICT Program is applicable.
- Acts as the overarching guidance for the SNC risk assessment and risk management procedures.
- Contains important definitions for the RICT Program.
- Details many of the requirements, per NEI 06-09 Revision 0-A (Reference 1), for the RICT Program.
- Identifies departmental and position responsibilities within the RICT program.
- Outlines the requirement to identify and implement Risk Management Actions (RMAs) when the RMAT is exceeded or is anticipated to be exceeded.
- Describes the necessary attributes for the SNC CRMP tool.

The above guidance is consistent with NEI-06-09 (Reference 1).

The CRMP is maintained as an SNC procedure. It is managed by the Fleet Work Control Manager and is under the ownership of Fleet Work Management (FWM). The ownership of this procedure is subject to change if deemed appropriate. The RICT portion of this procedure is currently designated as applicable to Farley and Vogtle Units 1 and 2. Upon approval of the RICT program for HNP, the procedure will be revised to note that it is also applicable to HNP Units 1 and 2.

2.2 Risk Management Actions for the Risk Informed Completion Time Program

This procedure (Reference 3) describes the risk assessment and management processes for the SNC fleet of nuclear plants. It provides general guidelines for the risk assessment and management of maintenance activities, both planned and emergent. This procedure is a sub-tier procedure to the On-Line CRMP, described above.

Risk Management Actions are targeted toward RMA candidates in order to manage and control increases in CDF/LERF attributed to internal events, fire events, and other hazards modeled in CRMP which include the following:

- Identify RMA candidates which identify SSCs, initiating events and fire zone considered important for a given plant configuration when a RICT is implemented.
- Develop RMAs using RMA candidates and develop additional RMAs, as appropriate.
- Communicate RMAs to Operations, Fire Protection personnel, and other affected departments to facilitate RMA planning and RMA implementation.

- Implement RMAs for conditions which require RMA implementation as required prior reaching RMAT.
- Document implementation of RMAs in the Control Room Narrative Log. The time of actual implementation and removal of RMAs should be documented. This may be accomplished in multiple log entries.

The risk management procedure also indicates that while the Outage and Scheduling department is responsible for the planning, scheduling and assessing planned maintenance items, the site Operations department is primarily responsible for the evaluation of emergent work for the RICT Program. This evaluation includes the risk assessments and the calculation of the RMATs and RICTs.

The Risk Management Actions program guidance is maintained as a SNC procedure. It is primarily utilized by the Outage and Scheduling and Operations Departments under the ownership of Fleet Work Management. The ownership of this procedure is subject to change if deemed appropriate. This procedure is currently designated as applicable only to Farley and Vogtle Units 1 and 2. Upon approval of the RICT program for HNP, the procedure will be revised to note that it is also applicable to HNP Units 1 and 2.

2.3 Calculation of RMAT and RICT for the RICT Program

This procedure (Reference 4) provides requirements and limitations of the RICT program at SNC. It includes the guidance necessary for the calculation of RMATs and RICTs for the RICT Program. It provides the steps necessary to perform the automated calculation using the CRMP tool, as well as providing the necessary steps for a manual calculation.

For planned maintenance, personnel from the Outage and Scheduling department will calculate the RICT Program values. For emergent work, the calculation will be performed by the Operations department. If plant conditions demand that the Operations department is unable to perform the calculations, this responsibility is delegated to the Outage and Scheduling department personnel. However, entry into a Technical Specification Limiting Condition for Operation (LCO) Action statement is the responsibility of the licensed operators; this is also true for the RICT Program. Consequently, even though Outage and Scheduling may calculate a RICT in anticipation of some future entry into the RICT Program, the actual RICT will be put into place by the control room staff. In other words, the on-shift licensed operators and shift management will be generating the paperwork necessary for entry into the RICT Program, just as they do for entry into an LCO Action statement. Additionally, the Plant Manager or designee is responsible for approving entry into a planned RICT and the Shift Manager is responsible for approving entry into an emergent RICT.

The RMAT and the RICT risk levels are referenced to the Core Damage Frequency (CDF) and the Large Early Release Frequency (LERF) associated with the “zero-maintenance” state. The actual calculation evaluates the Incremental CDF (ICDF) and the Incremental LERF (ILERF) to determine the RMAT and RICT values. The evaluation is performed using the single top internal events PRA model, internal flooding model, Fire PRA model, and a bounding seismic analysis.

The procedure contains the following guidance, restrictions and limitations, which are based on, and consistent with, NEI 06-09 (Reference 1):

- Guidance on the use of RMAs, including the conditions under which a Common Cause Failure RMAs are developed.
- Conditions under which a RICT Program may not be used.
- States that a RICT may not go beyond the 30 day back stop limit.
- Guidance on plant configuration changes, for example, the procedure requires recalculating the RICT and RMAT within 12 hours of the change.
- Conditions for exiting the RICT Program.
- Prohibitions from entering the RICT Program during a TS Loss of Function (LOF) Condition..

The above guidance is maintained in a SNC procedure. As already mentioned, the calculation of RICT Program values are the responsibility of the Operations department (emergent conditions) and the Outage and Scheduling group (planned conditions). The procedure is managed by Fleet Work Management (FWM) and is under the direction of the FWM Manager. The ownership of this procedure is subject to change if deemed appropriate. This procedure is currently designated as applicable to Farley and Vogtle Units 1 and 2. Upon approval of the RICT program for HNP, the procedure will be revised to note that it is also applicable to HNP Units 1 and 2.

2.4 PRA Functionality Determination

This procedure (Reference 5) provides requirements for determining whether structures, systems and components (SSCs) that are declared inoperable per Technical Specifications can be considered PRA functional in RICT calculations. This procedure lists three specific conditions under which an inoperable SSC per Technical Specifications is considered "PRA Functional," based NEI 06-09 guidance (Reference 1). They are as follows:

1) Condition 1: If the SSC is declared inoperable per Technical Specifications due to degraded performance parameters and the PRA success criteria are met, then the component may be considered PRA functional, subject to the following:

    - The degraded condition must be identified, and there is a reasonable expectation that additional degradation will not occur during the RICT.

    - For example, a valve fails its in-service testing stroke time acceptance criteria, but the response time of the valve is not relevant to the ability of the valve to provide its mitigation function as required in the PRA; therefore, the valve may be considered PRA functional.

2) Condition 2: If the condition causing the inoperability per Technical Specifications impacts one or more functions modeled in CRMP, and the inoperable SSC is still capable of supporting one or more functions modeled in CRMP, then the unaffected function(s) may be considered PRA functional.

    - For example, a valve is inoperable but secured in the closed position. Supported functions of the valve require the valve to open and close. The condition can be addressed in CRMP by failing functions which require an open valve, but the valve may be considered PRA functional for functions which require a closed valve.

3) Condition 3: If the condition causing the inoperability per Technical Specifications impacts only function(s) that are not modeled in CRMP and the HNP PRA has concluded that the affected function(s) has no risk impact, then the SSC may be considered PRA functional.

   - For example, a pump backup start feature is inoperable and the feature is not credited in the PRA model (assumed failed); the RICT calculation may assume availability of the associated pump since the risk of the nonfunctional backup start feature is part of the baseline risk.

If the Functionality determination concludes that the inoperable SSC(s) is not PRA Functional, the SSC will be treated as failed during the RICT calculation.

A RICT entry is not permitted for a TS loss of function condition.

When a situation arises requiring a “PRA Functional” assessment, site Operations department will perform the assessment and determine whether or not a specific SSC may be considered “PRA Functional.” RIE personnel will support the Operations personnel on an as-needed basis during the “PRA Functional” assessment. If the Technical Specification Front Stop will be exceeded in less than 24 hours, the formal evaluation will be performed as soon as possible.

