200 Exelon Way
Kennett Square, PA 19348

www.constellation.com

10 CFR 50.90

JAFP-22-2020

March 4, 2022

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

James A. FitzPatrick Nuclear Power Plant
Renewed Facility Operating License No. DPR-59
NRC Docket No. 50-333

Subject: Supplemental Information No. 1 for James A. FitzPatrick Nuclear Power Plant to Adopt Risk Informed Completion Times TSTF-505, Revision 2, "Provide Risk-Informed Extended Completion Times – RITSTF Initiative 4b." and 10 CFR 50.69, "Risk-Informed categorization and treatment of structures, systems and components for nuclear power reactors."

References:

1. Letter from D. Gudger (Exelon Generation Company, LLC) to U.S. Nuclear Regulatory Commission, "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,' " dated July 30, 2021 (ML21211A053)

2. Letter from D. Gudger (Exelon Generation Company, LLC) to U.S. Nuclear Regulatory Commission, "Application to Adopt 10 CFR 50.69, Risk-Informed categorization and treatment of structure, systems and components for nuclear power reactors," dated July 30, 2021 (ML21211A078)

3. Letter from J. Poole (Senior Project Manager, U.S. Nuclear Regulatory Commission) "James A. FitzPatrick Nuclear Power Plant – Audit Plan in Support of Review of License Amendment Request Regarding TSTF-505, Revision 2, Provide Risk-Informed Extended Completion Times – RITSTF Initiative 4B" and 10 CFR 50.69, "Risk-Informed Categorization and Treatment of Structures, Systems and Components for Nuclear Power Reactors" (EPID L-2021-LLA-0143 and EPID L-2021-LLA-0142) dated October 22, 2021 (ML21285A149)

By letters dated July 30, 2021 (References 1 and 2), Constellation Energy Generation, LLC (CEG) requested to change the James A. FitzPatrick Nuclear Power Plant (JAF) Technical Specification (TS). The proposed amendments 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. ML21211A053) and modify the licensing basis in accordance with the application to adopt 10 CFR 50.69, "Risk-Informed categorization and treatment of structures, systems and components for nuclear power reactors."

By letter dated October 22, 2021 (Reference 3), the NRC notified CEG of their intent to conduct a regulatory virtual audit the week of January 18, 2022 with CEG staff and associated contractors in support of the License Amendment Requests (LARs) in References 1 and 2. The letter contains a virtual audit plan with attached audit questions.

This letter is a supplement to both References 1 and 2 LARs. Attachment 1 to this letter provides a response to several of the audit questions posed by the NRC staff during the regulatory virtual audit.

Attachments 2 and 3 to this letter provides the revised TS markups and TSB markups, respectively, to address the requested supplemental information. The information provided in Attachments 2 and 3 to this letter supersedes the information provided in Attachments 2 and 3 of Reference 1 for TS pages and their associated Basis pages and inserts. All other information in Attachments 2 and 3 of Reference 1 remains unchanged.

CEG has reviewed the information supporting a finding of no significant hazards consideration and the environmental consideration provided to the NRC in Reference 1 and 2. The supplemental information provided in this letter does not affect the bases for concluding that the proposed license amendments do not involve a significant hazards consideration. Furthermore, the supplemental information provided in this letter does not affect the bases for concluding that neither an environmental impact statements nor an environmental assessment needs to be prepared in connection with the proposed amendments.

There are no commitments contained in this response.

In accordance with 10 CFR 50.91, "Notice for public comment; State consultation," paragraph (b), CEG is notifying the State of New York of this application for license amendment by transmitting a copy of this letter and its attachments to the designated State Official.

Should you have any questions concerning this letter, please contact Jessie Hodge at (610) 765-5532.

I declare under penalty of perjury that the foregoing is true and correct. Executed on the 4th day of March 2022.

Respectfully,

David T. Gudger

_____

David T. Gudger
Sr. Manager - Licensing
Constellation Energy Generation, LLC

Attachments:
1. Response to NRC Audit Questions
2. Revised Technical Specification Marked-Up Pages
3. Revised Technical Specification Basis Marked-Up Pages

cc:	USNRC Region I, Regional Administrator	w/ attachments
	USNRC Senior Resident Inspector	"
	USNRC Project Manager	"
	A. L. Peterson, NYSERDA	"
	B. Frymire, NYSPSC	"

ATTACHMENT 1

License Amendment Request

James A. FitzPatrick Nuclear Power Plant

Docket No. 50-333

Response to NRC Audit Questions

APLA 2

APLA QUESTION 02a (TSTF 505) – Dispositions of PRA Model Assumptions and Sources of Uncertainty

The NRC staff SER for NEI 06-09, Revision 0-A, specifies that the LAR should identify key assumptions and sources of uncertainty and to assess and disposition each as to their impact on the RMTS application. NUREG-1855, Revision 1, presents guidance on the process of identifying, characterizing, and qualitative screening of model uncertainties.

The tables in Enclosure 9 to the LAR provide dispositions for identified key assumptions and sources of uncertainty. Additional information is needed for the NRC staff to make a determination that the key assumptions and sources of uncertainty have been appropriately assessed for impact on the Technical Specifications Task Force (TSTF) Traveler 505 (TSTF 505)[1] application, including that impacts on the limiting conditions for operation (LCOs) to be included within the scope of the RMTS program have been considered. Address the following:

a) *Topic 7 in Table E9-3 of Enclosure 9 to the LAR, "Scope of equipment credited in the fire PRA model," explains that some components were conservatively assumed to be failed based on lack of cable data. Such components were referred to as Unknown Location (UNL) components. The LAR states that a sensitivity analysis was performed to determine the impact of the treatment of UNL components by removing all UNL components from every fire scenario. Based on the results of the sensitivity study, the LAR states "the scope of assumed failures in the Fire PRA introduces negligible conservatism to both Fire CDF [core damage frequency] and LERF [large early release frequency]." Similarly, LAR Enclosure 9, Table E9-3, Topic #54, "Extent of circuit analysis," explains that systems/functions for which circuit analysis was not performed were conservatively assumed to be failed. The LAR states that a sensitivity analysis was performed to determine the impact of this treatment by assuming these systems/functions were never impacted by a fire. Based on the results of the sensitivity study, the LAR states "the scope of assumed failures in the Fire PRA introduces negligible conservatism to both Fire CDF and LERF." In neither of the above cases does the LAR provide the results of the uncertainty analyses nor does it address the impacts to applicable RICTs. The NRC staff reviewed the sensitivity study results provided in the fire PRA uncertainty and sensitivity analysis report on the portal and notes that the impact to CDF and LERF is not insignificant (i.e., risk reduction in the 7 to 8% range) and that the impact to estimated RICTs was not performed. NRC staff notes that*

---

[1] *TSTF-505, Revision 2, "Provide Risk-informed Extended Completion Times, RITSTF Initiative 4b," dated June 14, 2011 (ADAMS Accession No. ML17290A082)*

conservatism in PRA modeling could have a nonconservative impact on the RICT calculations while having only a small or modest impact on total CDF or LERF. It is not clear to NRC staff that the modelling assumption applied to untraced cables and to functions/systems for which circuits analysis was not performed has no impact on the RICT program calculations. If a structure, system, or component (SSC) is part of a system not credited in the fire PRA or it is supported by a system that is assumed to always fail, then the risk-increase due to taking that SSC out of service is masked. Therefore, address the following:

i. Identify the systems or components that are assumed to be always failed in the PRA or not included in the PRA (due to lack of cable tracing, lack of circuit analysis, or other reasons). Justify that these assumptions have an inconsequential impact on the RICT calculations (e.g., describe and provide RICT results of a sensitivity study using LCO conditions that could be most impacted by these modeling assumptions having RICTs less than the 30-day backstop).

ii. If in response to part (i) above, it cannot be determined that the cited assumption has an inconsequential impact on the estimated RICTs, then identify the LCO conditions impacted by the treatment of this modeling assumption for which RMAs will be applied during a RICT. Include discussion of the kinds of RMAs that would be applied and justification that the RMAs will be sufficient to address this modeling assumption.

Response to APLA 2a.i (TSTF 505)

The following functions/systems/components are included as UNLs and always assumed failed with the exception of the Feedwater system which is credited by exclusion.

System/Equipment	Function Failed in FPRA
CST	LPCI/LPCS Alternate Injection supply
Demin	CST Refill (other water sources credited)
RHR	Drywell Sprays
Feedwater	RPV Injection (credited by exclusion)
Feedwater	Feedwater Reg. Valve Bypass Line for RPV Injection (Normal path is credited)

System/Equipment	Function Failed in FPRA
Feedwater	Feedwater MOVs to Isolate Spurious Feedwater Pump Operation (Pump trip and redundant valves credited for isolation)
Firewater	Motor Drive Fire Pump for RPV Injection (Diesel Fire Pumps credited)
LPCS	LPCS DG Auto Start Relay Inputs (RHR Pumps provide redundant input and credited)
LPCS	LPCS Containment Isolation Valve AOV 13A/B (Relief Valves credited for line isolation)
LPCS	LPCS Pump ADS Inputs for 2E-K12A/B and 2E-K15A/B relays (RHR Pumps provide redundant input and credited)
LPCI	LPCI MOVs 43A/B and 53A/B to Isolate Recirc Pump Seal Leak (Pump trip credited)
N2	Backup N2 Supply (Normal supply credited)
RBC	RBC Pump Auto Start Relays when in Standby (Normally running pumps credited)
RBC	RBC MOV 175A/B Logic Failing ESW Cooling to CRD (RBC cooling credited)
Radwaste	CST Refill (other water sources credited)
Turbine Stop Valves	Main Condenser Isolation

The only function/system/components listed above that may impact a RICT calculation is the credit by exclusion of the Feedwater system. The other functions/systems/components are not associated with a LCO or only provide additional redundancy if it was explicitly modeled in the FPRA. No credit for Feedwater in the FPRA is judged to be conservative and not representative of the best estimate fire risk. The FPRA has been peer reviewed and has all F&O closed by the Appendix X closure process. The credit by exclusion approach for Feedwater in the FPRA is an acceptable approach to obtain best estimate risk results.

In any event, a sensitivity study was performed in which the Feedwater system was always failed for RICT calculations associated with HPCI, RCIC, and depressurization, as these could be cases where too much credit for Feedwater could result in a longer RICT result. The sensitivity study results indicate that no credit for Feedwater does not change the calculated RICTs.

Tech Spec	TS Condition	Base Model RICT Estimate (days)	Sensitivity RICT Estimate (days)	Percent Change for Total CDF Delta	Percent Change for Total LERF Delta (1)
3.5.1.D	D. HPCI SYSTEM INOPERABLE AND CONDITION A ENTERED	30	30	10.8%	4.1% (1)
3.5.1.F	F. ONE REQUIRED ADS VALVE INOPERABLE AND CONDITION A ENTERED	30	30	21.6%	2.6% (1)
3.5.3.A	A. RCIC SYSTEM INOPERABLE	30	30	10.4%	0.1% (1)

Notes to Table:

1 The calculated RICT is bounded by the LERF delta results. The sensitivity study results indicate that no credit for Feedwater has a minimum impact on the calculated delta results and ultimately no change in the RICT estimate.

Response to APLA 2a.ii (TSTF 505)

See response to APLA 2a.i.

APLA QUESTION 02b (TSTF 505) – Dispositions of PRA Model Assumptions and Sources of Uncertainty

b) *Issue 7.5 in Table E9-5 of Enclosure 9 to the LAR, "FLEX equipment reliability," is identified as a potential "key" source of uncertainty because FLEX equipment reliability is not modeled in the PRA. The "Assumptions Made / Approach" column in this table explains that FLEX strategies are credited in the PRA model via an operator action to align the FLEX equipment for station blackout (SBO) / extended loss of AC power (ELAP) scenarios and for loss of battery charging scenarios. This operator action is stated to be the dominant contributor for FLEX strategy failure.*

   The NRC memorandum dated May 30, 2017, "Assessment of the Nuclear Energy Institute 16-06, 'Crediting Mitigating Strategies in Risk-Informed Decision Making,' Guidance for Risk-Informed Changes to Plants Licensing Basis,"[2] provides the NRC's staff assessment of challenges to incorporating FLEX equipment and strategies into a PRA model in support of risk-informed decision-making in accordance with the guidance of Regulatory Guide (RG) 1.200[3], Revision 2.

   With regards to equipment failure probability, the NRC staff concluded the following in the aforementioned May 30, 2017, memorandum (Conclusion 8):

   > *The uncertainty associated with failure rates of portable equipment should be considered in the PRA models consistent with the [American Society of Mechanical Engineers (ASME)/American Nuclear Society (ANS) Standard RA-Sa-2009[4]], as endorsed by RG 1.200. Risk-informed applications should address whether and how these uncertainties are evaluated.*

   With regards to Human Reliability Analysis (HRA), NEI 16-06[5] Section 7.5 recognizes that the current HRA methods do not translate directly to human actions required for implementing mitigating strategies. Sections 7.5.4 and 7.5.5 of NEI 16-06 describe such actions to which the current HRA methods cannot be directly applied, such as: debris removal, transportation of portable equipment, installation of equipment at a staging

---

[2] Memorandum from M. Reisi-Fard, NRC, to J. G. Giitter, NRC, "Assessment of the Nuclear Energy Institute 16-06, 'Crediting Mitigating Strategies in Risk-Informed Decision Making,' Guidance for Risk-Informed Changes to Plants Licensing Bases," dated May 30, 2017 (ADAMS Accession No. ML17031A269).
[3] NRC RG 1.200, Revision 2, "Acceptability of Probabilistic Risk Assessment Results for Risk-Informed Activities," dated March 2009 (ADAMS Accession No. ML090410014).
[4] ASME/ANS Standard RA-Sa-2009, "Standard for Level 1/Large Early Release Frequency Probabilistic Risk Assessment for Nuclear Power Plant Applications," dated February 2009.
[5] NEI Report 16-06, "Crediting Mitigating Strategies in Risk-Informed Decision Making," dated August 2016 (ADAMS Accession No. ML16286A297).

location, routing of cables and hoses; and those complex actions that require many steps over an extended period, multiple personnel and locations, evolving command and control, and extended time delays. In the May 30, 2017, memorandum, the NRC staff concludes (Conclusion 11):

> *Until gaps in the human reliability analysis methodologies are addressed by improved industry guidance, [Human Error Probabilities] HEPs associated with actions for which the existing approaches are not explicitly applicable, such as actions described in Sections 7.5.4 and 7.5.5 of NEI 16-06, along with assumptions and assessments, should be submitted to NRC for review.*

Regarding the PRA credit for FLEX strategies, address the following:

i. *Summarize the FLEX strategies including the equipment and actions that have been quantitatively credited for each of the PRA models used to support this application. Include discussion of whether the credited FLEX equipment is portable or permanently installed equipment, and whether the credited equipment (regardless of whether it is portable or permanently-installed) are like other plant equipment (i.e., SSCs with sufficient plant-specific or generic industry data).*

ii. *Explain how the dependency of FLEX strategy implementation success on successful time-dependent declaration of ELAP is incorporated into the FLEX modeling. If not included, then provide justification that the exclusion of this failure event from the model does not significantly impact RICTs.*

iii. *Regarding credited FLEX equipment, provide a discussion detailing the methodology used to assess the failure probabilities of each piece of equipment. Include in the discussion justification(s) for parameter values and how the uncertainties associated with the parameter values are considered in the RICT process in accordance with ASME/ANS RA-Sa–2009, as endorsed by RG 1.200 (e.g., supporting requirements for HLR-DA-D).*

iv. *Enclosure 9 to the LAR states that both the FLEX equipment and operator actions are represented by a human error probability (HEP)-based event since it is the dominant contributor. Given there are uncertainty concerns with both FLEX equipment and human error probabilities, it is unclear to the NRC staff if the use of a 'bounding' basic event (BE) adequately addresses these sources of uncertainty and the as-implemented FLEX strategies.*

1. *Provide details of the FLEX equipment and operator actions that are represented by this 'bounding' FLEX BE. Include in this discussion the failure probabilities for each item and the dependency analysis between actions.*
2. *Provide justification that the 'bounding' FLEX BE HEP value adequately represents the FLEX equipment and actions that the BE is representing. Include in this discussion how the uncertainties associated with FLEX are adequately addressed by the 'bounding' BE.*

v. *The NRC staff observed in Table 6-3 of PRA Notebook JF-PRA-005.33 that the feasibility of two FLEX human failure events (HFEs) (i.e., TDG-XHE-FO-START and ADS-XHE-FO-X1XSBO) has not been verified. Discuss how the feasibility of FLEX operator actions are determined. Include in this discussion whether any credited FLEX operator actions have been determined to be unfeasible and provide justification for their inclusion in the PRA model.*

vi. *Regarding the HRA, discuss whether the credited operator actions related to FLEX equipment contain actions described in Sections 7.5.4 and 7.5.5 of NEI 16-06.*

For credited operator actions related to FLEX equipment that contain actions described in Sections 7.5.4 and 7.5.5 of NEI 16-06, address one of the following:

1. *Justify and provide results of LCO specific sensitivity studies that assess the impact on the RICTs proposed in this application from the FLEX independent and dependent HEPs associated with deploying and staging FLEX portable equipment, and FLEX equipment and failure probabilities. Address the following in the response:*

   a. *Justify the independent and joint HEP values selected for the sensitivity studies, including justification of why the chosen values constitute bounding realistic estimates.*

   b. *Discuss the bases for the chosen TS LCO conditions in the sensitivity studies. Because the 30-day RICT back-stop condition could mask the impact of this uncertainty in the sensitivity study, discuss whether the RICTs for plant configurations involving more than one LCO entry (e.g., where the calculated RICTs are less than the 30-day backstop) are significantly impacted by this uncertainty.*

c. *Provide numerical results on specific selected RICTs and discussion of the results.*

d. *Discuss whether the uncertainty associated with FLEX HEPs is a key source of uncertainty for the RMTS program.*

   If this uncertainty is "key," then describe and provide a basis for how this uncertainty will be addressed in the RMTS program (e.g., programmatic changes such as identification of additional RMAs, program restrictions or the use of bounding analyses which address the impact of the uncertainty). If the programmatic changes include identification of additional RMAs, then (1) describe how these RMAs will be identified prior to the implementation of the RMTS program, consistent with the guidance in Section 2.3.4 of NEI 06 09; and (2) for those TS LCOs in LAR Enclosure 12 ("Risk Management Action Examples") that are significantly impacted by this uncertainty, provide updated RMAs that may be considered during a RICT program entry to minimize any potential adverse impact from this uncertainty, and explain how these RMAs are expected to reduce the risk associated with this uncertainty.

OR:

2. *Provide a description of the methodology used to assess the operator actions and how this meets the Capability Category II supporting requirements (SRs) of the ASME/ANS RA-Sa-2009 PRA Standard, as endorsed by RG 1.200, Revision 2. Address the following in the response:*

a. *Describe how each of the performance shaping factors (a), (f), (g), and (h) defined in SR HR-G3 of the PRA Standard were evaluated,*

b. *Describe how each of the human action dependencies listed in SR HR-G7 of the PRA Standard were evaluated, and*

c. *Explain how maintenance procedures for the portable equipment were reviewed for possible pre-initiator human failures that renders the equipment unavailable during an event, and whether the probabilities of the pre-initiator human failure events were assessed in accordance with high level requirement (HLR) HR-D of the PRA standard.*

Response to APLA 2b.i (TSTF 505)

The JAF FLEX strategies are summarized in the Final Integrated Plan[6]. As a high-level summary, the PRA credits the following:

- Controlling Reactor Pressure to Maintain HCTL and allow RCIC Operation (~200-400 psig). This operator action is modeled in the PRA and involves permanently installed equipment. This action involves operation of RCIC and SRVs which are considered common BWR equipment.
- Shedding DC loads to extend battery life. This operator action is modeled in the PRA and involved only permanently installed equipment. This action involves operation of control switches and electrical disconnects which are considered common considered common commercial nuclear plant equipment.
- Depressurizing the RPV Using Portable Power Packs. This action involves using the B.5.b portable power supply to open SRVs.
- Aligning RPV Makeup Water from Diesel-Driven pumps. This operator action and related plant equipment is modeled in the PRA and involves re-alignment of permanently installed equipment using portable hoses and spool pieces. Permanently installed fire protection pumps (76P-1, 4) are cross-connected to the LPCI system via the RHRSW system. This action involves operation of control switches and piping connections which are considered common commercial nuclear plant equipment.
- Aligning portable generators to maintain vital DC power. This operator action is modeled in the PRA. One of Two portable FLEX Generators are aligned to permanently installed MCCs. The current PRA model includes the operator action as bounding and does not yet explicitly model the two portable generators. Such generators are similar to the installed emergency diesel generators but on a smaller scale.
- Venting the primary containment via a newly installed Hardened Containment Vent System (HCVS). The current model does not explicitly credit the HCVS equipment but rather an operator action to locally operate primary containment vent valves manually. This HCVS-like capability existed prior to the Fukushima event and provides an equivalent PRA benefit. This action involves operation of control switches and valves which are considered common commercial nuclear plant equipment.

Response to APLA 2b.ii (TSTF 505)

For the strategies discussed in the response to question APLA-2-b-i, the following provides a summary of ELAP declaration:

- Controlling Reactor Pressure to Maintain HCTL and allow RCIC Operation (~200-400 psig). This operator action is directed by EOPs independent of the ELAP Procedure (FSG-ELAP).
- Shedding DC loads to extend battery life. This operator action is directed by AOP-49 “Station Blackout” independent of the FSG-ELAP.

[6] CC-JF-118-1003, FLEX FINAL INTEGRATED PLAN, Revision 000

- Depressurizing the RPV Using Portable Power Packs. This action is directed by Technical Support Guideline TSG-12 independent of ELAP declaration. The Power Packs are located on the Battery Cart in the Warehouse Battery Room.
- Aligning RPV Makeup Water from Diesel-Driven pumps. This operator action is directed by EOPs independent of the FSG-ELAP.
- Aligning portable generators to maintain vital DC power. This operator action is directed by the ELAP procedure. The ELAP declaration is directed by procedure FSG-ELAP is included within the cognitive portion of the HRA evaluation for the HFE included in the PRA model.
- Venting the primary containment via a newly installed Hardened Containment Vent System (HCVS). This operator action is directed by EOPs independent of the FSG-ELAP.

Response to APLA 2b.iii (TSTF 505)

For the strategies discussed in the response to question APLA-2-b-i, the following provides a summary of the treatment of equipment failure rates:

- Controlling Reactor Pressure to Maintain HCTL and allow RCIC Operation (~200-400 psig). This is solely an operator action and reliability of RCIC and SRVs is addressed with industry standard system modeling. Basic events within the system models are populated with industry data (INL[7]) Bayesian updated with available plant-specific data.
- Shedding DC loads to extend battery life. This is treated solely as an operator action. The shedding action is bypassed in the PRA model if DC equipment failures occur.
- Depressurizing the RPV Using Portable Power Packs. This is treated solely as an operator action.
- Aligning RPV Makeup Water from Diesel-Driven pumps. The equipment in the permanently installed fire protection flowpath addressed with industry standard system modeling. The system model includes primarily pumps and valves, and, of note, the diesel pump failure rates are derived from the INL “Engine-Driven Pump” component category. The passive hoses and spool pieces are assumed bounded by the operator action.
- Aligning portable generators to maintain vital DC power. The model currently assumes the operator action dominates and equipment is not explicitly modeled. The HEP is assigned a value of 5.8E-3 and given there are redundant portable generators of a standard internal-combustion design, equipment failure rates are similarly small.
- Venting the primary containment via a newly installed Hardened Containment Vent System (HCVS). This operator action is directed by EOPs independent of the FSG-ELAP. Although the system is new, components are common types of nuclear plant equipment (i.e., valves) and basic events within the system models are populated with industry data (INL).

---

[7] NUREG/CR-6928, Industry-Average Performance for Components and Initiating Events at U.S. Commercial Nuclear Power Plants (2015 update: http://nrcoe.inel.gov/resultsdb/publicdocs/AvgPerf/ComponentUR2015.pdf)

Response to APLA 2b.iv.1 (TSTF 505)

This bounding of the FLEX Generator equipment was addressed via sensitivity analysis (JF-MISC-021, Rev. 1). As a sensitivity, an additional equipment basic event was logically ORed with the existing FLEX Generator alignment HFE. This basic event was set to 1E-2 and 0.1 in successive sensitivity calculations. Sensitivity results showed a very small impact which demonstrates that the current modeling reasonably represents the uncertainty associated with the FLEX Generator alignment strategy.

Response to APLA 2b.iv.2 (TSTF 505)

Sensitivity Analysis has been used to demonstrate that the uncertainties associated with FLEX are adequately addressed by the 'bounding' BE

Response to APLA 2b.v (TSTF 505)

The text associated with Table 6-3 of the Portable Equipment Notebook (JF-PRA-005.33) refers to the HRA Notebook (JF-PRA-004) for HFE basis and justification. For the TSG-8 Generator action (TDG-XHE-FO-START) the HRA Notebook references the Site FLEX Implementation Plan (CC-JF-118, Rev. 5; EDS0-5, Rev. 1). These documents address TSG-8 as a viable FLEX-related strategy and the PRA correspondingly takes credit for the strategy. Further, this action is included in the time critical and time sensitive operator action program (OP-JF-102-106, Rev. 5) where it is included as action TCA-19. The FLEX and Time Critical Action Programs support feasibility.

For the Local SRV actuation action (ADS-XHE-FO-X1XSBO) the HRA Notebook references procedure TSG-12 (B.5.b Extreme Damage Mitigation Strategies). Feasibility is not explicitly defined in the HRA Notebook for this HFE. However, this strategy is only credited when HPCI or RCIC operate and operators initiate shedding of DC loads. With a long time window (>4 hours) and adequate procedure direction, the HFE is feasible and PRA reasonably models plant capabilities in this regard.

Response to APLA 2b.vi.1.a (TSTF 505)

Actions outlined by Sections 7.5.4 and 7.5.5 of NEI 16-06 involve event response involving potentially different performance shaping factors than those credited in PRA models prior to FLEX strategy development. These involve debris removal, transportation of equipment, staging locations, routing of cables and hoses, and the potential for generally more complicated alignments. In the JAF PRA, two HFEs reasonably meet this criterion:

- FDG-XHE-FO-START Operator Fails to Align FLEX Diesel Generator
- TDG-XHE-FO-START Operator Fails to Align TSG-8 Diesel Generator to RCIC

Alignment of the FLEX pumps does not meet this criterion because JAF relies on the installed diesel fire pumps for FLEX alternate RPV injection and the cross-tie is a simple piece of equipment that does not require debris removal, transportation, or complicated routing. Similarly, actions such as RPV pressure control for RCIC, local SRV manipulation, and DC load shedding do not meet this criterion.

These two HFEs and their related joint HFEs have been selected for a sensitivity study which sets their values to the 95th percentile failure rates in order to bound realistic estimates. An additional sensitivity was performed that set only the two independent HFEs to their 95% values. Table APLA-2-b-vi-1-a-1 lists the values of these HEPs along with a sample Impacted Joint HEPs. The entire list of JHEPs containing one or more of the HFEs identified has not been provided in this response due to the large number of events that comprise the list (41 dependent events).

