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

Brunswick Steam Electric Plant, Unit Nos. 1 and 2
Renewed Facility Operating License Nos. DPR-71 and DPR-62
Docket Nos. 50-325 and 50-324

Subject: Supplement to 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"

References:

1. Letter from J. A. Krakuszeski (Duke Energy Progress, 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 April 1, 2021 (ADAMS Accession No. ML21091A053).

2. Letter from J. A. Krakuszeski (Duke Energy Progress, LLC) to U.S. Nuclear Regulatory Commission, "Supplement to 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 April 26, 2021 (ADAMS Accession No. ML21116A161).

3. E-mail from W. Jessup (U.S. Nuclear Regulatory Commission) to J. L. Vaughan (Duke Energy), "RE: List of Items to be Docketed for Brunswick TSTF-505," dated September 30, 2021.

Ladies and Gentlemen:

By letter dated April 1, 2021 (Reference 1), as supplemented by letter dated April 26, 2021 (Reference 2), Duke Energy Progress, LLC (Duke Energy) requested an amendment to the Brunswick Steam Electric Plant (BSEP), Unit Nos. 1 and 2 Technical Specifications (TS). The proposed amendment would modify TS requirements to permit the use of Risk-Informed Completion Times in accordance with TSTF-505, Revision 2, "Provide Risk-Informed Extended Completion Times – RITSTF [Risk-Informed TSTF] Initiative 4b," (ADAMS Accession No. ML18183A493).

By e-mail dated September 30, 2021 (Reference 3), the Nuclear Regulatory Commission (NRC) provided a list of questions to Duke Energy delineating information that would need to be docketed in support of the NRC staff's review of the proposed amendment. The NRC staff's list of questions was developed and finalized during a regulatory audit in September 2021.

The Enclosure provides Duke Energy's responses to select regulatory audit questions. Attachments 1 and 2 provide revised TS markups for BSEP that entirely supersede the markups provided in References 1 and 2. Attachment 3 provides a revised Table E1-1, "In-Scope TS Actions to Corresponding PRA Functions" that supersedes Table E1-1 in Reference 1. Attachment 3 also includes four new sub-tables that provide additional information regarding the design success criteria for instrumentation TS proposed to be in scope of the Risk-Informed Completion Time (RICT) Program.

Duke Energy has reviewed the information supporting the No Significant Hazards Consideration and the Environmental Consideration that was previously provided to the NRC in Reference 1. The additional information provided in this license amendment request (LAR) supplement does not impact the conclusion that the proposed license amendment does not involve a significant hazards consideration. Additionally, the information does not impact the conclusion that there is no need for an environmental assessment to be prepared in support of the proposed amendment.

There are no regulatory commitments made in this submittal.

In accordance with 10 CFR 50.91, Duke Energy is notifying the State of North Carolina of the supplement to this LAR by transmitting a copy of this letter and enclosure to the designated State Official.

Please refer any questions regarding this submittal to Mr. Lee Grzeck, Manager – Nuclear Fleet Licensing, at (980) 373-1530.

I declare, under penalty of perjury, that the foregoing is true and correct. Executed on November 1, 2021.

Sincerely,

John A. Krakuszeski

JLV/jlv

Enclosure: Supplemental Information

Attachments:

1. Proposed Technical Specification Changes (Mark-Up) – Unit 1
2. Proposed Technical Specification Changes (Mark-UP) – Unit 2
3. Revised Table E1-1, "In-Scope TS Actions to Corresponding PRA Functions"

cc:

Ms. Laura Dudes, Regional Administrator, Region II
Mr. Andrew Hon, Project Manager
Mr. Gale Smith, NRC Senior Resident Inspector

Chair - North Carolina Utilities Commission
Mr. David Crowley, Radioactive Materials Branch Manager, Radiation Protection Section, NC DHHS

ENCLOSURE

SUPPLEMENTAL INFORMATION

NOTE: The NRC staff's questions are in italics throughout this enclosure to distinguish from the Duke Energy responses.

Probabilistic Risk Assessment (PRA) Licensing Branch A Internal Events PRA Questions

APLA Q1 – Instrumentation and Controls Modeling in the probabilistic risk assessment (PRA)

The U.S. Nuclear Regulatory Commission (NRC) Safety Evaluation Report (SER) for Nuclear Energy Institute (NEI) Topical Report NEI 06-09 specifies that the License Amendment Request (LAR) for a Risk Informed Completion Time (RICT) program should provide a comparison of the Technical Specification (TS) functions to the PRA modeled functions and that justification should be provided to show that the scope of the PRA model is consistent with the licensing basis assumptions.

Table E1-1 in Enclosure 1 of the LAR identifies the TS Limiting Conditions for Operations (LCOs) and corresponding Conditions proposed to be included in the RICT program and describes how the structures, systems and components (SSCs) covered in the TS LCO are implicitly or explicitly modeled in the PRA. For certain TS LCO Conditions, the table explains that the associated SSCs are not modeled in the PRAs but will be conservatively represented using a surrogate event.

For several TS LCO Conditions, Table E1-1 indicates that instrumentation and control (I&C) detail in existing PRA models is insufficient to explicitly model the Condition. In these cases, the LAR indicates that the inoperability of the associated SSC (e.g., channel) will therefore be modeled using a surrogate event. For other TS LCO Conditions in the RICT program, it is not clear to the NRC staff whether I&C is always modeled in sufficient detail to support implementation of Technical Specifications Task Force (TSTF) Traveler 505 (TSTF 505), based on documentation in the LAR. Address the following points regarding I&C modeling in the PRA that supports the proposed RICT program:

a. *For certain TS LCO Conditions, LAR Table E1-1 states "SSCs are modeled consistently with the TS scope…" but it does not provide any additional details. For these conditions discuss the following:*

    i. *Scope of the I&C SSCs that are explicitly included in the PRA (e.g., bistables, relays, sensors, integrated circuit cards).*

    ii. *Description of the level of detail modeled (e.g., Are all channels of an actuation circuit modeled?).*

    iii. *Discussion of what data are used and whether plant specific data are used.*

    iv. *Discussion of the associated TS functions for which a RICT can be applied.*

b. *Table E9-1 in Enclosure 9 to the LAR identifies digital feedwater water control system modeling as a potential key source of uncertainty (Item #12). This uncertainty was dispositioned with a sensitivity study. However, it is not clear to the NRC staff whether there are other digital systems (e.g., steam leak detection modules, reactor recirculation speed controls) that are credited in the BNP's PRA.*

i. *Confirm that no other digital I&C systems are credited in the PRA models that will be used in the RICT program beyond the feedwater control system.*

ii. *If other digital I&C systems are credited in the PRA models that will be used in the RICT program, then:*

1. *Identify those systems and provide the results of a sensitivity study on the SSCs in the RICT program demonstrating that the uncertainty associated with modeling digital I&C systems has inconsequential impacts on the RICT calculations.*

2. *Alternatively, identify which LCOs are determined to be impacted by the digital I&C system modeling for which risk management actions (RMAs) will be applied during a RICT. Explain and justify the criteria used to determine what level of impact to the RICT calculation required additional RMAs.*

c. *For TS LCO 3.3.5.1 (Emergency Core Cooling System (ECCS) Instrumentation) Conditions E and F concerning the Automatic Depressurization System (ADS) Trip System, Table E1-1 states that the ADS system instrumentation is not modeled in detail in the PRA, and therefore, a surrogate will be used that represents failure to depressurize the reactor.*

Explain further the surrogate proposed to model TS LCO 3.3.5.1 Conditions E and F and explain how the surrogate depressurization function modeled is appropriate for accident sequences.

d. *For TS LCO 3.3.5.2 (Reactor Core Isolation Cooling (RCIC) Instrumentation) Condition B, Table E1-1 states that the individual elements of the RCIC initiation logic are not incorporated in the BNP PRA model. The table further states multiple surrogates that represent common cause failure of the RCIC initiation system would be utilized.*

Explain further what component failures will be used as a surrogate to model TS LCO 3.3.5.2 Condition B. Include in this discussion how the surrogate method modeled is appropriate for accident sequences.

e. *For LCO 3.3.6.1 (Primary Containment Isolation (PCI) Instrumentation) Condition A, Table E1-1 states that the associated SSCs are not modeled in the PRA and proposes to use a surrogate event that represents failure of the PCI electrical system. The functions covered by this condition operate differently in response to failures of the electrical systems that power the instrumentation logic circuits (e.g., loss of power results in isolation for the Reactor Water Cleanup (RWCU) system, loss of power results in an inability to isolate for the RCIC system).*

Describe how the generic electrical system failure surrogate applies to all the functions covered by this condition, given that the various functions operate differently in response to failure of the electrical system.

Duke Energy Response to APLA Q1, Part 1.a.i

In general, scope of the I&C SSCs that are explicitly included in the PRA includes: Transmitters (sensors), Master trip units (bistables), relays. For the suppression pool level logic and the Condensate Storage Tank (CST) level logic only the level switches and associated relays are modeled.

Duke Energy Response to APLA Q1, Part 1.a.ii

For those I&C SSCs that are explicitly included in the PRA, all channels of an actuation circuit are modeled.