The above guidance is maintained in SNC procedures. It is used primarily by Operations and RIE personnel with Operations personnel having the primary responsibility for making “PRA Functionality” determinations. The procedure is managed by the Administrative department and is under the direction of the FWM Manager. The ownership of this procedure is subject to change if deemed appropriate. This procedure is currently designated as applicable to Farley and Vogtle Units 1 and 2. Upon approval of the RICT program for HNP, the procedure will be revised to note that it is also applicable to HNP Units 1 and 2.

2.5 Recording LCOs

This procedure includes instructions relative to LCO Tracking for the Risk Informed Completion Time (RICT) Program. Provisions are included for recording and tracking RICTs. The RICT portion of this procedure is currently applicable to Vogtle 1&2 and Farley only (Reference 6). It also provides the Operations department with the guidance for maintaining Control Room Operator narrative logs and LCO logs as well as other control room documentation. It will be revised to accommodate HNP prior to implementation of the RICT program at HNP. The Recording LCOs procedure provides the guidance necessary for the operation of the interface tool between the operator narrative log and LCO log with the CRMP monitor.

The above guidance is maintained as an Operations departmental procedure. It is used by the Operations department, and Operations management is responsible for its content and maintenance. The ownership of this procedure is subject to change if deemed appropriate.

3.0 RICT Program Training

The scope of the training for the RICT Program will include training on rules for the new TS program, CRMP modifications, TS Actions included in the program, and procedures. This training will be conducted for SNC site and corporate personnel. The personnel that will require training are as follows:

Site Personnel

Operations Site Functional Area Manager
Operations Personnel (Licensed and Non-Licensed)
Operations Training
Outage & Scheduling Site Functional Area Manager
Outage & Scheduling Personnel
Work Week Managers
Nuclear Licensing Site Personnel
Selected Maintenance Personnel
Site Engineering
Risk Informed Engineering Site Risk Analyst and Backups
Other Management

Corporate Personnel

Operations Corporate Functional Area Manager
Outage & Scheduling Corporate Functional Area Manager
Nuclear Licensing Corporate Functional Area Manager and Site Functional Area Manager
Nuclear Licensing Personnel
Risk Informed Engineering Management
Selected Risk Informed Engineering Personnel
Other Management

Training will be carried out in accordance with SNC training procedures and processes (e.g., Reference 8). These procedures were written based on the Institute of Nuclear Power Operations (INPO) Accreditation (ACAD) requirements, as developed and maintained by the National Academy for Nuclear Training. SNC has developed three levels of training for implementation of the RICT Program at Farley and Vogtle Units 1 and 2, and these will be adopted for training for implementation of the RICT Program at HNP once the HNP RICT program is approved. They are described below:

3.1 Level 1 Training

This is the most detailed training. It is intended for the individuals who will be directly involved in the implementation of the RICT Program. This level of training includes the following attributes:

- Specific training on the revised Technical Specifications
- New Record Keeping Requirements
- Case Studies
- Hands-on time with the CRMP monitor
- Calculating a RMAT and RICT
- Identifying appropriate Risk Management Actions (RMA)
- Determining PRA Functionality
- Common Cause Failure Considerations

3.2 Level 2 Training

This training is geared towards Supervisors, Managers, and individual contributors who need to understand the RICT Program. It is significantly more detailed than Level 3 Training (described below), but it is different from Level 1 Training in that hands-on time with the CRMP monitor and Case Studies are not included. The concepts of the RICT Program will be taught, but this group of personnel will not be qualified to perform the tasks of the Control Room Operators or the Work Week Managers.

3.3 Level 3 Training

This training will be intended for the remaining personnel who should have an awareness of the RICT Program. These employees need basic knowledge of RICT Program requirements and procedures, but they do not need working knowledge of these requirements and procedures. This training will cover RICT Program concepts that are important to disseminate throughout the organization.

The above training will be conducted within the procedural guidance set forth in SNC's Training and Qualification procedures (e.g., References 9 and 10).

4.0 References

1. Nuclear Energy Institute (NEI) Topical Report (TR) NEI 06-09, "Risk-Informed Technical Specifications Initiative 4b, Risk-Managed Technical Specifications (RMTS) Guidelines," Revision 0-A, October 2012 (ADAMS Accession No. ML12286A322).

2. Southern Nuclear Company NMP-GM-031, "On-Line Configuration Risk Management Program."

3. Southern Nuclear Company NMP-GM-031-003, "Risk Management Actions for 10 CFR 50.65(a)(4) and the Risk Informed Completion Time Program," Version 8.0, January 2020.

4. Southern Nuclear Company NMP-GM-031-002, "Calculation of RMAT and RICT for the RICT Program," Version 5.0, January 2020.

5. Southern Nuclear Company NMP-GM-031-004, "PRA Functionality Determination," Version 5.0, January 2020.

6. Southern Nuclear Company NMP-OS-027, "Recording Limiting Conditions for Operation," Version 2, November, 2020.

7. Not Used

8. Southern Nuclear Company NMP-TR-104, "SNC Training Committees," Version 20.1.

9. Southern Nuclear Company NMP-TR-415, "Systems Operator Initial and Continuing Training Program," Version 5.2.

10. Southern Nuclear Company NMP-TR-416, "Licensed Operator Continuing Training Program Administration," Version 12.1.

ENCLOSURE 11

Edwin I. Hatch Nuclear Plant - Units 1 and 2
License Amendment Request to Revise Technical Specifications
to Adopt Risk Informed Completion Times TSTF-505, Revision 2,
"Provide Risk-Informed Extended Completion Times - RITSTF Initiative 4b"

Risk and Performance Monitoring Program

Table of Contents

1.0 Introduction

This Enclosure provides summaries of the three procedures that govern the implementation of the Southern Nuclear Operating Company (SNC) Risk-Informed Completion Time (RICT) Program's Calculation of Cumulative Risk and Performance Monitoring.

Calculation of cumulative risk for the RICT Program is discussed in step 14 of Section 2.3.1 and step 7.1 of Section 2.3.2 of Topical Report NEI 06-09, Revision 0-A (Reference 1). The Performance Monitoring Program is discussed in Section 2.3, Element 3 of Regulatory Guide (RG) 1.174 (Reference 2). Further elaboration on the Performance Monitoring Program is found in Section 3 of RG 1.177 (Reference 3). The NRC's Safety Evaluation of NEI 06-09 (Reference 1) requests that the above procedures be discussed in the License Amendment Request.

The procedures referred to are currently effective with respect to the approved Farley and Vogtle RICT programs and will be made effective for HNP once the RICT program is approved for implementation at HNP.

2.0 Risk Informed Applications

This procedure contains the instructions for the calculation of cumulative risk. The Risk Informed Engineering (RIE) Department is the procedure owner and the RIE site engineer is responsible for executing the procedure. The procedure requires the calculation of cumulative risk at least every fuel cycle, not to exceed 24 months.

The procedure requires gathering historical data with respect to RICT Program entries for an assessment period which, as previously mentioned, is one fuel cycle, not to exceed 24 months. The procedure provides the method for calculating the cumulative Incremental Core Damage Probability (ICDP) and Incremental Large Early Release Probability (ILERP). These values are then converted into average annual values which are then compared to the limits of RG 1.174 (Reference 2).

If any limits are exceeded, a Condition Report (CR) is written to ensure the data is reviewed to assess the cause and to implement any necessary corrective actions to ensure future plant operation is within the guidance. This evaluation assures that RMTS program implementation meets RG 1.174 (Reference 2) guidance for small risk increases.