Table APLA-2-b-vi-1-a-1 HFEs for Sensitivity with Sample of Impacted JHEPs

BE-ID	Description (IHEPs), Constituents (JHEPs)	Base Value	95th
FDG-XHE-FO-START	Operator Fails to Align FLEX Diesel Generator	5.8E-03	1.7E-02
TDG-XHE-FO-START	Operator Fails to Align TSG-8 Diesel Generator to RCIC	1.0E-01	2.6E-01
Combination 172	FWS-XHE-FO-INJ, FDG-XHE-FO-START, ADS-XHE-FO-X1XSBO	6.7E-06	6.7E-05
Combination 176	FDG-XHE-FO-START, FWS-XHE-FO-DHR, ADS-XHE-FO-X1XSBO	2.1E-06	2.1E-05
Combination 255	FWS-XHE-FO-INJ, FXT-XHE-FO-ESWA, FXT-XHE-FO-ESWB, FDG-XHE-FO-START, ADS-XHE-FO-X1XSBO	6.2E-07	6.2E-06
Combination 262	FXT-XHE-FO-ESWA, FXT-XHE-FO-ESWB, FDG-XHE-FO-START, FWS-XHE-FO-DHR, ADS-XHE-FO-X1XSBO	5.1E-07	5.1E-06
Combination 308	LCI-XHE-FO-MOV25, FDG-XHE-FO-START	1.5E-03	4.8E-03
Combination 309	FDG-XHE-FO-START, FXT-XHE-FO-AILT	1.7E-05	1.7E-04
Combination 310	FDG-XHE-FO-START, ADS-XHE-FO-X1XSBO	4.4E-04	4.4E-03

Note 1) The FPRA uses the same base and 95th values as the internal events.
Note 2) The entire list of JHEPs containing one or more of the HFEs identified has not been provided in this response due to the large number of events that comprise the list (41 dependent events). The FPRA JHEPs are not listed due to the large number of events (> 100 combinations)
Note 3) Description of JHEP Constituent HEPs:
ADS-XHE-FO-X1XSBO – Failure to Depress RPV From RPV Using Portable Power Packs
FWS-XHE-FO-DHR – Operators Fail to Realign Main Heat Sink After Offsite AC Recovered
FWS-XHE-FO-INJ – Operators Fail to Restart Feedwater After Offsite AC Recovered
FXT-XHE-FO-AILT – Failure to crosstie fire water to LPCI Loop A for long-term RPV injection (Late)
FXT-XHE-FO-ESWA – Failure to align fire water to ESW given train A EDGs available only
FXT-XHE-FO-ESWB – Failure to align fire water to ESW given train B EDGs available only
LCI-XHE-FO-MOV25 – Operator Fails to Locally Open LPCI Injection Valve for Long-Term Injection

Response to APLA 2b.vi.1.b (TSTF 505)

Offsite Power, Emergency Diesel Generator, and DC Power specs are the most relevant to the FLEX actions. Table APLA-2-b-vi-1-c-1 lists these Specs for JAF. The sensitivity studies involved several LCOs with multiple pieces of equipment out of service that resulted in less than the 30-day backstop.

Response to APLA 2b.vi.1.c (TSTF 505)

Two sensitivities were performed

(1) Independent FLEX HFEs and their associated dependent HFEs set to their 95th percentile
(2) Independent FLEX HFEs set to their 95th percentile

Table APLA-2-b-vi-1-c-1 provides the results of the sensitivity study that set the independent HFEs and their associated dependent HFEs to their 95th percentile.

Table APLA-2-b-vi-1-c-1 Results for NEI 16-06 Sensitivity
Independent FLEX HFEs and associated dependent HFEs set to their 95th percentile

Tech Spec	TS Condition	Original RICT Estimate (days)	Sensitivity RICT Estimate (days)	Percent Change for Total CDF Delta	Percent Change for Total LERF Delta
3.6.1.3.A.29	A. ONE OR MORE PENETRATION FLOW PATHS WITH ONE PCIV INOPERABLE FOR REASONS OTHER THAN CONDITIONS D AND E	27.2	27.2	4.3%	0.3%
3.6.1.3.C.29	C. ONE OR MORE PENETRATION FLOW PATHS WITH ONE PCIV INOPERABLE FOR REASONS OTHER THAN CONDITIONS D AND E	27.2	27.2	4.3%	0.3%
3.8.1.C.1	C. TWO OFFSITE CIRCUITS INOPERABLE	19.7	19.3	2.1%	1.7%
3.8.1.E.5	TWO EDG SUBSYSTEM INOPERABLE	17.5	15.7	19.6%	11.7%
3.8.4.B.1	B. ONE 125 VDC ELECTRICAL POWER SUBSYSTEM INOPERABLE FOR REASONS OTHER THAN CONDITION A	0.4	0.4	0.1%	2.1%

Table APLA-2-b-vi-1-c-1 Results for NEI 16-06 Sensitivity
Independent FLEX HFEs and associated dependent HFEs set to their 95th percentile

Tech Spec	TS Condition	Original RICT Estimate (days)	Sensitivity RICT Estimate (days)	Percent Change for Total CDF Delta	Percent Change for Total LERF Delta
3.8.4.B.2	B. ONE 125 VDC ELECTRICAL POWER SUBSYSTEM INOPERABLE FOR REASONS OTHER THAN CONDITION A	0.5	0.5	1.6%	1.4%
3.8.7.A.1	A. ONE OR MORE AC ELECTRICAL POWER DISTRIBUTION SUBSYSTEMS INOPERABLE	30.0	30.0	0.1%	2.5%
3.8.7.A.2	A. ONE OR MORE AC ELECTRICAL POWER DISTRIBUTION SUBSYSTEMS INOPERABLE	30.0	30.0	0.2%	2.4%
3.8.7.A.3	A. ONE OR MORE AC ELECTRICAL POWER DISTRIBUTION SUBSYSTEMS INOPERABLE	4.3	4.0	26.0%	7.4%
3.8.7.A.4	A. ONE OR MORE AC ELECTRICAL POWER DISTRIBUTION SUBSYSTEMS INOPERABLE	1.4	1.4	7.6%	1.7%
3.8.7.A.5	A. ONE OR MORE AC ELECTRICAL POWER DISTRIBUTION SUBSYSTEMS INOPERABLE	0.04	0.04	16.2%	0.7%
3.8.7.B.1	B. ONE 125 VDC ELECTRICAL POWER DISTRIBUTION SUBSYSTEM INOPERABLE	0.4	0.4	0.1%	2.1%
3.8.7.B.2	B. ONE 125 VDC ELECTRICAL POWER DISTRIBUTION SUBSYSTEM INOPERABLE	0.5	0.5	1.6%	1.4%
3.8.1.D.5	D. ONE OFFSITE CIRCUIT INOPERABLE AND ONE EDG SUBSYSTEM INOPERABLE	30.0	30.0	13.9%	8.2%
3.8.1.B.1	B. ONE EDG SUBSYSTEM INOPERABLE	30.0	30.0	9.5%	0.3%

Table APLA-2-b-vi-1-c-2 provides the results of the sensitivity study that only set the two independent HFEs to their 95th percentile.

Table APLA-2-b-vi-1-c-2 Results for NEI 16-06 Sensitivity – Independent FLEX HEPs set to 95th

Tech Spec	TS Condition	Original RICT Estimate (days)	Sensitivity RICT Estimate (days)	Percent Change for Total CDF Delta	Percent Change for Total LERF Delta
3.6.1.3.A.29	A. ONE OR MORE PENETRATION FLOW PATHS WITH ONE PCIV INOPERABLE FOR REASONS OTHER THAN CONDITIONS D AND E	27.2	27.4	11.1%	0.7%
3.6.1.3.C.29	C. ONE OR MORE PENETRATION FLOW PATHS WITH ONE PCIV INOPERABLE FOR REASONS OTHER THAN CONDITIONS D AND E	27.2	27.4	11.1%	0.7%
3.8.1.C.1	C. TWO OFFSITE CIRCUITS INOPERABLE	19.8	20.1	1.9%	1.0%
3.8.1.E.5	TWO EDG SUBSYSTEM INOPERABLE	17.5	17.6	0.3%	0.6%
3.8.4.B.1	B. ONE 125 VDC ELECTRICAL POWER SUBSYSTEM INOPERABLE FOR REASONS OTHER THAN CONDITION A	0.4	0.4	0.0%	0.2%
3.8.4.B.2	B. ONE 125 VDC ELECTRICAL POWER SUBSYSTEM INOPERABLE FOR REASONS OTHER THAN CONDITION A	0.5	0.5	1.6%	1.4%
3.8.7.A.1	A. ONE OR MORE AC ELECTRICAL POWER DISTRIBUTION SUBSYSTEMS INOPERABLE	30.0	30.0	2.4%	3.4%
3.8.7.A.2	A. ONE OR MORE AC ELECTRICAL POWER DISTRIBUTION SUBSYSTEMS INOPERABLE	30.0	30.0	2.7%	3.4%

Table APLA-2-b-vi-1-c-2 Results for NEI 16-06 Sensitivity – Independent FLEX HEPs set to 95th					
Tech Spec	**TS Condition**	**Original RICT Estimate (days)**	**Sensitivity RICT Estimate (days)**	**Percent Change for Total CDF Delta**	**Percent Change for Total LERF Delta**
3.8.7.A.3	A. ONE OR MORE AC ELECTRICAL POWER DISTRIBUTION SUBSYSTEMS INOPERABLE	4.3	4.1	4.0%	4.3%
3.8.7.A.4	A. ONE OR MORE AC ELECTRICAL POWER DISTRIBUTION SUBSYSTEMS INOPERABLE	1.4	1.4	0.4%	1.1%
3.8.7.A.5	A. ONE OR MORE AC ELECTRICAL POWER DISTRIBUTION SUBSYSTEMS INOPERABLE	0.04	0.2	0.3%	91.1%
3.8.7.B.1	B. ONE 125 VDC ELECTRICAL POWER DISTRIBUTION SUBSYSTEM INOPERABLE	0.4	0.4	0.0%	0.2%
3.8.7.B.2	B. ONE 125 VDC ELECTRICAL POWER DISTRIBUTION SUBSYSTEM INOPERABLE	0.5	0.5	1.6%	1.4%
3.8.1.D.5	D. ONE OFFSITE CIRCUIT INOPERABLE AND ONE EDG SUBSYSTEM INOPERABLE	30.0	30.0	0.4%	0.9%
3.8.1.B.1	B. ONE EDG SUBSYSTEM INOPERABLE	30.0	30.0	5.1%	4.7%

Comparing Tables APLA-2-b-vi-1-c-1 and 2, the impact of the JHEPs is minor and results are more driven by the equipment unavailable within the specs versus the FLEX generators.

<u>Response to APLA 2b.vi.1.d (TSTF 505)</u>

The results from the HEP 95th sensitivity study show that the FLEX HEPs is not a key source of uncertainty for the RMTS program.

In general, 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.

Risk Management procedures contain guidance for development of RMAs in support of the RICT program. Development of RMAs considers those developed for other processes, such as the RMAs developed under the 10CFR 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.

RMAs are identified based on the configuration-specific risk. There are three categories of RICT RMAs:

1) Actions to increase risk awareness and control, such as briefing of crews on risk important operator actions and procedures.
2) Actions to reduce the duration of maintenance activities, such as performing activities around the clock.
3) Actions to minimize the magnitude of the risk increase, such as protecting risk important equipment or minimizing fire risk in risk important rooms.

General RMAs are developed for input into the site-specific RICT system guidelines. These guidelines are developed using a graded approach. Consideration is given for system functionality. These RMAs include:

- Consideration of rescheduling maintenance to reduce risk
- Discussion of RICT in pre-job briefs
- Consideration of proactive return-to-service of other equipment
- Efficient execution of maintenance.

In addition to the RMAs developed qualitatively for the system guidelines, RMAs are developed based on the Real-Time Risk tool to identify configuration-specific RMA candidates to manage the risk associated with internal events, internal flooding, and fire events. These actions include:

- Identification of important equipment or trains for protection
- Identification of important Operator Actions for briefings
- Identification of key fire initiators and fire zones for RMAs in accordance with the site Fire RMA process
- Identification of dominant initiating events and actions to minimize potential for initiators
- Consideration of insights from PRA model cutsets, through comparison of importances.

Common cause RMAs are also 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.

Examples of common cause RMAs include:

- Performance of non-intrusive inspections on alternate trains
- Confidence runs performed for standby SSCs
- Increased monitoring for running components
- Expansion of monitoring for running components
- Deferring maintenance and testing activities that could generate an initiating event which would require operation of potentially affected SSCs
- Readiness of operators and maintenance to respond to additional failures
- Shift briefs or standing orders which focus on initiating event response or loss of potentially affected SSCs.

Response to APLA 2b.vi.2.a (TSTF 505)

Because a response to RAI question APLA-2b.v1.1 is provided above, no response to this question is required.

Response to APLA 2b.vi.2.b (TSTF 505)

Because a response to RAI question APLA-2b.v1.1 is provided above, no response to this question is required.

Response to APLA 2b.vi.2.c (TSTF 505)

Because a response to RAI question APLA-2b.v1.1 is provided above, no response to this question is required.

APLA QUESTION 02c (TSTF 505) – Dispositions of PRA Model Assumptions and Sources of Uncertainty

c) *Issue #6.2, "Reactor Building effectiveness," in Table E9-5 of Enclosure 9 to the LAR is identified as a "key" source of uncertainty because the PRA does not take much credit for the Reactor Building as a means of fission product retention (e.g., failure rate of 0.99). The LAR states that fission product retention is reasonably treated, but modeling is potentially conservative. The NRC staff reviewed the sensitivity study results provided in the key assumptions and sources of uncertainty notebook on the portal and notes that the impact to calculated RICTs can be significant by reducing the failure rate of the Reactor Building to 0.1. Specifically, while the RICTs for most Technical Specifications (TSs) increased as expected, the RICTs for several TSs associated with containment systems decreased (generally by about 5 days, from about 30 days to 25 days). The results presented in the notebook, this conclusion is unclear to the NRC staff. The implication of this result is that the conservative treatment of Reactor Building*

effectiveness is masking the risk of certain plant configurations, and not necessarily by an insignificant or negligible amount. Therefore, address the following:

i. *Justify that the Reactor Building effectiveness assumption has an inconsequential impact on the RICT calculations (e.g., describe and provide RICT results of a sensitivity study using LCO conditions that could be most impacted by this modeling assumption having RICTs less than the 30-day backstop).. In the response, address the basis for the assumption in both the baseline PRA and sensitivity case.*

ii. *If in response to part (i) above, it cannot be determined that the cited assumption has an inconsequential impact on the estimated RICTs, then identify the LCO conditions impacted by the treatment of this modeling assumption for which RMAs will be applied during a RICT. Include discussion of the kinds of RMAs that would be applied and justification that the RMAs will be sufficient to address this modeling assumption.*

Response to APLA 2c.i (TSTF 505)

The commentary included in Section 8.6 in the key assumptions and sources of uncertainty notebook[8] cited in the question provides the rationale for the conclusions regarding reactor building effectiveness in the RICT application. The documentation notes that LERF is sensitive to the treatment of the reactor building effectiveness. It also showed that RICT results were sensitive, mainly toward increasing the allowed outage times. However, as noted in the question, a few containment specs had decreased allowed times given the increased credit for the reactor building; an apparently contradictory result. However, the uncertainty notebook recognized this result and attributed this to the containment isolation function bypassing credit for the reactor building in the model.

In terms of further discussion of this result, when the reactor building is credited, baseline LERF is reduced significantly but LERF given unavailable containment isolation (primary containment isolation specs assumed entered) remains elevated. This higher LERF condition is primarily related to fire events which independently fail the containment isolation valve redundant to the valve unavailable within the LCO. In fact, LERF for the LCO condition is similar for the baseline LCO condition as well and the reactor building effectiveness improved LCO condition. Thus, the delta between the base and LCO conditions is higher for the reactor building effective sensitivity. Because the RICT program is oriented to delta results as an acceptance criterion, a lower allowed outage time is yielded because the sensitivity baseline is lower and drives a higher delta.

[8] "Assessment of Key Assumptions and Sources of Uncertainty for the James A. FitzPatrick Nuclear Power Plant PRA," JF-MISC-021, Revision 1

Thus, this apparently contradictory result is explainable in terms of the model and the RICT application. Further, the uncertainty notebook notes that not all containment isolation failures would actually bypass the reactor building, as assumed in the PRA model. Therefore, the effect of the reactor building effectiveness on the containment isolation LCO sensitivity cases is less pronounced than the sensitivity results suggest.

In terms of justifying the judgement that uncertainty in the reactor building effectiveness can be neglected during RICT program implementation:

- The overall RICT impact is small. The maximum impact was a decrease of approximately 5 days for sampled Technical Specifications. These consist of 3.6.1.2.C, 3.6.1.3.A, 3.6.1.3.C, 3.6.1.3.E, 3.6.1.6.C, and 3.6.1.6.D. The change is a small fraction of the 30 day backstop (17%=5 days/30 days) and is expected to be significantly offset by configuration control processes such as risk awareness and protection of redundant equipment.
- RICT impact is mixed in terms of the various Tech Specs. Only the Primary Containment specs have reduced durations and the impact is shown to be bounded by the sensitivity assessment.
- There still remains little justifiable basis to credit the Reactor Building for significant attenuation of releases. The sensitivity study assumed an optimistic representation of the potential for reactor building scrubbing which is over-emphasizing the calculated LERF deltas.

Response to APLA 2c.ii (TSTF 505)

During a RICT condition, configuration control processes such as risk awareness and protection of redundant equipment provide benefits which qualitatively mitigate risk. As noted in the response to question APLA-2-c-i, such processes are judged to fully offset the risk-oriented uncertainty associated with reactor building effectiveness for severe accident release mitigation.

APLA QUESTION 02a (50.69) – Dispositions of PRA Model Assumptions and Sources of Uncertainty

Paragraphs (c)(1)(i) and (ii) of 10 CFR 50.69 require that a licensee's PRA be of sufficient quality and level of detail to support the SSC categorization process, and that all aspects of the integrated, systematic process used to characterize SSC importance must reasonably reflect the current plant configuration and operating practices, and applicable plant and industry operational experience. The guidance in NEI 00-04 specifies sensitivity studies to be conducted for each PRA model to address uncertainty. The sensitivity studies are performed to ensure that assumptions and sources of uncertainty (e.g., human error, common cause failure, and maintenance probabilities) do not mask importance of components. NEI 00-04 guidance states that additional "applicable sensitivity studies" from characterization of PRA adequacy should be considered.

The NRC staff notes that assessment of uncertainty may identify the need for additional sensitivity studies as presented in Table 5-2 and Table 5-3 of NEI 00-04. LAR Attachment 6 identifies the key assumptions and sources of uncertainty for the fire PRA and provides dispositions for each source of uncertainty. The NRC staff reviewed the dispositions provided in LAR Attachment 6 and noted that some uncertainties appeared to have the potential to impact the 10 CFR 50.69 categorization results. As part of NRC staff's review during the audit of JAF internal events, fire, and risk applications uncertainty analysis reports, it was noted that certain sources of uncertainty identified in those reports appear to the NRC staff to be potential key sources of uncertainty for the 10 CR 50.69 categorization process. Therefore, address the following:

a) LAR Attachment 6 concerning the Cable Selection uncertainty states it is not a source of fire PRA modeling uncertainty because JAF assigns routing locations based on known routing locations. However, Item #12 of Table E9-3 of the Fitzpatrick TSTF-505 LAR states the systems and functions that were not analyzed were failed in all fire scenarios.[9] It appears to the NRC staff that not all cable routing was assumed to have a known location. Such components are identified as unknown location (UNL) components. The TSTF-505 LAR states that a sensitivity analysis was performed to determine the impact of the treatment of UNL components by not failing them in all fire scenarios. Based on the sensitivity study, the LAR states it is concluded that the scope of assumed failures introduces negligible conservatism to both fire core damage frequency (CDF) and large early release frequency (LERF) risk values. The LAR does not provide the results of the uncertainty analyses, but the NRC staff reviewed the sensitivity study results provided in the fire PRA uncertainty analysis report, which determined an 8 and 7 percent impact on fire CDF and LERF, respectively. The NRC staff notes that these results could impact categorization results and in addition, conservative modeling choices can

[9] Gudger, D.T., Exelon Generation Company LLC letter to U.S. Nuclear Regulatory Commission Document Control Desk, "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.'' dated July 30, 2021 (ADAMS Accession No. ML21211A053).

potentially mask the importance of other SSCs or, in other words, artificially lower the risk importance values of other SSCs below the safety significance threshold criteria. In light of these observations address the following:

i. Identify the UNL systems or components that are assumed to be always failed in the PRA. Justify that the UNL assumption does not impact the results of the RISC categorization process under 10 CFR 50.69.

ii. If the modeling addressed in part (i) above cannot be justified to have minimal impact on the RISC categorization results, then propose a mechanism that ensures a sensitivity study is performed during categorization that specifically addresses the uncertainty associated with SSCs for which cable routing is unknown or not modeled.

Response to APLA 2a.i (50.69)

The following functions/systems/components are included as UNLs and always assumed failed with the exception of the Feedwater system which is credited by exclusion.

System/Equipment	Function Failed in FPRA
CST	LPCI/LPCS Alternate Injection supply
Demin	CST Refill (other water sources credited)
RHR	Drywell Sprays
Feedwater	RPV Injection (credited by exclusion)
Feedwater	Feedwater Reg. Valve Bypass Line for RPV Injection (Normal path is credited)
Feedwater	Feedwater MOVs to Isolate Spurious Feedwater Pump Operation (Pump trip and redundant valves credited for isolation)
Firewater	Motor Drive Fire Pump for RPV Injection (Diesel Fire Pumps credited)
LPCS	LPCS DG Auto Start Relay Inputs (RHR Pumps provide redundant input and credited)
LPCS	LPCS Containment Isolation Valve AOV 13A/B (Relief Valves credited for line isolation)
LPCS	LPCS Pump ADS Inputs for 2E-K12A/B and 2E-K15A/B relays (RHR Pumps provide redundant input and credited)

System/Equipment	Function Failed in FPRA
LPCI	LPCI MOVs 43A/B and 53A/B to Isolate Recirc Pump Seal Leak (Pump trip credited)
N2	Backup N2 Supply (Normal supply credited)
RBC	RBC Pump Auto Start Relays when in Standby (Normally running pumps credited)
RBC	RBC MOV 175A/B Logic Failing ESW Cooling to CRD (RBC cooling credited)
Radwaste	CST Refill (other water sources credited)
Turbine Stop Valves	Main Condenser Isolation

A sensitivity study was performed in which all of the UNL components were assumed to be available. The sensitivity study resulted in no new components meeting the criteria for HSS categorization.

RESPONSE TO APLA 2a.ii (50.69)

See response to APLA 2a.i.

APLA QUESTION 02c (50.69) – Dispositions of PRA Model Assumptions and Sources of Uncertainty

c) NUREG-1921 discusses the need to consider a minimum value for the joint probability of multiple HFEs in HRAs.[10] NUREG-1921 refers to Table 2-1 of NUREG-1792[11] which recommends that joint human error probability (JHEP) values should not be below 1E-5. Table 4-4 of EPRI 1021081 provides a lower limiting value of 1E-6 for sequences with a very low level of dependence.[12] Therefore, the available guidance provides for assigning JHEPs that are less than 1E-5, but only through assigning proper levels of dependency. Cutsets with JHEP values less than this value should be individually reviewed (e.g., for timing, cues) to check the dependency between all operator actions in the cutset.

[10] NUREG-1921, "EPRI/NRC-RES Fire Human Reliability Analysis Guidelines - Final Report," dated July 2012
(ADAMS Accession No. ML12216A104).
[11] NUREG-1792, "Good Practices for Implementing Human Reliability Analysis (HRA)," dated April 2005 (ADAMS
Accession No. ML051160213).
[12] EPRI 1021081, "Establishing Minimum Acceptable Values for Probabilities of Human Failure Events."

In LAR Attachment 6, the disposition to the post-fire HRA uncertainty states that a floor value of 1E-06 was applied for identified dependent combinations. The disposition continues by stating this source of uncertainty will be addressed by the NEI 00-04 HEP sensitivity study. The NRC staff notes the NEI 00-04 HEP sensitivity study addresses other sources of human error probability uncertainties other than JHEP floor values. In addition, the NRC staff reviewed the sensitivity study results provided in the fire PRA uncertainty analysis report and notes the results demonstrated a 59 percent and 20 percent impact on the fire CDF and LERF values, respectively. In light of these observations:

> *i. Provide a description of the fire JHEP sensitivity study that was performed and the quantitative results that justify that the JHEP floor value has an inconsequential impact on the RISC categorization process under 10 CFR 50.69.*

RESPONSE TO APLA 2c.i (50.69)

The JAF Fire HRA Dependency Analysis assessment process is consistent with NUREG-1921 Section 6.2 which states, "For fire HRA, it is recommended that the application of a lower bound follow the same guidance as was applied to the internal events PRA." The internal events PRA applies a floor value of 5E-7. The JAF FPRA applies a slightly more conservative lower bound floor value of 1.0E-06.

As part of the RISC categorization process an application specific sensitivity study was performed using the 95th percentile value of the HEPs and JHEPs. In this case, the 95th percentile JHEP is a factor of 10 such that the new floor value is 1E-5 for the application specific sensitivity study. Therefore, the results of the sensitivity study using a 1E-5 floor value for the JHEPs are used to determine component categorization with respect to the sensitivity which are provided for consideration during the categorization process. The sensitivity study resulted in no new components meeting the criteria for HSS categorization.

RESPONSE TO APLA 2c.ii (50.69)

See response to APLA 2c.i.

APLA QUESTION 02d (50.69) – Dispositions of PRA Model Assumptions and Sources of Uncertainty

d) LAR Attachment 6, regarding lack of electrical coordination, states that this source of uncertainty is not a key source for this application. The LAR does not provide the results of the uncertainty analyses, but NRC staff reviewed the sensitivity study results provided in the fire PRA uncertainty analysis report, which determined an 8 percent and 3 percent impact on fire CDF and LERF, respectively. The NRC staff notes that these results could impact categorization results and, in addition, conservative modeling choices can potentially mask the

importance of other SSCs or, in other words, artificially lower the risk importance values of other SSCs below the safety significance threshold criteria. In light of these observations address the following:

i. Describe and provide the results of the electrical coordination sensitivity study.

ii. Provide justification that the assumed electrical coordination used in the fire PRA does not impact the results of the RISC categorization process.

iii. Alternatively, propose a mechanism that ensures a sensitivity study is performed during RISC categorization that specifically addresses the uncertainty associated with SSCs for which coordination is unknown or not modeled.

RESPONSE TO APLA 2d.i (50.69)

The FPRA performed an in-depth electrical coordination study using the plant electrical calculations for the credited FPRA power supplies. Several power supplies were identified as not being fully coordinated with respect to the FPRA or a calculation was not available. If cable length could be used to show coordination then that was considered during the development of the FPRA.

A sensitivity study was performed which assumed that all power supplies were fully coordinated for the FPRA. The sensitivity study resulted in a 8% decrease in CDF and 3% decrease in LERF. The decrease in risk was largely associated with the DC and 120 VAC power supplies. These systems include electrical coordination calculations such that the FPRA does not include conservative assumptions regarding the electrical coordination status for these power supplies. Therefore, the sensitivity study results showed that the modeling of electrical coordination in the FPRA is not conservative but representative of the plant design.

The following table lists the power supplies that are treated as not fully coordinated in the FPRA. The table also identifies if the power supply is credited for fire safe shutdown (SSD).