Technical Specification Condition	Function	i. Scope of the I&C SSCs that are explicitly included in the PRA	ii. Description of the level of detail modeled
TS 3.3.2.2 Condition A	-	Transmitters (sensors), Master trip units (bistables), relays	All channels of an actuation circuit modeled
TS 3.3.4.1 Condition A	-	Transmitters (sensors), Master trip units (bistables), relays	All channels of an actuation circuit modeled
TS 3.3.5.1 Condition B	Function 1.a	Transmitters (sensors), Master trip units (bistables), relays	All channels of an actuation circuit modeled
	Function 2.a	Transmitters (sensors), Master trip units (bistables), relays	All channels of an actuation circuit modeled
	Function 1.b	Transmitters (sensors), Master trip units (bistables), relays	All channels of an actuation circuit modeled
	Function 2.b	Transmitters (sensors), Master trip units (bistables), relays	All channels of an actuation circuit modeled
	Function 3.a	Transmitters (sensors), Master trip units (bistables), relays	All channels of an actuation circuit modeled
	Function 3.b	Transmitters (sensors), Master trip units (bistables), relays	All channels of an actuation circuit modeled
	Function 2.e	*Modeled in PRA by surrogate*	
TS 3.3.5.1 Condition C	Function 1.c	Transmitters (sensors), Master trip units (bistables), relays	All channels of an actuation circuit modeled
	Function 1.d	Relays	All channels of an actuation circuit modeled
	Function 2.c	Transmitters (sensors), Master trip units (bistables), relays	All channels of an actuation circuit modeled
	Function 2.d	Transmitters (sensors), Master trip units (bistables), relays	All channels of an actuation circuit modeled
	Function 2.f	Relays	All channels of an actuation circuit modeled
	Function 3.c	Transmitters (sensors), Master trip units (bistables), relays	All channels of an actuation circuit modeled

Technical Specification Condition	Function	i. Scope of the I&C SSCs that are explicitly included in the PRA	ii. Description of the level of detail modeled
TS 3.3.5.1 Condition D	Function 3.d	Level switches, relays	All channels of an actuation circuit modeled
	Function 3.e	Level switches, relays	All channels of an actuation circuit modeled
TS 3.3.5.1 Condition E	*Modeled in PRA by surrogate*		
TS 3.3.5.1 Condition F	*Modeled in PRA by surrogate*		
TS 3.3.5.2 Condition B	Function 1	Transmitters (sensors), Master trip units (bistables), relays	All channels of an actuation circuit modeled
TS 3.3.5.2 Condition D	Function 3	Level switches, relays	All channels of an actuation circuit modeled
TS 3.3.6.1 Condition A	*Modeled in PRA by surrogate*		

Duke Energy Response to APLA Q1, Part 1.a.iii

The I&C SSC failure rate data used in the Brunswick Nuclear Plant (BNP) PRA is taken from the NRC Industry Average Parameter Estimates, the NRC updated data to NUREG/CR-6928, for component failure rates and the NRC Common Cause Database, if available. For those reliability type codes which are not captured by the NRC Industry Average Parameter Estimates or the NUREG/CR-6928 data due to differences in failure modes or type code boundaries, BNP uses a database based on an aggregation of multiple available data sources, including other NUREGs and various PRAs across the industry, aggregated to generate a failure probability (integrated data from multiple sources into a single data set). Plant specific data was not used in the development of the I&C SSC failure rates.

Duke Energy Response to APLA Q1, Part 1.a.iv

TS 3.3.2.2 Condition A (Feedwater and Main Turbine High Water Level Trip Instrumentation: One feedwater and main turbine high water level trip channel inoperable)

The function associated with TS 3.3.2.2, Condition A for which a RICT can be applied is to provide a trip of the two feedwater pump turbines and the main turbine during an excessive feedwater flow event. This high-water level trip function indirectly initiates a reactor scram from the main turbine and trips the feedwater pumps, thereby terminating the event. The reactor scram mitigates the reduction in Minimum Critical Power Ratio and increase in Linear Heat Generation Rate.

TS 3.3.4.1 Condition A (ATWS Recirculation Pump Trip Instrumentation: One or more channels inoperable)

The function associated with TS 3.3.4.1, Condition A for which a RICT can be applied is the initiation of a recirculation pump trip following events in which a scram does not, but should, occur. This insertion of negative reactivity lessens the effects of an Anticipated Transient Without Scram (ATWS) event (preserves the integrity of the fuel cladding). Tripping the recirculation pump adds negative reactivity from the increase in steam voiding in the core area as core flow decreases. When the Reactor Vessel Water Level – Low Level 2 or Reactor Vessel Pressure – High setpoint is reached, the recirculation pump drive motor breakers trip.

The ATWS recirculation pump trip instrumentation is not assumed to mitigate any accident or transient in the safety analysis; however, its inclusion in the Technical Specifications was based on its contribution to the reduction of overall plant risk (i.e., 10 CFR 50.36(c)(2)(ii)).

TS 3.3.5.1 Condition B (ECCS Instrumentation) – Functions 1.a, 2.a, 1.b, 2.b, 3.a, 3.b, 2.e

In general, the function associated with TS 3.3.5.1, Condition B for which a RICT can be applied is to initiate appropriate responses from various systems (Core Spray, Low Pressure Coolant Injection (LPCI), High Pressure Coolant Injection (HPCI), ADS, Diesel Generators) to ensure that the fuel is adequately cooled in the event of a design basis accident or transient.

Functions 1.a, 2.a Reactor Vessel Water Level – Low Level 3

With respect to the "Reactor Vessel Water Level – Low Level 3" function, the ECCS and associated diesel generators are initiated at this water level to ensure that core spray and flooding functions are available to prevent or minimize fuel damage. The core cooling function of the ECCS that is initiated by this instrumentation ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

Function 1.b, 2.b Drywell Pressure – High (Core Spray System and LPCI System)

Receipt of the Drywell Pressure – High Function (coincident with receipt of the Reactor Steam Dome Pressure- Low Function) initiates the low pressure ECCS and associated diesel generators in order to minimize the possibility of fuel damage when there is high pressure in the drywell. The core cooling function of the ECCS that is initiated by this instrumentation ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

Function 3.a Reactor Vessel Water Level – Low Level 2 (HPCI System)

The Reactor Vessel Water Level – Low Level 2 Function is capable of initiating HPCI during the transients described in Section 6.3 (ECCS) of the Brunswick UFSAR.

Function 3.b Drywell Pressure – High (HPCI System)

Receipt of the Drywell Pressure – High Function initiates the HPCI System in order to minimize the possibility of ADS actuation. The Drywell Pressure- High Function is not assumed in accident or transient analyses.

Function 2.e Reactor Vessel Shroud Level (LPCI System) [Modeled in PRA by surrogate]

The Reactor Vessel Shroud Level Function is provided as a permissive to allow the RHR System to be manually aligned from the LPCI mode to the suppression pool cooling/spray or drywell spray modes. The permissive ensures that water in the vessel is at least two thirds core height before the manual transfer is allowed, which in turn ensures that LPCI is available to prevent or minimize fuel damage.

<u>TS 3.3.5.1 Condition C (ECCS Instrumentation) – Functions 1.c, 1.d, 2.c, 2.d, 2.f, 3.c</u>

In general, the function associated with TS 3.3.5.1, Condition C for which a RICT can be applied is to initiate appropriate responses from various systems (Core Spray, LPCI, HPCI, ADS, Diesel Generators) to ensure that the fuel is adequately cooled in the event of a design basis accident or transient.

Function 1.c, 2.c Reactor Steam Dome Pressure – Low (Core Spray System and LPCI System)

The Reactor Steam Dome Pressure – Low is one of the Functions capable of permitting initiation of the ECCS and associated diesel generators during the transients analyzed in Section 6.3 (ECCS) of the Brunswick UFSAR. The core cooling function of the ECCS that is initiated by this instrumentation ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46. Low reactor steam dome pressure signals are used as permissives for the low pressure ECCS subsystems to ensure that, prior to opening the injection valves, the reactor pressure has fallen to a value below the subsystems' maximum design pressure. The low reactor steam dome pressure signals are also used in the Drywell Pressure – High logic circuits to distinguish high drywell pressure caused by a Loss of Coolant Accident (LOCA) from that caused by loss of drywell cooling.

Function 1.d, 2.f Core Spray and RHR Pump Start – Time Delay Relays (Core Spray System and LPCI System)

The purpose of the Core Spray and RHR pump start time delay relays is to stagger the start of the Core Spray and RHR pumps that are in each of Divisions I and II, thus limiting the starting transients on the 4.16 kV emergency buses. These time delay Functions for which a RICT can be applied are necessary when power is being supplied from either the normal power sources (offsite power) or the standby power sources (diesel generators). The accident and transient analyses assume that the pumps will initiate when required and excess loading will not cause failure of the power sources.

Function 2.d Reactor Steam Dome Pressure – Low (Recirculation Pump Discharge Valve Permissive)

Low reactor steam dome pressure signals are used as permissives for recirculation pump discharge valve closure and recirculation pump discharge bypass valve closure. This ensures that the LPCI subsystems inject into the proper Reactor Pressure Vessel location assumed in the safety analysis. The Reactor Steam Dome Pressure – Low Function is capable of closing the valve(s) during the transients analyzed in Section 6.3 (ECCS) of the Brunswick UFSAR.