The procedure further instructs personnel to document the periodic assessment in a calculation including the cumulative risk, the method of monitoring the cumulative risk, comparison with RG 1.174 limits (Reference 2), and any condition reports issued including references to items that track development and/or completion of corrective actions. This procedure is under the oversight of the RIE department.

3.0 Performance Monitoring Program

Performance Monitoring is described in the Maintenance Rule implementation procedure as well as the On-Line Configuration Management procedure. This procedure is currently applicable to Farley and Vogtle. Upon approval of the RICT program for HNP, the procedure will be revised to note that it is also applicable to HNP.

The purpose of performance monitoring is to monitor the effects of the RICT on a particular SSC's performance which has had its Completion Time (CT) extended by the RICT Program. In other words, this program is used to ensure that the use of the RICT program, for a specified SSC, does not degrade the performance of that SSC over time. The SSCs in the scope of the RICT program are also in the scope of the Maintenance Rule. Additionally, it does not alter the system or train Operability requirements with respect to the number of systems and trains required to be Operable nor does it change the stated TS performance criteria (e.g. flow rate, response times, stroke times, setpoints, etc.).

These procedures are under the oversight of the Engineering Systems Department (Maintenance Rule Implementation) and Work Management (On-Line Configuration Risk Management Program). The RIE site engineer has the primary responsibility for the execution of performance monitoring program for the Risk Informed Completion Time Program. The ownership of these procedures is subject to change as deemed appropriate.

Monitoring the actual performance of a component under the Maintenance Rule is done on a monthly basis. Consequently, if it is determined that the RICT was the cause, or a contributing factor, in exceeding Maintenance Rule performance criteria, corrective actions are initiated.

Although others are possible, these actions may include a moratorium on future entries into pre-planned RICTs for a period of time, or restricting the use of a RICT for specific configurations or components. Whatever the corrective actions, they are communicated to the site RIE Engineer for his or her evaluation.

4.0 References

1. Nuclear Energy Institute (NEI) Topical Report (TR) NEI 06-09, "Risk-Informed Technical Specifications Initiative 4b, Risk-Managed Technical Specifications (RMTS) Guidelines," Revision 0-A, October 2012 (ADAMS Accession No. ML12286A322).

2. Regulatory Guide 1.174, “An Approach for Using Probabilistic Risk Assessment in Risk- Informed Decisions on Plant Specific Changes to the Licensing Basis,” US Nuclear Regulatory Commission, Revision 3, January 2018 (ADAMS Accession No. ML17317A256).

3. Regulatory Guide 1.177, “An Approach for Plant-Specific, Risk-Informed Decision Making: Technical Specifications,” US Nuclear Regulatory Commission, Revision 2, January 2021 (ADAMS Accession No. ML20164A034)

ENCLOSURE 12

Edwin I. Hatch Nuclear Plant – Units 1 and 2
License Amendment Request to Revise Technical Specifications
to Adopt Risk Informed Completion Times TSTF-505, Revision 2,
"Provide Risk-Informed Extended Completion Times - RITSTF Initiative 4b"

Risk Management Action Examples

1 Introduction

This enclosure describes the process for identification and implementation of Risk Management Actions (RMAs) applicable during extended Completion Times (CTs) and provides examples of RMAs. RMAs will be governed by plant procedures for planning and scheduling maintenance activities. The procedures will provide guidance for the determination and implementation of RMAs when entering the Risk-Informed Completion Time (RICT) Program consistent with the guidance provided in NEI 06-09-A, Revision 0-A [1].

2 Responsibilities

For planned entries into the RICT Program, Work Management is responsible for developing the RMAs with assistance from Operations and Risk Informed Engineering (RIE). Operations is responsible for approval and implementation of RMAs. For emergent entry into extended CTs, Operations is also responsible for developing the RMAs.

3 Procedural Guidance

For planned maintenance activities, implementation of RMAs will be required if it is anticipated that the Risk Management Action Time (RMAT) will be exceeded. For emergent activities, RMAs must be implemented if the RMAT is reached. Also, if an emergent event occurs requiring recalculation of a RMAT already in place, the procedure will require a re-evaluation of the existing RMAs for the new plant configuration to determine if new RMAs are appropriate. These requirements of the RICT Program are consistent with the guidance of NEI 06-09 [1].

For emergent entry into a RICT, if the extent of condition is not known, RMAs related to the success of redundant and diverse SSCs and reducing the likelihood of initiating events relying on the affected function will be developed to address the increased likelihood of a common cause event.

RMAs will be implemented in accordance with current procedures [2] [3] [4] no later than the time at which an Incremental Core Damage Probability (ICDP) of 1E-6 is reached, or no later than the time when an Incremental Large Early Release Probability (ILERP) of 1E-7 is reached. If, as the result of an emergent condition, the Instantaneous Core Damage Frequency (ICDF) or the Instantaneous Large Early Release Frequency (ILERF) exceeds 1E-3 per year or 1E-4 per year, respectively, RMAs are also required to be implemented. These requirements are consistent with the guidelines of NEI 06-09 [1].

By determining which Structures, Systems, or Components (SSCs) are most important from a CDF or LERF perspective for a specific plant configuration, RMAs may be created to protect these SSCs. Similarly, knowledge of the initiating event or sequence contribution to the configuration-specific CDF or LERF allows development of RMAs that enhance the capability to mitigate such events. The RMA process also makes use of existing qualitative programs such as the Protected Train/Equipment [5] and Switchyard Work controls [6]. If the planned activity or emergent condition includes an SSC that is identified to impact Fire PRA, as identified in the current Configuration Risk Management Program (CRMP), Fire PRA specific RMAs associated with that SSC will be implemented per the current plant procedure. RMAs are developed based on the Protected Train/Equipment program [5] and on the CRMP tool to identify configuration-specific RMA candidates to manage the risk associated with internal events, internal flooding, and fire events.

It is possible to credit RMAs in RICT calculations, to the extent the associated plant equipment and operator actions are modeled in the PRA; however, such quantification of RMAs is neither required nor expected by NEI 06-09 [1]. Nonetheless, if RMAs will be credited to determine RICTs, the process used will be consistent with the guidance in NEI 06-09-A [1].

Site procedures classify RMAs into the three categories described below, in accordance with NEI 06-09-A:

Tier 1 Actions to increase risk awareness and control.
- Brief operating shifts and increase operator awareness of configurationspecific risks.
- Conduct pre-job briefing of maintenance personnel, emphasizing risk aspects of planned maintenance activities.
- Increase control of activities that could result in an initiating event (e.g. loss of offsite power).
- Protect redundant components identified by the protected train/component process.
- Protect functional components that are most important for mitigating risk significant events in the CRM.
- Require a knowledgeable observer or subject matter expert to be present for the maintenance activity, or for applicable portions of the activity.

Tier 2 Actions to reduce the duration of maintenance activities.
- Pre stage parts and materials.
- Conduct training on mockups to familiarize maintenance personnel with the activity.
- Perform maintenance around the clock.
- Establish contingency plans to restore to functional status those out of service components that are most important to accident mitigation.
- Defer activities that could result in an initiating event (e.g. loss of offsite power).
- Protect a greater number of the functional components that are most important for mitigating non-fire and fire events.
- Establish alternate success paths for performance of the safety function of the out-of-service equipment. Equipment used to establish these alternate success paths need not necessarily be within the overall scope of the maintenance rule (can use portable equipment).
- Evaluate and implement alternate plant alignments that minimize risk. For example, minimize the number of components running on the protected train safety bus during a

diesel generator extended AOT, such that load shed of the protected safety bus loads is more likely to succeed.