POWER SUPPLY	DESCRIPTION	Credited for SSD
71-05-6A	REACTOR PROTECTION SYSTEM, DISTRIBUTION PANEL 05-6A, RPS BUS A	No
71-05-6B	REACTOR PROTECTION SYSTEM, DISTRIBUTION PANEL 05-6B, RPS BUS B	No
71AC10	RELAY ROOM 120VAC DISTRIBUTION PANEL	No

POWER SUPPLY	DESCRIPTION	Credited for SSD
71AC9	DISTRIBUTION PANEL 71AC9 COMMON CONTROL & INSTRUMENT BUS 9	No
71ACA2	EM CONTROL AND INSTRUMENT DISTRIBUTION PANEL A2	Yes
71ACA3	EM CONTROL AND INSTRUMENT DISTRIBUTION PANEL A3	No
71ACA4	EM CONTROL AND INSTRUMENT DISTRIBUTION PANEL A4	Yes
71ACA5	EM CONTROL AND INSTRUMENT DISTRIBUTION PANEL A5	No
71ACA6	NORMAL CONTROL AND INSTRUMENT DISTRIBUTION PANEL A6	No
71ACB2	EM CONTROL AND INSTRUMENT DISTRIBUTION PANEL B2	Yes
71ACB3	EM CONTROL AND INSTRUMENT DISTRIBUTION PANEL B3	Yes
71ACB4	EM CONTROL AND INSTRUMENT DISTRIBUTION PANEL B4	Yes
71ACB5	EM CONTROL AND INSTRUMENT DISTRIBUTION PANEL B5	No
71ACB6	NORMAL CONTROL AND INSTRUMENT DISTRIBUTION PANEL B6	No
71ACUPS	RR UNINTERRUPTABLE POWER SUPPLY	Yes
71ACUPS-1	RR UNINTERRUPTABLE POWER SUPPLY	Yes
71ACUPS-2	RR UNINTERRUPTABLE POWER SUPPLY	No
71BMCC-1	125VDC BUS 71BMCC-1 REACTOR BUILDING	Yes
71BMCC-2	125VDC BUS 71BMCC-2 REACTOR BUILDING	Yes
71BMCC-3	125VDC BUS 71BMCC-3 REACTOR BUILDING	Yes

POWER SUPPLY	DESCRIPTION	Credited for SSD
71BMCC-4	125VDC BUS 71BMCC-4 REACTOR BUILDING	Yes
71BMCC-6	125VDC BUS 71BMCC-6 REACTOR BUILDING	Yes
71DC-A1	DC DISTRIBUTION CABINET	No
71DC-A2	DC DISTRIBUTION PANEL RELAY RM	Yes
71DC-A3	125VDC DISTRIBUTION CABINET	Yes
71DC-A4	DC DIST PNL EDG BLDG	Yes
71DC-B1	DC DISTRIBUTION CABINET	No
71DC-B2	DC DISTRIBUTION PANEL	Yes
71DC-B3	125VDC DISTRIBUTION CABINET	Yes
71DC-B4	DC DIST PNL EDG BLDG	Yes
71ESSA1	SAFEGUARD SYS CONTROL AND INST BUS A1	Yes
71ESSB1	SAFEGUARD SYS CONTROL AND INST BUS B1	Yes
71MCC-153	600VAC MCC	Yes
71MCC-155	600VAC MCC	Yes
71MCC-163	600VAC MCC	Yes
71MCC-165	600VAC MCC	Yes
71MCC-251	600VAC MCC - ELEC BAY EL 272' BUS 125100	Yes
71MCC-253	600V MCC	Yes
71MCC-341	600VAC MCC - ELECTRIC BAY EL. 272' BUS 134100	No
71RR24DCA	24VDC DISTRIBUTION PANEL 71RR24DCA (RELAY ROOM)	No
71RR24DCB	24VDC DISTRIBUTION PANEL 71RR24DCB (RELAY ROOM)	No

RESPONSE TO APLA 2d.ii (50.69)

See response to APLA 2d.i.

RESPONSE TO APLA 2-d-iii (50.69)

See response to APLA 2d.i.

APLA QUESTION 04 (TSTF 505) – Digital Instrumentation and Control Modeling

NEI 06-09 states, concerning the quality of the PRA model, that "RG 1.174, Revision 1, and RG 1.200, Revision 1 define the quality of the PRA in terms of its scope, level of detail, and technical adequacy. The quality must be compatible with the safety implications of the proposed TS change and the role the PRA plays in justifying the change."

Regarding digital instrumentation and controls (I&C), NRC staff notes the lack of consensus industry guidance for modeling these systems in plant PRAs to be used to support risk-informed applications. In addition, known modeling challenges exist such as the lack of industry data for digital I&C components, the difference between digital and analog system failure modes, and the complexities associated with modeling software failures including common cause software failures. Also, though reliability data from vendor tests may be available, this source of data is not a substitute for in-the-field operational data. Given these challenges, the uncertainty associated with modeling a digital I&C system could impact the RICT program. However, it is not clear to NRC staff whether the licensee credited digital systems in the PRA models that will be used in the RICT program or whether this modelling can impact the RICT calculations. Therefore, address the following:

a) *Identify the digital I&C systems credited in the PRA models that will be used in the RICT program.*
b) *For the digital I&C systems credited in the PRA models that will be used in the RICT program, justify that the modeling uncertainty associated with crediting these digital I&C systems in the PRA models has an inconsequential impact on the RICT calculations (e.g., describe and provide the results of a sensitivity study performed for each digital system modeled in the PRA).*
c) *As an alternative to item (b) above, identify the LCO conditions impacted by digital I&C system modeling and for which RMAs will be applied during a RICT. Explain and justify the criteria used to determine what level of impact to the RICT calculation requires additional RMAs.*

Response to APLA 4 (TSTF 505)

There are no digital systems credited in the JAF PRA. However, the Feedwater System was converted to digital on 10/7/2020 (EC 625089) and this has been captured with a PRA URE against the MOR (JF2017A).

APLA/APLB QUESTION 06 (TSTF 505) – Total Risk and Accounting for the SOKC

Regulatory Guide 1.174[13] provides the risk acceptance guidelines for total CDF (1E-04 per year) and LERF (1E-05 per year). NRC staff notes based on RG 1.174 and Section 6.4 of NUREG-1855, Revision 1, for a Capability Category II risk evaluation, the mean values of the risk metrics (total and incremental values) need to be compared against the risk acceptance guidelines. 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 that are explicitly input to the PRA models, including explicit consideration of the state-of-knowledge correlation (SOKC) between events. In general, the point estimate CDF and LERF obtained by quantification of the cutset probabilities using mean values for each basic event probability does not produce a true mean of the CDF and LERF. Under certain circumstances, a formal knowledge (SOKC) is unimportant (i.e., the risk results are well below the acceptance guidelines). Section 2 of Enclosure 5 to the LAR states that the total CDF and LERF values presented in Table E5-1 for FitzPatrick are "point estimate values" which are likely lower than the mean CDF and LERF values. The total CDF and LERF values presented in Table E5-1 include the seismic hazard contribution based on the seismic penalty values that will be used in the RICT calculations. While the total CDF and LERF values do not approach the RG 1.174 guidelines of 1E-04 per year for CDF or 1E-05 per year for LERF, the current PRA models and associated risk results could potentially increase in response to information requests (e.g., requests on the acceptability of fire PRA methods and requests concerning FLEX modeling) and in future model updates. Therefore, address the following:

a) *Demonstrate, that after the total mean internal events (including internal flooding) and fire CDF and LERF values are calculated to account for the SOKC and for potential changes in risk due to any updates to PRA models performed in response to NRC staff requests, the total risk for Unit 1 and Unit 2 is in conformance with RG 1.174 risk acceptance guidelines (i.e., CDF < 1E-04 per year and LERF < 1E-05 per year). Include identification of the fire PRA parameters that are assumed to be correlated in the parametric uncertainty analysis of fire events (e.g., fire ignition frequencies, non-suppression probabilities, severity factors, spurious probabilities, fire human error probabilities), as well as the sources used for the associated uncertainty distributions*

---

[13] *NRC RG 1.174, Revision 3, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," dated January 2018 (ADAMS Accession No. ML17317A2565).*

(e.g., NUREG-2169[14], NUREG/CR-1278[15], NUREG/CR-7150[16], and EPRI HRA Calculator uncertainty distributions).

b) *As an alternative to Part a) above, propose a mechanism that, prior to implementation of the RMTS program: (1) the total mean internal events (including internal flooding) and fire CDF and LERF will be calculated to account for the SOKC and updates to PRA models performed in response to NRC staff requests; and (2) the updated total risk (including seismic risk) values are still in conformance with the RG 1.174 risk acceptance guidelines (i.e., CDF < 1E 04 and LERF < 1E 05 per year).*

c) *Discuss how the SOKC will be addressed for the RICT program, and how this treatment is consistent with NUREG-1855, Revision 1, when the risk increase associated with SOKC is considered.*

Response to APLA/APLB 06a (TSTF 505)

The mean CDF and LERF values derived via Monte Carlo sampling are indeed different than the corresponding Point Estimate CDF and LERF values. Because the RICT program application is a “delta” type application (i.e., acceptability is based on the difference in risk calculated for the base model configuration and that calculated for a configuration in which equipment is unavailable), the impact of the SOKC uncertainty on RICT estimates is considered negligible and Point Estimate values are adequate to inform the difference between plant configurations (i.e., the “delta” risk between different plant configurations). While mean CDF and LERF values are different than the point estimate values for the base model, the mean CDF and LERF values are also different than the point estimate values reflective of an equipment unavailable plant configuration. As a sensitivity, the delta risk was evaluated using both point estimate and mean values for a condition where RCIC is assumed unavailable for an extended LCO. Each model (IEPRA and FPRA) was quantified using point estimate and Monte Carlo processes. This yielded point estimate values for the base and RCIC unavailable plant configurations. Monte Carlo simulation was then used with 5000 samples to calculate the corresponding mean values.

The FPRA uses the FPIE uncertainty parameters for basic events that are common to both models (e.g., component failures). For parameters that are specific to the FPRA the uncertainty parameters used in the FPRA are based on the current industry guidance. The parameters include:

---

[14] *NUREG-2169, "Nuclear Power Plant Fire Ignition Frequency and Non-Suppression Probability Estimation Using the Updated Fire Events: United States Fire Event Experience Through 2009,” January 2015, (ADAMS Accession No. ML15016A069).*

[15] *NUREG/CR-1278, “Handbook of Human Reliability Analysis with Emphasis on Nuclear Power Plant Applications: Final Report,” August 1983 (ADAMS Accession No. ML072100299).*

[16] *NUREG/CR-7150, “Joint Assessment of Cable Damage and Quantification of Effects from Fire (JACQUE-FIRE): Final Report,” May 2014 (ADAMS Accession No. ML12313A105).*

- Fire Ignition Frequencies – NUREG-2169 or updated guidance for specific bins (e.g., NUREG-2230 for electrical cabinets, NUREG-2178 for main control board, etc.)
- Fire HRA – Assigned by the HRA calculator
- Circuit Failure Likelihood Probabilities – NUREG/CR-7150 Vol. 2
- The fire scenario severity factors (e.g., pump fire split fractions) are point estimates and therefore use generic error factor estimates. The fire scenario non suppression probabilities use generic NUREG-2178 error factors because the calculated non suppression probabilities include multiple fire modeling and manual suppression parameters.

Table APLA-6-a-1 provides the results of these calculations which show that the delta-risk results using mean and point estimate values are very similar and are not significant to the RICT application. Two other sensitivities were also performed, the first assuming an EDG is unavailable and the second assuming that a division of RHR A unavailable for Suppression Pool Cooling support. Tables APLA-6-a-2 and APLA-6-a-3, respectively, provide the results of these additional sensitivities which also demonstrate a small increase in delta risk when mean values are quantified.

Table APLA-6-a-1 Summary of Mean vs Point Estimate Results (IPRA & FPRA)

	CDF Point Estimate (/yr)	CDF Propagated Mean (/yr)	LERF Point Estimate (/yr)	LERF Propagated Mean (/yr)
Base	1.98E-05	1.96E-05	4.10E-06	4.06E-06
RCIC Failed (TS 3.5.3)	3.29E-05	3.20E-05	5.09E-06	4.96E-06
Delta	1.30E-05	1.25E-05	9.88E-07	8.91E-07
% Increase in Delta	n/a	95.7%	n/a	90.2%
RICT (days)	30	30	30	30

Note - The propagated mean values may be less than the point estimate mean values because of the FPRA uncertainty results. This is because transient fires are the top contributors which have a FIF distribution where the mean (3.33E-3) is close to the 95th (9.62E-3) but the 5th (1.94E-5) is significantly smaller. Also, the top contributing cutset are scenarios that include a single basic event failure such that correlation between events is not an uncertainty issue.

Table APLA-6-a-2 Summary of Mean vs Point Estimate Results (IPRA & FPRA)				
	CDF Point Estimate (/yr)	CDF Propagated Mean (/yr)	LERF Point Estimate (/yr)	LERF Propagated Mean (/yr)
Base	1.98E-05	1.96E-05	4.10E-06	4.06E-06
EDG Failed (Ts 3.6.1.9)	2.32E-05	2.08E-05	4.77E-06	4.35E-06
Delta	3.36E-06	1.25E-06	6.68E-07	2.85E-07
% Increase in Delta	n/a	37.2%	n/a	103.6%
RICT (days)	30	30	30	30
Note - The propagated mean values may be less than the point estimate mean values because of the FPRA uncertainty results. This is because transient fires are the top contributors which have a FIF distribution where the mean (3.33E-3) is close to the 95th (9.62E-3) but the 5th (1.94E-5) is significantly smaller. Also, the top contributing cutset are scenarios that include a single basic event failure such that correlation between events is not an uncertainty issue.				

Table APLA-6-a-3 Summary of Mean vs Point Estimate Results (IPRA & FPRA)				
	CDF Point Estimate (/yr)	CDF Propagated Mean (/yr)	LERF Point Estimate (/yr)	LERF Propagated Mean (/yr)
Base	1.98E-05	1.96E-05	4.10E-06	4.06E-06
RHR-SPC Division Failed (3.8.1-B)	5.73E-05	5.75E-05	5.66E-06	5.68E-06
Delta	3.75E-05	3.79E-05	1.56E-06	1.62E-06
% Increase in Delta	n/a	101.1%	n/a	103.6%
RICT (days)	30	30	30	30
Note - The propagated mean values may be less than the point estimate mean values because of the FPRA uncertainty results. This is because transient fires are the top contributors which have a FIF distribution where the mean (3.33E-3) is close to the 95th (9.62E-3) but the 5th (1.94E-5) is significantly smaller. Also, the top contributing cutset are scenarios that include a single basic event failure such that correlation between events is not an uncertainty issue.				

Response to APLA/APLB 06b (TSTF 505)

The SOKC has been shown to be small, see response to question APLA 6a and is judged reasonably addressed by the point-estimate based process described in the JAF submittal.

Response to APLA/APLB 06c (TSTF 505)

The SOKC has been shown to be small, see response to question APLA-6-a and is judged reasonably addressed by the point-estimate based process described in the JAF submittal.

APLA QUESTION 08a (TSTF 505) – In-Scope LCOs and Corresponding PRA Modeling

The NRC SER for NEI 06-09 specifies that the LAR should provide a comparison of the TS functions to the PRA modeled functions to show that the PRA modelling is consistent with the licensing basis assumptions or to provide a basis for when there is a difference. Table E1-1 in Enclosure 1 of the LAR identifies each TS LCO proposed for the RICT program, describes whether the systems and components participating in the TS LCO are implicitly or explicitly modeled in the PRA, and compares the design basis and PRA success criteria. For certain TS LCO conditions, the table explains that the associated SSCs are not modelled in the PRAs but will be represented using a surrogate event that fails the function performed by the SSC. For some LCO conditions, the LAR did not provide sufficient information for NRC staff to conclude that the PRA modeling will be sufficient for each proposed LCO Condition. Address the following:

a) *Regarding TS LCO 3.3.2.2, "Feedwater and Main Turbine High Water Level Trip Instrumentation," Condition A, "One feedwater and main turbine high water level trip channel inoperable," the required function outlined in Table E1-1 is stated to be prevention of turbine moisture intrusion. However, the FitzPatrick TS Bases for LCO 3.3.2.2 indicate that the safety function addressed by this LCO is ensuring that thermal limits are not challenged during an overfeed event. This is ensured by tripping the main turbine and two feedwater (FW) pump turbines upon receipt of a high reactor water level signal. Table E1-1 also notes that the high-level trip channels required by LCO 3.3.2.2 are not modeled explicitly in the PRA. In the absence of explicitly modeled high water level instrumentation, a surrogate (FW pump failure) has been proposed to represent the failure of any channel of the FW high level instrumentation to support RICT program implementation.*

   Surrogates selected for RICT applications should correlate directly to the safety function against which the LCO has been established in a manner that defeats the safety function addressed by the LCO. It would therefore be expected that the surrogate event for LCO 3.3.2.2 would represent a failure of one or both FW pumps to trip or an alternate surrogate that would pose challenges to thermal limits should the high-water level instruments fail to perform their intended function. Considering this, discuss why the surrogate proposed in the LAR sufficiently bounds the failure of one high-level instrument failure for the purposes of developing a RICT for LCO 3.3.2.2.

Response to APLA 8a (TSTF 505)

The proposed surrogate events to represent LCO 3.3.2.2 include failure of HPCI and RCIC relay coils, which fail the associated pumps, which are responsible for system initiation upon receipt of reactor low level and high drywell pressure.

APLA QUESTION 08b (TSTF 505) – In-Scope LCOs and Corresponding PRA Modeling

b) *Regarding TS LCO 3.3.4.1, "Anticipated Transient Without Scram Recirculation Pump Trip (ATWS-RPT) Instrumentation," Condition A, "One or more channels inoperable," the design and PRA success criteria are in terms of trains rather than the ATWS-RPS logic described on Page 12 of LAR Attachment 5 (i.e., one-out-of-two taken twice based on two trip systems and two channels per trip system). Based on the information in the "Other Comments" column of Table E1-1, it appears the success criteria are in terms of the two trains of the reactor recirculation system and, in particular, the recirculation pump motor breakers, which is a surrogate for ATWS-RPS because the PRA does not model the ATWS-RPS instrumentation. This same table describes the design success criteria as "one of two trains" and the PRA success criteria as "two of two trains," which seems to imply that the PRA model assumes that if any channel of ATWS-RPT is out-of-service (OOS) then both trains of reactor recirculation are OOS. Address the following:*

   i. *Clarify if the NRC staff's understanding of the modeling of the ATWS-RPT surrogate is correct. If not, describe how this surrogate is modeled to determine a RICT and justify that this is bounding for TS 3.3.4.1 Condition A.*

   ii. *Explain why the PRA success criteria is more limiting than the design success criteria and the implications for this to the RICT program.*

Response to APLA 8b.i (TSTF 505)

Upon additional review of the PRA model, it is noted that the ATWS RPT Instrumentation is modeled explicitly. This modeling includes the one-out-of-two taken twice logic discussed with a success criteria of one of two trains. For future RICTs, the explicitly modeled instrumentation will be used to represent the LCO.

Response to APLA 8b.ii (TSTF 505)

The PRA Success criteria is consistent with the design success criteria. During ATWS scenarios, it is important for the recirc pumps to trip in order to eliminate forced circulation and

reduce flow through the core to reduce reactor power. As a result of successful recirc pump trip, reactor power is reduced to below safety relief valve capacity, protecting from overpressure, and steam directed to the torus is minimized, increasing available time for operators to take action to initiate SLC.

Failure of either recirc pumps to trip results in a condition in which the PRA assumes power is not reduced sufficiently to prevent RPV over-pressurization.

APLA QUESTION 08c (TSTF 505) – In-Scope LCOs and Corresponding PRA Modeling

c) *Regarding TS LCO 3.3.5.1, "Emergency Core Cooling System (ECCS) Instrumentation," Condition G, "As required by Required Action A.1 and referenced in Table 3.3.5.1-1," LAR Table E1-1 identifies Core Spray (CS) Pump Discharge Pressure – High as being modeled using the surrogate CS minimum flow bypass valves. It is unclear to the NRC staff how the surrogate minimum flow bypass valves are bounding for the modeling of the CS Pump Discharge Pressure – High function. Provide justification that the surrogate (CS minimum flow bypass valves) used to model the CS Pump Discharge Pressure – High function is bounding for RICT determination.*

Response to APLA 8c (TSTF 505)

The surrogate events used to represent LCO 3.3.5.1, Condition G are a fails closed minimum bypass valve for each division of core spray. The minimum bypass valve is normally open to protect the core spray pump from damage caused by overheating in no or low flow conditions. This valve closes once adequate flow is available.

With this valve failed closed, the PRA model assumes that the core spray line has low flow and provides insufficient volume, logically failing the pump.

APLA QUESTION 08d (TSTF 505) – In-Scope LCOs and Corresponding PRA Modeling

d) *Regarding TS LCO 3.3.6.1, "Primary Containment Isolation Instrumentation," Condition A, "One or more required channels inoperable," LAR Table E1-1 identifies that instrumentation to isolate primary containment for the Reactor Water Cleanup (RWCU) system, Shutdown Cooling (SDC) system, and Traversing Incore Probe (TIP) system are modeled using surrogates, specifically affected motor operated valves (MOVs) and relays. The LAR does not provide sufficient information about how these functions are modeled to conclude that the surrogates are bounding. Provide justification that the surrogates used to model these functions are bounding for RICT determination. In the response, identify the MOVs and relays that are modeled as surrogates.*

Response to APLA 8d (TSTF 505)

Surrogate components used:
12MOV-15: Reactor Water Clean Up Supply Inboard Isolation Valve
12MOV-18: Reactor Water Clean Up Supply Outboard Isolation Valve
12MOV-69: Reactor Water Clean Up Containment Isolation Valve
10MOV-17: RHR SDC Outboard Isolation Valve
10MOV-18: RHR SDC Inboard Isolation Valve

All surrogate equipment used to represent LCO 3.3.6.1 utilize fails open/fails to close failure modes to represent the loss of the ability to isolate containment. A loss of instrumentation would ultimately result in the same condition in which isolation valves and associated equipment did not operate and remained in an open, un-isolated configuration.

Note that the Traversing Incore Probe (TIP) is screened from the PRA Containment Isolation Analysis. It is a small line which does not meet the =>2" effective cross-sectional area criteria for PRA modeling.

APLA QUESTION 08e (TSTF 505) – In-Scope LCOs and Corresponding PRA Modeling

e) *Regarding TS LCO 3.3.7.2, "Condenser Air Removal Pump Isolation Instrumentation," Condition A, "One or more required channels inoperable," LAR Table E1-1 explains that the SSCs are not currently modeled in the PRA and that the PRA model will be updated to model these SSCs prior to exercising the RICT program for this TS. This is consistent with the Implementation Item in LAR Attachment 6, which also states that the PRA Success Criteria will match the Design Success Criteria. Address the following:*

   i. *Describe the proposed PRA modeling associated with TS 3.3.7.2.A.*

   ii. *Explain how the inoperability of the mechanical vacuum pump isolation instrumentation impacts CDF or LERF and how a change in CDF and LERF can be calculated for the RICT estimate.*

   iii. *If applicable, provide an update to the associated implementation item.*

Response to APLA 8e.i (TSTF 505)

We envision creating a condenser scrubbing model to be used for stuck open MSIV scenarios. This would be similar to the existing treatment of the Reactor Building Effectiveness except recognizing that the condenser integrity is a separate barrier for sequences with Primary and Secondary Containment bypass. This modeling would be informed by MAAP analysis.

Response to APLA 8e.ii (TSTF 505)

This logic would impact Level 2 modeling (e.g., LERF) only. If the condenser pathway can be justified to prevent large releases following core damage with the MSIVs open, this logic will be probabilistically credited in the PRA. If condenser scrubbing cannot be justified, the new condenser scrubbing logic will be set to TRUE in the base model. If set to TRUE, the new logic would be available for sensitivity purposes only and any calculations using the baseline model would not reflect any LERF credit. Related to the mechanical vacuum pump isolation function in RICT calculations, if failed or unavailable, this would likely be assumed to fail any credit taken for condenser pathway scrubbing.

Response to APLA 8e.iii (TSTF 505)

Not applicable, PRA model has not yet been updated to address this.

APLA QUESTION 08f (TSTF 505) – In-Scope LCOs and Corresponding PRA Modeling

f) *Regarding TS LCO 3.5.1, "ECCS-Operating," Condition E, "One required ADS valve inoperable," LAR Table E1-1 explains that the PRA Success Criteria is "Seven of eleven SRVs are required for ATWS scenarios and two of eleven SRVs are required during non-ATWS scenarios," which is different than the design success criteria of "Five of seven ADS valves." This is also applicable to TS 3.5.1 Condition F, "One required ADS valve inoperable and one low pressure ECCS injection/spray system inoperable." The design success criterion is required to provide pressure relief so that the ECCS can successfully mitigate small loss of coolant accidents and the FitzPatrick UFSAR explains that only seven of the SRVs can be actuated by signals from the ADS. The PRA success criteria appear to be what is required to prevent over-pressurization of the reactor coolant system during normal plant operations and load rejections. Address the following:*

   i. *Provide justification that the PRA success criteria do not result in a non-conservative RICT for both Condition E and Condition F.*

   ii. *If justification cannot be provided, provide revised PRA success criteria that are applicable to the ADS function of the ECCS and explain how the PRA models an out of service ADS SRV for the RICT calculation. In the response, provide an updated estimate of the RICT for this configuration (i.e., revision to the Table E1-2 RICT estimate for both Conditions E and F).*

Response to APLA 8f.i (TSTF 505)

Within the PRA, ADS is assumed to be inhibited, per EOP guidance. With this, all 11 SRVs (7 ADS and 4 non-ADS) require operator action to open in RPV depressurization mode (overpressure relief mode remains automatic). Success criteria for RPV depressurization is a function of the type of accident sequence occurring.

Based upon multiple MAAP calculations (thermal-hydraulic), the success criteria for RPV depressurization is assumed to require:

- 3 SRVs open in Transient and Small LOCA. Analysis shows that 2 open SRVs is adequate to support RPV injection from Core Spray and LPCI but 3 SRVs are currently required to bound/support injection from alternate RPV injection systems (RHRSW, etc.).
- 1 SRV open in Medium LOCA (model currently conservatively uses Transient/SLOCA gate logic)
- 3 SRVs open in ATWS.

Initial overpressurization protection (relief mode) is assumed to require:

- Recirc Pump Trip and 7 SRVs open in ATWS with MSIVs closed
- Recirc Pump Trip and 5 SRVs open in ATWS with MSIVs open
- 1 SRV opens in non-ATWS Transient or Small LOCA

Response to APLA 8f.ii (TSTF 505)

See response to item 8f.i. above.

APLA QUESTION 08g (TSTF 505) – In-Scope LCOs and Corresponding PRA Modeling

g) *Regarding TS LCO 3.6.1.3, "Primary Containment Isolation Valves (PCIVs)," Condition A, "One or more penetration flow paths with one PCIV inoperable…," LAR Table E1-1 explains that "any PCIV not explicitly modeled will use a pre-existing small leak event for the RICT calculations." The LAR does not explain what is meant by a "pre-existing small leak event" or how this is bounding for all applicable RICT calculations. Address the following:*

   i. *Explain what is meant by "pre-existing small leak event" and justify that this surrogate is bounding for all PCIVs not explicitly modeled in the PRA.*

   ii. *Explain how this surrogate is implemented in the RTR model for operator calculation of a RICT.*

Response to APLA 8g.i (TSTF 505)

The ”pre-existing small leak” event contained within the PRA MOR directly under the “Primary containment isolation system failure” gate. Setting this event to True for any unmodeled component would act as a conservative surrogate given there would be no credit for any redundant equipment that would potentially mitigate PCIS failure (i.e. concurrent inboard and outboard isolation valve failure in order to fail to isolate for a single line).

Response to APLA 8g.ii (TSTF 505)

A configuration variable “Small PCIS Leak” will be implemented into the RTR model in the event a RICT is to be performed and the affected component is not contained within the model.

APLA QUESTION 08h (TSTF 505) – In-Scope LCOs and Corresponding PRA Modeling

h) Regarding TS LCO 3.6.1.6, “Reactor Building-to-Suppression Chamber Vacuum Breakers,” Condition C, “One line with one or more reactor building-to-suppression chamber vacuum breakers inoperable for opening,” LAR Table E1-1 explains that the SSCs are not currently modeled in the PRA and that the PRA model will be updated to model these SSCs prior to exercising the RICT program for this TS. This is consistent with the implementation item in LAR Attachment 6, which also states that the PRA Success Criteria will match the Design Success Criteria. Address the following:

i. Describe the proposed PRA modeling associated with TS LCO 3.6.1.6 Condition C.

ii. Explain how the inoperability of the vacuum breakers impacts CDF or LERF and how a change in CDF and LERF can be calculated for the RICT estimate.

iii. If applicable, provide an update to the associated implementation item.

Response to APLA 8h.i (TSTF 505)

The Reactor Building to Torus Vacuum Breakers are included in the current containment isolation model. This modeling requires the breakers to be closed to prevent containment bypass. However, the model does not address the fail to open failure mode of these vacuum

breakers. We envision reviewing the vapor suppression model to address the open function during LOCA events. Such a demand may be required to preclude significant negative pressure in the torus airspace following containment spray actuation.