The core cooling function of the ECCS ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

Function 3.c Reactor Vessel Water Level – High (HPCI System)

The function of Reactor Vessel Water Level – High for which a RICT can be applied is to trip the HPCI turbine to prevent overflow into the main steam lines, which precludes an unanalyzed event.

<u>TS 3.3.5.1 Condition D (ECCS Instrumentation) – Functions 3.d, 3.e</u>

In general, the function associated with TS 3.3.5.1, Condition D for which a RICT can be applied is to initiate appropriate responses from various systems (Core Spray, LPCI, HPCI, ADS, Diesel Generators) to ensure that the fuel is adequately cooled in the event of a design basis accident or transient.

Function 3.d Condensate Storage Tank Level – Low (HPCI System)

The function of Condensate Storage Tank Level – Low for which a RICT can be applied is to ensure, upon the water level in the CST falling below a preselected level, that the suppression pool suction valves automatically open and the CST suction valve automatically closes. This ensures that an adequate supply of makeup water is available to the HPCI pump.

Function 3.e Suppression Chamber Water Level – High (HPCI System)

The function of Suppression Chamber Water Level – High for which a RICT can be applied is to initiate transferring the suction source of HPCI from the CST to the suppression pool upon high suppression pool water level to eliminate the possibility of HPCI continuing to provide additional water from a source outside containment. The Suppression Chamber Water Level – High Function is assumed to actuate for the small line break events (up to 1” nominal) where HPCI is the preferred event response system.

<u>TS 3.3.5.1 Condition E (ECCS Instrumentation) – Functions 4.a, 4c, 5.a, 5.c</u> [Modeled in PRA by surrogate]

In general, the function associated with TS 3.3.5.1, Condition E for which a RICT can be applied is to initiate an appropriate response from ADS to ensure that the fuel is adequately cooled in the event of a design basis accident or transient.

Function 4.a, 5.a Reactor Vessel Water Level – Low 3 (ADS)

Low RPV water level indicates that the capability to cool the fuel may be threatened. Should RPV water level decrease too far, fuel damage could result. Therefore, ADS receives one of the signals necessary for initiation from this Function. The core cooling function of the ECCS ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

Function 4.c, 5.c Reactor Vessel Water Level – Low Level 1 (ADS)

This Function is used by the ADS as a confirmatory low water level signal. ADS receives one of the signals necessary for initiation from Reactor Vessel Water Level - Low Level 3 signals. In order to prevent spurious initiation of the ADS due to spurious Low Level 3 signals, a Low Level 1 signal must also be received before ADS initiation commences.

TS 3.3.5.1 Condition F (ECCS Instrumentation) – Functions 4.b, 4.d, 4.e, 5.b, 5.d, 5.e [Modeled in PRA by surrogate]

In general, the function associated with TS 3.3.5.1, Condition F for which a RICT can be applied is to initiate an appropriate response from ADS to ensure that the fuel is adequately cooled in the event of a design basis accident or transient.

Function 4.b, 5.b ADS Timer (ADS)

The purpose of the ADS Timer Function is to delay depressurization of the reactor vessel to allow the HPCI System time to maintain reactor vessel water level. By delaying initiation of the ADS Function, there is time to monitor the success or failure of the HPCI System to maintain water level, and then to decide whether or not to allow ADS to initiate, to delay initiation further by recycling the timer, or to inhibit initiation permanently.

Function 4.d, 4.e, 5.d, 5.e Core Spray and RHR (LPCI Mode) Pump Discharge Pressure – High

The Pump Discharge Pressure – High signals from the CS and Resdidual Heat Removal (RHR) pumps are used as permissives for ADS initiation, indicating that there is a source of low pressure cooling water once the ADS has depressurized the vessel. ADS depressurizes the reactor vessel so that the low pressure ECCS can perform the core cooling functions. This core cooling function of the ECCS ensures that the fuel peak cladding temperature remains below the limits of 10 CFR 50.46.

TS 3.3.5.2 Condition B (Reactor Core Isolation Cooling (RCIC) System Instrumentation) – Function 1.

In general, the purpose of the RCIC System instrumentation for which a RICT can be applied is to initiate actions to ensure adequate core cooling when the reactor vessel is isolated from its primary heat sink (the main condenser) and normal coolant makeup flow from the Reactor Feedwater System is insufficient or unavailable, such that RCIC System initiation occurs and maintains sufficient reactor water level. The sufficient water level provided by RCIC System initiation precludes the initiation of the low pressure ECCS pumps.

Function 1. Reactor Vessel Water Level – Low Level 2

Low Reactor Pressure Vessel (RPV) water level indicates that normal feedwater flow is insufficient to maintaint reactor vessel water level. Should RPV water level decrease too far, the RCIC System is initiated at Level 2 to assist in maintaining water level above the top of the active fuel.

<u>TS 3.3.5.2 Condition D (Reactor Core Isolation Cooling (RCIC) System Instrumentation) – Function 3.</u>

In general, the purpose of the RCIC System instrumentation for which a RICT can be applied is to initiate actions to ensure adequate core cooling when the reactor vessel is isolated from its primary heat sink (the main condenser) and normal coolant makeup flow from the Reactor Feedwater System is insufficient or unavailable, such that RCIC System initiation occurs and maintains sufficient reactor water level. The sufficient water level provided by RCIC System initiation precludes the initiation of the low pressure ECCS pumps.

Function 3. Condensate Storage Tank Level – Low

The function of Condensate Storage Tank Level – Low for which a RICT can be applied is to ensure, upon the water level in the CST falling below a preselected level, that the suppression pool suction valves automatically open and the CST suction valve automatically closes. This ensures that an adequate supply of makeup water is available to the RCIC pump.

<u>TS 3.3.6.1 Condition A (Primary Containment Isolation Instrumentation)</u> [Modeled in PRA by surrogate]

In general, the purpose of the Primary Containment Isolation Instrumentation for which a RICT can be applied is to automatically initiate closure of appropriate primary containment isolation valves (PCIVs). The function of the PCIVs, in combination with other accident mitigation systems, is to limit fission product release during and following postulated Design Basis Accidents. Primary containment isolation instrumentation has inputs to the trip logic of several isolation functions listed in Brunswick TS Table 3.3.6.1-1. Each of these isolation functions is further expanded upon in the Brunswick TS 3.3.6.1 Bases.

<u>Duke Energy Response to APLA Q1, Part 1.b.i</u>

Duke Energy confirms that no other digital I&C systems are credited in the PRA models that will be used in the RICT program beyond the feedwater control system.

<u>Duke Energy Response to APLA Q1, Part 1.b.ii</u>

No additional digital systems sensitivity studies are warranted.

<u>Duke Energy Response to APLA Q1, Part 1.c</u>

The BNP PRA currently only credits manual depressurization and thus for TS LCO 3.3.5.1 (Emergency Core Cooling System (ECCS) Instrumentation), Conditions E and F, the surrogate chosen is the basic event representing “Operators failing to depressurize the reactor vessel.” This in effect fails the entire depressurization function in the appropriate accident sequences.

Duke Energy Response to APLA Q1, Part 1.d

Upon further examination, the failure of Reactor Vessel Water Level – Low Level 2 actuation signal is explicitly modeled in the PRA for RCIC initiation. Thus, for this Condition, Table E1-1 is updated in Attachment 3 to reflect that the SCCs are explicitly modeled with the following note: "SSCs are modeled consistently with the TS scope and so can be directly evaluated by the CRMP."

Duke Energy Response to APLA Q1, Part 1.e

The surrogate basic event chosen for LCO 3.3.6.1 (Primary Containment Isolation (PCI) Instrumentation), Condition A represents "FAILURE OF CONTAINMENT ISOLATION SIGNAL." This conservative surrogate basic event does not differentiate what causes the containment isolation signal, but rather simply fails the signal in the PRA.The surrogate is not a 'loss of electrical power' dependency event.

APLA Q2 – System and Surrogate Modeling Used in the PRA Models

The NRC SER for NEI 06-09 specifies that the LAR should provide a comparison of the TS functions to the PRA modeled functions and that justification should be provided to show that the scope of the PRA model is consistent with the licensing basis assumptions. Table E1-1 in Enclosure 1 of the LAR identifies the TS LCOs and corresponding Conditions proposed to be included in the RICT program and describes how the systems and components covered in the TS LCO are implicitly or explicitly modeled in the PRA. For certain TS LCO Conditions, the table explains that the associated SSCs are not modeled in the PRAs but will be conservatively represented using a surrogate event. For some LCOs, the LAR did not provide sufficient information regarding surrogate PRA modeling that will be used in the RICT calculations for NRC staff to assess the acceptability of the surrogate approaches. To address this observation, address the following:

a. Table E1-1 states that the primary containment air lock is not incorporated in the BNP model and a large pre-existing leak failure surrogate will be used in the PRA model to support a RICT for TS LCO 3.6.1.2 (Primary Containment Air Lock) Condition C. It is unclear to the NRC staff what constitutes a large leak and what PRA model function the pre-existing failure would represent.

   Explain further the proposed surrogate to model TS LCO 3.6.1.2 Condition C and discuss how the surrogate is equivalent or bounding for the airlock.

b. Table E1-1 states that not all Primary Containment Isolation Valves (PCIVs) are incorporated in the BNP model and that a pre-existing containment failure surrogate will be used in the PRA model to support a RICT for TS LCO 3.6.1.3 (PCIVs) Condition A. It is unclear to the NRC staff what constitutes a containment failure and what PRA model function the pre-existing failure would represent.