- Walkdowns of key safety systems by on-shift SROs and management personnel before and during the work activity.
- Increasing surveillance frequencies of key safety functions by testing alternate equipment prior to the planned work or frequent inspections of standby equipment during work.
- Establish other compensatory measures such as temporary power or pumps.
- Reschedule risk significant work.
- Reduce the duration of risk significant work.

Tier 3 - Actions to minimize the magnitude of the risk increase.

- Suspend or minimize activities on redundant systems
- Suspend or minimize activities on other systems that adversely affect the CDF or LERF
- Suspend or minimize activities on systems that may cause a trip or transient to minimize the likelihood of an initiating event that the out-of-service component is meant to mitigate
- Use temporary equipment to provide backup power, ventilation, etc.
- Reschedule other risk-significant activities
- Take immediate action to restore to functional status those out of service components that are most important to accident mitigation.
- If unable to transition below RED in a reasonable amount of time, not to exceed 3 days from the time a RED condition was entered, consider an orderly transition to Mode 3.
- Contact RIE staff for additional guidance on potential means of lowering risk below RED.
- Implement actions that generate increased fire risk awareness, control, and coordination.
- Confirm the availability of alternate success paths for safe shutdown if required. (Farley/Hatch only)
- Protect functional components that are most important for mitigating fire events.
- For high risk fire zones, verify and maintain functionality of the following:
    - Detection
    - Suppression
    - Barriers
    - Fire Pumps
- For any selected fire zones with degraded or unavailable fire protection equipment, the following actions may be taken:
    - Place restrictions on work activities (including “hot work”) that could cause fires.
    - Place restrictions on storage and movement of transient combustibles.
    - Perform walkdowns to verify orderly storage of transient combustibles.
    - Implement fire watches.
    - Install temporary fire barriers such as fire wraps, blankets, or other approved barriers to protect cables or other SSCs from being damaged.
    - Pre-stage firefighting personnel and/or equipment to reduce fire severity and propagation.
    - Perform thermography to identify electrical hot spots.
    - Defer circuit breaker operations for 480V and higher voltage breakers.

Determination of RMAs involves the use of both qualitative and quantitative considerations for the specific plant configuration and the practical means available to manage risk. The scope and number of RMAs developed and implemented are reached in a graded manner. Procedural guidance for development of RMAs in support of the RICT program builds off the RMAs developed for other processes, such as the RMAs developed under the 10 CFR 50.65(a)(4) program and the protected equipment program. Additionally, Common Cause RMAs are developed to address the potential impact of common cause failures.

For emergent conditions where the extent of condition is not performed prior to entering into the Risk Management Action Times or the extent of condition cannot rule out the potential for common cause failure, common cause RMAs are expected to be implemented to mitigate common cause failure potential and impact. Common cause RMAs are developed to ensure availability of redundant SSCs, to ensure availability of diverse or alternate systems, to reduce the likelihood of initiating events that require operation of the out-of-service components, and to prepare plant personnel to respond to additional failures. Common cause RMAs are developed by considering the impact of loss of function for the affected SSCs.

Common Cause RMAs lower configuration risk by focusing on

- Availability of SSCs providing redundancy to the failed SSC,
- Availability of diverse SSCs (e.g. HPCI vs. RCIC) providing redundancy for functions performed by the failed SSC,
- Reducing the likelihood of events that can impact the availability of diverse or redundant SSCs,
- Reducing the likelihood of events for which event mitigation may require operation of diverse or redundant SSCs,
- Readiness of operators to respond to initiating events assuming SSCs susceptible to failure by common cause will fail, and
- Readiness of maintenance to respond to additional failures of diverse and redundant SSCs.

Common Cause RMAs include the following actions:

- Defer maintenance and testing activities that could generate an initiating event for which event mitigation may require operation of SSCs susceptible to failure by common cause.
- Establish a compensatory action, shift brief, or standing order that focuses on actions operators will take in response to an initiating event and failure of SSCs susceptible to failure by common cause.
- For the SSCs that provide redundancy to the failed SSC,
    - Reduce the likelihood of unavailability, including for support systems and power supplies.
    - Perform non-intrusive inspections.
    - Defer maintenance and testing activities that could impact availability of the SSC.
- For diverse SSCs (e.g. normal charging pump) that provide redundancy for functions performed by the failed SSC,

  - Reduce the likelihood of unavailability, including for support systems and power supplies.
  - Perform non-intrusive inspections.
  - Defer maintenance and testing activities that could impact availability of the SSC.
- For applicable standby SSCs, perform an operability/functionality run.
- Establish an alternate functional capability (e.g. installation of portable equipment).
- Generate and implement a contingency plan to
- Enable prompt installation of an alternate functional capability (e.g. shiftly review of procedures on use of portable equipment), or
- Enable prompt restoration of functionality of a failed SSC (e.g. maintenance crash cart)
- For applicable running components, monitor parameters more frequently and/or expand the scope of parameter monitoring.
- For applicable SSCs, perform monitoring and inspection activities based on review of information/data from previous testing, maintenance, and/or operating experience.
- General guidance for RMAs that maintain functionality of important equipment:
- Protect other systems that perform the same function.
- Place standby equipment in service.
- If available, stage temporary equipment such as FLEX equipment and perform a shift brief on its use.

4 Examples

Representative examples of RMAs that may be considered during a RICT Program entry, to reduce the risk impact and ensure adequate defense-in-depth, for TS 3.8 electrical equipment are provided below.

4.1 TS 3.8.1 Electrical Action Statements

To adequately demonstrate a reasonable balance of defense-in-depth is maintained, the following sample RMAs are provided for TS 3.8 Action Statements, which pertain to safety-related electrical equipment.

4.1.1 TS 3.8.1 Required Action A.3

For TS 3.8.1 Condition A, one required offsite circuit inoperable, the sample calculated RICT provided in Enclosure 1 is on the order of 7.7 days. The front stop completion time is 72 hours. Example RMAs to ensure a reasonable balance of defense-in-depth is maintained during the example emergent scenario for TS 3.8.1 Condition A are as follows:

1. Actions to increase risk awareness and control.
   a. Briefing of the on-shift operations crew concerning the unit activities, including any compensatory measures established, and review of the appropriate emergency operating procedures for a Loss of Offsite Power and station blackout including bus crossties.

b. Notification of the Transmission Control Center (TCC) of the configuration so that any planned activities with the potential to cause a grid disturbance are deferred.
c. Deferral of maintenance and testing activities with the potential to cause an initiating event.
d. Periodic walkdowns by on-shift SROs and/or management personnel to verify implementation of established risk management actions.

2. Actions to reduce the duration of maintenance activities.
    a. For preplanned RICT entry, creation of a sub schedule related to the specific evolution which is reviewed for personnel resource availability.
    b. For preplanned RICT entry, confirmation of work package preparation and parts availability prior to entry.
    c. Work the activity around the clock.
    d. Engage specialty contractors or subject matter experts.

3. Actions to minimize the magnitude of the risk increase.
    a. Evaluation of weather conditions for threats to the reliability of remaining offsite power supply.
    b. Management of elective maintenance in the switchyard, on the station electrical distribution systems, and on the main and auxiliary transformers associated with the unit in the RICT
    c. Protection of the remaining offsite source, including switchyard and transformer.
    d. Maintain operability/availability of components identified as having high importance according to the configuration-specific evaluation with CRMP software.
    e. Reduce the likelihood of fire in fire zones identified as having high risk significance according to the configuration-specific evaluation with CRMP software. Actions may include verification of availability of fire protection equipment (suppression, detection, and barriers) and restricting work activities that impact fire protection equipment availability, involve hot work, or introduce transient combustible materials. Additional potential actions include establishing fire watches, minimizing high energy circuit breaker operations, and surveying for electrical hot spots using thermography.
    f. For preplanned RICT entry, evaluation prior to the RICT entry of the redundant train(s) to ensure no active equipment issues that could result in inoperability during the RICT.