Response to APLA 8h.ii (TSTF 505)

Stuck Open Reactor Building to Torus represents a containment bypass pathway. This failure mode has been explicitly included in the PRA model and CDF and LERF estimates are developed similarly to other modeled components. The failure to open on demand could lead to Torus failure in certain scenarios. This failure mode has not yet been addressed by the PRA and the PRA cannot currently provide RICT inputs for the related technical specification.

Response to APLA 8h.iii (TSTF 505)

Not applicable, PRA model has not yet been updated to address this.

APLA Question 12 – Update of the Internal Events (including Internal Flooding) PRA with F&O Resolutions

RG 1.200 provides guidance for addressing PRA acceptability. RG 1.200 describes a peer review process using ASME/ANS RA-Sa–2009 as one acceptable approach for determining the technical acceptability of the PRA.[17] The primary results of peer reviews are the facts and observations (F&Os) recorded by the peer review team and the subsequent resolution of these F&Os. A process to close finding-level F&Os is documented in Appendix X to the NEI guidance documents NEI 05-04, NEI 07-12, and NEI 12-13,[18] which was accepted by the NRC in a letter dated May 3, 2017.[19]
As part of NRC staff's review during the audit regarding the JAF internal events PRA model (FPIE) peer reviews and F&O closures, it was noted that the current JAF FPIE model of record is dated 2017 and incorporated F&O resolutions from the 2010 peer review. However, the staff notes that one 2010 F&O remained open and six new F&Os were identified during the 2020 full-scope peer review, which were subsequently closed out in the August 2020 F&O Closure review. Based on the staff's review of the latest F&O closure review, it appears that at least three of these F&Os required additional model updates other than those performed in the 2017 FPIE model update. It is unclear to the NRC staff whether the JAF FPIE model of record incorporates all resolutions required for F&O closure.

In addition, the current JAF fire PRA model of record revision date is March 2021 to address fire F&Os for the closure reviews. However, it is unclear whether the FPIE F&O resolutions were incorporated in the fire PRA updates. The NRC staff notes that the technical adequacy of the fire PRA model depends on the underlying FPIE model it utilizes.

In light of these observations, provide the following information:

a) Confirm that all modeling updates performed to resolve the internal events PRA F&Os were incorporated into the FPIE PRA and, as applicable, the internal flooding and fire PRAs used to support this application.

b) If it cannot be confirmed in response to part (a) above that all internal events modeling updates performed to resolve F&Os were incorporated into the PRAs, then propose a mechanism that ensures that all internal events modeling updates performed to resolve F&Os that could impact risk are incorporated into the FPIE PRA and, as applicable, the internal flooding and fire PRAs prior to implementation of the categorization program.

---

[17] ASME/ANS PRA standard ASME/ANS-RA-Sa-2009, "Addenda to ASME/ANS RA-S-2008, Standard for Level
1/Large Early Release Frequency Probabilistic Risk Assessment for Nuclear Power Plant Applications."
[18] Appendix X to the Nuclear Energy Institute (NEI) guidance documents NEI 05-04, NEI 07-12, and NEI 12- 13 ,
titled "NEI 05-04/07-12/12-06 Appendix X: Close-out of Facts and Observations (F&Os)" (ADAMS Package
Accession No. ML17086A431)
[19] NRC Acceptance letter of the NEI Appendix X, dated May 3, 2017 (ADAMS Accession No. ML 17079A427)

c) *Alternatively, for the internal events modeling updates performed to resolve F&Os which were not incorporated into the FPIE PRA used to support this application, justify that these updates have an inconsequential impact on this application and on the results of the RISC categorization process (e.g., describe these internal events F&Os; their resolutions; their impact on the internal events, internal flooding and fire PRAs; their impact on the dispositions of key assumptions/sources of uncertainty for this application; and their impact on the categorization results).*

Response to APLA 12a

The August 2020 Closure Review was supported by an Application Specific Model (JF-ASM-007) which included some modeling refinements beyond the 2017 Model of Record. Refinements included the adjustment of some HFEs, some internal flooding frequency revisions, a complete regeneration of Joint HEPs, and revision to support system initiating event adjustment factors and recoveries. These improvements are being formally added into the Model of Record as part of a 2021 periodic model update currently underway for JAF. This updated model will be available to support program implementation. Given that all F&Os were closed and the ASM model is controlled by the PRA model update and maintenance program, ER-AA-600-1015, the JAF FPIE PRA is judged to be adequate technical quality to support the application.

Regarding the Fire PRA, the Fire HRA includes re-development of HEPs and JHEPs such that these IEPRA adjustments are not relevant. In addition, internal flooding and support system initiating events frequencies do not play a role in FPRA.

Response to APLA 12b

The PRA model update and maintenance program, ER-AA-600-1015, provides the mechanism to ensure that relevant model improvements, including those to support F&O closure, are incorporated into the models which support implementation of the categorization program.

Response to APLA 12c

Relative to the significance of F&O closure modifications to the PRA model, a set of sensitivity assessments was performed:

- RICT sample calculations (i.e., Enclosure 1) were re-performed with the F&O ASM Model (JF2017AA, JF2017CF5)
- RICT Sensitivity Assessments supporting the Uncertainty Assessment (i.e., Enclosure 9) were re-performed with the F&O ASM Model.
- A 50.69 Categorization review was re-performed using the F&O ASM Model.

A review was performed to assess the impact of utilizing the JF2017AA ASM for RICT applications versus the previously utilized JF2017A MOR. Shifts in results obtained

were very minor with two exceptions. The RICT estimate for TS 3.8.4.A (125 VDC Battery Charger) changed from 0.4 days to 30 days. This shift in results for the 3.8.4.A estimate was an expected result as one of the notable refinements included in the JF2017AA ASM was involved DC power HEPs. Specifically, the HEP for aligning an alternate charger was recently developed in detail. Of note, alignment or pre-staging of such alternate chargers would likely be employed as part of RMAs for such a case. Also, unavailability of a battery board remains at the 0.4 day value. Additionally, a 25% increase in estimated RICT time was noted for 3.3.5.1.C (Reactor Pressure – Low, Injection Permissive) from 23.9 days to 30 days. This improvement results from a detailed HRA evaluation for the action to manually open ECCS injection valves if the low pressure permissive instrumentation has failed. Finally, a 3% increase occurred for 3.8.1.C (Two Offsite Circuits unavailable) from 19.7 days to 20.4 days. Beyond this, changes to RICT estimates remained at or below 1%.

The completion time sensitivities related to the uncertainty analysis show that results do not vary much from model version to model version. The containment isolation specifications (e.g., 3.6.1.3.A/C/E) varied by ~-2 days (~-7%) between the model revisions. Most other cases saw a reduction of approximately one day of completion time although the offsite circuits saw some cases with slightly increased completion times. Overall, the choice of these particular models has a small impact on the uncertainty in calculated completion times.

When 50.69 categorization was reviewed using the F&O ASM, 16 additional basic events met PRA HSS criteria. These additional 16 basic events do not introduce any new systems which did not have at least one other component identified when the JF2017A model is used for PRA categorization.

APLB 2 (TSTF-505) Modeling Uncertainty

RG 1.200 states "NRC reviewers, [will] focus their review on key assumptions and areas identified by peer reviewers as being of concern and relevant to the application." The relatively extensive and detailed reviews of fire PRAs undertaken in support of license amendment requests (LARs) to transition to NFPA-805 determined that implementation of some of the complex fire PRA methods often used non-conservative and over-simplified assumptions to apply the method to specific plant configurations. Some of these issues were not always identified in F&Os by the peer review teams but are considered potential key assumptions by the NRC Staff because using more defensible and less simplified assumptions could substantively affect the fire risk and fire risk profile of the plant. The NRC Staff evaluates the acceptability of the PRA for each new risk-informed application and, as discussed in RG 1.174, recognizes that the acceptable technical adequacy of risk analyses necessary to support regulatory decision-making may vary with the relative weight given to the risk assessment element of the decision-making process. The NRC staff notes that the calculated results of the PRA are used directly to calculate a RICT which subsequently determines how long SSCs (both individual SSCs and multiple, unrelated SSCs) controlled by Technical Specifications can remain inoperable. Therefore, the PRA results are given a very high weight in a TSTF-505

application and the NRC Staff requests additional information on the following issues that have been previously identified as potentially key fire PRA assumptions.

a) *Minimum Joint Human Error Probability*

NUREG-1921, "EPRI/NRC-RES Fire Human Reliability Analysis Guidelines- Final Report," (ADAMS Accession No. ML12216A104), discusses the need to consider a minimum value for the joint probability of multiple human failure events (HFEs) in human reliability analyses (HRAs).

NUREG-1921 refers to Table 2-1 of NUREG-1792, "Good Practices for Implementing Human Reliability Analysis (HRA)," (ADAMS Accession No. ML051160213), which recommends that joint human error probability (HEP) values should not be below 1E-5. Table 4-4 of Electrical Power Research Institute (EPRI) 1021081, "Establishing Minimum Acceptable Values for Probabilities of Human Failure Events," provides a lower limiting value of 1E-6 for sequences with a very low level of dependence. Therefore, the guidance in NUREG-1921 allows for assigning joint HEPs that are less than 1E-5, but only through assigning proper levels of dependency.

LAR Enclosure 9 Table E9-6 (Topic #12) explains that the sensitivity to the joint HEP floor value is evaluated by using a joint HEP of 1E-6 in the fire PRA. However, even if the assumed minimum joint HEP values are shown to have no impact on the current fire PRA risk estimates, it is not clear to the NRC staff how it will be ensured that the impact remains minimal for future PRA model revisions. In light of these observations:

i. *Provide a description of the sensitivity study that was performed and the quantitative results that justify that the minimum joint HEP value has an inconsequential impact on the RICT application.*

ii. *If, in response part (i), if it cannot be justified that the minimum joint HEP value has no impact on the application, then provide the following:*

1. *Confirm that each joint HEP value used in the FPRA below 1E-5 includes its own justification that demonstrates the inapplicability of the NUREG-1792 lower value guideline (i.e., using such criteria as the dependency factors identified in NUREG-1921 to assess level of dependence). Provide an estimate of the number of these joint HEP values below 1.0E-5, discuss the range of values, and provide at least two different examples where this justification is applied.*

2. *If joint HEP values used in the fire PRA below 1E-5 cannot be justified, add an implementation item to set these joint HEPs to 1E-5 in the fire PRA prior to the implementation of the RICT Program.*

b) *Well-Sealed MCC cabinets*

Guidance in Frequently Asked Question 08-0042 from Supplement 1 of NUREG/CR-6850 applies to electrical cabinets below 440 V. With respect to Bin 15 as discussed in

Chapter 6, it clarifies the meaning of "robustly or well-sealed." Thus, for cabinets of 440V or less, fires from well-sealed cabinets do not propagate outside the cabinet. For cabinets of 440 V and higher, the original guidance in Chapter 6 remains and requires that Bin 15 panels which house circuit voltages of 440 V or greater are counted because an arcing fault could compromise panel integrity (an arcing fault could burn through the panel sides, but this should not be confused with the high energy arcing fault type fires)." Fire PRA FAQ 14-0009, "Treatment of Well-Sealed MCC Electrical Panels Greater than 440V" (ADAMS Accession No. ML15119A176) provides the technique for evaluating fire damage from MCC cabinets having a voltage greater than 440V. Therefore, propagation of fire outside the ignition source panel must be evaluated for all MCC cabinets that house circuits of 440 V or greater.

i. Describe and justify how fire propagation outside of well-sealed MCC cabinets greater than 440 V is evaluated.

ii. If well-sealed cabinets less than 440 V are included in the Bin 15 count of ignition sources, provide justification for using this approach as this is contrary to the guidance.

c) <u>Transient Fire Influencing Factors</u>

LAR Enclosure 9 Table E9-3 Topics #46 and #47 explain that the methodology for assigning transient influence factors is based on NUREG/CR-6850 and applicable FAQs, specifically FAQ 12-0064. Review of information on the portal [JF-PRA-021.06, Appendix B] indicates that a weighting factor of "very high" or "50" was not used in any fire PAU, which is contrary to the guidance in FAQ 12-0064 that the entire range of ranking values be exercised. Provide a sensitivity study that assigns weighting factors of "50" per the guidance in FAQ 12-0064.

d) <u>Fire Scenario Treatment of the Main Control Board</u>

LAR Enclosure 9 Table E9-2 Topic #41 explains that Main Control Board (MCB) fire scenarios were developed using the latest industry guidance provided in NUREG/CR-6850. Traditionally, the cabinets on the front face of the MCB have been referred to as the MCB for purposes of fire PRA. Appendix L of NUREG/CR-6850, "EPRI/NRC Fire PRA Methodology for Nuclear Power Facilities" (ADAMS Accession Nos. ML052580075) provides a refined approach for developing and evaluating those fire scenarios. Fire PRA FAQ 14-0008, "Main Control Board Treatment dated July 22, 2014 (ADAMS Accession No. ML14190B307) clarifies the definition of the MCB and effectively provides guidance for when to include the cabinets on the back side of the MCB as part of the MCB for fire PRA. It is important to distinguish between MCB and non-MCB cabinets because misinterpretation of the configuration of these cabinets can lead to incomplete or incorrect fire scenario development. This FAQ also provides several alternatives to NUREG/CR-6850 for using Appendix L to treat partitions in an MCB enclosure. Therefore, address the following:

Briefly describe the main control room MCB configuration, and use the guidance in FAQ 14-0008 to determine whether cabinets on the rear side of the MCB are a part of the MCB. Provide your justification using the FAQ guidance.

i. If the cabinets on the rear side of the MCB are part of a single integral MCB enclosure using the definition in FAQ 14-0008, then confirm that guidance in FAQ 14-0008 was used to develop fire scenarios in the MCB and determine the frequency of those scenarios.

ii. If the cabinets on the rear side of the MCB are part of a single integral MCB enclosure and the guidance in FAQ 14-0008 was not used to develop fire scenarios involving the MCB, then provide a description of how the fire scenarios for the backside cabinets are developed and an explanation of how the treatment aligns with NRC accepted guidance.

iii. If in response to parts (i and ii) above, the current treatment of the MCB and those cabinets on the rear side of the MCB cannot be justified using NRC accepted guidance, then justify that the treatment has no impact on the RICT calculations.

Response to APLB Question 2a.i

The JAF Fire HRA Dependency Analysis assessment process is consistent with NUREG-1921 Section 6.2 which states, “For fire HRA, it is recommended that the application of a lower bound follow <u>the same guidance</u> as was applied to the internal events PRA.” The internal events PRA applies a floor value of 5E-7. The JAF FPRA applies a slightly more conservative lower bound floor value of 1.0E-06.

An application specific sensitivity study was performed to determine the impact on the RICT application where the minimum joint HEP value was increased to 1E-5 for the FPRA. The sensitivity study included in scope Tech Specs where a RICT calculation is applicable and the calculated RICT was less than 100 days. The following table provides the results of the sensitivity study. The sensitivity study resulted in minimal changes to the RICT estimates in most cases, and at most less than a 10% change. Tech Spec 3.6.1.2.C (from 28.8 to 26.1 days) and Tech Spec 3.6.1.3.A (from 27.7 to 25.2 days) showed the largest changes; each is associated with containment isolation. A review of the results for those Tech Spec conditions concluded that no new RMAs would be identified given the increase in the FPRA JHEP floor value of 1E-6 to the sensitivity study value of 1E-5. Given the small change in the RICT results from this sensitivity study, it is judged that the minimum joint HEP has an inconsequential impact on the RICT application.

Tech Spec	LCO Condition	Original RICT Estimate (days)	Sensitivity RICT Estimate (days)	Change in RICT Estimate (days)
3.3.5.1.B	As Required by Action A.1 and referenced in Table 3.3.5.1-1	30	30	0
3.3.5.1.C	As Required by Action A.1 and referenced in Table 3.3.5.1-1	23.9	23.2	0.7
3.5.1.A	One low pressure ECCS injection/spray subsystem inoperable	30	30	0
3.5.1.D	Two ECCS injection subsystems inoperable OR One ECCS injection and one ECCS spray subsystem inoperable	30	30	0
3.6.1.2.C	One or more primary containment air locks inoperable for reasons other than condition A or B	28.4	25.7	2.6
3.6.1.3.A	One or more penetration flow paths with one PCIV inoperable for reasons other than conditions D and E	27.3	24.9	2.4
3.6.2.3.A	One RHR suppression pool cooling subsystem inoperable	30	30	0
3.7.1.C	One RHRSW subsystem inoperable for reasons other than condition A	7.1	7.1	0
3.7.2.A	One ESW subsystem inoperable	30	30	0
3.8.1.C	Two required offsite circuits inoperable	19.7	19.8	0.1
3.8.1.D	One required offsite circuit inoperable AND one DG inoperable	30	30	0

Response to APLB Question 2a.ii

See response to APLB Question 2a.i.

Response to APLB Question 2b.i

Well-sealed MCC cabinets greater than 440 V were evaluated consistent with the guidance in FAQ 14-0009. Per the guidance, fire propagation outside the MCC from an arching fault was modeled. The FAQ guidance for fire modeling was used to assign the fire severity factors.

Response to APLB Question 2b.ii

Electrical cabinets less than 440 V are included in the Bin 15 count of ignition sources consistent with the guidance in FAQ 08-0042 from Supplement 1 of NUREG/CR-6850. Per the

guidance, the electrical cabinet is included if it could not be dismissed that the cabinet penetrations would not readily allow for the passage of air.

It is noted that the electrical cabinet frequency is not sensitive to small changes in the electrical cabinet count. For example, removing 50 electrical cabinets from the electrical cabinet count results in a 5% increase in per cabinet frequency.

Response to APLB Question 2c

PAU transient influence factors were assigned based on plant walkdowns and input from site personnel familiar with the daily activities at the plant. Per the guidance in FAQ 12-0064 the ranking of medium was used as the normal or average ranking for the PAUs in the applicable location set (i.e., CAR, TB, PW). Low and high rankings were used to distinguish the PAUs in the location set with less or more transient activity. Consistent with the FAQ the special case of very high was also considered. It was determined that none of the PAUs' as a whole, could be classified as very high taking into consideration that a ranking of very high for a PAU in a plant location also has the effect of lowering the transient frequency for all other PAUs in that location set.

The TB (Turbine Building) plant location includes nine PAUs, three of which are the general open large areas of each elevation of the Turbine Building where most equipment is located and transient activity occurs. These PAUs were assigned a high ranking value compared to the other six PAUs. It was determined that each PAU elevation of the TB, as a whole, was not different from each other such that the special case of very high should be applied to one PAU thereby decreasing the frequency in the others. Therefore, the very high ranking is not used for the TB plant location.

The CAR (Control/Aux./Reactor Building) plant location includes 31 PAUs, eight of which are sections of the general open large areas of each elevation of the Reactor Building where most equipment is located and transient activity occurs. These PAUs were assigned a high ranking value. It was determined that each PAU elevation of the Reactor Building, as a whole, was not different from each other such that the special case of very high should be applied to one PAU thereby decreasing the frequency in the others. The CAR PAU of the Relay Room was also assigned a high ranking value. Similarly, it was determined the Relay Room did not meet the criteria for the very high ranking when compared to the other CAR PAUs. Therefore, the very high ranking is not assigned for the CAR plant location.

The PW (Plant Wide) plant location includes 29 PAUs. Similar to the TB and CAR plant locations, several of the PAUs are large areas (e.g., Radwaste Building elevations, Screenhouse, Outside area). It was determined that each PW PAU, as a whole, was not different from each other such that the special case of very high should be applied to one PAU thereby decreasing the frequency in the others. Therefore, the very high ranking is not used for the PW plant location.

Based on the above, when considering the PAU definitions and the guidance in FAQ 12-0064, it was concluded that the special case of very high ranking value was not appropriate.

Response to APLB Question 2d

The main control room MCB is a horseshoe configuration with six control boards. The six control boards are enclosed panels with access doors on the back of the control boards. The MCB is not a "walk through" configuration and there are no controls on the back of the control boards as defined in FAQ 14-0008. Therefore, only the six control boards were included as part of the MCB per the guidance in FAQ 14-0008. There are other electrical cabinets in the main control room that are not connected to the MCB. Consistent with the guidance in FAQ 14-0008 these electrical cabinets are counted and modeled consistent with Bin 15 electrical cabinets.

Response to APLB Question 2d.i

See response to APLB Question 2d.

Response to APLB Question 2d.ii

See response to APLB Question 2d.

Response to APLB Question 2d.iii

See response to APLB Question 2d.i and 2d.ii.

APLC 01 (TSTF-505) Seismic LERF

APLC Question 01 – Seismic Large Early Release Frequency Calculation [TSTF-505]
Section 2.3.1, Item 7, of NEI 06-09, Revision 0-A (ADAMS Accession No. ML12286A322), states that the "impact of other external events risk shall be addressed in the [Risk Managed Technical Specifications] RMTS program," and explains that one method to do this is by "performing a reasonable bounding analysis and applying it along with the internal events risk contribution in calculating the configuration risk and the associated [Risk-Informed Completion Time] RICT." The NRC staff's safety evaluation for NEI 06-09 (ADAMS Accession No. ML071200238) states that "[w]here [probabilistic risk assessment] PRA models are not available, conservative or bounding analyses may be performed to quantify the risk impact and support the calculation of the RICT."

LAR Enclosure 4, Section 3 presents the details of an approach for determining the seismic LERF. The LAR explains that a conservative seismic LERF of 8.0E-07 per year was estimated from the estimated seismic CDF, the estimated seismic-induced containment failure

probabilities for four accident sequences, and the estimated seismic conditional large early release probability (CLERP) for each of the four accident sequences. The accident sequences and associated containment failure/bypass probabilities (fraction of SCDF) were developed from a review of past and current seismic PRAs (SPRAs), most of which were developed in response to Near Term Task Force Recommendation (NTTF) 2.1 regarding seismic risk. It is stated that the seismic capacities for failure of the containment SSCs for each of the sequences is "reasonably judged to be on the low end of the capacity range given the range of fragilities." The CLERP for each accident sequence is stated to be either 1.0 or 0.21 as developed from the at-power internal events PRA, as shown in Table E4-3. The licensee mentioned median capacities for several seismic failure modes, S-DCDLRF, S-DCD, and S-ATWS were selected based on the information presented in Appendix A. It appears that the licensee did not provide this appendix in the LAR.

The NRC staff has two concerns with the methodology: site-specific seismic fragility and use of the internal events model to develop SCLERPs. The licensee did not provide a justification of industry data applicability to the JAF plant configuration or the difference between normal operation and seismic events. It is noted that accident sequences that would not lead to a large early release for an internal initiating event could be classified as large early release for a seismic initiating event. In addition, the licensee calculated the SLERF using the sum of 0.32 by fraction of SCDF times SCLERP in Table E4-3. The NRC staff verified the calculation and found that number should be approximately 0.33, which indicates that the SLERF in the LAR is slightly underestimated.

a) *Clarify where is Appendix A mentioned in the LAR or provide source of document.*

b) *Verify the SCLERP calculation in Table E4-3, and SLERF calculation on page E4-23.*

c) *Justify that the seismic fragilities used to develop the SLERF are applicable to the JAF plant configuration and applicable SSCs. In the response, provide plant-specific justification for the use of fragilities that are different than those assumed in the IPEEE.*

d) *Justify that CLERPs developed from accident sequences in the internal events model are applicable for seismic-induced accident sequences. The justification should include the basis for applicability of the large early release categorization for internal events to seismic events for each of the accident sequences having a CLERP less than 1.0.*

e) *If parts c) and/or d) cannot be justified, provide a revised evaluation that is based on plant-specific information.*

RESPONSE TO TSTF-505 APLC-01a

The Appendix A in question is included in an internal Constellation document (JF-MISC-018, R0) that provides supporting details and was not intended to be cited or included in the JAF RICT LAR. Constellation uploaded this internal document to the e-portal during the audit for NRC viewing.

RESPONSE TO TSTF-505 APLC-01b

The 0.32 average SCLERP cited in Enclosure 4 of the LAR is included in the documentation as a two significant figure value. The six significant digits value is 0.324861 (obviously the full precise value has even more significant digits); the full (not rounded) average SCLERP value was used in the LAR SLERF estimation.

The NRC may reproduce the 0.32 average SCLERP estimate documented in the LAR by using more significant figures, 0.205718, for the 0.21 SCLERP value.

Refer to the response to question APLC-01d regarding that investigation into the 0.21 value shows that the value is revised to 0.29 and thus the total average SCLERP would increase to 0.40.

RESPONSE TO TSTF-505 APLC-01c

Refer to Appendix A of JF-MISC-018, R0 (provided in response to APLC-01a above) for related details. The discussion below is based on information in Appendix A as well as the main body of JF-MISC-018, R0.

A seismic PRA (SPRA) was not developed for the JAF IPEEE (Individual Plant Examination for External Events) or the NTTF 2.1 Seismic request. A seismic margins assessment (SMA) was performed for the IPEEE which included an analysis of seismic capacities up to an assigned review level earthquake; those analyses do not provide plant-specific realistic fragilities for most SSCs. As such, JAF does not have plant-specific SSC fragilities to use for the TSTF-505 LAR SLERF estimation, nor are plant-specific fragilities necessary for the JAF TSTF-505 SLERF analysis.

The approach to the RICT seismic penalty SLERF estimation is to provide a conservative estimation of the breakdown of SCDF by accident sequence type and then apply seismically-biased CLERP estimates to each accident sequence type to arrive at a weighted-average SCLERP. Given that the JAF SCDF estimate is based on a convolution of the JAF seismic hazard curve with a limiting plant HCLPF (based on the IPEEE SMA), and the fact that JAF does not have a detailed plant-specific seismic PRA to assist in estimating the spectrum of SPRA accident sequence types, the breakdown of SCDF by accident sequence type must consider representative fragility information from available industry sources. The need for the use of representative seismic fragility information is acknowledged in numerous industry and NRC guidelines; some of these are summarized below.

Appendix H of the 2013 EPRI SPRA Implementation Guide states the following regarding the use of representative seismic fragilities:

> *"Table H-1 provides a summary of fragilities based on a survey of available industry information. The fragilities provided in Table H-2 are selected to be reasonable representative fragilities based on the assessment of industry information summarized in Table H-1.... This information is intended for use in... SPRA scoping evaluations to support risk-informed applications (such as License Amendment Request submittals to the NRC) in the absence of plant-specific seismic fragilities. ...*
>
> *In selecting a reasonable representative value for the purposes of supporting an SPRA scoping evaluation (such as to support a risk-informed License Amendment Request submittal), the fragilities in Table H-2 may be used. However, the ranges of fragilities in Table H-1 should be reviewed to ensure that the selection of a reasonable representative value appropriately supports the intent of the SPRA scoping evaluations.*

These representative fragilities are not intended to be conservatively low values. Plant-specific fragilities for a given SSC may result in higher or lower Am values than those provided in Table H-2....

If the analyst has a purpose for the use of conservatively low representative fragilities to highlight an issue or for other purpose (for example, regulatory requirements or guidelines require "conservative" estimates for SSCs not supported by detailed plant-specific calculations), consult the information in Table H-2 to identify ranges of values to assist in the selection of low values."

Similarly, Section 4.2.4 of Volume 2 of the NRC RASP (Risk Assessment Standardization Project) handbook provides the following guidance to NRC risk analysts when developing seismic risk information in the absence of available plant-specific fragility information:

"The fragilities of the major SSCs must be obtained to calculate seismic failure probabilities. Preferably, the analyst should use the plant-specific fragility value if one exists for the plant. In the absence of plant-specific SSC fragilities, fragility values from power plants of similar vintage may be used as surrogates by NRC risk analysts when obtaining risk insights for operational events via the SDP, the ASP Program, Notice of Enforcement Discretion (NOED) evaluations, and event assessments under the Management Directive 8.3, "NRC Incident Investigation Program." For plant-specific risk-informed licensing applications, the fragility values should be developed by meeting the appropriate Standard and guidance. A more extensive collection of SSC seismic fragilities is available in an NRC document (Not Publicly Available, ADAMS Accession No. ML071220070), which contains proprietary information.