   Explain further the surrogate proposed to model TS LCO 3.6.1.3 Condition A and discuss how the surrogate is equivalent or bounding for the non-modeled PCIVs.

c. *Table E1-1 states that a vapor suppression function surrogate will be used in the PRA model to support a RICT for TS LCO 3.6.1.6 (Suppression Chamber-to-Drywell Vacuum Breakers) Condition A. It is unclear to the NRC staff what constitutes the vapor suppression function and the SSCs associated with this function.*

   Explain further the propose surrogate used to model TS LCO 3.6.1.6 Condition A and discuss how the surrogate vapor suppression function modeled is appropriate for the relevant accident sequences.

Duke Energy Response to APLA Q2, Part a

The surrogate basic event from the PRA Model proposed [CN-2PREEXIST (PRE-EXISTING CONTAINMENT FAILURE)] is equivalent or bounding for the primary containment air lock because it maps directly to a containment isolation failure. Thus, core damage accident sequences which demand the containment be isolated following core damage will progress directly to a large early release because the containment isolation function is failed. In the future, if detailed modeling is developed and goes through the appropriate levels of reviews per the PRA standard, then the intent would be to begin using the explicitly modeled components.

Duke Energy Response to APLA Q2, Part b

The surrogate basic event proposed [CN-2PREEXIST (PRE-EXISTING CONTAINMENT FAILURE)] is equivalent or bounding for the non-modeled PCIVs because the event maps directly to a containment isolation failure. Thus, core damage accident sequences which demand the containment be isolated following core damage will progress directly to a large early release because the containment isolation function is failed. In the future, if detailed modeling is developed and goes through the appropriate levels of reviews per the PRA standard, then the intent would be to begin using the explicitly modeled components.

Duke Energy Response to APLA Q2, Part c

The proposed surrogate basic event [SPN1VBV-OO-I-III (ONE VACUUM BREAKER FAILS OPEN DURING ACCIDENT (CLS I,III))] represents Vacuum Breaker failure, which results in the failure of the vapor suppression function when required for the relevant accident sequences. In the future, if detailed modeling is developed and goes through the appropriate levels of reviews per the PRA standard, then the intent would be to begin using the explicitly modeled components.

The vapor suppression failures are mapped to relevant accident sequences, such as LOCAs and ATWS events. The vapor suppression system at BNP is designed to mitigate the effects of blowdown forces during a severe accident. This containment failure mode is addressed both in the Level 1 PSA for RPV rupture cases and in the Level 2 CET in node CZ (Energetic Events causing containment failure) for possible occurrence during core melt progression.

Also, the vapor suppression function is considered for the suppression pool bypass sequences.

APLA Q3 – PRA Modeling Success Criteria

The NRC SER for NEI 06-09 specifies that the LAR should provide a comparison of the TS functions to the PRA modeled functions and that justification be provided to show that the scope of the PRA model is consistent with the licensing basis assumptions.

Table E1-1 in Enclosure 1 of the LAR states for TS LCO 3.5.1 (ECCS – Operating) Conditions F, G, and H, the PRA success criteria are three safety relief valves (SRVs), including ADS valves, for non-Anticipated Transient Without Scram (ATWS) scenarios and ten SRVs, including ADS valves, for ATWS scenarios. The PRA success criterion of three SRVs appears to support the depressurization function required by TS LCO 3.5.1 while the criterion of ten SRVs appears to support the over-pressurization protection function required by TS LCO 3.4.3 SRVs. However, only seven of the eleven SRVs are equipped to provide the automatic depressurization function required by the ADS. Further, Attachment 5 of the LAR indicates that LCO 3.4.3 Condition A will not be included in the RICT program since plant shutdown is required within 12 hours if one required SRV is inoperable. It is unclear to the NRC staff how the PRA treatment of SRVs that do not perform the ADS function will be utilized in RICT calculations.

a. *Clarify what PRA success criteria are associated with the ADS functions covered by TS LCO 3.5.1 Conditions F, G, and H.*

Duke Energy Response to APLA Q3, Part a

PRA Success Criteria that require at least 3 Safety Relief Valves (SRVs) (including ADS valves) for non-ATWS scenarios are scenarios that have high-pressure systems that are not adequate to maintain reactor vessel inventory makeup. The SRVs can be opened automatically by the ADS or manually by the operators to lower the reactor vessel pressure to allow injection from the low-pressure systems. Success is three out of eleven SRVs opened to depressurize the reactor vessel until the LPCI and/or Core Spray (CS) systems can be used to restore reactor vessel water level. The scenarios are:

- Medium LOCA event success criteria that requires HPCI or manual/automatic depressurization using at least three SRVs followed by initial injection from one train of either CS or LPCI.
- Small LOCA event success criteria that requires Reactor vessel depressurization using at least 3 SRVs followed by injection from one train of CS, one train of LPCI, or Condensate Injection.
- Transient event success criteria for loss of feedwater with no HPCI or RCIC that requires Reactor vessel depressurization using at least 3 SRVs followed by injection from one train of CS, one train of RHR, or Condensate Injection.

The PRA success criteria of 3 SRVs supports the ADS function associated with the TS 3.5.1 (ECCS – Operating) LCO. For TS Operability purposes, 6 of 7 ADS valves are required to meet LCO 3.5.1. Conditions F, G and H all include the statement "One required ADS valve inoperable," which are the conditions associated with one required ADS valve inoperable (i.e., two ADS valves inoperable).

The PRA success criteria of 10 SRVs supports the requirements of the TS 3.4.3 LCO (not proposed for the RICT Program), which also credits the non-ADS valves.

The ADS circuitry to auto open the ADS valves is not modeled in the Brunswick PRA. An open on demand failure is the same as non-ADS (i.e., due to high pressure, not due to the ADS system). Therefore, only the manual actuation of ADS valves is available.

The Human Reliability Analysis (HRA) event OPER-DRPRESS in the Brunswick PRA for failure to depressurize the reactor vessel to allow for low pressure injection is part of the logic for manual operation of all SRVs.

The entries in Table E1-1 (Attachment 3) for TS 3.5.1, Conditions F, G and H have been revised to reflect the appropriate success criteria discussed above.

b. *Explain why non-ADS SRVs are included in the success criteria for TS LCO 3.5.1. If the non-ADS SRVs are credited for meeting the associated success criteria, include in this explanation how a non-ADS SRV can be credited for satisfying this TS LCO.*

Duke Energy Response to APLA Q3, Part b

The ADS SRVs have an automatic function of the Automatic Depressurization System. The ADS SRVs automatically actuate with Reactor Low Water level and Core Spray and/or RHR pump discharge pressure. The non-ADS SRVs do not have the circuitry for automatic actuation with Reactor Low Water level and Core Spray and/or RHR pump discharge pressure. Therefore, the non-ADS SRVs cannot be credited to meet the LCO of TS 3.5.1.

Although the non-ADS SRVs do not have the automatic actuation capability to meet the requirements of LCO 3.5.1, they are considered functionally available for the PRA success criteria since they are the same type of SRV as the ADS SRVs. They are all Target Rock Model 7567F and located on the Main Steam lines. All SRVs automatically open at their preset pressures and have control switches to manually open and close. The non-ADS SRVs provide the same pressure relief function as the ADS valves using the manual control switches.

The procedural step where the equivalent SRVs are utilized (i.e., non-ADS SRVs) is as follows: Per 0EOP-01-RVCH Rev 0, for Emergency Depressurization column, "If Any ADS valve CANNOT be opened and Torus level is greater than -8 feet Then Open other SRVs until seven are OPEN."

IF torus level is greater than **-8 feet**,
THEN **open** seven ADS valves

IF	THEN
Any ADS valve **CANNOT** be opened **AND** Torus level is greater than **-8 feet**	**Open** other SRVs until seven are OPEN
Less than five SRVs can be opened **AND** RPV pressure is more than **100 psig** above torus pressure	**Rapidly depressurize** until RPV pressure is less than **100 psig** above torus pressure using Table P-2 methods • **Exceed 100°F/hr** cooldown rate if necessary • **Exceed** offsite release rate limits if necessary

ED-4

APLA Q5 – PRA Model Update Process

Section 2.3.4 of NEI 06-09 specifies that "criteria shall exist in PRA configuration risk management to require PRA model updates concurrent with implementation of facility changes that significantly impact RICT calculations."

LAR Enclosure 7 states that if a plant change or a discovered condition is identified and can have significant impact on the RICT calculations then an unscheduled update of the PRA models will be implemented. More specifically, the LAR states that if the plant changes meet specific criteria defined in the plant PRA and update procedures then the change will be incorporated into applicable PRA models without waiting for the next periodic PRA update. Describe the conditions under which an unscheduled PRA update (i.e., more than once every two refueling cycles) would be performed and the criteria that would be used to require a PRA update. In the response define what is meant by "significant impact to the RICT Program calculations."