4.1.2 TS 3.8.1 Required Action B.4

For TS 3.8.1 Condition B, one Same Unit DG or the swing DG inoperable, the sample calculated RICT provided in Enclosure 1 is on the order of 30 days. The front stop completion time is 72 hours. Example RMAs to ensure a reasonable balance of defense-in-depth is maintained during the example emergent scenario for TS 3.8.1 Condition B are as follows:

1. Actions to increase risk awareness and control.
    a. Briefing of the on-shift operations crew concerning the unit activities, including any compensatory measures established, and review of the appropriate emergency operating procedures for a Loss of Offsite Power and station blackout including bus crossties.
    b. Notification of the Transmission Control Center (TCC) of the configuration so that any planned activities with the potential to cause a grid disturbance are deferred.
    c. Deferral of maintenance and testing activities with the potential to cause an initiating event.
    d. Periodic walkdowns by on-shift SROs and/or management personnel to verify implementation of established risk management actions.

2. Actions to reduce the duration of maintenance activities.
    a. For preplanned RICT entry, creation of a sub schedule related to the specific evolution which is reviewed for personnel resource availability.
    b. For preplanned RICT entry, confirmation of work package preparation and parts availability prior to entry.
    c. Work the activity around the clock.
    d. Engage specialty contractors or subject matter experts.

3. Actions to minimize the magnitude of the risk increase.
    a. Evaluation of weather conditions for threats to the reliability of offsite power supplies
    b. Protect the redundant diesels and associated switchgear.
    c. Management of elective maintenance in the switchyard, on the station electrical distribution systems, and on the main and auxiliary transformers associated with the unit in the RICT
    d. Protection of the offsite source, including switchyard and transformer.
    e. Maintain operability/availability of components identified as having high importance according to the configuration-specific evaluation with CRMP software.
    f. Reduce the likelihood of fire in fire zones identified as having high risk significance according to the configuration-specific evaluation with CRMP software. Actions may include verification of availability of fire protection equipment (suppression, detection, and barriers) and restricting work activities that impact fire protection equipment availability, involve hot work, or introduce transient combustible materials. Additional potential actions include establishing fire watches, minimizing high energy circuit breaker operations, and surveying for electrical hot spots using thermography.
    g. For preplanned RICT entry, evaluation prior to the RICT entry of the redundant train(s) to ensure no active equipment issues that could result in inoperability during the RICT.

4.1.3 TS 3.8.1 Required Action C.4

For TS 3.8.1 Condition C, one required Opposite Unit DG inoperable, the sample calculated RICT provided in Enclosure 1 is on the order of 30 days. The front stop completion time is 7 days. Example RMAs to ensure a reasonable balance of defense-in-depth is maintained during the example emergent scenario for TS 3.8.1 Condition C are as follows:

1. Actions to increase risk awareness and control.
    a. Briefing of the on-shift operations crew concerning the unit activities, including any compensatory measures established, and review of the appropriate emergency operating procedures for a Loss of Offsite Power and station blackout including bus crossties.
    b. Notification of the Transmission Control Center (TCC) of the configuration so that any planned activities with the potential to cause a grid disturbance are deferred.
    c. Deferral of maintenance and testing activities with the potential to cause an initiating event.
    d. Periodic walkdowns by on-shift operations and/or management personnel to verify implementation of established risk management actions.

2. Actions to reduce the duration of maintenance activities.
    a. For preplanned RICT entry, creation of a sub schedule related to the specific evolution which is reviewed for personnel resource availability.
    b. For preplanned RICT entry, confirmation of work package preparation and parts availability prior to entry.
    c. Work the activity around the clock.
    d. Engage specialty contractors or subject matter experts.

3. Actions to minimize the magnitude of the risk increase.
    a. Evaluation of weather conditions for threats to the reliability of remaining offsite power supplies
    b. Protect the appropriate redundant components.
    c. Management of elective maintenance in the switchyard, on the station electrical distribution systems, and on the main and auxiliary transformers associated with the unit in the RICT
    d. Protection of the offsite sources, including switchyard and transformer.
    e. Maintain operability/availability of components identified as having high importance according to the configuration-specific evaluation with CRMP software.
    f. Reduce the likelihood of fire in fire zones identified as having high risk significance according to the configuration-specific evaluation with CRMP software. Actions may include verification of availability of fire protection equipment (suppression, detection, and barriers) and restricting work activities that impact fire protection equipment availability, involve hot work, or introduce transient combustible materials. Additional potential actions include establishing

fire watches, minimizing high energy circuit breaker operations, and surveying for electrical hot spots using thermography.

g. For preplanned RICT entry, evaluation prior to the RICT entry of the redundant train(s) to ensure no active equipment issues that could result in inoperability during the RICT.

4.1.4 TS 3.8.1 Required Action D.2

For TS 3.8.1 Condition D, two or more required offsite circuits inoperable, the sample calculated RICT provided in Enclosure 1 is on the order of 5.4 days. The front stop completion time is 24 hours. Example RMAs to ensure a reasonable balance of defense-in-depth is maintained during the example emergent scenario for TS 3.8.1 Condition D are as follows:

1. Actions to increase risk awareness and control.
    a. Briefing of the on-shift operations crew concerning the unit activities, including any compensatory measures established, and review of the appropriate emergency operating procedures for a Loss of Offsite Power and station blackout including bus crossties.
    b. Notification of the Transmission Control Center (TCC) of the configuration so that any planned activities with the potential to cause a grid disturbance are deferred.
    c. Deferral of maintenance and testing activities with the potential to cause an initiating event.
    d. Periodic walkdowns by on-shift operations and/or management personnel to verify implementation of established risk management actions.

2. Actions to reduce the duration of maintenance activities.
    a. For preplanned RICT entry, creation of a sub schedule related to the specific evolution which is reviewed for personnel resource availability.
    b. For preplanned RICT entry, confirmation of work package preparation and parts availability prior to entry.
    c. Work the activity around the clock.
    d. Engage specialty contractors or subject matter experts.

3. Actions to minimize the magnitude of the risk increase.
    a. Management of elective maintenance in the switchyard, on the station electrical distribution systems, and on the main and auxiliary transformers associated with the unit in the RICT
    b. Maintain operability/availability of components identified as having high importance according to the configuration-specific evaluation with CRMP software.
    c. Reduce the likelihood of fire in fire zones identified as having high risk significance according to the configuration-specific evaluation with CRMP software. Actions may include verification of availability of fire protection

equipment (suppression, detection, and barriers) and restricting work activities that impact fire protection equipment availability, involve hot work, or introduce transient combustible materials. Additional potential actions include establishing fire watches, minimizing high energy circuit breaker operations, and surveying for electrical hot spots using thermography.

d. For preplanned RICT entry, evaluation prior to the RICT entry of the redundant train(s) to ensure no active equipment issues that could result in inoperability during the RICT.