Many of the values in the collection are obtained from the Individual Plant Examination of External Events (IPEEE) vintage and older compilations. In the case that plant-specific fragilities are not available, the analyst should review this collection along with more recent results to select appropriate surrogate values for the situation being analyzed. In addition, as seen from the collection, the recorded fragility values may have a wide range for a given component....

A number of seismic PRAs are being performed in connection with the implementation of the NTTF Recommendation 2.1. These PRAs will provide a more current estimates of fragilities using the recent guidance....

These values should not be taken as NRC staff-endorsed values and the values for a specific situation should be determined using the collection of data and other relevant information as described above."

The conclusion from the above is that representative fragility information is needed in certain situations (typically when a plant SPRA is not available with plant-specific fragilities) and in such cases the analyst should consider the following: 1) range of fragility values; 2) recent fragility information; 3) available plant information to inform the selection of representative fragility values; and 4) to select representative fragility values appropriate for the risk information development at hand.
Accordingly, the JAF seismic penalty SLERF estimation process included consideration of a range of fragility information for the following to support the SCDF breakdown estimation:

- Containment structure
- Containment bypass
- Direct to core damage (not containment structure)
- Failure to scram

Fragility information from full-power SPRAs was obtained from past SPRAs (1980s vintage), EPRI 2013 SPRA Implementation Guide (which summarizes fragility information from 1980s and 1990s SPRAs) and more recent SPRAs (thirteen of them) submitted (in the 2015-2019 time frame) in response to the NRC NTTF 2.1 seismic request.

The first item above is the containment structure itself (such a fragility is often modeled in an SPRA directly as SCDF as well as directly as SLERF). These fragilities cover a spectrum of failure modes of containment and primary containment structures, as well as soil failure in a couple cases.

Containment bypass considers other SSC failures (e.g., RPV support failure, containment penetration lines, steam generator anchorage failure [applicable to PWRs]) that are often modeled in SPRAs to directly defeat the containment function and thus directly to SCDF and SLERF.

Direct to core damage are SSCs that do not directly defeat the containment structure and are often modeled in SPRAs directly as SCDF but not necessarily direct to SLERF). These fragilities cover a spectrum of failure modes of other key structures (e.g., Diesel Generator buildings, Control buildings, Auxiliary buildings, intakes), as well as key SSCs (e.g., main control boards, cable trays).

Failure to scram are reactor internal failure modes that are often modeled in SPRAs as mechanical failures to scram. These fragilities cover a spectrum of failure modes such as core shroud failure, control rod drive failure mechanisms and fuel channel buckling.

The lower end of the range of fragility values from the industry information review was used for each of the above SSCs in the SLERF estimation process of the LAR. As an example, consider

the Containment Structural and Containment Bypass fragility failures comprising the Direct to LERF accident sequence type. Excluding the western U.S. data (where seismic demand and design are significantly higher than rest of U.S. and JAF), the seismic capacity characteristics of the remaining 92 fragility records for such failure modes are:

- Average Am (median seismic capacity) value is 2.7g

- 90% of the records (i.e., 83 out of 92) are >1.5g (and the remaining 10% are in the 0.9g to 1.45g range)
- For the most recent SPRAs (i.e., the NTTF 2.1 SPRA submittals), all the Direct to LERF type fragilities reviewed (44 fragility records, excluding the western US data) are >1.5g PGA (the majority are >2g and the average is 2.3g).

As such, a nominal 1.5g was used in the JAF seismic penalty estimation of the breakdown of SCDF as the Am value to represent the fragility for the Direct to LERF type accident sequences. This value is reasonable as a selection to represent a conservative lower end of the range of expected fragility values for containment structural and containment bypass failure modes. Refer to Appendix A of JF-MISC-018, R0 (provided for NRC staff viewing on e-portal during the audit in response to APLC-01a above) for industry fragilities for the other accident types.

In summary, JAF does not have plant-specific SSC fragilities to use for the TSTF-505 LAR SLERF estimation, nor are plant-specific fragilities necessary for the JAF TSTF-505 SLERF analysis. Consistent with industry risk assessment guidance documents, the breakdown of SCDF by accident sequence type in the JAF seismic LERF penalty calculation uses representative fragility information (and values from the low end of the ranges are used in the JAF SLERF calculations) from available industry sources of at-power SPRAs. This approach has been used on other past RICT LARs and is judged a reasonable approach for this purpose of estimating an SLERF in the absence of a plant-specific SPRA and plant-specific fragilities.

RESPONSE TO TSTF-505 APLC-01d

This response addresses in the following order the two points of this question:

- LERF metric for internal event sequences and seismic sequences
- Use of FPIE to calculate seismic CLERPs

LERF Metric

The majority of U.S. NPPs (Nuclear Power Plants) use the same definition of LERF (typically a two-characteristic metric of magnitude of radionuclide release and timing of radionuclide release) for all hazard risk assessments. To use a different LERF metric for different hazard

PRA models confuses the analysis and comparison of site LERF and LERF among hazards, as well as risk applications. One may postulate that external hazard-induced failures of offsite facilities can complicate offsite evacuation and sheltering, and thus impact assumptions of what comprises an "Early" radionuclide release, but such risk analysis aspects are typically treated as quantitative sensitivity studies and not as a justification to change the definition of the LERF metric for individual external hazard PRA models. Consistent with this typical hazard PRA approach, and typical of other NPP RICT seismic penalty calculations, the JAF seismic penalty calculation does not define a different LERF metric (i.e., the same definition of LERF used in the JAF FPIE PRA is assumed for the JAF TSTF-505 LAR seismic penalty calculation).

A discussion of the detailed bases of the JAF LERF metric are not provided here in this response; however, the basic definition is that "Large" is >10% of the end-of-cycle CsI inventory released to environment, and "Early" is this magnitude release occurring within 4.5 hrs. after the declaration per plant procedure of a General Emergency.

<u>FPIE PRA Used to Calculate SCLERPs</u>

FPIE PRA CLERPs (other than 1.0 values for certain accident sequence types, which would directly apply to FPIE as well as seismic) are not used in the JAF seismic penalty SLERF calculation. Rather, the FPIE PRA logic model is used as a vehicle with which to calculate a seismically-biased CLERP value for certain accident sequence types for use in the JAF seismic penalty SLERF calculation.

The JAF TSTF-505 LAR seismic penalty SLERF calculation uses only two SCLERPs, a 1.0 SCLERP value and a 0.21 SCLERP value. As discussed in the latter half of Section 3 of Enclosure 4 of the JAF TSTF-505 LAR, the 0.21 SCLERP is the result of two seismically-biased quantifications (one for CDF and one for LERF, and the division of the two produces the CLERP for that condition) of the JAF FPIE PRA. The following seismically-biased adjustments are made in the FPIE PRA quantifications to produce the 0.21 SCLERP:

- Only sequences initiated by a LOOP and with RPV adequate core cooling injection systems failed at t=0 are used

- All emergency diesel generators are set to failed at t=0 (set to logical TRUE value); this is for the purpose of conservatism and to simplify the calculation (as opposed to developing and modeling representative fragilities for various SSCs providing AC power)

- Recovery of offsite AC and onsite emergency AC are set to failed (set to logical TRUE value), i.e., seismic PRAs often set such recoveries to high failure probabilities or do not credit them.

These seismically-biased adjustments to the FPIE PRA logic model produce station blackout scenarios with no RPV injection at t=0, no AC recovery and no adequate core cooling recovery. This SCLERP includes manual alignment of diesel fire pump for ex-vessel debris cooling (with a high failure probability, 0.5) in the primary containment after core melt and RPV melt-through. The resulting SCLERP for this accident sequence type is documented in the LAR as 0.21.

Based on detailed investigations into the 0.21 SCLERP for the TSTF-505 APLC-01d response, it was identified that logic modeling in the success branch of a particular node in the short-term SBO (IBE) Containment Event Tree (CET) logic was not automatically recognizing some of the seismically-biased adjustments made in the sensitivity quantifications. The FPIE PRA base logic is negligibly impacted by this issue and is producing the proper base LERF results, but for the seismic IBE (S-IBE) conservative sensitivity quantification, a portion of the result was being lost. The issue manifests when many basic events are set to TRUE, such as in the seismically-biased sensitivity study used to generate the 0.21 value used in the LAR. This issue was corrected with a workaround for this APLC-01 response and the conservative S-IBE SCLERP to apply to the S-LOOP accident type in the SLERF estimate should be 0.29 (not the 0.21 used in the LAR). A PRA update record ("URE" in the Constellation risk management processes) has been entered into the JAF PRA log to investigate this success branch logic and revise the success branch logic in question (it appears at this time that the logic in question is only in the IBE CET).

Regardless of the value revision discussed above, this SCLERP result is judged applicable for use in the SLERF penalty calculation for seismic-induced LOOP accident sequences. This SCLERP value is conservatively applying one of the worst-case scenarios (i.e., no RPV injection with probability of 1.0 at t=0) to cover the entire spectrum of potential plant conditions for the S-LOOP accident sequence type in the seismic penalty SLERF estimation. Other types of scenarios for S-LOOP include (among others) SBOs with initial RPV injection (which would have a significantly lower SCLERP) and LOOP scenarios with emergency AC power and initial RPV injection available but no containment heat removal (also which would have a significantly lower SCLERP).

This SCLERP value is also used for the DCD (Direct to Core Damage) accident type in the JAF TSTF-505 SLERF estimation process. These direct to core damage (but not SLERF) accident scenarios are characterized as loss of all injection at t=0, no core cooling recovery and containment not seismically failed. The SCLERP of 0.29 used above for the S-LOOP accidents would be applicable to the S-DCD accidents as well. Some DCD contributors may have a higher SCLERP and some a lower SCLERP, but as a general characterization of DCD the 0.29 is reasonable as it is a severe scenario with no injection at t=0 but with high failure probability (0.5) credit for manual alignment of ex-vessel core debris cooling.

Replacing the 0.21 SCLERP with 0.29 for the JAF TSTF-505 SLERF estimation process (non-rounded value used, 0.29437…) increases the Sequence-Weighted Average SCLERP, i.e., the total average SCLERP from the LAR value of 0.32 to 0.40. Accordingly, the SLERF estimate increases from the 8.0E-07/yr. LAR value to 1.0E-06/yr. This is a comparatively minor increase from the perspective of RICT calculations and seismic risk to total plant risk.

Note: Constellation is hereby reporting in this supplement to the JAF TSTF-505 LAR (1) the change in SCLERP value of 0.21 to 0.29 (for S-LOOP and S-DCD); (2) the resultant change in value of the Sequence-Weighted Average SCLERP as reported in Table E4-3, SPECTRUM OF SCDF ACCIDENT SEQUENCES AND ASSOCIATED SCLERP; and (3) the associated revised SLERF penalty value of 1.0E-06/yr. (SCDF of 2.5E-6/yr. x avg. SCLERP of 0.40 = 1.0E-6/yr.) for plant configurations in which the plant is at power and the primary containment is inerted with nitrogen. A revised Table E4-3 is provided on the next page.

RESPONSE TO TSTF-505 APLC-01e

The above responses to APLC-01a through APLC-01d provide the justification for the reasonableness of the JAF TSTF-505 seismic penalty SLERF calculation.

TABLE E4-3[4]

SPECTRUM OF SCDF ACCIDENT SEQUENCES AND ASSOCIATED SCLERP

L1 SPRA ACCIDENT SEQUENCE TYPE	FRACTION OF SCDF[1]	SCLERP[2]	COMMENT
S-LOOP: Seismic-induced loss of offsite power.	0.65	0.29	Based on CLERP results for LOOP with no injection at t=0 accidents with no AC recovery (i.e., Class IBE) and no adequate core cooling injection recovery in the JAF FPIE Level 2 PRA. This SCLERP result is applicable to a seismic-induced accident sequence with loss of all injection at t=0 and no recovery given that the probability of the LERF release is a function of the accident progression phenomena and containment failure location (e.g., drywell shell melt-through) and not directly influenced by seismic impacts. This accident category for the purposes of this seismic penalty RICT calculation includes, in addition to the SBO with no AC recovery, those S-LOOP sequences with EDG in operation but subsequent injection failure or S-LOOP scenarios also including seismic-induced LOCAs. The SCLERP for early SBO with no recovery is higher in probability than these sub-sets of the S-LOOP accident type.

TABLE E4-3[4]

SPECTRUM OF SCDF ACCIDENT SEQUENCES AND ASSOCIATED SCLERP

L1 SPRA ACCIDENT SEQUENCE TYPE	FRACTION OF SCDF[1]	SCLERP[2]	COMMENT
S-DCD: Scenarios direct to core damage but not direct LERF (e.g., CB structural failures)	0.20	0.29	These direct to core damage (but not SLERF) accident scenarios are scenarios that characterized as loss of all injection at t=0, no injection recovery and containment not seismically failed. The SCLERP of 0.29 used above for the S-LOOP accidents would be applicable to the S-DCD accidents as well.
S-DCDLRF: Scenarios direct to LERF (e.g., containment structural failures)	0.10	1.00	By definition, the accidents scenarios defined by seismic-induced failures that would be modeled as direct LERF receive an SCLERP probability of 1.0.

TABLE E4-3[4]

SPECTRUM OF SCDF ACCIDENT SEQUENCES AND ASSOCIATED SCLERP

L1 SPRA ACCIDENT SEQUENCE TYPE	FRACTION OF SCDF[1]	SCLERP[2]	COMMENT
S-ATWS: S-ATWS unmitigated	0.05	1.00	Unmitigated ATWS scenarios are assigned an SCLERP of 1.0 based on the results of the JF2017A Level 2 PRA results. The JAF FPIE-based CLERP for Class IV core damage accidents is effectively 1.0 (i.e., 0.99). Based on review of the Class IV LERF cutsets from the JF2017A FPIE and Table 3.4-3 of JF-PRA-013, Rev. 0 (Reference [37]), the ATWS CLERP is overwhelmingly dominated by accident phenomena issues: 1) primary containment drywell shell melt-through (basic event SIF) is approximately 99% of the CLERP; and 2) other energetic phenomena such as steam explosion (basic event DI-EXRXSTMEXP) or corium attack of pedestal (DI-CM-PEDFL) induced failure of primary containment. These Level 2 failures are directly applicable to the SPRA as they do not take inappropriate probabilistic credit for functions that may be influenced by seismic-induced impacts.

TABLE E4-3[4]

SPECTRUM OF SCDF ACCIDENT SEQUENCES AND ASSOCIATED SCLERP

L1 SPRA ACCIDENT SEQUENCE TYPE	FRACTION OF SCDF[1]	SCLERP[2]	COMMENT
S-LOOP with long term loss of containment cooling	Note (3)	Note (3)	Declaration of a general emergency would be in accordance with JAF Emergency Action Levels. However, the JAF PRA includes a 5% probability (basic event ID "ZZZ-L2-GE-LATE") that the General Emergency declaration is delayed and thus can result in an "Early" release for these sequences (refer to Appendix F of the JAF Level 2 PRA notebook (Reference [36])). Using a 5E-02 SCLERP value would be conservative because it would not account for the containment failure location in reducing release magnitude (i.e., if failure occurs above the suppression pool water line the release would be scrubbed and not a "High" magnitude release). The 0.05 SCLERP is lower than the S-LOOP SCLERP above of 0.29 and this sub-category of S-LOOP is conservatively included in the seismic penalty averaged SCLERP estimate in the S-LOOP contribution above.

TABLE E4-3[4]

SPECTRUM OF SCDF ACCIDENT SEQUENCES AND ASSOCIATED SCLERP

L1 SPRA ACCIDENT SEQUENCE TYPE	FRACTION OF SCDF[1]	SCLERP[2]	COMMENT
S-LOOP with S-LOCA with early loss of injection	Note (3)	Note (3)	SCLERP would be similar to JAF FPIE LOOP early loss of injection case above except the probabilities of containment failure due to certain energetic phenomena (e.g., direct containment heating; high pressure blowdown overwhelming vapor suppression) are much lower likelihood (or even precluded) given the LOCA condition. As such, this sub-category of S-LOOP including a seismic-induced LOCA is conservatively included in the seismic penalty averaged SCLERP estimate in the S-LOOP contribution above.
S-LOOP with S-LOCA and long term loss of containment cooling	Note (3)	Note (3)	Same basis discussed above for S-LOOP with loss of containment cooling. This sub-category of S-LOOP is conservatively included in the seismic penalty averaged SCLERP estimate in the S-LOOP contribution above.
S-Transients (no LOOP)	0.00	n/a	S-Transients (no seismic-induced LOOP) are reasonably assumed to be non-significant contributors to SCDF and SLERF. This is typical of past SPRAs and due in large part to the comparatively very low seismic capacity of offsite power equipment (primarily ceramic insulators).

TABLE E4-3[4]

SPECTRUM OF SCDF ACCIDENT SEQUENCES AND ASSOCIATED SCLERP

L1 SPRA ACCIDENT SEQUENCE TYPE	FRACTION OF SCDF[1]	SCLERP[2]	COMMENT
Sequence-Weighted Average SCLERP:		0.40	Sum of (Fraction of SCDF x SCLERP) over all sequence types

Notes to Table E4-3:

(1) Range of key SSC fragilities in industry SPRAs used to inform SCDF breakdown by accident type (refer to discussion earlier in this section, "Seismic Large Early Release Frequency").

(2) These are JAF 2017A FPIE PRA-based CLERP estimates that are reviewed and adjusted, if necessary, to reflect seismic considerations (e.g., no credit for recovery of offsite power or injection), yielding the "SCLERP" label.

(3) These SCDF accident sequence types are variants of the S-LOOP category and are addressed in this average SCLERP estimate by conservatively incorporating them into the S-LOOP category, as summarized in the Comment column.

(4) This is a revision to the Table E.4-3 contained in Enclosure 4 of the JAF TSTF-505/50.69 LAR. This revision shows the revised SCLERP of 0.29 for IBE scenarios with loss of all core cooling at t=0, and the resulting revised average SLCERP of 0.40. The reference numbers cited in this revised table are unchanged here and refer to the References in Enclosure 4 of the JAF TSTF-505/50.69 LAR.

APLC 01 (50.69) Alternative Seismic Approach

50.69 APLC Question 01 – Alternative Seismic Approach

Section 50.69(b)(2)(ii) of 10 CFR requires that the LAR contain a description of the measures taken to assure that the quality and level of detail of the systematic processes that evaluate the plant for internal and external events during normal operation, low power, and shutdown are adequate for the categorization of SSCs.

In the LAR, the licensee proposes to address seismic hazard risk using the alternative seismic approach for seismic Tier 2 plants described in Electric Power Research Institute (EPRI) 3002017583, "Alternative Approaches for Addressing Seismic Risk in 10 CFR 50.69 Risk-Informed Categorization," dated February 2020, and other qualitative considerations. The NRC staff understands that EPRI 3002017583 is an updated version of EPRI 3002012988, "Alternative Approaches for Addressing Seismic Risk in 10 CFR 50.69 Risk-Informed Categorization," dated July 2018.

The NRC staff reviewed EPRI 3002017583 and its earlier version of EPRI 3002012988 in conjunction with its review and approval of the LaSalle County Station LAR to adopt 10 CFR 50.69 (ADAMS Accession No. ML21082A422). This LAR was the first LAR approved for a seismic Tier 2 plant. The NRC staff has not endorsed EPRI 3002012988 or EPRI 3002017583 as a topical report for generic use. Therefore, each licensee needs to perform a plant-specific review for applicability of the EPRI Tier 2 alternative seismic approach to their plant.

In addition, the NRC staff is aware that EPRI recently published an updated alternative seismic approach in EPRI 3002022453, "Alternative Approaches for Addressing Seismic Risk in 10 CFR 50.69 Risk-Informed Categorization," dated September 2021.

The licensee is requested to address the following:

a. *Identify and justify any differences between the proposed alternative seismic approach and that approved in the NRC staff's safety evaluation of the LaSalle County Station LAR to adopt 10 CFR 50.69, including any plant-specific considerations.*

b. *Clarify which version of the EPRI guidance will be used in the implementation of the proposed alternative seismic approach.*

RESPONSE TO APLC 50.69 1A

In review of the LaSalle SE, there are no differences identified from the proposed alternative seismic approach documented in the NRC staff's safety evaluation of the LaSalle County Station LAR to adopt 10 CFR 50.69, including any plant-specific considerations.

RESPONSE TO APLC 50.69 1B

The FitzPatrick LAR cites EPRI Report 3002017583 as applicable to the submittal. The citation for EPRI Report 3002017583 is ADAMS Accession No. ML21082A170. The Fitzpatrick LAR also cites mark-ups to EPRI Report 3002017583 that were submitted with LaSalle 50.69 LAR RAI responses of 10/16/20 and 01/22/21. In the Fitzpatrick LAR, these are cited as References 5 and 6:

[5] Exelon Generation Company, LLC. Letter to NRC, LaSalle County Station, Units 1 and 2, Renewed Facility Operating License Nos. NPF-11 and NPF-18, NRC Docket Nos. 50-373 and 50-374, Response to Request for Additional Information [...], "LaSalle License Amendment Request to Renewed Facility Operating Licenses to Adopt 10 CFR 50.69, Risk-Informed Categorization and Treatment of Structures, Systems, and Components for Nuclear Power Reactors," (EPID L-2020-LLA-0017), October 16, 2020 (ADAMS Accession No. ML20290A791).

[6] Exelon Generation Company, LLC. Letter to NRC, LaSalle County Station, Units 1 and 2, Renewed Facility Operating License Nos. NPF-11 and NPF-18, NRC Docket Nos. 50-373 and 50-374, "Response to Request for Additional Information Regarding the License Amendment Request to Adopt 10 CFR 50.69 (EPID L-2020-LLA-0017)," January 22, 2021 (ADAMS Accession No. ML21022A130).

The FitzPatrick LAR also incorporates the following additional LaSalle 50.69 LAR RAI response that does not include any mark-ups to EPRI Report 3002017583 but addresses process issues associated with the proposed alternative seismic approach. In the Fitzpatrick LAR, this is cited as Reference 37 and specifically excludes LaSalle RAI APLC 50.69-RAI No. 12 that addresses a non-seismic topic (external events).

[37] Exelon Generation Company, LLC. Letter to NRC, LaSalle County Station, Units 1 and 2, Renewed Facility Operating License Nos. NPF-11 and NPF-18, NRC Docket Nos. 50-373 and 50-374, "Response to Request for Additional Information Regarding the License Amendment Request to Adopt 10 CFR 50.69 (EPID L-2020-LLA-0017)," October 1, 2020, ADAMS Accession Number ML20275A292.

Additional Background Information

A discussion of the technical update timeline of EPRI Report 3002022453 is provided below. The revision history is described in EPRI 3002022453, Section 1.4, "Tier 1 and Tier 2 Lead Plant Submittals".

"The criteria in this report was initially published in Technical Update 3002012988. That report was used in a lead plant license amendment request (LAR) for the Tier 1 criteria by Exelon Generation for the Calvert Cliffs plant [17, 18][20]. Updates to the report criteria were developed as part of responses to NRC requests for additional information (RAIs) [19, 20]. The NRC approved the amended Calvert Cliffs license on February 28, 2020 [21]. The next Technical Update (3002017583) incorporated updates submitted to the NRC in the Calvert Cliffs RAI submittals [19, 20]. These updates were primarily associated with the case studies in Section 3.

EPRI 2002017583 was then used in a lead plant license amendment request (LAR) for the Tier 2 criteria by Constellation Generation for the LaSalle plant [22]. Edits to the report criteria were developed as part of responses to NRC requests for additional information (RAIs) [23, 24, 25]. The NRC approved the amended LaSalle license on May 27, 2021 [26].

This Technical Report incorporates technical updates submitted to the NRC in RAI submittals for LaSalle [24, 25]. These updates were primarily associated with the Tier 2 seismic correlated failure assessment process in Section 2.2.1, associated Appendices A and B, and a new Appendix C.

Aside from those updates, the technical criteria in this report remains unchanged from the criteria reviewed in the lead plant LAR and RAI submittals. A few additional minor editorial changes were also incorporated but the technical criteria for Tier 1 is consistent with the NRC approved criteria for the Calvert Cliffs lead plant and the Tier 2 criteria is consistent with the NRC approved criteria for the LaSalle lead plant.

The report development process is depicted in Figure 1-3 as reproduced from EPRI Report 3002022453.

---

[20] This section includes references to submittals generally applicable to the content in this EPRI report. Both lead plant licensees made additional submittals to NRC as part of their 50.69 LAR that do not impact the content of this report. The full list of submittals associated with each LAR are noted in the NRC letters approving the license amendment [21, 26].

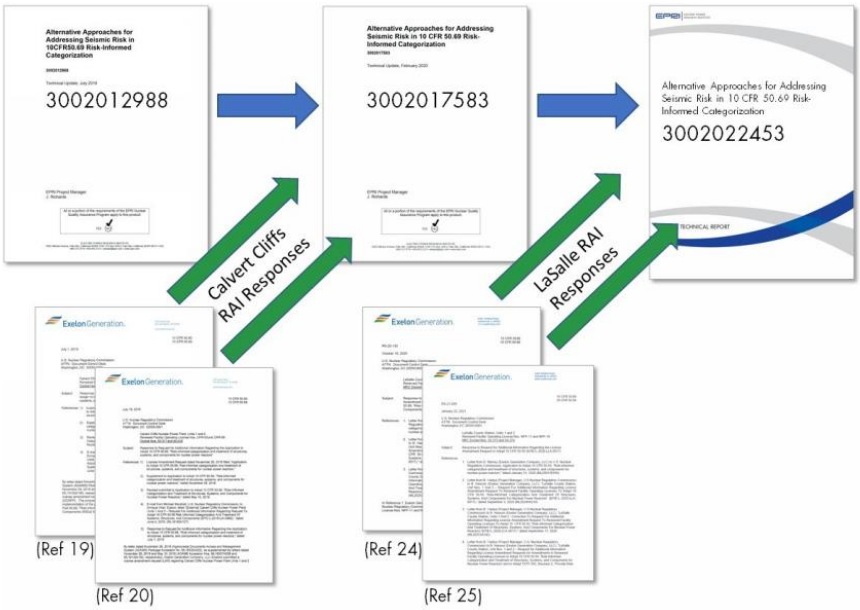

Figure 1-3
Development of final report with Lead Plant RAIs

Cited References [17-26] in EPRI 3002022453:

17. Application to Adopt 10 CFR 50.69, “Risk-informed categorization and treatment of structures, systems, and components for nuclear power reactors,” Exelon Generation, Calvert Cliffs Nuclear Power Plant, November 28, 2018 (ML18333A022).

18. “Risk-informed Categorization and Treatment of Structures, Systems, and Components for Nuclear Power Reactors,” Revised submittal to Application to Adopt 10 CFR 50.69, Exelon Generation, Calvert Cliffs Nuclear Power Plant, May 10, 2019 (ML19130A180).

19. Response to Request for Additional Information Regarding the Application to Adopt 10 CFR 50.69, “Risk-informed categorization and treatment of structures, systems, and components for nuclear power reactors,” Exelon Generation, Calvert Cliffs Nuclear Power Plant, July 1, 2019 (ML19183A012).

20. Response to Request for Additional Information Regarding the Application to Adopt 10 CFR 50.69, "Risk-informed categorization and treatment of structures, systems, and components for nuclear power reactors," Exelon Generation, Calvert Cliffs Nuclear Power Plant, July 19, 2019 (ML19200A216).

21. Calvert Cliffs Nuclear Power Plant, Units 1 and 2- Issuance of Amendment Nos. 332 and 310 Re: Risk-informed Categorization and Treatment of Structures, Systems, and Components for Nuclear Power Reactors (EPID L-2018-LLAa-0482), Nuclear Regulatory Commission, February 28, 2020 (ML19330D909).

22. Application to Adopt 10 CFR 50.69, “Risk-informed categorization and treatment of structures, systems, and components for nuclear power reactors,” Exelon Generation, LaSalle County Station, January 31, 2020 (ML20031E699).