Duke Energy Response to APLA Q5

Plant modifications and procedure changes potentially impacting the PRA undergo a thorough review process to determine the impact on the PRA. These changes to the plant are screened based on fleet procedural requirements, which includes an absolute delta in Core Damage Frequency (CDF) (or Large Early Release Frequency (LERF)) or a percentage increase in CDF (or LERF), whichever is greater. These values are consistent with industry norms. If a plant change exceeds these values, then an interim model change is implemented. A non-routine update may be completed based on engineering judgment if the quantitative criteria are not met, which may include the potential impact to one or more applications. Additionally, a PRA model update is completed when it is determined that the current PRA model does not adequately represent the plant in supporting any PRA applications of interest.

A "significant impact to the RICT Program calculations" as it relates to the PRA update process would be a plant design or procedural changes that exceed the quantitative limits described above.

Note: The above response is consistent with the response provided on the docket as part of the NRC-approved Harris TSTF-505 license amendment request. The response for Harris was provided in Duke Energy letter dated July 27, 2020 (ADAMS Accession No. ML20209A304). By letter dated March 31, 2021 (ADAMS Accession No. ML21047A314), the NRC issued a license amendment to Harris for the adoption of TSTF-505 and acknowledged the Duke Energy PRA model update process in the associated Safety Evaluation.

APLA Q6 – Total Risk Consideration of State-of-Knowledge Correlation and Modeling Updates

Regulatory Guide (RG) 1.174 provides the risk acceptance guidance for total CDF (1E-04 per year) and LERF (1E-05 per year). Table E5-1b of Enclosure 5 to the LAR shows that the total LERF for BNP Unit 2 is 8.51E-06 per year using the baseline Model of Record (MOR) PRA. 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 in this context are the means of the probability distributions that result from the propagation of the uncertainties on the PRA input parameters and model uncertainties explicitly reelected in the PRA models. In general, the point estimate CDF and LERF values obtained by quantification of the cutset probabilities using mean values for each basic event probability do not produce a true mean of the CDF and LERF. Under certain circumstances, a formal propagation of uncertainty may not be required if it can be demonstrated that the State of Knowledge Correlation (SOKC) is unimportant (i.e., the risk results are well below the acceptance guidelines).

Demonstrate that the total risk for Unit 2 will conform to the RG 1.174 risk acceptance guidelines (i.e., CDF < 1E-04 per year and LERF < 1E-05 per year) after the internal events and fire PRA models are updated to include the potential increases in risk associated with SOKC and updates to PRA models performed in response to NRC staff requests. Include identification of the fire PRA parameters for which SOKC was applied in the parametric uncertainty analysis of fire events.

Duke Energy Response to APLA Q6

The total risk for Unit 2 does conform to the RG 1.174 risk acceptance guidelines for CDF and LERF.

The total risk for Unit 2 is 4.75E-05 for CDF and 8.76E-06 for LERF after the internal events, internal flooding, and fire PRA models have been updated to include the potential impacts in risk associated with SOKC as well as the addition of the proposed seismic penalty.

An assessment of parametric uncertainty was performed for Unit 2 Internal Events, Internal Flooding, and Fire CDF and LERF using UNCERT with a Monte-Carlo sampling approach with 10,000 samples for each of the models. The parametric uncertainty analysis addresses SOKC for basic events sharing the same type code and that appear in the same cutset. The impact of the SOKC is reflected by an increase in the calculated risk from the simulation, if applicable. Given that the UNCERT program results do not indicate significant increase in risk over the point estimate risk, it is concluded that there are no significant data correlations from type-coded data events. However, the potential for non-type coded data events specific to the fire analysis needed to be examined.

The following areas of uncertainty were assessed for data correlation and evaluated as follows:

	Area of Uncertainty	Discussion
1.	Fire ignition frequency	The BNP fire scenarios are based on single ignition sources. Therefore, there are no correlated ignition frequencies within an individual cutset, precluding SOKC occurrence concerns.
2.	Non-detection probabilities	A generic non-detection probability is used in quantifying the scenario frequencies. Multiple detectors are not credited, so that for individual scenarios, there is no correlated data.
3.	Non-suppression probabilities	There is no correlation between various types of suppression, in that they are uniquely different.
4.	Heat release rate severity factor/split fraction	See Item 1. In addition, the source target relationship is based on a single distance that is used to calculate the Heat Release Rate (HRR) severity factors. The split of the generic HRRs are quantified as two individual scenarios, precluding any correlated data in single cutsets.
5.	Circuit failure Probabilities	With the exception of basic events where the sum of the hot shorts probabilities exceed 1.0, cutsets including the same component type and failure mode with the same hot short probabilities are assumed completely correlated. The UNCERT code does not address this correlation, so an analysis showing the potential change in CDF/LERF has been performed and is included in the results in the response to this question.

APLA Q7 – Supplemental Diesel Sensitivity Analysis

Topical Report NEI 06-09 and the NRC's SER for NEI 06-09 specify that an LAR for RICT program implementation should identify key assumptions and sources of uncertainty and should assess/disposition each as to its impact on the RICT program. Section 2.3.4 of NEI 06-09-A states that sensitivity studies should be performed on the base PRA model prior to initial implementation of the RICT program on uncertainties that could potentially impact the results of an RICT calculation. NEI 06-09-A also states that the insights from the sensitivity studies should e used to develop appropriate risk management actions (RMAs), including highlighting risk significant operator actions, confirming availability and operability of important standby equipment, and assessing the presence of severe or unusual environmental conditions.

Enclosure 9 to the LAR identifies key assumptions and sources of uncertainty associated with the PRA MOR. Item #8 of Table E9-1 identified the use assumed failure rates for the non-safety Supplemental Diesel Generator (SUPP-DG) as a source of uncertainty and provided results of sensitivity study on RICT estimates. The Case A47-1 (Distribution Systems – Operating, Unit 1- One alternating current (AC) electrical power distribution subsystem inoperable for planned maintenance due to either inoperable load group E3 bus(es) or inoperable load group E4 bus(es)) demonstrates a reduction of 2.9 days of the RICT calculation which constitutes an 18.8% impact.

Address the following related to the SUPP-DG:

a. *Discuss whether the RICTs for other TS LCOs (i.e., those in scope of the RICT program but not evaluated in Table E9-1 Item #8 of the LAR) and for plant configurations involving more than one LCO entry are significantly impacted by the SUPP-DG uncertainties. For those TS LCOs that are significantly impacted by this source of uncertainty, identify the LCOs and how this source of uncertainty impacts the RICT (e.g., describe and provide the results of a sensitivity study). Also, discuss the basis for the chosen plant configurations involving more than one LCO entry.*

b. *Describe how sources of uncertainty associated with SUPP-DG will be addressed in the RICT program. Provide updated RMAs that may be considered during a RICT program entry to minimize any potential adverse impact from SUPP-DG uncertainties and explain how these RMAs are expected to reduce the risk associated with this source of uncertainty.*

   OR

c. *Provide a detailed justification that the sensitivities of the computed RICTs to SUPP-DG uncertainties do not need to be addressed in the RICT program as required by Section 2.3.4 of NEI 06-09-A.*

Duke Energy Response to APLA Q7

During the initial modeling of the supplemental diesel generator (SUPP-DG) in the PRA, it was assessed that the most appropriate available data to use for the SUPP-DG failure rates was the emergency diesel generator (EDG) data. However, since the initial modeling was performed, the 2015 Parameter Estimates update became available that provided more types of generator data. To address the key uncertainty regarding the SUPP-DG failure rate data, BNP intends to implement the Station Blackout Diesel Generator (SBO-DG) failure rate data into the SUPP-DG data in place of the EDG failure rate data. This data will also be Bayesian updated to account for the plant specific experience of the SUPP-DG. The SUPP-DG is tested on a monthly basis. The impact on RICTs where the emergency power has a relatively high risk-importance will be approximately what was shown in the SUPP-DG sensitivity analysis. For other RICTs, the impact is negligible. Thus, the use of EDG failures rates for the SUPP-DG data will no longer be a key uncertainty for the RICT program upon implementation of the Bayesian-updated SBO-DG failure rate data into the SUPP-DG data. If more applicable data to the SUPP-DG becomes available, the Brunswick PRA will incorporate that data per the PRA change process. The change to use the SBO failure rate data will be implemented prior to implementing the RICT Program.

With respect to the basis for the chosen plant configurations involving more than one LCO entry, the most limiting configuration, as analyzed in the base case sample calculations, was chosen for the SDG sensitivity analysis.

<u>APLA Q8 – Supplemental Diesel Failure Data</u>

Item #8 of Table E9-1 notes that the PRA MOR uses generic industry failure data for standard Emergency DGs (EDGs), despite also acknowledging that non-safety related DGs typically have higher failure probabilities than EDGs. In addition to the sensitivity analyses discussion above, provide justification for using failure probabilities for EDGs in lieu of using non-safety related DG failure probabilities. This justification should focus on surveillance frequencies, quality, maintenance activities and other factors that typically differentiate commercial and safety grade equipment.

<u>Duke Energy Response to APLA Q8</u>

For the response to this question, refer to the response to APLA Question 7 above regarding implementing the SBO-DG failure rate data into the SUPP-DG data in place of the EDG failure rate data prior to implementing the RICT Program.