4.1.5 TS 3.8.1 Required Action E.1 and E.2

For TS 3.8.1 Condition E, one required offsite circuit inoperable and one required DG inoperable, the sample calculated RICT provided in Enclosure 1 is on the order of 19 hours for an emergent RICT. By current CRMP calculation, the use of the RICT Program on this Action for planned equipment outages is precluded by the instantaneous CDF or LERF limits of 1E-03 or 1E-04, respectively. A RICT may still be entered for this action in the event of an unplanned equipment failure in accordance with NEI 06-09 guidance. The front stop completion time is 12 hours. Example RMAs to ensure a reasonable balance of defense-in-depth is maintained during the example emergent scenario for TS 3.8.1 Condition E are as follows:

1. Actions to increase risk awareness and control.
   a. Briefing of the on-shift operations crew concerning the unit activities, including any compensatory measures established, and review of the appropriate emergency operating procedures for a Loss of Offsite Power and station blackout including bus crossties.
   b. Notification of the Transmission Control Center (TCC) of the configuration so that any planned activities with the potential to cause a grid disturbance are deferred.
   c. Deferral of maintenance and testing activities with the potential to cause an initiating event.
   d. Periodic walkdowns by on-shift operations and/or management personnel to verify implementation of established risk management actions.

2. Actions to reduce the duration of maintenance activities.
   a. Work the activity around the clock.
   b. Engage specialty contractors or subject matter experts.

3. Actions to minimize the magnitude of the risk increase.
   a. Evaluation of weather conditions for threats to the reliability of remaining offsite power supplies
   b. Management of elective maintenance in the switchyard, on the station electrical distribution systems, and on the main and auxiliary transformers associated with the unit in the RICT
   c. Protection of the remaining offsite source, including switchyard and transformer.

d. Maintain operability/availability of components identified as having high importance according to the configuration-specific evaluation with CRMP software.
e. Reduce the likelihood of fire in fire zones identified as having high risk significance according to the configuration-specific evaluation with CRMP software. Actions may include verification of availability of fire protection equipment (suppression, detection, and barriers) and restricting work activities that impact fire protection equipment availability, involve hot work, or introduce transient combustible materials. Additional potential actions include establishing fire watches, minimizing high energy circuit breaker operations, and surveying for electrical hot spots using thermography.

4.2 TS 3.8.4 Electrical Action Statements

4.2.1 TS 3.8.4 Required Action A.1

For TS 3.8.4 Condition A, swing DG DC electrical power subsystem inoperable due to performance of SR 3.8.4.3 or SR 3.8.6.6 OR one or more required other unit DG DC electrical power subsystems inoperable, the sample calculated RICT provided in Enclosure 1 is on the order of 30 days. The front stop completion time is 7 days. Example RMAs to ensure a reasonable balance of defense-in-depth is maintained during the example emergent scenario for TS 3.8.4 Condition A are as follows:

1. Actions to increase risk awareness and control.
   a. Briefing of the on-shift operations crew concerning the unit activities, including any compensatory measures established, and review of the appropriate emergency operating procedures for a Loss of Offsite Power and station blackout including bus crossties.
   b. Notification of the Transmission Control Center (TCC) of the configuration so that any planned activities with the potential to cause a grid disturbance are deferred.
   c. Deferral of maintenance and testing activities with the potential to cause an initiating event.
   d. Periodic walkdowns by on-shift operations and/or management personnel to verify implementation of established risk management actions.

2. Actions to reduce the duration of maintenance activities.
   a. For preplanned RICT entry, creation of a sub schedule related to the specific evolution which is reviewed for personnel resource availability.
   b. For preplanned RICT entry, confirmation of work package preparation and parts availability prior to entry.
   c. Work the activity around the clock.
   d. Engage specialty contractors or subject matter experts.

3. Actions to minimize the magnitude of the risk increase.
    a. Evaluation of weather conditions for threats to the reliability of remaining offsite power supplies
    b. Management of elective maintenance in the switchyard, on the station electrical distribution systems, and on the main and auxiliary transformers associated with the unit in the RICT
    c. Protection of the remaining offsite source, including switchyard and transformer.
    d. Maintain operability/availability of components identified as having high importance according to the configuration-specific evaluation with CRMP software.
    e. Reduce the likelihood of fire in fire zones identified as having high risk significance according to the configuration-specific evaluation with CRMP software. Actions may include verification of availability of fire protection equipment (suppression, detection, and barriers) and restricting work activities that impact fire protection equipment availability, involve hot work, or introduce transient combustible materials. Additional potential actions include establishing fire watches, minimizing high energy circuit breaker operations, and surveying for electrical hot spots using thermography.
    f. For preplanned RICT entry, evaluation prior to the RICT entry of the redundant train(s) to ensure no active equipment issues that could result in inoperability during the RICT.

4.2.2 TS 3.8.4 Required Action B.3

For TS 3.8.4 Condition B, required same unit DG DC battery charger on one subsystem inoperable OR required swing DG DC battery charger inoperable for reasons other than Condition A, the sample calculated RICT provided in Enclosure 1 is on the order of 30 days. The front stop completion time is 72 hours. Example RMAs to ensure a reasonable balance of defense-in-depth is maintained during the example emergent scenario for TS 3.8.4 Condition B are as follows:

1. Actions to increase risk awareness and control.
    a. Briefing of the on-shift operations crew concerning the unit activities, including any compensatory measures established, and review of the appropriate emergency operating procedures for a Loss of Offsite Power and station blackout including bus crossties.
    b. Notification of the Transmission Control Center (TCC) of the configuration so that any planned activities with the potential to cause a grid disturbance are deferred.
    c. Deferral of maintenance and testing activities with the potential to cause an initiating event.
    d. Periodic walkdowns by on-shift operations and/or management personnel to verify implementation of established risk management actions.

2. Actions to reduce the duration of maintenance activities.
    a. For preplanned RICT entry, creation of a sub schedule related to the specific evolution which is reviewed for personnel resource availability.
    b. For preplanned RICT entry, confirmation of work package preparation and parts availability prior to entry.
    c. Work the activity around the clock.
    d. Engage specialty contractors or subject matter experts.

3. Actions to minimize the magnitude of the risk increase.
    a. Evaluation of weather conditions for threats to the reliability of remaining offsite power supplies
    b. Management of elective maintenance in the switchyard, on the station electrical distribution systems, and on the main and auxiliary transformers associated with the unit in the RICT
    c. Protection of the remaining offsite source, including switchyard and transformer.
    d. Maintain operability/availability of components identified as having high importance according to the configuration-specific evaluation with CRMP software.
    e. Reduce the likelihood of fire in fire zones identified as having high risk significance according to the configuration-specific evaluation with CRMP software. Actions may include verification of availability of fire protection equipment (suppression, detection, and barriers) and restricting work activities that impact fire protection equipment availability, involve hot work, or introduce transient combustible materials. Additional potential actions include establishing fire watches, minimizing high energy circuit breaker operations, and surveying for electrical hot spots using thermography.
    f. For preplanned RICT entry, evaluation prior to the RICT entry of the redundant train(s) to ensure no active equipment issues that could result in inoperability during the RICT.

4.2.3 TS 3.8.4 Required Action C.1

For TS 3.8.4 Condition C, one Same Unit DG DC electrical power subsystem inoperable for reasons other than Condition B OR swing DG DC electrical power subsystem inoperable for reasons other than Condition A or B, the sample calculated RICT provided in Enclosure 1 is on the order of 30 days. The front stop completion time is 12 hours. Example RMAs to ensure a reasonable balance of defense-in-depth is maintained during the example emergent scenario for TS 3.8.4 Condition C are as follows:

1. Actions to increase risk awareness and control.
    a. Briefing of the on-shift operations crew concerning the unit activities, including any compensatory measures established, and review of the appropriate emergency operating procedures for a Loss of Offsite Power and station blackout including bus crossties.

b. Notification of the Transmission Control Center (TCC) of the configuration so that any planned activities with the potential to cause a grid disturbance are deferred.
c. Deferral of maintenance and testing activities with the potential to cause an initiating event.
d. Periodic walkdowns by on-shift operations and/or management personnel to verify implementation of established risk management actions.