23. Response to Request for Additional Information regarding LaSalle License Amendment Request to Renewed Facility Operating Licenses to Adopt 10 CFR 50.69, “Risk-Informed Categorization and Treatment of Structures, Systems, and Components for Nuclear Power Reactors,” Exelon Generation, LaSalle County Station, October 1, 2020 (ML20275A292).

24. Response to Request for Additional Information regarding LaSalle License Amendment Request to Renewed Facility Operating Licenses to Adopt 10 CFR 50.69, “Risk-Informed Categorization and Treatment of Structures, Systems, and Components for Nuclear Power Reactors,” Exelon Generation, LaSalle County Station, October 16, 2020 (ML20290A791).

25. Response to Request for Additional Information regarding LaSalle License Amendment Request to Renewed Facility Operating Licenses to Adopt 10 CFR 50.69, "Risk-Informed Categorization and Treatment of Structures, Systems, and Components for Nuclear Power Reactors," Exelon Generation, LaSalle County Station, January 22, 2021 (ML21022A130).

26. LaSalle County Station, Unit Nos. 1 and 2 - Issuance of Amendment Nos. 249 and 235 Related to Application to Adopt 10 CFR 50.69, "Risk-Informed Categorization and Treatment of Structures, Systems, and Components for Nuclear Power Reactors" (EPID l-2020-lla-0017), Nuclear Regulatory Commission, May 27, 2021 (ML2108A422).

APLC 02 (TSTF-505) Seismic LOOP

APLC QUESTION 02 – Evaluation of Seismic Induced Loss of Offsite Power [TSTF-505]

Section 2.3.1, Item 7, of NEI 06-09, Revision 0-A, states that the "impact of other external events risk shall be addressed in the RMTS program," and explains that one method to do this is by "performing a reasonable bounding analysis and applying it along with the internal events risk contribution in calculating the configuration risk and the associated [Risk-Informed Completion Time] RICT." The NRC staff's safety evaluation for NEI 06-09 states that "[w]here [probabilistic risk assessment] PRA models are not available, conservative or bounding analyses may be performed to quantify the risk impact and support the calculation of the RICT."

Section 3 of Enclosure 4 to the LAR does not address the incremental risk associated with a seismically-induced loss of offsite power (LOOP) that may occur following the design basis seismic event. It is unclear to the NRC staff whether accident scenarios associated with the seismically-induced (and therefore unrecoverable) LOOP frequency could already be addressed to some extent in the internal events PRA for unrecovered LOOP events.

Demonstrate that seismically-induced LOOP has an inconsequential impact on the proposed RICTs. If it cannot be demonstrated that seismically-induced LOOP has an inconsequential impact on the proposed RICTs, explain how the impact of seismically-induced LOOP will be included in the proposed RICTs.

RESPONSE TO TSTF-505 APLC-02

The JAF TSTF-505 Enclosure 4 seismic penalty calculation is intended to address the fraction of seismic events within (i.e., at or below) the design basis by conservatively including very low magnitude seismic events (as low as 0.0005g peak ground acceleration, PGA, i.e., 1/300th of the JAF Safe Shutdown Earthquake, SSE of 0.15g PGA) in the SCDF and SLERF convolution calculations. These very low magnitudes are also >100x lower than the JAF Operating Basis Earthquake, OBE of 0.08g PGA; the plant is reasonably expected to remain online for seismic events below the OBE. The JAF OBE and SSE values are cited, among other places, in the JAF IPEEE Submittal (New York Power Authority, James A. FitzPatrick Nuclear Plant Individual Plant Examination of External Events, JAF-RPT-MISC-02211, Rev. 0; NRC ADAMS #ML093441161 for transmittal letter). In response to this question, more discussions and calculations are provided below regarding the inconsequential impact on RICT calculations from plant challenges associated with seismic-induced LOOP from earthquakes within the design basis.

The approach used in the discussion below is the same as used in past LARs that have explicitly discussed this topic, i.e., 1) estimate the annual frequency of seismic-induced LOOP; 2) assume no offsite AC recovery within 24 hrs; and 3) compare the result with the internal

events PRA frequency estimate for non-recovered LOOP. The methodology used for computing the seismically-induced LOOP frequency is to convolve the JAF mean seismic hazard curve with an offsite power seismic fragility. Previous TSTF-505 applications have approached this discussion conservatively by performing the seismic-induced LOOP convolution calculation over the entire hazard curve (not just the portion of the hazard curve below the design basis). That same approach is used in this response.

Table APLC2-1 provides the JAF mean PGA seismic hazard data (this is the same hazard curve data as used in Enclosure 4 of the JAF TSTF-505 LAR) and the LOOP seismic-induced failure probability (increasing with increasing seismic magnitude) based on the seismic fragility of offsite power. The seismic-induced LOOP convolution calculation in Table APLC2-1 includes the entire seismic hazard curve from earthquake magnitudes well below the JAF operating basis earthquake to well beyond the JAF safe shutdown earthquake.

The failure probabilities for seismic-induced LOOP are represented by failure of ceramic insulators in the offsite AC power distribution system, based on the following seismic fragility data from Table A-0-4 of the NRC RASP Handbook, Volume 2, Revision 1.02 (NRC ADAMS Accession No. #ML17349A301). This is a common offsite power seismic fragility used for Central and Eastern US SPRAs and seismic risk calculations:

Offsite Power Seismic Capacity (ceramic insulators):

- Median Acceleration Capacity, Am = 0.30g PGA
- Randomness uncertainty, $\beta_R = 0.30$
- Modeling uncertainty, $\beta_U = 0.45$

Given the mean frequency and failure probability for each seismic hazard interval, it is straightforward to compute the estimated frequency of seismically induced loss of offsite power for the JAF site by multiplying the hazard interval occurrence frequency and the offsite power fragility failure probability. The hazard interval frequency calculation approach and the fragility failure probability calculation approach are the same as that described in Section 3 of Enclosure 4 of the JAF TSTF-505 LAR. As shown in Table APLC2-1, the total seismic-induced LOOP frequency across the entire seismic hazard curve is estimated at 1.4E-5/yr. Note that this overstates the “within design basis” challenge frequency but is conservative for this purpose.

The JAF full-power internal events (FPIE) PRA models LOOP from plant-centered, switchyard-centered, grid-related, and weather-related events. Based on the JAF FPIE PRA, the total 24-hr non-recovered LOOP frequency is 2.2E-3/yr., as shown in Table APLC2-2.

Assuming offsite AC recovery failure probability of 1.0 for 24 hrs for seismic-induced LOOP, the total (i.e., across the entire hazard curve) 24-hr non-recovered seismic-induced LOOP frequency is 0.6% (1.4E-5 / 2.2E-3 = 0.006) of the total 24-hr non-recovered LOOP frequency

already addressed in the FPIE PRA. The “within design basis” (i.e., up to the SSE) 24-hr non-recovered seismic-induced LOOP frequency is 0.1% (convolved result up to 0.15g PGA SSE 2.8E-6 / 2.2E-3 = 0.001) of the total 24-hr non-recovered LOOP frequency already addressed in the FPIE PRA.

As can be seen, the 24-hr non-recovered seismic-induced LOOP frequency is a very small percentage of the frequency of such challenges already captured in the FPIE PRA (which is explicitly used in RICT calculations) such that it will not significantly impact RICT Program calculations, and it can be omitted from explicit analysis in RICT calculations.

TABLE APLC02-1
JAF SEISMIC-INDUCED LOOP FREQUENCY ESTIMATE (ACROSS ENTIRE SEISMIC HAZARD CURVE)

JAF Offsite Power HCLPF (Table A-0-4, NRC RASP Handbook, Vol 2, Rev 1.02)			JAF Seismic Hazard Curve		Convolution Calculation (JAF Offsite Power HCLPF fragility with Seismic Hazard)			
HCLPF (g, PGA)	Am (g, PGA)	βc	Peak Ground Acceleration (g)	Mean Exceedance Frequency (/yr)	Hazard Interval Representative Magnitude (geo. mean, g PGA)	Hazard Interval Fragility[1] (Mean)	Hazard Interval Occurrence Frequency (/yr)	Convolved Frequency (/yr)
0.09	0.30	0.54	0.0005	5.57E-02	0.0007	1.89E-29	1.42E-02	2.68E-31
			0.001	4.15E-02	0.0022	5.52E-20	3.01E-02	1.66E-21
			0.005	1.14E-02	0.0071	1.83E-12	6.57E-03	1.20E-14
			0.01	4.83E-03	0.0122	1.48E-09	2.20E-03	3.26E-12
			0.015	2.63E-03	0.0212	4.37E-07	1.85E-03	8.07E-10
			0.03	7.84E-04	0.0387	7.09E-05	4.93E-04	3.50E-08
			0.05	2.91E-04	0.0612	1.55E-03	1.63E-04	2.52E-07
			0.075	1.28E-04	0.0866	1.02E-02	5.76E-05	5.90E-07
			0.1	7.04E-05	0.1225	4.68E-02	4.05E-05	1.90E-06
			0.15	2.99E-05	0.2121	2.54E-01	2.33E-05	5.92E-06
			0.3	6.65E-06	0.3873	6.75E-01	4.58E-06	3.09E-06
			0.5	2.07E-06	0.6124	9.03E-01	1.29E-06	1.17E-06
			0.75	7.77E-07	0.8660	9.74E-01	4.07E-07	3.96E-07
			1	3.70E-07	1.2247	9.95E-01	2.50E-07	2.49E-07
			1.5	1.20E-07	2.1213	1.00E+00	1.07E-07	1.07E-07
			3	1.31E-08	3.8730	1.00E+00	1.12E-08	1.12E-08
			5	1.92E-09	6.1237	1.00E+00	1.58E-09	1.58E-09
			7.5	3.36E-10	8.6603	1.00E+00	2.49E-10	2.49E-10
			10	8.68E-11	10	1.00E+00	8.68E-11	8.68E-11
							Total Convolved Seismic LOOP Across Hazard Curve (1/yr):	1.4E-05

TABLE APLC02-2
LOSS OF OFFSITE POWER (LOOP) NON-RECOVERY FREQUENCY

LOOP Contributor	**JAF FPIE PRA LOOP Initiator Contributor Frequency(1) (/yr)**	**JAF FPIE PRA Probability of Non-Recovery of Offsite AC by 24 Hrs(2)**	**JAF FPIE PRA 24-hr Non-Recovered LOOP Frequency (/yr)**
Plant-Centered	1.91E-03	8.14E-03	1.55E-05
Switchyard-Centered	1.28E-02	2.25E-02	2.88E-04
Grid-Related	2.89E-02	2.11E-02	6.10E-04
Weather-Related	5.72E-03	2.25E-01	1.29E-03
Total:			2.2E-03

(1) Values per Table B-3 of JAF Initiating Events Notebook, JF-PRA-001, Rev. 1, August 2020.
(2) Values per Table B-5 of JAF Initiating Events Notebook, JF-PRA-001, Rev. 1, August 2020.

APLC 02 (50.69) Implementation of Alternative Seismic Approach

50.69 APLC Question 02 – Implementation of EPRI Report 3002017583, Section 2.3.1

In Section 3.2.3, "Seismic Hazards," of Enclosure 1 to the LAR, the licensee states that the categorization team will evaluate correlated seismic failures and seismic interactions between SSCs for each system categorized. The licensee states that this process is detailed in EPRI 3002017583, Section 2.3.1. The licensee also states that determination of seismic insights will make use of the full power internal events PRA model supplemented by focused seismic walkdowns.

The NRC staff notes that the LAR does not include any site-specific information on how the guidance in EPRI 3002017583, Section 2.3.1 and its revision markups included in the supplements to the LaSalle County Station LAR to adopt 10 CFR 50.69 will be applied to the seismic evaluation for 10 CFR 50.69 categorization at James A. FitzPatrick. Such information is important for evaluating seismic risk insights for seismic Tier 2 plants and should be included in the LAR.

The licensee is requested to describe how it will implement the guidance in EPRI 3002017583, Section 2.3.1 and its revision markups included in the supplements to the LaSalle County Station LAR to adopt 10 CFR 50.69, taking into account any plant-specific conditions.

RESPONSE TO 50.69 APLC 02

The Constellation ER-AA-569 series of procedures provide the FitzPatrick specific categorization guidance for categorizing systems, including the seismic hazard risk assessment that implements the guidance in Section 2.3.1 of EPRI report 3002017583. The methodology FitzPatrick will use to address the seismic safety significance process does not have any deviations from the approach outlined in the EPRI report 3002017583 other than clarifying notes for the Tier 2 process implementers.

The methodology used for categorization at FitzPatrick seeks to identify unique seismic insights of a component relative to the categorization process. The assessment will encompass the following high level process steps to identify components as high safety significant (HSS) from a seismic standpoint:

1. Gather the population of SSCs in the system being categorized and review existing seismic information. This step may use the results of the required Tier 1 assessment that is performed along with the Tier 2 assessment[21]

2. Assign seismic capacity-based SSC equipment class IDs for SSCs in the system being categorized.

3. Perform a series of screenings to refine the list of SSCs subject to correlation sensitivity studies. Screens will identify:

   - Inherently Rugged SSCs
   - SSCs not in L1 or L2 PRAs
   - Already HSS SSCs

   The above screened SSCs will still be evaluated for seismic interactions.

4. SSCs identified in Step 3 can be screened from consideration as functional correlation surrogate events. They are removed from the remainder of the process (can be considered LSS) unless they are subject to interaction source considerations.

5. Perform Tier 2 Walkdown(s) focusing on identifying seismic correlated or interaction SSC failures.

6. Screen out from further seismic considerations SSCs that are determined through the walkdown to be of high seismic capacity and not included in seismically correlated groups or correlated interaction groups since their non-seismic failure modes are already addressed for 50.69 categorization in the FPIE PRA and Fire PRA. Those remaining components proceed forward for inclusion of associated seismic surrogate events in the Tier 2 Adjusted PRA Model.

7. Develop a Tier 2 Adjusted PRA Model and incorporate seismic surrogate events into the model to reflect the potential seismically correlated and interaction conditions identified in prior steps. The seismic surrogate basic events shall be added to the PRA under the appropriate areas in the logic model (e.g., given that the Tier 2 Adjusted PRA Model uses only LOOP and SLOCA sequences, the seismic surrogate events should be added to system and/or nodal fault tree structures that tie into

---

[21] As stated in EPRI 3002017583, the technical basis for the Tier 1 approach in Section 2.2.2 of EPRI 3002017583 generally applies for Tier 2 plants. This is also stated in a LaSalle Request for Additional Information (RAI) response letter to the NRC (Reference ML20290A791).

these sequence types). The probability of each seismic surrogate basic event added to the model should be set to 1.0E-04 (based on guidance in EPRI 3002017583).

8. Quantify only the LOOP and small LOCA initiated accident sequences of the Tier 2 Adjusted PRA Model. The event frequency of the LOOP initiator shall be set to a value of 1.0 and the event frequency for the small LOCA initiator shall be set to a value of 1.0E-02. Remove credits for restoration of offsite power and other functional recoveries (e.g., Emergency Diesel Generator (EDG) and DC power recovery).

9. SSCs screened out in Steps 5c, 6, or 9 in Figure 1 below can be considered LSS.

10. Prepare documentation of the Tier 2 analysis results, including identification of seismic unique HSS SSCs, for presentation to the IDP.

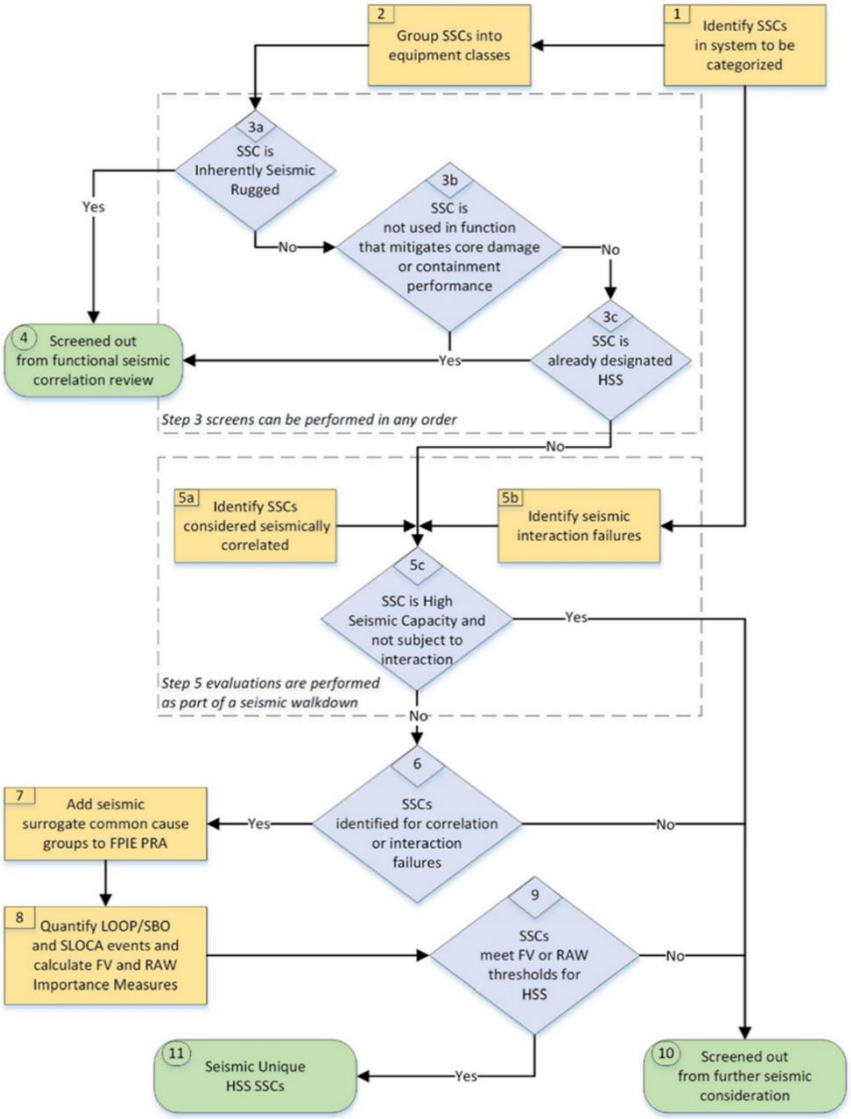

Figure 1: Approach to Seismic Assessment[22]

---

[22] Reproduced from EPRI Report 3002017583 *Alternative Approaches for Addressing Seismic Risk in 10 CFR 50.69 Risk-Informed Categorization Figure 2-3,* EPRI, Palo Alto, CA: 2020; with EPRI markups provided in Attachment 2 of the following references:

- Exelon Generation Company, LLC. Letter to NRC, LaSalle County Station, Units 1 and 2, Renewed Facility Operating License Nos. NPF-11 and NPF-18, NRC Docket Nos. 50-373 and 50-374, Response to Request for Additional Information [...], "LaSalle License Amendment Request to Renewed Facility Operating Licenses to Adopt 10 CFR 50.69, Risk-Informed Categorization and Treatment of Structures, Systems, and Components for Nuclear Power Reactors," (EPID L-2020-LLA-0017), October 16, 2020 ADAMS Accession No. ML20290A791.

- Exelon Generation Company, LLC. Letter to NRC, LaSalle County Station, Units 1 and 2, Renewed Facility Operating License Nos. NPF-11 and NPF-18, NRC Docket Nos. 50-373 and 50-374, "Response

APLC 03 (TSTF-505) External Flooding

APLC Question 03 – External Flood Hazard [TSTF-505]

Section 2.3.1, Item 7, of NEI 06-09, Revision 0-A, states that the "impact of other external events risk shall be addressed in the RMTS program," and explains that one method to do this is by documenting prior to the RMTS program that external events that are not modeled in the PRA are not significant contributors to configuration risk. The SE for NEI 06-09 states that "[o]ther external events are also treated quantitatively, unless it is demonstrated that these risk sources are insignificant contributors to configuration-specific risk."
LAR Enclosure 4, Section 5 concluded that FitzPatrick's external flooding hazard is screened out utilizing the Initial Preliminary Screening Criterion C1, "Event damage potential is less than events for which the plant is designed." However, the licensee identified both local intense precipitation stillwater and probable maximum flood maximum water surface elevation of 272.8 ft, which is greater than the existing current design basis controlling flood elevation of 262 ft and is slightly above site grade (nominally 272 ft). An operator action item is required to verify water intrusion is not occurring at building outer doors and to close doors as appropriate if sustained local intense precipitation is occurring. The LAR did not describe it as an RMA to ensure that the flood protection features, which are integral to flood protection and important for screening of external flooding, continue to be available and functional during the proposed RICTs.

a) Justify that the potential 0.8 feet water above site grade that could enter buildings will have no risk to plant operation.

b) Clarify if the referenced building outer doors of buildings are water resistant and any water intrusion has no potential to damage any SSCs.

c) Discuss the conditions required to enter Procedure AOP-13 and the acceptance criteria for verifying water intrusion is not occurring.

RESPONSE TO TSTF-505 APLC-03A AND TSTF-505 APLC-03B

Following the Fukushima Dai-ichi nuclear power plant accident, the JAF external flooding analysis was updated and documented in the station's reevaluation report (FHRR), which was submitted to NRC for review on March 12, 2015 (Reference [1]). This analysis describes that the Local Intense Precipitation (LIP) flood causing mechanism is the only mechanism that exceeds the current Design Basis (CDB) of the plant and resulted in an unanalyzed condition. However, the JAF Focused Evaluation (FE) (Reference [2]) evaluated this condition and found that the plant is designed to withstand the effects of the LIP mechanism provided the exterior doors to the plant are in their normally closed position.

---

to Request for Additional Information Regarding the License Amendment Request to Adopt 10 CFR 50.69 (EPID L-2020-LLA-0017)," January 22, 2021 ADAMS Accession No. ML21022A130.

The doors credited in the analysis are not water-tight, but were walked down to determine gap sizes, the presence of weather stripping, and the door's overall condition. In-leakage from the doors (through the observed gaps) was accounted for in JAF-RPT-00035 (Sections 5.1 through 5.15 provide a description of each door) and it was determined that the volume of water that could infiltrate from the 0.8 ft of ponding is far less than the volume available in the lowest elevation of the Turbine Building where no safety related SSCs are located. The Staff Assessment (SA) of the FE (Section 3.1.2 – Reference [3]) concurred with the conclusion that the flood protection features (e.g., exterior non-water tight doors) are reliable for slowing water infiltration during the event and preventing damage to safety-related equipment.

The Focused Evaluation, including the evaluation and conclusions, were subsequently submitted to NRC for review. An SA was issued by NRC on April 16, 2018 (Reference [3]) and Section 3 concludes with *"…the Licensee's evaluation relied upon passive existing flood protection features to demonstrate adequate flood protection."* Therefore, the event damage potential is less than event for which the plant is designed and Criterion C1 was utilized for screening External Flood from inclusion in the RICT program.

RESPONSE TO TSTF-505 APLC-03C:

The doors are normally closed and passive. Operator actions are only required if the doors themselves are not in their normally closed positions. Exterior doors that are propped open have personnel stationed to monitor entry and exit, as normal operating procedure. Although there is no explicit acceptance criteria for verifying that water intrusion is not occurring, operators are trained to report abnormal conditions. It is expected that any leakage would be reported, evaluated, and addressed as needed.

AOP-13 (Reference [4]) is entered if on-site flooding is observed, rainfall is predicted to exceed 2 inches per hour, or greater than 6 inches in a 24-hour period. This rainfall amount is significantly less than the approximately 16 inches in 1 hour that is required to produce flood depths of 0.8 feet around the plant buildings. A storm of this magnitude would be detected by the National Weather Service and weather satellites well in advance of the storm arriving, providing more than adequate time to implement AOP-13. In the SA of the FE (Reference [2]), Section 3.1.3 concludes with: *"Because the staff considers the verification that doors are closed in accordance with AOP-13 to be a simple action that does not warrant further analysis, the staff concludes there is no need to review the overall site response."* Given the simple nature of these verification actions and NRC's concurrence they do not need to be reviewed, RMAs for verification actions are not warranted.

REFERENCES

1. JAF-RPT-14-00035, Rev. 000, Fukushima Project Walkdown of Plant Features That Are Potentially Subject to BDBEE Flood Water Infiltration, February 2015.

2. JAFP-17-0078, James A. Fitzpatrick Nuclear Power Plant – Focused Evaluation Summary Pursuant to 10 CFR 50.54(f) Request for Information Regarding Recommendation 2.1: Flooding of the Near-Term Task Force Review of Insights from the Fukushima Dai-ichi Accident, dated July 27, 2017 (ADAMS Accession No. ML172086063).

3. U.S. Nuclear Regulatory Commission Letter, James A. Fitzpatrick Nuclear Power Plant – Staff Assessment of Flooding Focused Evaluation (CAC NO. MG022), dated April 16, 2018 (ADAMS Accession No. ML18075A432).

4. James A. FitzPatrick Nuclear Power Plant, Abnormal Operating Procedure, AOP-13, Rev. 37, Severe Weather

.

APLC 03 (50.69) External Hazards Screening

50.69 APLC Question 03 – External Hazards Screening

NEI 00-04, "10 CFR 50.69 SSC Categorization Guideline," Revision 0, Section 5.4, "Assessment of Other External Hazards," provides guidance on the assessment of other external hazards (excluding fire and seismic) in the 10 CFR 50.69 categorization of SSCs.

Figure 5-6, "Other External Hazards," of NEI 00-04 illustrates a process that begins with an SSC selected for categorization and proceeds through a flow chart for each external hazard. Figure 5-6 of NEI 00-04 shows that if a component participates in a screened scenario, then it has to be shown that the failure of the component does not result in the screened scenario becoming an unscreened scenario in order for the component to be considered a candidate low safety-significant component. In addition, NEI 00-04, Section 5.4 explicitly states,

> *If it can be shown that the component either did not participate in any screened scenarios or, even if credit for the component was removed, the screened scenario would not become unscreened, then it is considered a candidate for the low safety-significant category.*

In Section 3.2.4, "Other External Hazards," of Enclosure 1 to the LAR, the licensee states, in part, that all external hazards, except for seismic, were screened for applicability to JAF per a plant-specific evaluation. The licensee provides a summary of external hazards screening results in Attachment 4, "External Hazards Screening," of Enclosure 1 to the LAR. The licensee provides a summary of the progressive screening approach for external hazards in Attachment 5, "Progressive Screening Approach for Addressing External Hazards," of Enclosure 1 to the LAR. The NRC staff notes that the LAR does not address any considerations with respect to the application of Figure 5-6 of NEI 00-04 to the screening of other external hazards.

The licensee is requested to address the following:

a. *Clarify whether SSCs credited for screening of external hazards will be evaluated using the guidance illustrated in Figure 5-6 of NEI 00-04 during the implementation of the 10 CFR 50.69 categorization process.*

b. *Identify the external hazards addressed in Attachment 4, "External Hazards Screening," of Enclosure 1 of the LAR that will be evaluated according to the flowchart in Figure 5-6 of NEI 00-04.*

c. *If the approach illustrated in Figure 5-6 of NEI 00-04 will not be used, describe the proposed approach and provide its justification.*

RESPONSE TO 50.69 APLC 3A

During categorization of SSCs, consistent with the guidance in NEI 00-04, Figure 5-6 will be followed.

RESPONSE TO 50.69 APLC 3B

Although Figure 5-6 of NEI 00-04 applies to all external hazards, two external hazards credited SSCs in their screening: (1) External Flooding and (2) Local Intense Precipitation. These two hazards have SSCs that are credited per Figure 5-6 to allow the hazard to screen as shown in Table 1 below. All other hazards listed in the 50.69 LAR Attachment 4 were screened without crediting SSCs.

TABLE 1

List of Doors/Barriers Credited for Screening XF Hazard[23]

Openings	Normal Position	Building
Door A	Closed	Heater Bay
Door C	Closed	Screenwell Building
Door E1	Closed	Diesel Generator Room
Door E2	Closed	Diesel Generator Room
Door F1	Closed	Diesel Generator Room
Door F2	Closed	Diesel Generator Room
Door G	Closed	Turbine Building Track Bay
Door I	Closed	Electrical Bay
Door M	Closed	Reactor Building Track Bay
Hatch 1 (H1)	Closed	Reactor Building

[23] This list is from Table 3.1-1 of the NRC Staff Assessment of the JAF Flooding Focused Evaluation (ML18075A432).