<u>APLA Q9 – PRA Success Criteria for Service Water Systems</u> (Part a. only)

The descriptions of the Nuclear Service Water (NSW) and Conventional Service Water (CSW) systems for TS LCO 3.7.2 (Service Water and Ultimate Heat Sink) Condition B in Table E1-1 of Enclosure 1 to the LAR suggest that the success criteria for these systems are a function of various plant configurations. Additionally, based on the information provided in LAR Table E1-1 it appears the PRA success criteria credit an operator action to throttle the Turbine Building Closed Cooling Water (TBCCW) heat exchanger outlet valve to reduce the required number of CSW pumps. Relative to the NSW and CSW systems as they are used in the PRA and the proposed RICT program, address the following:

a. *Provide a further detailed discussion/explanation of the modeling of the NSW/CSW systems in the PRA and the associated success criteria. Explain whether and how the different success criteria are captured in the Configuration Risk Management Program (CRMP) for the real-time plant configuration.*

<u>Duke Energy Response to APLA Q9, Part a</u>

<u>Success Criteria (NSW pump running)</u>

Given a running NSW pump, one CSW pump is sufficient for the CSW header during shutdown if the TBCCW heat exchanger throttle valve functions to reduce flow through the TBCCW heat exchanger. Successful throttling of the TBCCW heat exchanger reduces the required number of CSW pumps to one (for CSW header supply).

The model logic uses the loss of 2 or 3 CSW pumps and the failure to throttle service water to the TBCCW to fail the CSW header supply. A single CSW pump and the capability to throttle service water to the TBCCW satisfies the success criteria of being sufficient to meet CSW header requirements. The running NSW pump would supply the NSW header.

<u>Success Criteria (NSW supply failed)</u>

If the NSW header is to be supplied from CSW because the NSW supply is failed, then an additional CSW pump is required. In this instance, either all three CSW pumps must function, or two of three CSW pumps must function with successful throttling of TBCCW flow.

During normal operation, one NSW pump and two CSW pumps are in service to provide Service Water System (SWS) loads. The SWS is divided into two major headers: NSW and CSW headers. The headers are normally operated independently. However, opening the normally closed valves allows for the CSW header to supply the NSW equipment, if required.

Currently, the PRA model logic is more conservative than the success criteria. If the NSW supply is failed, then loss of flow to the NSW header from the CSW pumps is TRUE anytime throttling service water flow to the TBCCW failure is TRUE. Another input to the loss of flow to the NSW header is the loss of 2 or 3 CSW pumps. To meet the success criteria when the NSW supply is failed, 2 or 3 CSW pumps and the capability to throttle the service water to the TBCCW are required.

The CRMP uses the same model as the base PRA model for the NSW and CSW systems, with the same success criteria as described above.

<u>APLA Q10 – HRA for FLEX Operator Actions</u>

Section 4.4 of Enclosure 9 to the LAR discusses how FLEX strategies were used in the current PRA model to support implementation of a RICT program. This section notes that the FLEX equipment currently credited in the PRA model includes permanently installed diesel generators, portable pumps and portable air compressors. It also explains that post-initiator operator actions modeled include failure to load shed, failure to align and start FLEX diesel generators, failure to refuel FLEX diesel generators (if needed), failure to align and start FLEX portable pumps and failure to align and start FLEX air compressors.

The staff notes that the Electric Power Research Institute (EPRI) issued Technical Update 3002013018 which includes examples and guidance for how to perform HRA for the use of onsite portable equipment in a variety of contexts. Address the following items related to FLEX strategies and the HRA used to support implementation of the RICT program:

a. Describe the HRA methodology used for crediting operator actions related to FLEX equipment.

b. Describe the credited operator actions related to FLEX equipment and discuss the methodology used to assess the associated human-error probabilities and the licensee personnel that performs these actions. The discussion should include a summary of how the licensee evaluated the impact of the plant-specific human error probabilities and associated scenario-specific performance shaping factors listed in (a)-(j) of supporting requirement HR-G3 of American Society of Mechanical Engineers (ASME)/American Nuclear Society (ANS) Standard RA-Sa-2009, as endorsed by RG 1.200.

c. *Regarding FLEX pre-initiators evaluation, discuss whether 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 as described in HLR-HR-D of ASME/ANS RA-Sa-2009, as endorsed by RG 1.200.*

d. *Discuss FLEX strategy initiation. Discuss whether the procedures for the initiation or entry into mitigation strategies are explicit. Discuss the technical bases for probability of failure to initiate mitigating strategies. Include in this discussion the cue to declare an Extended Loss of AC Power (ELAP) and how this action is incorporated into the PRA model.*

Duke Energy Response to APLA Q10

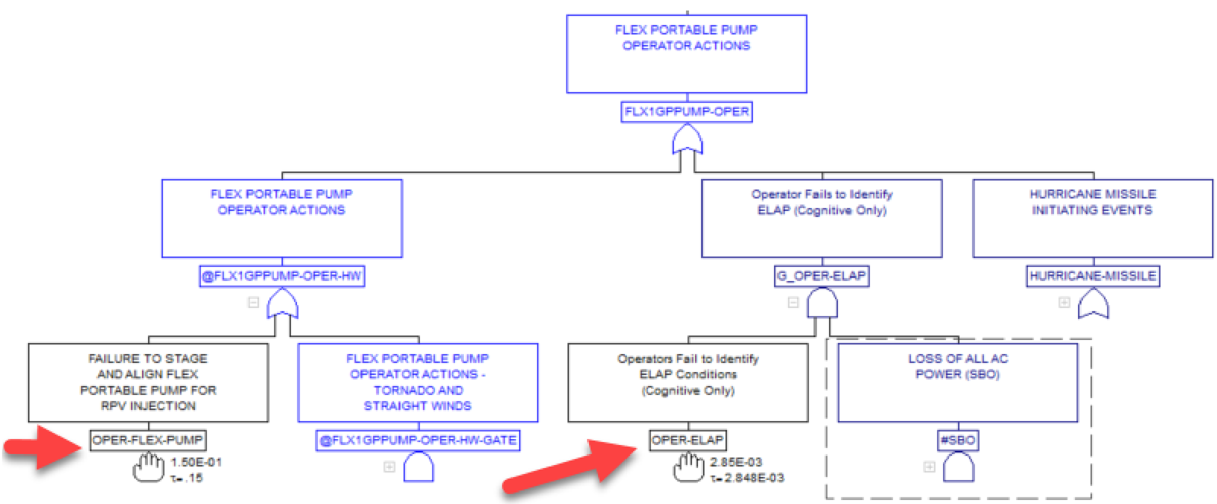
FLEX related operator actions credited in the BNP PRA model were evaluated per ASME/ANS RA-Sa-2009 PRA standard supporting criterion HR-G3. The EPRI, "HRA Calculator," was used to quantify the events, explicitly addressing all performance shaping factors identified in HR-G3. Licensed operators and procedure writers were interviewed to gain insights for development of the operator actions. These tasks mirror typical actions that are exercised on a regular basis for testing and preventive maintenance (PMs) and utilize long time frames for the execution portion, therefore lessening the impact on potential extreme performance shaping factors.

Initial FLEX guidance is provided by procedure 0EOP-01-FSG-01, "FLEX Initial Assessment and Equipment Staging." Entry conditions into the FLEX procedures are directed by the Emergency Operating Procedures as depicted in the following table.

Operator Action	Description	Guidance	Notes
OPER-FLEXDG	Failure to Align FLEX DG to Battery Chargers	0EOP-01-FSG-04	FLEX HRAs are similar to normal actions from other HRAs and there is a relatively long-time frame for completion making use of the HRA Calculator appropriate. Sensitivity studies show that BNP RICTs are not sensitive to FLEX HRAs.
OPER-FLEX-PUMP	Failure to Stage and Align FLEX Portable Pump for RPV Injection	0EOP-01-FSG-01 0EOP-01-FSG-07 0EOP-01-FSG-02	FLEX HRAs are similar to normal actions from other HRAs and there is a relatively long-time frame for completion making use of the HRA Calculator appropriate. Sensitivity studies show that BNP RICTs are not sensitive to FLEX HRAs.
OPER-FLEX-COMP	Failure to Stage and Align FLEX Air Compressors	0EOP-01-FSG-01 0EOP-01-FSG-05	FLEX HRAs are similar to normal actions from other HRAs and there is a relatively long-time frame for completion making use of the HRA

Operator Action	Description	Guidance	Notes
			Calculator appropriate. Sensitivity studies show that BNP RICTs are not sensitive to FLEX HRAs.
OPER-FLEXDG-REFUEL	Failure to Refuel the FLEX-DG to Meet 24-hour Mission Time	0EOP-01-FSG-06	FLEX HRAs are similar to normal actions from other HRAs and there is a relatively long-time frame for completion making use of the HRA Calculator appropriate. Sensitivity studies show that BNP RICTs are not sensitive to FLEX HRAs.
OPER-ELAP	Operators Fail to Identify ELAP Conditions (Cognitive Only)	0EOP-01-FSG-01	This operator action is only applied to the internal events portion of the PRA model. The cognitive portion of the fire applied operator actions is included in their screening value.

Note: Operator action "OPER-ELAP" is only applied to the internal events portion of the PRA model. The "OPER-ELAP" operator action is in the model in conjunction with the applicable operator action for the FLEX components as shown in the fault tree figure below. Therefore, either the failure of the decision to implement FLEX guidelines or the actual failure to deploy and apply the FLEX equipment will result in propagating up the fault tree.