2. Actions to reduce the duration of maintenance activities.
   a. For preplanned RICT entry, creation of a sub schedule related to the specific evolution which is reviewed for personnel resource availability.
   b. For preplanned RICT entry, confirmation of work package preparation and parts availability prior to entry.
   c. Work the activity around the clock.
   d. Engage specialty contractors or subject matter experts.

3. Actions to minimize the magnitude of the risk increase.
   a. Evaluation of weather conditions for threats to the reliability of remaining offsite power supplies
   b. Management of elective maintenance in the switchyard, on the station electrical distribution systems, and on the main and auxiliary transformers associated with the unit in the RICT
   c. Protection of the remaining offsite source, including switchyard and transformer.
   d. Maintain operability/availability of components identified as having high importance according to the configuration-specific evaluation with CRMP software.
   e. Reduce the likelihood of fire in fire zones identified as having high risk significance according to the configuration-specific evaluation with CRMP software. Actions may include verification of availability of fire protection equipment (suppression, detection, and barriers) and restricting work activities that impact fire protection equipment availability, involve hot work, or introduce transient combustible materials. Additional potential actions include establishing fire watches, minimizing high energy circuit breaker operations, and surveying for electrical hot spots using thermography.
   f. For preplanned RICT entry, evaluation prior to the RICT entry of the redundant train(s) to ensure no active equipment issues that could result in inoperability during the RICT.

4.2.4 TS 3.8.4 Required Action D.3

For TS 3.8.4 Condition D, one or more required same unit station service DC battery chargers on one subsystem inoperable, the sample calculated RICT provided in Enclosure 1 is on the order of 30 days. The front stop completion time is 72 hours. Example RMAs to ensure a reasonable balance of defense-in-depth is maintained during the example emergent scenario for TS 3.8.4 Condition D are as follows:

1. Actions to increase risk awareness and control.
    a. Briefing of the on-shift operations crew concerning the unit activities, including any compensatory measures established, and review of the appropriate emergency operating procedures for a Loss of Offsite Power and station blackout including bus crossties.
    b. Deferral of maintenance and testing activities with the potential to cause an initiating event.
    c. Periodic walkdowns by on-shift operations and/or management personnel to verify implementation of established risk management actions.

2. Actions to reduce the duration of maintenance activities.
    a. For preplanned RICT entry, creation of a sub schedule related to the specific evolution which is reviewed for personnel resource availability.
    b. For preplanned RICT entry, confirmation of work package preparation and parts availability prior to entry.
    c. Walkdown of work prior to execution.

3. Actions to minimize the magnitude of the risk increase.
    a. Evaluation of weather conditions for threats to the reliability of remaining offsite power supplies
    b. Management of elective maintenance on the station electrical distribution systems associated with the unit in the RICT
    c. Protection of the opposite station DC system.
    d. Maintain operability/availability of components identified as having high importance according to the configuration-specific evaluation with CRMP software.
    e. Reduce the likelihood of fire in fire zones identified as having high risk significance according to the configuration-specific evaluation with CRMP software. Actions may include verification of availability of fire protection equipment (suppression, detection, and barriers) and restricting work activities that impact fire protection equipment availability, involve hot work, or introduce transient combustible materials. Additional potential actions include establishing fire watches, minimizing high energy circuit breaker operations, and surveying for electrical hot spots using thermography.
    f. For preplanned RICT entry, evaluation prior to the RICT entry of the redundant train(s) to ensure no active equipment issues that could result in inoperability during the RICT.

4.2.5 TS 3.8.4 Required Action E.1

For TS 3.8.4 Condition E, one Same Unit station service DC electrical power subsystem inoperable for reasons other than Condition D, the sample calculated RICT provided in Enclosure 1 is on the order of 14.1 days. The front stop completion time is 2 hours. Example

RMAs to ensure a reasonable balance of defense-in-depth is maintained during the example emergent scenario for TS 3.8.4 Condition E are as follows:

1. Actions to increase risk awareness and control.
    a. Briefing of the on-shift operations crew concerning the unit activities, including any compensatory measures established, and review of the appropriate emergency operating procedures for Loss of DC busses.
    b. Deferral of maintenance and testing activities with the potential to cause an initiating event.
    c. Periodic walkdowns by on-shift operations and/or management personnel to verify implementation of established risk management actions.

2. Actions to reduce the duration of maintenance activities.
    a. For preplanned RICT entry, creation of a sub schedule related to the specific evolution which is reviewed for personnel resource availability.
    b. For preplanned RICT entry, confirmation of work package preparation and parts availability prior to entry.
    c. Work the activity around the clock.
    d. Engage specialty contractors or subject matter experts.

3. Actions to minimize the magnitude of the risk increase.
    a. Management of elective maintenance on the station electrical distribution systems associated with the unit in the RICT
    b. Protection of the opposite division station DC system.
    c. Maintain operability/availability of components identified as having high importance according to the configuration-specific evaluation with CRMP software.
    d. Reduce the likelihood of fire in fire zones identified as having high risk significance according to the configuration-specific evaluation with CRMP software. Actions may include verification of availability of fire protection equipment (suppression, detection, and barriers) and restricting work activities that impact fire protection equipment availability, involve hot work, or introduce transient combustible materials. Additional potential actions include establishing fire watches, minimizing high energy circuit breaker operations, and surveying for electrical hot spots using thermography.
    e. For preplanned RICT entry, evaluation prior to the RICT entry of the redundant train(s) to ensure no active equipment issues that could result in inoperability during the RICT.

4.3 TS 3.8.7 Electrical Action Statements

4.3.1 TS 3.8.7 Required Action A.1

For TS 3.8.7 Condition A, one or more required Opposite Unit AC or DC electrical power distribution subsystems inoperable, the sample calculated RICT provided in Enclosure 1 is on the order of 13.2 days. The front stop completion time is 7 days. Example RMAs to ensure a reasonable balance of defense-in-depth is maintained during the example emergent scenario for TS 3.8.7 Condition A are as follows:

1. Actions to increase risk awareness and control.
    a. Briefing of the on-shift operations crew concerning the unit activities, including any compensatory measures established, and review of the appropriate emergency operating procedures for loss of distribution systems including alternate power sources.
    b. Deferral of maintenance and testing activities with the potential to cause an initiating event.
    c. Periodic walkdowns by on-shift operations and/or management personnel to verify implementation of established risk management actions.

2. Actions to reduce the duration of maintenance activities.
    a. For preplanned RICT entry, creation of a sub schedule related to the specific evolution which is reviewed for personnel resource availability.
    b. For preplanned RICT entry, confirmation of work package preparation and parts availability prior to entry.
    c. Work the activity around the clock.
    d. Engage specialty contractors or subject matter experts.

3. Actions to minimize the magnitude of the risk increase.
    a. Maintain operability/availability of components identified as having high importance according to the configuration-specific evaluation with CRMP software.
    b. Protect opposite train and components that become conditionally critical because of the configuration.
    c. Reduce the likelihood of fire in fire zones identified as having high risk significance according to the configuration-specific evaluation with CRMP software. Actions may include verification of availability of fire protection equipment (suppression, detection, and barriers) and restricting work activities that impact fire protection equipment availability, involve hot work, or introduce transient combustible materials. Additional potential actions include establishing fire watches, minimizing high energy circuit breaker operations, and surveying for electrical hot spots using thermography.

    d. For preplanned RICT entry, evaluation prior to the RICT entry of the redundant train(s) to ensure no active equipment issues that could result in inoperability during the RICT.