TABLE 1

List of Doors/Barriers Credited for Screening XF Hazard[23]

Hatch 2 (H2)	Closed	Reactor Building
Manhole 1 (M1)	Closed	Plant Yard

The other external hazards listed in Attachment 4 of Enclosure 1 of the LAR do not credit SSCs in order to screen the hazard.

RESPONSE TO 50.69 APLC 3C

The approach illustrated in Figure 5-6 of NEI 00-04 will be used. See the response to APLC Questions 03a and 03b above.

APLC 04 (TSTF-505) Ice Cover Hazard

TSTF-505 APLC QUESTION 04 – Ice Cover

Section 2.3.1, Item 7, of NEI 06-09, Revision 0-A, states that the "impact of other external events risk shall be addressed in the RMTS program," and explains that one method to do this is by documenting prior to the RMTS program that external events that are not modeled in the PRA are not significant contributors to configuration risk. The SE for NEI 06-09 states that "[o]ther external events are also treated quantitatively, unless it is demonstrated that these risk sources are insignificant contributors to configuration-specific risk."

LAR Enclosure 4, Table E4-4 indicates the ice cover hazard (i.e., the accumulation of frozen water on bodies of water such as lakes and rivers or on structures, systems, and components) is screened based on the Table E4-5 criteria of "C1" (Event damage potential is < events for which the plant was designed) and "C4" (Event is included in the definition of another event). However, Section 5.6 of the JAF Individual Plant Examination of External Events (IPEEE) identifies three events during extremely cold weather in February and March 1993 in which ice formation at the intake structure resulted in consequential restriction of cooling water flow to the screenwell. The response to one of these events was to scram the reactor and remove the circulating water pumps from service. In response to these events, an alarm was installed in the control room to alert the operators of intake blockage, a second alarm was installed in the Emergency and Plant Information (EPIC) computer to alert operators of the potential for reduced inflow of cold lake water, and changes were made to the abnormal operating procedures to define corrective actions should an ice blockage occur, which include progressive reductions in reactor power and the tripping of the circulating water pump. Therefore, it appears there is a potential for ice to form at the cooling water intake structure in the winter that could potentially fail the cooling water supply for such systems as the Ultimate Heat Sink, particularly if the alarms are unavailable.

It is not clear to the NRC staff how the criteria cited above are used to screen this hazard event for all plant configurations encompassed in the RICT program. Section 6 of LAR Enclosure 4 states for configurations allowed by the RICT program that "hazards for which the ability to achieve safe shutdown may be impacted by one or more 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." Accordingly, given that ice formation could impact the ability to achieve safe shutdown, especially for certain configurations, address the following:

a) *Explain how the "C1" and "C4" screening are used to screen the ice cover hazard from consideration for impact on RICT calculations given that ice formation events appear to be anticipated and could be a contributor to a core damage accident particularly for certain plant configurations. Include discussion of the alarms used to alert the operators of intake blockage and the potential for*

reduced inflow.

b) *If the screening criteria cited in the LAR are not sufficient to screen the ice cover hazard from consideration for impact on the RICTs for all plant configurations encompassed in the RICT program, then justify screening the ice cover hazard using another basis.*

c) *If it cannot be justified that the ice cover hazard can be screened for impact on the RICT calculations, then explain how the RICT program will mitigate or prevent the impact of the ice cover hazard during a RICT application.*

RESPONSE TO TSTF-505 APLC 4A

a) The concern with ice affecting the screenwell and the events documented in Section 5.6.1.2 of the IPEEE are noted. Table E4-4 of the LAR addresses two aspects of the 'Ice Cover' hazard, which remain applicable:

- The suction for the intake structure is at the bottom of Lake Ontario and designed to prevent ice from entering the intake. This aspect of ice cover is screened with Criterion C1, since the plant design accounts for this part of the hazard

- Another potential impact of ice cover is the Loss of Offsite Power (LOOP), which is screened with Criterion C4, since weather-related LOOPs are included in the internal events PRA.

The intake icing events described in the IPEEE and raised in this question are not explicitly discussed in the screening of Ice Cover in Table E4-4. However, this aspect of the hazard (loss of ultimate heat sink due to icing in the intake structure) is modeled explicitly in the internal events PRA. Specifically, the initiating event %TUHS, Loss of Plant Cooling, includes considerations of intake structure blockage due to ice, as well as other debris [Ref: JF-PRA-001, JAF PRA Initiating Events Notebook, Rev. 1]. The calculation of the total loss of plant cooling frequency (%TUHS) in the PRA includes the operator response to mitigate the blockage, which is both planned for and proceduralized in OP-4, Circulating Water System, and AOP-56, Intake Water Level Trouble. In addition to local monitoring of conditions in the intake, many indications are available in the control room to provide warning of potential intake water level trouble.

FitzPatrick operators have several indicators prior to total loss of intake flow that allow the operators to anticipate and take actions (e.g., operating the trash rakes or cycling gates to break up ice.). Operator actions to preclude loss of station cooling can be triggered through a number of indications such as:

- Low screenwell level (indication and alarm)
- Traveling Water Screen differential level (indication and alarm)
- Trash Rake differential level alarm
- Low Circulating Water pressure
- Rising Circulating Water Pump motor current
- EPIC alarms for change in intake water temperature
- Auto start of fire pumps with no indication of a pipe break or spray initiation
- Operator rounds or local monitoring of intake water levels
- Reports from Nine Mile Point 1 or 2 that icing is occurring

The icing conditions would be planned for (per OP-4) and significant time is available to correct the situation (including lowering power or scramming the reactor) prior to challenging the safety-related cooling system suctions.

- OP-4 (Rev. 91) provides steps to be taken in the event of cold lake temperature to minimize the likelihood of intake structure clogging due to ice (Section E.6 Cold Lake Temperature Months). This includes determining the susceptibility to frazil ice based on the environmental conditions at the site.

- AOP-56 (Rev. 24) provides numerous symptoms and entry conditions, based on a variety of indications and system responses (Sections: A. Entry Conditions; B. Symptoms; and C. Automatic Actions). The AOP provides procedures for responding to various different intake structure plugging events (which result in intake level changes), including due to ice.

Since ice plugging in the intake structure is accounted for explicitly in the internal events PRA as part of an initiating event (%TUHS), and the impact of configurations that could potentially affect the mitigation are accounted for in the initiating event frequency, it can be screened using Criterion C4, Event is included in the definition of another event.

Therefore, the screening criteria used for the Ice Cover hazard remain C1 and C4. Further, there are no configuration-specific considerations for this hazard.

RESPONSE TO TSTF-505 APLC 4B AND APLC 4C

The Ice Cover hazard is screened using Criteria C1 and C4, as described in Enclosure 4 to the LAR. Additional concerns regarding ice blockage of the intake structure and loss of safety-related plant cooling are also screened using Criterion 4, Event is included in the definition of another event.

APLC 04 (50.69) External Flood Hazard

APLC Question 04 – External Flood Hazard

NEI 00-04, "10 CFR 50.69 SSC Categorization Guideline," Revision 0, Section 5.4, "Assessment of Other External Hazards," provides guidance on the assessment of other external hazards (excluding fire and seismic) in the 10 CFR 50.69 categorization of SSCs

Figure 5-6, "Other External Hazards," of NEI 00-04 illustrates a process that begins with an SSC selected for categorization and proceeds through a flow chart for each external hazard. Figure 5-6 of NEI 00-04 shows that if a component participates in a screened scenario, then it has to be shown that the failure of the component does not result in the screened scenario becoming an unscreened scenario in order for the component to be considered a candidate low safety-significant component. In addition, NEI 00-04, Section 5.4 explicitly states,

> *If it can be shown that the component either did not participate in any screened scenarios or, even if credit for the component was removed, the screened scenario would not become unscreened, then it is considered a candidate for the low safety-significant category.*

In Section 3.2.4, "Other External Hazards," of Enclosure 1 to the LAR, the licensee states, in part, that all external hazards, except for seismic, were screened for applicability to JAF per a plant-specific evaluation. The licensee provides a summary of external hazards screening results in Attachment 4, "External Hazards Screening," of Enclosure 1 to the LAR. The licensee provides a summary of the progressive screening approach for external hazards in Attachment 5, "Progressive Screening Approach for Addressing External Hazards," of Enclosure 1 to the LAR.

In Attachment 4, the licensee lists all hazards as screened except internal events, internal flooding, internal fire, and seismic events. For the external flood hazard, the licensee states that the Flood Hazard Reevaluation Report identified both local intense precipitation stillwater and probable maximum flood maximum water surface elevation of 272.8 feet, which is slightly above site grade (nominally 272 feet). The licensee concludes that in-leakage will be minimal and interior drainage features would have more than enough capacity to mitigate the effects of any in-leakage from the normally closed exterior doors.

The licensee states that Procedure AOP-13, "Severe Weather," Revision 37 directs operators to verify water intrusion is not occurring at building outer doors and to close doors as appropriate if sustained local intense precipitation is occurring. The licensee also states, in part, that these doors should be categorized as high safety-significant since removal of any of these doors would result in an unscreened scenario. The NRC staff is unclear of the

importance of the interior drains when the doors are closed or open. In addition, the NRC staff notes that the categorization of the interior drains is not mentioned.

The licensee is requested to address the following:

a. *Clarify the role of the interior drains perform for local intense precipitation events when either the building outer doors are open or closed.*
b. *Provide justification that the interior drains do not impact the screening of the external flood hazard or propose a mechanism to ensure the interior drains are categorized in accordance with Figure 5-6 of NEI 00-04.*

RESPONSE TO 50.69 APLC 04

During a LIP event, the only credited flood protection features included in the Focused Evaluation for LIP are normally closed exterior doors, as stated in Attachment 4 of the LAR. JAF-RPT-00035, "Fukushima Project Walkdown of Plant Features that are Potentially Subject to BDBEE Flood Water Infiltration" (Reference 1) concludes that infiltration through the exterior door gaps will flow to lower elevations of the plant and not accumulate more than a few inches in areas where no safety related equipment is located. Drainage *features* include floor drains but it is noted that open stairwells will also convey water to lower elevations and the Floor Drain Tank will quickly become flooded and overflow onto the 250' Elevation of the Radwaste Building, then the East Turbine Building Pipe Tunnel (Elevation 252'). Water infiltrating from the Turbine Building 272' elevation will flow down the stairwell onto the 252' Elevation of either the Turbine or Admin Building. The conclusion is that the floor drains are not required to convey the infiltrated water but rather mentioned as a drainage feature that could prevent ponding should infiltration be minimal (the tank volume is 8,500 gallons compared to an estimated inflow of 210,000 gal through the door gaps).

In JAF-RPT-00035, Sections 5.1 through 5.15 give a detailed account of each door analyzed and the mechanisms credited for each door's infiltrated water's conveyance to lower elevation with no impacts to safety related equipment. The analysis was reviewed during the NRC's Staff Assessment of the Focused Evaluation, dated April 16, 2018 (ML18075A432 – Reference 2), and NRC staff concurred with the results that credit the exterior doors as the only flood protection features and determined they have adequate available physical margin (Section 3.1.2 – Reliability of Flood Protection Features).

References

1. JAF-RPT-14-00035, Rev. 000, Fukushima Project Walkdown of Plant Features That Are Potentially Subject to BDBEE Flood Water Infiltration, February 2015.

2. U.S. Nuclear Regulatory Commission Letter, James A. Fitzpatrick Nuclear Power Plant – Staff Assessment of Flooding Focused Evaluation (CAC NO. MG022), dated April 16, 2018 (ADAMS Accession No. ML18075A432).

EEEB Questions:

EEEB Question 1:

Table E1-1 in Enclosure 1 of the LAR: TS 3.8.1.A – The TS description states, "One required offsite circuit inoperable." The "SSCs Covered by TS LCO Condition" states, "Lines 3/4." The Design Success Criteria" states, "One offsite source". The NRC staff identified a lack of clarity in the definition of lines, circuits and sources and potential limitations of their use because of shared equipment. Please provide the definitions of line, circuit, and source. Also, please clarify the offsite configurations, including shared equipment (if any), and the design success criteria for meeting this TS LCO condition requirement.

Response:

Reserve power is supplied by two independent sources. One source consists of switch 71EDSC-10025, Reserve Station Service Transformer (RSST) 71T-2, circuit breakers 71-10412, 71-10404, and 71-10614. The second source consists of switch 71EDSC-10015, RSST 71T-3, circuit breakers 71-10312, 71-10304, and 71-10514. Each source also includes the interrupting devices, cabling, and controls required to transmit power from the 115 kV transmission network source to the plant Class 1E emergency buses. In order to be a qualified offsite circuit, as described in the plant Technical Specifications, a reserve power source must be powered from the 115 kV distribution system by one of the 115 kV lines. The JAF 115 kV distribution system is powered by two independent 115 kV lines (the South Oswego Substation Line (Line #4) and the Lighthouse Hill Line (Line #3)). Through their associated breakers and disconnect switches either of these lines can be aligned to either of the reserve power sources to form a qualified offsite circuit. Offsite Circuit: A qualified offsite circuit consists of all breakers, transformers, switches, interrupting devices, cabling, and controls required to transmit power from the 115 kV transmission network source to the plant Class 1E emergency buses, each qualified offsite circuit must be capable of maintaining rated frequency and voltage, and accepting required loads during an accident, while connected to the emergency buses. Each qualified offsite circuit consists of the incoming disconnect device to reserve station service transformer (RSST) 71T-2 or 71T-3, the associated RSST, (including the load tap changer, while in automatic or manual mode of operation) and the respective circuit path including feeder breakers to the 4.16 kV emergency bus 10500 or 10600. If one 115 kV transmission line or associated switch or circuit breakers is inoperable, then one of the offsite circuits must be declared inoperable. The South Oswego Substation 115 kV Line #4 is shared with Nine Mile Point Unit 1. Both the JAF and NMP1 Technical Specifications are written such that both Stations enter into an LCO if Line #4 is unavailable.

The OPERABILITY of the AC electrical power sources is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the plant. This includes maintaining the onsite (EDGs) or qualified offsite AC sources OPERABLE during accident conditions in the event of:

a. An assumed loss of all offsite power or all onsite AC power; and
b. A worst case single active component failure.

The Design Success Criteria is one offsite circuit or one EDG subsystem after the assumed worse case single active component failure. Therefore, in the case of 3.8.1.A, the one OPERABLE offsite circuit and two OPERABLE EDG subsystems are adequate to supply electrical power to the plant Class 1E Distribution System and meet the Design Success Criteria.

EEEB Question 2:

Table E1-1 in Enclosure 1 of the LAR: TS 3.8.1.B – The description states, "One required EDG subsystem inoperable", lists 4 EDG's in the SSCs and has a design success criteria of 1 of 2 EDG subsystems. Please clarify number of EDGs per subsystem and whether a single EDG can support the full load?

Response:

Each subsystem consists of 2 EDGs. Each generator is rated to supply 2600 kw @ 4160 VAC and 60 Hz to an emergency power division (I or II). While each emergency power division is normally designed to be supplied by an EDG pair, each generator has sufficient capacity to supply the required loads necessary to achieve safe reactor shutdown during an operational transient. [i.e., loss of offsite power (LOOP) or degraded 4160 VAC emergency bus voltage] without a loss of coolant accident (LOCA) and to maintain safe shutdown conditions during the transient. The voltage dip of 40% (which recovers to 93% in two (2) seconds) and a total 3000 kw connected load (i.e., 800 kw emergency substation and 2200 kw of acceleration torque produced by the largest ECCS pump load (core spray pump motor)) are within the thirty-minute rating (3050 kw) of each engine. A single EDG cannot supply the minimum safe shutdown load requirements of a design basis LOCA coincident with a LOOP (i.e., JAF licensing basis) since the minimum ECCS steady state load requirement exceeds an EDG rated capacity. While each emergency power division is designed to be supplied by an EDG pair, if an EDG were to fail during a LOCA event in conjunction with a LOOP, the programmed restart logic will not start the second residual heat removal pump powered from the 4.16 kV emergency bus associated with the failed EDG so that the remaining EDG in that EDG subsystem is not overloaded.

The OPERABILITY of the AC electrical power sources is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the plant. This includes maintaining the onsite (EDGs) or qualified offsite AC sources OPERABLE during accident conditions in the event of:

a. An assumed loss of all offsite power or all onsite AC power; and
b. A worst case single active component failure.

The Design Success Criteria is one offsite circuit or one EDG subsystem after the assumed worse case single active component failure. Therefore, in the case of 3.8.1.B, the two OPERABLE offsite circuits and the one OPERABLE EDG subsystem are adequate to supply electrical power to the plant Class 1E Distribution System and meet the Design Success Criteria.

EEEB Question 3:

Table E1-1 in Enclosure 1 of the LAR:

TS 3.8.1.C – Two required offsite circuits inoperable. The design success criteria refence 3.8.1.A, which is "one offsite source." The design success criteria for TS 3.8.1.B appear to defeat the TS condition's description, and therefore could potentially result in a loss of function. Please clarify the design success criteria for this TS condition.

Response:

T.S. 3.8.1.C applies when two offsite circuits are inoperable and is intended to provide assurance that an event with a coincident single failure will not result in a complete loss of redundant required features. These redundant required features are those that are assumed in the safety analysis to function to mitigate an accident, coincident with a loss of offsite power, such as ECCS. 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.

This level of degradation means that the offsite electrical power system does not have the capability to affect a safe shutdown and to mitigate the effects of an accident; however, the onsite AC sources have not been degraded. This level of degradation generally corresponds to a total loss of the immediately accessible reserve 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 EDG subsystems inoperable. However, two factors tend to decrease the severity of this degradation level: a. The configuration of the redundant AC electrical power system that remains available is not susceptible to a single bus or switching failure; and b. The time required to detect and restore an unavailable offsite power source is generally much less than that required to detect and restore an unavailable onsite AC source. With both of the offsite circuits inoperable, sufficient onsite AC sources are available to maintain the plant 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 active component failure were postulated as a part of the design basis in the safety analysis.

The OPERABILITY of the AC electrical power sources is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the plant. This includes maintaining the onsite (EDGs) or qualified offsite AC sources OPERABLE during accident conditions in the event of:

a. An assumed loss of all offsite power or all onsite AC power; and
b. A worst case single active component failure.

The Design Success Criteria is one offsite circuit or one EDG subsystem after the assumed worse case single active component failure. Therefore, in the case of 3.8.1.C, the two OPERABLE EDG subsystems are adequate to supply electrical power to the plant Class 1E Distribution System and meet the Design Success Criteria.

EEEB Question 4:

Table E1-1 in Enclosure 1 of the LAR: TS 3.8.1.D – The design success criteria reference TSs 3.8.1.A and B. With the clarification of TS 3.8.1.A design success criteria needed, the design success criteria for TS 3.8.1.D should also be clarified as needed.

Response:

The OPERABILITY of the AC electrical power sources is consistent with the initial assumptions of the accident analyses and is based upon meeting the design basis of the plant. This includes maintaining the onsite (EDGs) or qualified offsite AC sources OPERABLE during accident conditions in the event of:

a. An assumed loss of all offsite power or all onsite AC power; and
b. A worst case single active component failure.

The Design Success Criteria is one offsite circuit or one EDG subsystem after the assumed worse case single active component failure. Therefore, in the case of 3.8.1.D, the one OPERABLE offsite source and one OPERABLE EDG subsystem are adequate to supply electrical power to the plant Class 1E Distribution System and meet the Design Success Criteria.

EEEB Question 5:

Table E1-1 in Enclosure 1 of the LAR: TS 3.8.4.A - How many divisions, subsystems per division, and how many batteries, chargers, boards per subsystem.

Response:

There are two divisions of the 125 VDC independent power supply subsystems. Each subsystem consists of one battery, one battery charger, and the corresponding control equipment and interconnecting cabling supplying power to the associated bus.

An appropriately sized temporary battery charger, powered by Class 1E power, may be used to maintain the battery in a charged state. The battery remains operable when the temporary battery charger is in use, provided the requirements are met as specified in Technical Specifications. This TS allows operational flexibly to remove a permanent charger from service for maintenance and restore within a 7 day timeframe.

The loss of any DC electrical power subsystem does not prevent the minimum safety function from being performed. The design success criteria is one of the two 125VDC Subsystems.

EEEB Question 6:

Table E1-1 in Enclosure 1 of the LAR: TS 3.8.4.B – One 125 VDC electrical power subsystem inoperable for reasons other than condition A. The design success criteria reference TS 3.8.4.A. The TS description specifies "other than Condition A." Please explain why the design success criteria for TS 3.8.4.B should be the same as TS 3.8.4.A's

Response:

There are two divisions of the 125 VDC independent power supply subsystems. Each subsystem consists of one battery, one battery charger, and the corresponding control equipment and interconnecting cabling supplying power to the associated bus. T.S 3.8.4.A addresses the restoration of battery parameters to the design limits within 2 hours followings

the inoperability of a battery charger. If the subsystem is inoperable for any reason other than the battery charger, TS 3.8.4.B directs restoration of the 125VDC subsystem.

The loss of any DC electrical power subsystem does not prevent the minimum safety function from being performed. The design success criteria is one of the two 125VDC Subsystems.

EEEB Question 7:

TSTF-505, Revision 2, does not allow for TS loss of function conditions (i.e., those conditions that represent a loss of a specified safety function or inoperability of all required trains of a system required to be operable) in the risk informed completion time program.

Based on the Design Success Criteria in Table E1-1 for 3.3.8.1.A, it appears that the inoperability of one channel results in a loss of function; therefore, a RICT should not be applied. If the Staff's understanding is incorrect, please explain a condition where there would not be a loss of function when one channel is inoperable.

Response:

Each 4.16kV emergency bus has its own independent LOP instrumentation and associated trip logic. The voltage for each bus is monitored at two levels, Loss of Voltage and Degraded Voltage, which provides two different types of undervoltage protection functions. Each function has two relays, and both need to pick up in order to start the diesels i.e. two-out-of-two logic per function per bus. The loss of voltage protection picks up at 71.5% of nominal emergency bus voltage with a time delay of 2.5 seconds. The Degraded voltage picks up at 93% nominal emergency bus voltage with a time delay of 9 seconds with a LOCA and 45 seconds without a LOCA. This time delay is designed to allow sufficient time for the preferred power supply to recover, but short enough that sufficient power is available to the required equipment. Inoperability of one channel will cause a loss of function for the affected division.

A review of the LOP instrumentation circuits determined that a loss of function would occur for any single instrument inoperability listed in Table 3.3.8.1-1 for Functions 1. 4.16 kV Emergency Bus Undervoltage (Loss of Voltage) and 2. 4.16 kV Emergency Bus Undervoltage (Degraded Voltage). Since TSTF-505 does not allow use of risk informed completion time for TS loss of function, TS 3.3.8.1 LOP Instrumentation will be removed from the submittal. The TS markup and TS Bases markup have been updated to remove TS 3.3.8.1.

STSB Questions:

STSB Question 1:

For example,1.3-8, there should not be a "." after the completion times of 6 hours and 36 hours. Remove the "." from the completion times.

Response 1:

The station agrees with this comment and has updated the TS markup to address this comment.

STSB Question 2:

For TS 5.5.16 c.3, the "If" should be lower case "if". Make the "If" lower case to reflect "if".

Response 2:

The station agrees with this comment and has updated the TS markup to address this comment.

STSB Question 3:

Staff notes that best practice is to explain the loss of function (or equivalent) notes in the bases. The following bases do not have the note.

- *3.3.1.1.A.1 and A.2: Missing the note "not applicable when trip capability is not maintained"*
- *3.3.1.1.B.1 and B.2: Missing the note "not applicable when trip capability is not maintained"*
- *3.3.2.2.A.1: Missing the note "not applicable when trip capability is not maintained"*
- *3.3.4.1.A.1 and A.2: Missing the note "not applicable when trip capability is not maintained"*
- *3.3.5.1.B.1, B.2, and B.3: Missing the note "not applicable when trip capability is not maintained"*
- *3.3.5.1.C.1 and C.2: Missing the note "not applicable when trip capability is not maintained"*
- *3.3.5.1.D.1, D.2.1, and D.2.2: Missing the note "not applicable when trip capability is not maintained"*
- *3.3.5.1.E.1 and E.2: Missing the note "not applicable when trip capability is not maintained"*
- *3.3.5.1.F.1 and F.2: Missing the note "not applicable when trip capability is not maintained"*
- *3.3.5.1.G.1 and G.2: Missing the note "not applicable when trip capability is not maintained"*
- *3.3.5.3.B.1 and B.2: Missing the note "not applicable when trip capability is not maintained"*
- *3.3.5.3.D.1, D.2.1, and D.2.2: Missing the note "not applicable when trip capability is not maintained"*
- *3.3.6.1.A.1: Missing the note "not applicable when trip capability is not maintained"*
- *3.3.7.2.A.1 and A.2: Missing the note "not applicable when trip capability is not maintained"*
- *3.3.8.1.A.1: Missing the note "not applicable when trip capability is not maintained"*
- *3.6.1.2.C.1, C.2, and C.3: Missing the note included in the TS markup*

- *3.6.1.3.E.1: Missing the note included in the TS markup*

Response 3: The station agrees that adding the note to the bases would be a good practice. The submittal was based on TSTF-505 Rev 2 which does not have the note included in the TS bases. The TS bases markup has been updated to include the note for the applicable Technical Specifications. TS 3.3.8.1 and it's associated bases have been removed from the license amendment submittal.

STSB Question 4:

Staff notes that best practice is to remove outdated footnotes. For TS 3.6.1.9 A.1, the footnote is no longer applicable and the RICT is applied.

Response 4: The station agrees that the outdated footnote should be removed and has updated the TS markup to address this comment.

STSB Question 5:

TSTF-505, Revision 2, does not allow for TS loss of function conditions (i.e., those conditions that represent a loss of a specified safety function or inoperability of all required trains of a system required to be operable) in the risk informed completion time program.

Based on the design success criteria provided in the license amendment request Table E1-1, it appears that some LCO Actions may constitute a loss of function.

Response 5:

A review of the LOP instrumentation circuit determined that a loss of function would occur for any single instrument inoperability listed in Table 3.3.8.1-1 for Functions 1. 4.16 kV Emergency Bus Undervoltage (Loss of Voltage) and 2. 4.16 kV Emergency Bus Undervoltage (Degraded Voltage). Since TSTF-505 does not allow use of risk informed completion time for TS loss of function, TS 3.3.8.1 LOP Instrumentation will be removed from the submittal. The TS markup and TS Bases markup have been updated to remove TS 3.3.8.1.

STSB Question 6:

LAR Enclosure 1, Table E1-1 lists in the column of "TS 3.5.1.C" a condition with one train of HPCI inoperable. The corresponding column of the "SSCs Covered by TS LCO Condition" indicates that one train of HPCI is required to be OPERABLE, and the column of "Design Success Criteria" indicates that one of one train available.

Clarify for TS 3.5.1.C Condition with one train of HPCI inoperable, that the Design Success Criteria is RCIC is operable and ECCS injection/spray subsystems in conjunction with ADS are operable. Discuss the AOR that demonstrated adequacy of RCIC and ECCS injection/spray subsystems in conjunction with ADS for ensuring adequate core cooling and reference the NRC documents approving the AOR of the concern or address the acceptability of the AOR if it was not previously approved by the NRC.

Response 6:

ECCS and ADS:

From the T.S Bases 3.5.1 *ECCS - Operating*, on receipt of an initiation signal (LOCA), ECCS pumps automatically start; simultaneously, the system aligns, and the pumps inject

water, taken either from the CSTs or suppression pool, into the Reactor Coolant System (RCS) as RCS pressure is overcome by the discharge pressure of the ECCS pumps.

The ADS system consists of 7 of the 11 S/RVs. It is designed to provide depressurization of the RCS during a small break LOCA if HPCI fails or is unable to maintain required water level in the RPV. ADS operation reduces the RPV pressure to within the operating pressure range of the low pressure ECCS subsystems (CS and LPCI), so that these subsystems can provide coolant inventory makeup.