The Fire PRA model addresses the FLEX operator actions in the fire recovery rules where a screening value is applied. This screening value is considered to include the cognitive portion of the fire applicable FLEX operator action.

Pre-initiator human failures that would render FLEX equipment unavailable during an event have been considered in the development of the PRA model. None were found to be necessary or added. This peer-reviewed approach has been used with the other pre-initiator events included in the model and meets the requirements described in supporting criterion HLR-HR-D of the ASME/ANS RA-Sa-2009 PRA standard.

The emergency operating procedures provide clear instructions for when to take action using FLEX equipment and which FLEX procedures are to be utilized.

The procedural guidance for the initiation and entry into the FLEX mitigation strategies are well defined and explicit. The various Emergency Operating Procedures (EOP) are identified in the table above. Each procedural step for the operator action is identified, listed, and analyzed in the HRA calculator and the EPRI software assigns the industry accepted probability of failures accordingly based on the shaping factors for the event.

The initial FLEX entry, as directed from the EOPs is to 0EOP-01-PSA-01 (FLEX Initial Assessment and Equipment Staging) which explicitly assesses the scenario and determines what FLEX equipment will be needed. The guidance assesses the entry conditions, instructions, resources required, special equipment, staging location, and path from the FLEX storage facility. This initial FLEX guidance will then direct the operators to another FLEX procedure with FLEX equipment specific instructions.

APLA Q11 – FLEX Equipment in PRA Model

Section 4.4 of Enclosure 9 to the LAR discusses how FLEX strategies were credited in the current PRA model to support implementation of a RICT program. This section notes that the FLEX equipment currently credited in the PRA model includes permanently installed diesel generators, portable pumps and portable air compressors. Address the following:

a. *Discuss whether the FLEX diesel generators are similar to other permanently installed plant equipment (i.e., SSCs with sufficient plant-specific or generic industry data). Compare failure data of the FLEX diesel generators with that used for similar plant equipment credited elsewhere in the PRA (e.g., EDGs).*

b. *Describe the events for which portable equipment is credited in the PRA models (e.g., ELAP only, internal events, and external hazards that are within or beyond design basis). Additionally, describe the sources of data used for any credited portable FLEX equipment and denote whether any plant-specific failure rates are higher than expected based on generic industry data.*

Duke Energy Response to APLA Q11, Part a

Originally, BNP installed Severe Accident Mitigation Alternative (SAMA) diesel generators (DG) which were permanently installed. These permanently installed diesels were modeled in the PRA according to other permanently installed plant equipment. This equipment was modeled in the PRA and peer reviewed. The FLEX DGs at BNP are permanently installed plant equipment which replaced the previously installed SAMA diesels and were replaced in the PRA model as such. Both the SAMA and FLEX diesels' function is to power the battery chargers. NUREG/CR-6928 generic parameter estimates for emergency DGs were used for the permanently installed FLEX DGs. The permanently installed FLEX DGs are simpler than the EDGs with less external dependencies. They are expected to be as reliable as the EDGs.

Plant-specific data on FLEX DGs has been compiled across the Duke Energy fleet (Brunswick, Robinson, Harris, McGuire, Oconee and Catawba). FLEX DGs across the sites are very similar machines. The current data set contains the results from over 200 tests of varying scope (i.e., full load, 50% load, 20% load, other load, no load) and frequency (i.e., monthly, quarterly, yearly, biennial, triennial). Thus, for the FLEX DGs, the plant-specific failure rate has been determined in accordance with the PRA standard. The failure rate is presented in the table below and is used for the FLEX DG start failure rate. Note that this value includes both 'fail to start' events and 'fail to load' events. This start failure rate of the BNP FLEX DGs is between that of generic EDGs and SBO-DGs per 2015 SPAR Component Unreliability Data, as shown below.

However, due to relatively short run times during testing, the current data results are not considered sufficient for computing a plant-specific run failure rate. Thus, the SPAR SBO EDG run failure rate is used. Duke Energy concludes that this is a realistic approach since run failure rates for EDGs and SBO-DGs are very similar and sensitivities show that there is little impact to calculated RICTs.

Diesel Failure Probabilities

Failure Mode	SPAR EDG	SPAR SBO DG	BNP FLEX DG
Fails to Start	2.88E-3/demand	2.98E-2 /demand	8.28E-3 /demand
Fails to Load	3.72E-3/hour	--	--
Fails to RUN	1.52E-3/hour	1.50E-3/hour	1.50E-3/hour

Note: The above discussion of FLEX DG modeling and data was also provided in support of the Brunswick 10 CFR 50.69 application RAI responses (ADAMS Accession Nos. ML18306A523 and ML19044A366) and acknowledged by NRC staff in the Brunswick 10 CFR 50.69 Safety Evaluation (ADAMS Accession No. ML19149A471).

Sensitivity studies have been performed to assess the impact of the FLEX DG failure rates on RICT results. The FLEX sensitivity studies conducted are considered bounding for the FLEX impacts on RICTs. The studies conducted, which involved failure amplifications for FLEX equipment and FLEX operator actions, show little sensitivity. Based on the sensitivity studies, changes in the failure rate values for the FLEX DGs have a small to negligible impact on the calculated RICTs.

Duke Energy Response to APLA Q11, Part b

Portable FLEX equipment is credited as another source of injection into the vessel for core cooling and backup compressed air for wet well venting. These are typically accepted as conditions resulting from beyond design basis accidents and ELAP events.

Brunswick Internal Events, Internal Flooding and Fire PRA models credit FLEX equipment and related mitigating actions in the CRMP, as appropriate.

NUREG/CR-6928 generic parameter estimates for standby engine-driven pumps are used for the FLEX pumps, and engine-driven air compressors' parameter estimates are used for the FLEX air compressors. Generic values are used currently since plant-specific data is limited. Sensitivity studies show that the RICTs are not sensitive to the applied FLEX data.

The following table shows examples of the portable FLEX Basic Events modeled and the probabilities assigned in the BNP model that are used for RICT calculations. The last column shows the values from the latest NUREG/CR-6928 spreadsheet summary for comparison*. The BNP reliability data will transition to newer data via the model update process.

Basic Event	Description	Probability in BNP Model	*6928 Mean Probability
FLX1EDP-FS-01	DIESEL DRIVEN PUMP 0-FLEX-PMP-01 FAILS TO START	5.09E-03/Demand	2.17E-3/Demand
FLX1EDP-FR-01	DIESEL DRIVEN PUMP 0-FLEX-PMP-01 FAILS TO RUN	2.27E-3/hour	1.98E-3/hour
FLX0EDC-FS-02	DIESEL DRIVEN COMPRESSOR 0-FLEX-CMP-02 FAILS TO START	2.45E-3/Demand	8.24E-3/Demand
FLX0EDC-FR-02	DIESEL DRIVEN COMPRESSOR 0-FLEX-CMP-02 FAILS TO RUN	3.78E-3/hour	2.88E-4/hour

*Summary of SPAR Component Unreliability Data and Results – 2015 Parameter Estimation Update (12/21/2016).

Note: The above discussion of FLEX pump and FLEX air compressor modeling and data was also provided in support of the Brunswick 10 CFR 50.69 application RAI responses (ADAMS Accession Nos. ML18306A523 and ML19044A366) and acknowledged by NRC staff in the Brunswick 10 CFR 50.69 Safety Evaluation (ADAMS Accession No. ML19149A471).

APLA Q12 – PRA Model Upgrades with FLEX Strategies

Section 4.4 of Enclosure 9 to the LAR discusses how FLEX strategies were credited in the current PRA model to support implementation of a RICT program. However, no information is provided that denotes whether crediting FLEX strategies in the PRA constitutes a PRA upgrade.

a. *Describe whether incorporation of FLEX equipment into the supporting PRA model constitutes an upgrade to the PRA, along with the basis for the decision including the source of the definition of upgrade used.*

b. *If it is determined that inclusion of FLEX strategies constitutes an upgrade, describe supporting peer reviews that were done, as well as any Finding Closure Reviews and provide the disposition of remaining open findings.*

Duke Energy Response to APLA Q12, Part a

As summarized in Duke Energy's response to Brunswick 10 CFR 50.69 LAR RAI 8 (ADAMS Accession No. ML18306A523), Brunswick previously installed small diesel generators (called SAMA diesel generators). The SAMA diesel generators' primary risk significant function was to charge the batteries during a station blackout. The SAMA diesel generators were incorporated into the PRA model in the 2007 Model of Record (MOR) update. The SAMA diesel generators were added to the model prior to the last full scope Internal Events peer review in June of 2010. Inclusion of the SAMA diesel generators was within the scope of the June 2010 Internal Events peer review.

In the last Internal Events MOR update, which occurred in 2017, the function for charging the batteries during an SBO was shifted from the SAMA diesel generators to the FLEX diesel generators to reflect physical plant modifications completed at Brunswick. This change is basically a like-for-like replacement with respect to modeling in the PRA. The FLEX diesel generators have been modeled in the PRA using the same methods that were previously utilized for the SAMA diesel generators; therefore, this is not considered an upgrade. The NRC staff concurred with this position in the 10 CFR 50.69 Safety Evaluation (ADAMS Accession No. ML19149A471).