4.3.2 TS 3.8.7 Required Action B.1

For TS 3.8.7 Condition B, one or more (same unit or swing bus) DG DC electrical power distribution subsystems inoperable, the sample calculated RICT provided in Enclosure 1 is on the order of 62 hours for an emergent RICT. By current CRMP calculation, the use of the RICT Program on this Action for planned equipment outages is precluded by the instantaneous CDF or LERF limits of 1E-03 or 1E-04, respectively. A RICT may still be entered for this action in the event of an unplanned equipment failure in accordance with NEI 06-09 guidance. The front stop completion time is 12 hours. Example RMAs to ensure a reasonable balance of defense-in-depth is maintained during the example emergent scenario for TS 3.8.7 Condition B are as follows:

1. Actions to increase risk awareness and control.
    a. Briefing of the on-shift operations crew concerning the unit activities, including any compensatory measures established, and review of the appropriate emergency operating procedures for a Loss of Offsite Power and station blackout including bus crossties.
    b. Notification of the Transmission Control Center (TCC) of the configuration so that any planned activities with the potential to cause a grid disturbance are deferred.
    c. Deferral of maintenance and testing activities with the potential to cause an initiating event.
    d. Periodic walkdowns by on-shift operations and/or management personnel to verify implementation of established risk management actions.

2. Actions to reduce the duration of maintenance activities.
    a. Work the activity around the clock.
    b. Engage specialty contractors or subject matter experts.

3. Actions to minimize the magnitude of the risk increase.
    a. Evaluation of weather conditions for threats to the reliability of offsite power supplies
    b. Management of elective maintenance in the switchyard, on the station electrical distribution systems, and on the main and auxiliary transformers associated with the unit in the RICT
    c. Maintain operability/availability of components identified as having high importance according to the configuration-specific evaluation with CRMP software.
    d. Reduce the likelihood of fire in fire zones identified as having high risk significance according to the configuration-specific evaluation with CRMP software. Actions may include verification of availability of fire protection

equipment (suppression, detection, and barriers) and restricting work activities that impact fire protection equipment availability, involve hot work, or introduce transient combustible materials. Additional potential actions include establishing fire watches, minimizing high energy circuit breaker operations, and surveying for electrical hot spots using thermography.

4.3.3 TS 3.8.7 Required Action C.1

For TS 3.8.7 Condition C, one or more (Same Unit or swing bus) DG DC electrical power distribution subsystems inoperable, the sample calculated RICT provided in Enclosure 1 is on the order of 45.1 hours for an emergent RICT. By current CRMP calculation, the use of the RICT Program on this Action for planned equipment outages is precluded by the instantaneous CDF or LERF limits of 1E-03 or 1E-04, respectively. A RICT may still be entered for this action in the event of an unplanned equipment failure in accordance with NEI 06-09 guidance. The front stop completion time is 8 hours. Example RMAs to ensure a reasonable balance of defense-in-depth is maintained during the example emergent scenario for TS 3.8.7 Condition C are as follows:

1. Actions to increase risk awareness and control.
    a. Briefing of the on-shift operations crew concerning the unit activities, including any compensatory measures established, and review of the appropriate emergency operating procedures for a Loss of Offsite Power and station blackout including bus crossties.
    b. Notification of the Transmission Control Center (TCC) of the configuration so that any planned activities with the potential to cause a grid disturbance are deferred.
    c. Deferral of maintenance and testing activities with the potential to cause an initiating event.
    d. Periodic walkdowns by on-shift operations and/or management personnel to verify implementation of established risk management actions.

2. Actions to reduce the duration of maintenance activities.

    a. Work the activity around the clock.
    b. Engage specialty contractors or subject matter experts.

3. Actions to minimize the magnitude of the risk increase.
    a. Evaluation of weather conditions for threats to the reliability of offsite power supplies
    b. Management of elective maintenance in the switchyard, on the station electrical distribution systems, and on the main and auxiliary transformers associated with the unit in the RICT

   c. Maintain operability/availability of components identified as having high importance according to the configuration-specific evaluation with CRMP software.
   d. Reduce the likelihood of fire in fire zones identified as having high risk significance according to the configuration-specific evaluation with CRMP software. Actions may include verification of availability of fire protection equipment (suppression, detection, and barriers) and restricting work activities that impact fire protection equipment availability, involve hot work, or introduce transient combustible materials. Additional potential actions include establishing fire watches, minimizing high energy circuit breaker operations, and surveying for electrical hot spots using thermography.

4.3.4 TS 3.8.7 Required Action D.1

For TS 3.8.7 Condition D, one same unit station service DC electrical power distribution subsystem inoperable, the sample calculated RICT provided in Enclosure 1 is on the order of 39.4 hours for an emergent RICT. By current CRMP calculation, the use of the RICT Program on this Action for planned equipment outages is precluded by the instantaneous CDF or LERF limits of 1E-03 or 1E-04, respectively. A RICT may still be entered for this action in the event of an unplanned equipment failure in accordance with NEI 06-09 guidance. The front stop completion time is 2 hours. Example RMAs to ensure a reasonable balance of defense-in-depth is maintained during the example emergent scenario for TS 3.8.7 Condition D are as follows:

1. Actions to increase risk awareness and control.
   a. Briefing of the on-shift operations crew concerning the unit activities, including any compensatory measures established, and review of the appropriate emergency operating procedures for a Loss of Offsite Power and station blackout including bus crossties.
   b. Notification of the Transmission Control Center (TCC) of the configuration so that any planned activities with the potential to cause a grid disturbance are deferred.
   c. Deferral of maintenance and testing activities with the potential to cause an initiating event.
   d. Periodic walkdowns by on-shift operations and/or management personnel to verify implementation of established risk management actions.

2. Actions to reduce the duration of maintenance activities.
   a. Work the activity around the clock.
   b. Engage specialty contractors or subject matter experts.

3. Actions to minimize the magnitude of the risk increase.
   a. Management of elective maintenance on the station electrical distribution systems associated with the unit in the RICT
   b. Protection of the opposite train and components that may become conditionally critical due to the configuration.

c. Maintain operability/availability of components identified as having high importance according to the configuration-specific evaluation with CRMP software.
d. Reduce the likelihood of fire in fire zones identified as having high risk significance according to the configuration-specific evaluation with CRMP software. Actions may include verification of availability of fire protection equipment (suppression, detection, and barriers) and restricting work activities that impact fire protection equipment availability, involve hot work, or introduce transient combustible materials. Additional potential actions include establishing fire watches, minimizing high energy circuit breaker operations, and surveying for electrical hot spots using thermography.

5 References

[1] Nuclear Energy Institute (NEI) Topical Report (TR) NEI 06-09, "Risk-Informed Technical Specifications Initiative 4b, Risk-Managed Technical Specifications (RMTS) Guidelines," Revision 0-A, October 12, 2012 (ADAMS Accession No. ML 12286A322).

[2] Southern Nuclear Company NMP-GM-031, *"On-Line Configuration Risk Management Program," Version 9.0,* February 2021.

[3] Southern Nuclear Company NMP-GM-031-002, *"Calculation of RMAT and RICT for the RICT Program," Version 5.0,* January 2020.

[4] Southern Nuclear Company NMP-GM-031-003, *"Risk Management Actions for 10 CFR 50.65(a)(4) and the Risk Informed Completion Time Program," Version 8.0,* January 2020.

[5] NUREG-1855, *"Guidance on the Treatment of Uncertainties Associated with PRAs in Risk-Informed Decision Making," Revision 1,* March 2017.

[6] EPRI TR 1026511, *"Practical Guidance on the Use of Probabilistic Risk Assessment in Risk-Informed Applications with a Focus on the Treatment of Uncertainty," Technical Update, Electric Power Research Institue,* December 2012.