Although the system is initiated on a LOCA, ADS action is delayed, allowing the operator to interrupt the timed sequence if the system is not needed. The HPCI pump discharge pressure almost immediately exceeds that of the RCS, and the pump injects coolant into the vessel to cool the core. If the break is small, the HPCI System will maintain coolant inventory as well as vessel level while the RCS is still pressurized. If HPCI fails, it is backed up by ADS in combination with LPCI and CS. In this event, if the ADS timed sequence is allowed to time out, the selected safety/relief valves (S/RVs) would open, depressurizing the RCS, thus allowing the LPCI and CS to overcome RCS pressure and inject coolant into the vessel. If the break is large, RCS pressure initially drops rapidly and the LPCI and CS cool the core.

RCIC:

From functions and design requirements in the DBD-013 *Design Basis Document for RCIC*, the RCIC System prevents the reactor core from overheating following a reactor vessel isolation event accompanied by loss of coolant flow from the Feedwater System. This system adds water to keep the core covered so that the fuel cladding will not fail and result in fission product release without use of the High Pressure Coolant Injection System or rapid reactor vessel depressurization. The RCIC System automatically injects water into the reactor vessel through the Feedwater System. This occurs at a flow rate such that sufficient core cooling occurs to prevent fuel damage and to maintain reactor water level above the top of the core.

From the T.S. 3.5.3 Bases *RCIC System*, the RCIC System is not part of the ECCS; however, the RCIC System is included with the ECCS section because of their similar functions. The RCIC System is designed to operate either automatically or manually following reactor pressure vessel (RPV) isolation accompanied by a loss of coolant flow from the feedwater system to provide adequate core cooling and control of the RPV water level. Under these conditions, the High Pressure Coolant Injection (HPCI) and RCIC systems perform similar functions. The RCIC System design requirements ensure that the criteria of Reference 1 are satisfied.

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

In summary, ADS acts as the divisional ECCS equivalent of HPCI by ensuring depressurization of the vessel to allow Low Pressure ECCS pumps to inject on a LOCA. Therefore, with HPCI inoperable, the Design Success Criteria is met by ECCS

injection/spray subsystems in conjunction with ADS. Additionally, RCIC provides high pressure make up to the vessel as is required by the design of HPCI.

STSB Question 7:

LAR Enclosure 1, Table E1-1 lists in the column of "TS 3.5.3.A" a condition with RCIC system inoperable. The corresponding column of "the SSCs Covered by TS LCO Condition" indicates that one train of RCIC is required to be OPERABLE, and the column of "Design Success Criteria" indicates that one of one train available.

Clarify for TS 3.5.1.A Condition with one train of RCIC inoperable, that the Design Success Criteria is HPCI is operable. Discuss the AOR that demonstrated adequacy of HPCI for ensuring overall plant capability to provide makeup inventory at high reactor pressure and reference the NRC documents approving the AOR of the concern or address the acceptability of the AOR if it was not previously approved by the NRC.

Response 7:

From the TS 3.5.3 Bases *RCIC System*, the RCIC System is not part of the ECCS; however, the RCIC System is included with the ECCS section because of their similar functions. The RCIC System is designed to operate either automatically or manually following reactor pressure vessel (RPV) isolation accompanied by a loss of coolant flow from the feedwater system to provide adequate core cooling and control of the RPV water level. Under these conditions, the High Pressure Coolant Injection (HPCI) and RCIC systems perform similar functions.

Make up water to Rx vessel as a back-up to RCIC per GE High Pressure Coolant Injection System Design Specification, 22A4313, Rev. 0.

From FSAR 6.4.1 *HPCI System*, the HPCI System controls automatically start the system and bring it to design flow rate in approximately 30 sec from receipt of a reactor vessel low-low water level signal or a drywell high pressure signal. The HPCI startup time assumed in the ECCS LOCA analysis is 60 sec. Also, the HPCI system has been shown to mitigate the low-level effect of a Loss of Feedwater event with a startup time of 60 sec.

From FSAR 14.5.5.3 *Loss of Feedwater*, since RCIC delivers about one-tenth of the flow that HPCI does, if RCIC successfully maintains vessel level, then HPCI will also do so with a 60 second start time.

In conclusion, as HPCI is 10 times the flow rate, performs similar functions, and is designed as a backup to RCIC. HPCI is sufficient to meet the design success criteria in the event RCIC is inoperable. To ensure the makeup to the vessel at high reactor pressure.

ATTACHMENT 2

License Amendment Request

James A. FitzPatrick Nuclear Power Plant

Docket No. 50-333

Revised Technical Specification Marked-Up Pages (Red Text)

TS Pages

1.3-13
3.1.7-1
3.3.1.1-1
3.3.2.2-1
3.3.4.1-1
3.3.5.1-2 thru -6
3.3.5.3-1 and -2
3.3.6.1-1
3.3.7.2-1
3.5.1-1 and -2
3.5.3-1
3.6.1.2-3
3.6.1.3-2 and -3
3.6.1.3-5
3.6.1.6-1
3.6.1.7-1
3.6.1.9-1
3.6.2.3-1
3.7.1-1
3.7.2-1
3.7.6-1
3.8.1-2 thru -4
3.8.4-1 and -2
3.8.7-1
5.5-15

1.3 Completion Times

EXAMPLES	EXAMPLE 1.3-7 (continued) and operation may continue in accordance with Condition A, provided the Completion Time for Required Action A.2 has not expired.
IMMEDIATE COMPLETION TIME	When "Immediately" is used as a Completion Time, the Required Action should be pursued without delay and in a controlled manner.

INSERT A

INSERT A

EXAMPLES (continued)

EXAMPLE 1.3-8

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One subsystem inoperable.	A.1 Restore subsystem to OPERABLE status.	7 days OR In accordance with the Risk Informed Completion Time Program.
B. Required Action and associated Completion Time not met.	B.1 Be in MODE 3. AND B.2 Be in Mode 5.	6 hours 36 hours

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

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

INSERT A

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

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

3.6 CONTAINMENT SYSTEMS

3.6.1.9 Residual Heat Removal (RHR) Containment Spray System

LCO 3.6.1.9 Two RHR containment spray subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One RHR containment spray subsystem inoperable.	A.1 Restore RHR containment spray subsystem to OPERABLE status.	7 days
B. Two RHR containment spray subsystems inoperable.	B.1 Restore one RHR containment spray subsystem to OPERABLE status.	8 hours
C. Required Action and associated Completion Time not met.	C.1 Be in MODE 3. AND C.2 Be in MODE 4.	12 hours 36 hours

OR

In accordance with the Risk Informed Completion Time Program

5.5 Programs and Manuals

5.5.14 Control Room Envelope Habitability Program (continued)

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

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

5.5.15 Surveillance Frequency Control Program

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

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

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

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

INSERT B

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, 2;

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

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

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

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

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

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

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

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 License Amendment No. [xxx], 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.

ATTACHMENT 3

License Amendment Request

James A. FitzPatrick Nuclear Power Plant
Docket No. 50-333

Revised Technical Specification Bases Marked-Up Pages (Red Text)
(for Information Only)

TS Bases Pages

B 3.1.7-2
B 3.3.1.1-21 and -22
B 3.3.2.2-4
B 3.3.4.1-5
B 3.3.5.1-25
B 3.3.5.1-27 thru -29
B 3.3.5.1-31 and -32
B 3.3.5.3-7 and -8
B 3.3.6.1-23
B 3.3.7.2-4
B 3.5.1-7 thru -9
B 3.5.3-3
B 3.6.1.2-6
B 3.6.1.3-5
B 3.6.1.3-7 and 08
B 3.6.1.6-4
B 3.6.1.7-4
B 3.6.1.9-3
B 3.6.2.3-2
B 3.7.1-3 and -4
B 3.7.2-4
B 3.7.6-2
B 3.8.1-7
B 3.8.1-10 thru -12
B 3.8.4-6 and -7
B 3.8.7-4 and -5

BASES

ACTIONS (continued)

they are inoperable due to failure of SR 3.3.1.1.2 and gain adjustments are necessary. Note 2 allows entry into associated Conditions and Required Actions to be delayed for up to 2 hours if the APRM is indicating a lower power value than the calculated power (i.e., the gain adjustment factor (GAF) is high (non-conservative)). The GAF for any channel is defined as the power value determined by the heat balance divided by the APRM reading for that channel. Upon completion of the gain adjustment, or expiration of the allowed time, the channel must be returned to OPERABLE status or the applicable Condition entered and the Required Actions taken. This Note is based on the time required to perform gain adjustments on multiple channels.

A.1 and A.2

Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time (RICT) Program. A Note has been provided to indicate that a RICT is not applicable when trip capability is not maintained.

Because of the diversity of sensors available to provide trip signals and the redundancy of the RPS design, an allowable out of service time of 12 hours has been shown to be acceptable (Ref. 18) to permit restoration of any inoperable channel to OPERABLE status. However, this out of service time is only acceptable provided the associated Function's inoperable channel is in one trip system and the Function still maintains RPS trip capability (refer to Required Actions B.1, B.2, and C.1 Bases). If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel or the associated trip system must be placed in the tripped condition per Required Actions A.1 and A.2. Placing the inoperable channel in trip (or the associated trip system in trip) would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. Alternatively, if it is not desired to place the channel (or trip system) in trip (e.g., as in the case where placing the inoperable channel in trip would result in a full scram), Condition D must be entered and its Required Action taken.

B.1 and B.2

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

Required Actions B.1 and B.2 limit the time the RPS scram logic, for any Function, would not accommodate single failure in both trip systems (e.g., one-out-of-one and one-out-of-one arrangement for a

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

typical four channel Function). The reduced reliability of this logic arrangement was not evaluated in Reference 18 for the 12 hour Completion Time. Within the 6 hour allowance, the associated Function will have all required channels OPERABLE or in trip (or any combination) in one trip system.

Completing one of these Required Actions restores RPS to a reliability level equivalent to that evaluated in Reference 18, which justified a 12 hour allowable out of service time as presented in Condition A. The trip system in the more degraded state should be placed in trip or, alternatively, all the inoperable channels in that trip system should be placed in trip (e.g., a trip system with two inoperable channels could be in a more degraded state than a trip system with four inoperable channels if the two inoperable channels are in the same Function while the four inoperable channels are all in different Functions). The decision of which trip system is in the more degraded state should be based on prudent judgment and take into account current plant conditions (i.e., what MODE the plant is in). If this action would result in a scram, it is permissible to place the other trip system or its inoperable channels in trip.

Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time (RICT) Program. A Note has been provided to indicate that a RICT is not applicable when trip capability is not maintained.

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

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

C.1

Required Action C.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same trip system for the same Function result in the Function not maintaining RPS trip capability. A Function is considered to be maintaining RPS trip capability when sufficient channels are OPERABLE or in trip (or the associated trip system is in trip), such that both trip systems will generate a trip signal from the given Function on a valid signal. For the typical Function with one-out-of-two taken twice logic and the IRM and

(continued)

BASES

ACTIONS

A.1 (continued)

allowed for a limited time with one channel inoperable. If the inoperable channel cannot be restored to OPERABLE status within the Completion Time, the channel must be placed in the tripped condition per Required Action A.1. Placing the inoperable channel in trip would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue with no further restrictions. Alternately, if it is not desired to place the channel in trip (e.g., as in the case where placing the inoperable channel in trip would result in a feedwater or main turbine trip), Condition C must be entered and its Required Action taken.

Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time (RICT) Program. A Note has been provided to indicate that a RICT is not applicable when trip capability is not maintained.

~~The Completion Time of 7 days is based on the low probability of the event occurring coincident with a single failure in a remaining OPERABLE channel.~~

B.1

With two or more channels inoperable, the feedwater and main turbine high water level trip instrumentation cannot perform its design function (feedwater and main turbine high water level trip capability is not maintained). Therefore, continued operation is only permitted for a 2 hour period, during which feedwater and main turbine high water level trip capability must be restored. The trip capability is considered maintained when sufficient channels are OPERABLE or in trip such that the feedwater and main turbine high water level trip logic will generate a trip signal on a valid signal. This requires two channels to each be OPERABLE or in trip. If the required channels cannot be restored to OPERABLE status or placed in trip, Condition C must be entered and its Required Action taken.

The 2 hour Completion Time is sufficient for the operator to take corrective action, and takes into account the likelihood of an event requiring actuation of feedwater and main turbine high water level trip instrumentation occurring during this period. It is also consistent with the 2 hour Completion Time provided in LCO 3.2.2 for Required Action A.1, since this instrumentation's purpose is to preclude a MCPR violation.

(continued)

BASES (continued)

ACTIONS

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

A.1 and A.2

With one or more channels inoperable, but with ATWS-RPT capability for each Function maintained (refer to Required Action B.1 Bases), the ATWS-RPT System is capable of performing the intended function. However, the reliability and redundancy of the ATWS-RPT instrumentation is reduced, such that a single failure in the same 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 both Functions, and the low probability of an event requiring the initiation of ATWS-RPT, 14 days is provided to restore the inoperable channel (Required Action A.1). Alternately, the inoperable channel may be placed in trip (Required Action A.2), since this would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. As noted, placing the channel in trip with no further restrictions is not allowed if the inoperable channel is the result of an inoperable breaker, since this may not adequately compensate for the inoperable breaker (e.g., the breaker may be inoperable such that it will not open). If it is not desired to place the channel in trip (e.g., as in the case where placing the inoperable channel 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.

Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time (RICT) Program. A Note has been provided to indicate that a RICT is not applicable when trip capability is not maintained.

(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 Functions 2.e and 2.h, since these Functions provide backup to administrative controls ensuring that operators do not divert LPCI flow from injecting into the core when needed, and do not spray the containment unless needed. Thus, a total loss of Function 2.e or 2.h 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 a redundant feature in the same system (e.g., both CS subsystems) cannot be automatically initiated due to inoperable, untripped channels within the same Function as described in the paragraph above. For Required Action B.2, the Completion Time only begins upon discovery that the HPCI System cannot be automatically initiated due to two inoperable, untripped channels for the associated Function in the same trip system. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time (RICT) Program. A Note has been provided to indicate that a RICT is not applicable when trip capability is not maintained.

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. 7) to permit restoration of any inoperable channel to OPERABLE status. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be placed in the tripped condition per Required Action B.3. Placing the inoperable channel in trip would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue.

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." For Required Action 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.

Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time (RICT) Program. A Note has been provided to indicate that a RICT is not applicable when trip capability is not maintained.

~~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. 7) to permit restoration of any inoperable channel to OPERABLE status.~~ If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, Condition H must be entered and its Required Action taken. The Required Actions do not allow placing the channel in trip since this action would either cause the initiation or it would not necessarily result in a safe state for the channel in all events.

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

Required Action D.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same Function result in a complete loss of automatic component initiation capability for the HPCI System. Automatic component initiation capability is lost if two Function 3.d channels associated with one CST or two Function 3.e channels are inoperable and untripped. In this situation (loss of automatic suction swap), the 24 hour allowance of Required Actions D.2.1 and D.2.2 is not appropriate and the HPCI System must be declared inoperable within 1 hour after discovery of loss of HPCI initiation capability. As noted, Required Action D.1 is only applicable if the HPCI pump suction is not aligned to the suppression pool, since, if aligned, the Function is already performed.

(continued)

BASES

ACTIONS

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

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

Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time (RICT) Program. A Note has been provided to indicate that a RICT is not applicable when trip capability is not maintained.

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. 7) to permit restoration of any inoperable channel to OPERABLE status. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be placed in the tripped condition per Required Action D.2.1 or the suction source must be aligned to the suppression pool per Required Action D.2.2. Placing the inoperable channel in trip performs the intended function of the channel (shifting the suction source to the suppression pool). Performance of either of these two Required Actions will allow operation to continue. If Required Action D.2.1 or D.2.2 is performed, measures should be taken to ensure that the HPCI System piping remains filled with water. Alternately, if it is not desired to perform Required Actions D.2.1 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.

within 24 hours

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 and the Core Spray Pump Discharge Pressure—High Functions result in redundant automatic initiation capability being lost for the feature(s). For Required Action E.1, the features would be those that are initiated by Functions 1.e, 1.f, and 2.g (e.g., low pressure ECCS). Redundant automatic initiation capability is lost if (a) two Function 1.e channels are inoperable, (b) two Function 1.f channels are

(continued)

BASES

ACTIONS

E.1 and E.2 (continued)

inoperable, (c) two Function 2.g channels are inoperable, or (d) one Function 1.e channel and one Function 1.f channel associated with different CS pumps are inoperable. Since each inoperable channel would have Required Action E.1 applied separately (refer to ACTIONS Note), each inoperable channel would only require the affected low pressure ECCS pump 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.

Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time (RICT) Program. A Note has been provided to indicate that a RICT is not applicable when trip capability is not maintained.

In this situation (loss of redundant automatic initiation capability), the 7 day allowance of Required Action E.2 is not appropriate and the subsystem associated with each inoperable channel must be declared inoperable within 1 hour. 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 Functions 3.f and 3.g 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 7 and considered acceptable for the 7 days allowed by Required Action E.2.

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock."

For Required Action E.1, the Completion Time only begins upon discovery that a redundant feature in the same system (e.g., both CS subsystems) cannot be automatically initiated due to inoperable channels within the same Function as described in the paragraph above. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration of channels.

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

(continued)

BASES

ACTIONS

F.1 and F.2 (continued)

allowing time for restoration or tripping of channels.

Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time (RICT) Program. A Note has been provided to indicate that a RICT is not applicable when trip capability is not maintained.

Because of the diversity of sensors available to provide initiation signals and the redundancy of the ECCS design, an allowable out of service time of 8 days has been shown to be acceptable (Ref. 7) to permit restoration of any inoperable channel to OPERABLE status if both HPCI and RCIC are OPERABLE. If either HPCI or RCIC is inoperable, the time is shortened to 96 hours. If the status of HPCI or RCIC changes such that the Completion Time changes from 8 days to 96 hours, the 96 hours begins upon discovery of HPCI or RCIC inoperability. However, the total time for an inoperable, untripped channel cannot exceed 8 days. If the status of HPCI or RCIC changes such that the Completion Time changes from 96 hours to 8 days, the "time zero" for beginning the 8 day "clock" begins upon discovery of the inoperable, untripped channel. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be placed in the tripped condition per Required Action F.2. Placing the inoperable channel in trip would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue. Alternately, if it is not desired to place the channel in trip (e.g., as in the case where placing the inoperable channel in trip would result in an initiation), Condition H must be entered and its Required Action taken.

or in accordance with the Risk Informed Completion Time (RICT) Program.

G.1 and G.2

Required Action G.1 is intended to ensure that appropriate actions are taken if multiple, inoperable channels within similar ADS trip system Functions result in automatic initiation capability being lost for the ADS. Automatic initiation capability is lost if either (a) one Function 4.b channel and one Function 5.b channel are inoperable, or (b) a combination of Function 4.d, 4.e, 5.d, and 5.e channels are inoperable such that channels associated with five or more low pressure ECCS pumps are inoperable.

In this situation (loss of automatic initiation capability), the 96 hour or 8 day allowance, as applicable, of Required Action G.2 is not appropriate, and all ADS valves must be declared inoperable within 1 hour after discovery of loss of ADS initiation capability.

(continued)

BASES

ACTIONS

G.1 and G.2 (continued)

The Completion Time is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This Completion Time also allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." For Required Action G.1, the Completion Time only begins upon discovery that the ADS cannot be automatically initiated due to inoperable channels within similar ADS trip system Functions as described in the paragraph above. The 1 hour Completion Time from discovery of loss of initiation capability is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time (RICT) Program. A Note has been provided to indicate that a RICT is not applicable when trip capability is not maintained.

Because of the diversity of sensors available to provide initiation signals and the redundancy of the ECCS design, an allowable out of service time of 8 days has been shown to be acceptable (Ref. 7) to permit restoration of any inoperable channel to OPERABLE status if both HPCI and RCIC are OPERABLE (Required Action G.2). If either HPCI or RCIC is inoperable, the time shortens to 96 hours. If the status of HPCI or RCIC changes such that the Completion Time changes from 8 days to 96 hours, the 96 hours begins upon discovery of HPCI or RCIC inoperability. However, the total time for an inoperable channel cannot exceed 8 days. If the status of HPCI or RCIC changes such that the Completion Time changes from 96 hours to 8 days, the "time zero" for beginning the 8 day "clock" begins upon discovery of the inoperable channel. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, Condition H must be entered and its Required Action taken. The Required Actions do not allow placing the channel in trip since this action would not necessarily result in a safe state for the channel in all events.

or in accordance with the Risk Informed Completion Time (RICT) Program.

H.1

With any Required Action and associated Completion Time not met, the associated feature(s) may be incapable of performing the intended function, and the supported feature(s) associated with inoperable untripped channels must be declared inoperable immediately.

(continued)

BASES

ACTIONS

B.1 and B.2 (continued)

Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time (RICT) Program. A Note has been provided to indicate that a RICT is not applicable when trip capability is not maintained.

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. 3) to permit restoration of any inoperable channel to OPERABLE status. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be placed in the tripped condition per Required Action B.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. 3) is acceptable to permit restoration of any inoperable channel to OPERABLE status (Required Action C.1). A Required Action (similar to Required Action B.1) limiting the allowable out of service time, if a loss of automatic RCIC initiation capability exists, is not required. This Condition applies to the Reactor Vessel Water Level—High (Level 8) Function whose logic is arranged such that any inoperable channel will result in a loss of automatic RCIC initiation capability due to closure of the RCIC steam inlet valve. As stated above, this loss of automatic RCIC initiation capability was analyzed and determined to be acceptable. This Condition also applies to the Manual Initiation Function. Since this Function is not assumed in any accident or transient analysis, a total loss of manual initiation capability (Required Action C.1) for 24 hours

is allowed. 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

(continued)

BASES

ACTIONS

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

only associated feature. In this case, automatic initiation capability (automatic suction source alignment) is lost if two Function 3 channels associated with the same CST are inoperable and untripped. In this situation (loss of automatic suction source alignment), 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 suction source cannot be automatically aligned to the suppression pool due to two inoperable, untripped channels in the same Function. The 1 hour Completion Time from discovery of loss of initiation capability (automatic suction source alignment) is acceptable because it minimizes risk while allowing time for restoration or tripping of channels.

Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time (RICT) Program. A Note has been provided to indicate that a RICT is not applicable when trip capability is not maintained.

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. 3) to permit restoration of any inoperable channel to OPERABLE status. If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be placed in the tripped condition per Required Action D.2.1, which performs the intended function of the channel (shifting the suction source to the suppression pool). Alternatively, Required Action D.2.2 allows the manual alignment of the RCIC suction to the suppression pool, which also performs the intended function. If Required Action D.2.1 or D.2.2 is performed, measures should be taken to ensure that the RCIC System piping remains filled with water. If it is not desired to perform Required Actions D.2.1 and D.2.2 (e.g., as in the case where shifting the suction source could drain down the RCIC suction piping), Condition E must be entered and its Required Action taken.

within 24 hours

(continued)

BASES

ACTIONS (continued)

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

A.1

Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time (RICT) Program. A Note has been provided to indicate that a RICT is not applicable when trip capability is not maintained.

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, 2.d, 2.g, 5.e, 5.f, 6.b, 7.a and 7.b (which have components common to RPS) and 24 hours for Functions other than Functions 2.a, 2.b, 2.d, 2.g, 5.e, 5.f, 6.b, 7.a and 7.b has been shown to be acceptable (Refs. 6 and 7) to permit restoration of any inoperable channel to OPERABLE status. This out of service time is only acceptable provided the associated Function is still maintaining isolation capability (refer to Required Action B.1 Bases). If the inoperable channel cannot be restored to OPERABLE status within the allowable out of service time, the channel must be placed in the tripped condition per Required Action A.1. Placing the inoperable channel in trip would conservatively compensate for the inoperability, restore capability to accommodate a single failure, and allow operation to continue 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.

Required Action B.1 is intended to ensure that appropriate actions are taken if multiple, inoperable, untripped channels within the same Function result in redundant isolation capability being lost for the associated penetration flow path(s). The MSL Isolation Functions (associated with MSIV isolation) are considered to be maintaining isolation capability when sufficient channels are OPERABLE or in trip (or the associated trip system 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

(continued)

BASES

ACTIONS

A.1 and A.2 (continued)

Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time (RICT) Program. A Note has been provided to indicate that a RICT is not applicable when trip capability is not maintained.

(Required Action A.1). Alternately, the inoperable channel, or associated trip system, 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 isolation valve, since this may not adequately compensate for the inoperable valve (e.g., the valve may be inoperable such that it will not isolate). 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 loss of condenser vacuum), or if the inoperable channel is the result of an inoperable valve, Condition B 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 result in the Function not maintaining condenser air removal pump isolation capability. The Function is considered to be maintaining condenser air removal pump isolation capability when sufficient channels are OPERABLE or in trip such that the condenser air removal pump isolation instruments will generate a trip signal from a valid Main Steam Line Radiation-High signal, and at least one isolation valve will close. This requires one channel of the Function in each trip system to be OPERABLE or in trip, and one condenser air removal pump isolation valve to be OPERABLE.

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

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

With any Required Action and associated Completion Time of Condition A or B not met, the plant must be brought to a MODE or other specified condition in which the LCO does not apply. To achieve this status, the plant must be brought to

(continued)

BASES

ACTIONS

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

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.

or in accordance with the Risk Informed Completion Time (RICT) Program. A Note has been provided to indicate that a RICT is not applicable if leakage exceeds limits or if loss of function.

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

Additionally, the air lock must be restored to OPERABLE status within 24 hours (Required Action C.3). The 24 hour Completion Time is reasonable for restoring an inoperable air lock to OPERABLE status considering that at least one door is maintained closed in each affected 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. This SR reflects the leakage rate testing requirements with regard to air lock leakage (Type B leakage tests). The acceptance criteria were approved in License Amendment 97 (Ref. 3). Subsequently, License Amendment 261 (Ref. 4) allowed an increased overall air lock leakage rate (i.e., Amendment 261 increased the value of L_a; therefore, the overall air lock

(continued)

BASES

ACTIONS

C.1 and C.2 (continued)

devices to be verified closed by use of administrative means. Allowing verification by administrative means is considered acceptable, since the function of locking, sealing, or securing components is to ensure that these devices are not inadvertently repositioned. Therefore, the probability of misalignment, once they have been verified to be in the proper position, is low.

D.1

With any MSIV leakage rate not within limit, the assumptions of the safety analysis may not be met. Therefore, the leakage must be restored to within limit within 8 hours. Restoration can be accomplished by isolating the penetration that caused the limit to be exceeded by use of one closed and de-activated automatic valve, closed manual valve, or blind flange. When a penetration is isolated, the leakage rate for the isolated penetration is assumed to be the actual pathway leakage through the isolation device. If two isolation devices are used to isolate the penetration, the leakage rate is assumed to be the lesser actual pathway leakage of the two devices. The 8 hour Completion Time is reasonable considering the time required to restore the leakage by isolating the penetration, the fact that MSIV closure will result in isolation of the main steam line(s) and a potential for plant shutdown, and the relative importance of MSIV leakage to the overall containment function.

Alternatively, a Completion Time can be determined in accordance with the Risk Informed Completion Time (RICT) Program. A Note has been provided to indicate that a RICT is not applicable if leakage exceeds limits or if loss of function.

E.1

With the one or more penetration flow paths with LPCI System or CS System air operated testable check valve leakage rate not within limits, the assumptions of the safety analysis may not be met. Therefore, the leakage must be restored to within limit within 72 hours. Restoration can be accomplished by isolating the penetration that caused the limit to be exceeded by use of one closed and de-activated automatic valve, or closed manual valve. When a penetration is isolated, the leakage rate for the isolated penetration is assumed to be the actual pathway leakage through the isolation device. If two isolation devices are used to isolate the penetration, the leakage rate is assumed to be the lesser actual pathway leakage of the two devices. The 72 hour Completion Time is reasonable considering the time required to restore the leakage and the importance to maintain these penetrations available to perform the required function during a design basis accident.

(continued)