During the same Internal Events model update in 2017, portable FLEX equipment and associated human actions were also added to the PRA model, as described in the Duke Energy response to Brunswick 10 CFR 50.69 LAR RAI 8 (ADAMS Accession No. ML18306A523), using methods consistent with those previously applied in the PRA.

When calculating RICTs, portable equipment will be credited for the functions modeled in the PRA. The FLEX diesel generators will continue to be modeled as well, as described above.

Incorporation of the SAMA diesel generators into the PRA model has been peer reviewed. Changing that function to the FLEX diesel generators does not constitute a significant change in scope or capability of the model, nor did it constitute implementation of a method not previously used in the PRA. Incorporation of portable equipment into the model does not significantly impact CDF and LERF metrics, does not constitute a significant change in scope or capability of the model, nor did it constitute implementation of a method not previously used in the PRA. Therefore, no model upgrades have been implemented by the addition of FLEX equipment and a peer review is not required.

Duke Energy Response to APLA Q12, Part b

Duke Energy has determined that the inclusion of the FLEX strategies does not constitute an upgrade. Therefore, a description of supporting peer reviews, as well as finding closure reviews, is not applicable.

PRA Licensing Branch C (APLC) External Hazards

APLC Q1 – Seismic Core Damage Frequency Calculation

As clarified in the NRC SER for NEI 06-09, other sources of risk (i.e., seismic and other external events) must be quantitatively assessed if they contribute significantly to configuration-specific risk. The SER for NEI 06-09 also states that bounding analyses or other conservative quantitative evaluations are permitted where realistic PRA models are unavailable.

Section 6.1 of the Enclosure 4 to the LAR, the licensee provided seismic bounding analysis, and calculated seismic core damage frequency (SCDF) and seismic large early release frequency (SLERF). The licensee used the review-level earthquake (RLE) spectral ratios that were developed for IPEEE assessment, as shown in Table E4-1 of the LAR. These RLE spectral ratios are very similar to those in Table C-2 of the safety/risk assessment results for Generic Issue 199 or in Table 2 of a letter from EPRI to NEI regarding seismic hazard estimates with an assumption of the same ratio between 5 hertz (Hz) and 2.5Hz. By using these spectral ratios, the calculated SCDF penalties, ranging from 1.8E-7 /yr to 9.5E-6 /yr, are very different among the five frequencies, peak ground acceleration (PGA), 10, 5, 2.5 and 1 Hz shown in Table E4-3 of the LAR. This difference is likely caused by using spectral ratios developed from seismic hazard curves that are different from the seismic hazard curves used in this application.

In addition, the seismic bounding analysis used an average of 5 frequencies of seismic hazard curves (PGA, 10, 5, 2.5 and 1 Hz), instead of an average of 4 frequencies of seismic hazard curves (PGA, 10, 5, and 1 Hz) proposed in Generic Issue 199. The licensee compared the difference between the two methods, with a non-conservative value from the 5-frequency method (2.81E-6 vs 3.46E-6 for SCDF and 1.35E-6 vs 1.67E-6 for SLERF penalties). However, the licensee did not provide the rationale for selecting a non-conservative averaging method.

a. *Regarding the RLE approach:*

   i. *Provide justification of why the spectral ratios developed from the RLE are applicable to the seismic hazard curves used in this application.*

   ii. *Alternatively to Part (i), if the justification cannot be provided, calculate the spectral ratios based on the seismic hazard curves used for this application and use them to obtain and provide updated seismic penalty values.*

b. Regarding the averaging method:

i. Provide the rationale for selecting a non-conservative averaging method.

ii. Alternatively to Part (i), if the rationale cannot be provided, use an averaging method that is consistent with commonly accepted method and provide updated seismic risk penalty values.

Duke Energy Response to APLC Q1

The following information in response to APLC Q1 provides the analysis for the Brunswick site with respect to the beyond design basis seismic hazard and supersedes the information provided in Section 6.1 of the original LAR entirely.

Purpose

The following develops and documents an estimate of seismic risk at Brunswick and determines a quantitative seismic penalty for implementation of RICTs (References 1 and 2). A seismic PRA is not available for BNP, so point estimates of the SCDF and SLERF have been developed using:

(1) the updated BNP site-specific seismic hazard estimate developed in response to the Near-Term Task Force (NTTF) recommendations to strengthen protection against natural phenomena such as earthquakes (Reference 3), and

(2) the BNP-specific plant-level level high confidence of low probability of failure (HCLPF) capacity of 0.3g referenced to PGA from the USNRC in the GI-199 Assessment (Reference 4). HCLPF is the capacity representing 95 percent confidence that the conditional probability of failure of an SSC is 5 percent or less. The 0.3g value is consistent with the BNP Individual Plant Examination for External Events (IPEEE) RLE (Reference 5).

The estimation of the SCDF/SLERF is performed by convoluting the PGA-based seismic hazard curve for the BNP site with the BNP PGA-based HCLPF. This is a commonly used approach to estimate SCDF when a seismic PRA is not available (Reference 6). This approach has previously been used by the NRC staff in the resolution of GI-199 and during reviews of various risk-informed license amendments. The BNP SCDF/SLERF estimates can be used as a seismic penalty in the RICT decision making process.

References

1. TSTF-505-A, Rev. 2, “Technical Specifications Task Force Improved Standard Technical Specifications Change Traveler”, November 2018.

2. NEI 06-09, Rev. 0, “Risk-Informed Technical Specifications Initiative 4b – Risk Managed Technical Specifications (RMTS) Guidelines”, November 2006.

3. "Seismic Hazard and Screening Report (CEUS Sites), Response to NRC Request for Information Pursuant to 10 CFR 50.54(f) Regarding the Seismic Aspects of Recommendations 2.1 of the Near-Term Task Force Review of Insights from the Fukushima Dai-Ichi Accident," ADAMS Accession Number ML14106A461, Duke Energy Letter BSEP-14-0028 to U.S. Nuclear Regulatory Commission, Washington, D.C., March 31, 2014.

4. "Generic Issue 199 (GI-199), Implications of Updated Probabilistic Seismic Hazard Estimates in Central and Eastern United States on Existing Plants Safety Risk Assessment," ADAMS Accession Number ML11356A034, U.S. Nuclear Regulatory Commission, Washington, DC, Aug. 2010.

5. Carolina Power & Light, "Brunswick Nuclear Plant, Individual Plant Examination for External Events – Final Report," June 1995.

6. EPRI 3002000709, "Seismic Probabilistic Risk Assessment Implementation Guide," Electric Power Research Institute, December 2013.

7. NRC Letter, "Request for Information Pursuant to Title 10 of the Code of Federal Regulations 50.54(f) Regarding Recommendations 2.1, 2.3 and 9.3 of the Near-Term Task Force Review of Insights from the Fukushima Dai-Ichi Accident," ADAMS Accession No. ML12053A340, March 12, 2012.

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9. Kennedy, R.P., "Overview of Methods for Seismic PRA and Margin Analysis Including Recent Innovations", conference paper at Tokyo 1999 OECD/NEA Workshop on Seismic Risk, "Proceedings of the OECD/NEA Workshop on Seismic Risk," NEA/CSNI/R(99)28, February 2001.

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11. Newmark, N. M. and W. J. Hall. NUREG/CR-0098, "Development of Criteria for Seismic Review of Selected Nuclear Power Plants." U.S. Nuclear Regulatory Commission: Washington D.C. May 1978.

12. Electric Power Research Institute (EPRI), Final Report 1025286, "Seismic Walkdown Guidance For Resolution of Fukushima Near-Term Task Force Recommendation 2.3: Seismic," June 2012.

13. EVAL EC 408926, Rev. 0, Seismic Margin Analysis and Seismic Safe Shutdown Equipment List As-Built / As-Operated Review.

14. Seismic PRA – Hatch 1 and 2: Seismic Probabilistic Risk Assessment Quantification Report, H-RIE-SEIS-U00-001-002, Southern Nuclear PRA Calculation, January 2, 2019.

15. Peach Bottom Atomic Power Station, Units 2 and 3, Seismic Probabilistic Risk Assessment Report, Response to NRC Request for Information Pursuant to 1 O CFR 50.54(f) Regarding Recommendation 2.1 of the Near-Term Task Force Review of Insights from the Fukushima Dai-Ichi Accident, Exelon Generation Letter RS-18-098 to U.S. Nuclear Regulatory Commission, August 28, 2018.

16. Columbia Generating Station Docket No. 50-397, Seismic Probabilistic Risk Assessment Response to NRC Request for Information Pursuant to 10 CFR 50.54(F) Regarding Recommendation 2.1 of the Near-Term Task Force (NTTF) Review of Insights from The Fukushima Dai-Ichi Accident (MF3726, MF3727), Energy Northwest Letter GO2-19-136 to U.S. Nuclear Regulatory Commission, September 26, 2019, ADAMS Accession No. ML19273A907.

17. Limerick Generating Station, Units 1 and 2, Response to Request for Additional Information, 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,” Exelon Generation Letter to U.S. Nuclear Regulatory Commission, August 12, 2019, ADAMS Accession No. ML19224B705.

18. 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, " Nine Mile Point Nuclear Station, Unit 2, Renewed Facility Operating License No. NPF-69, Exelon Generation Letter NMP2L2706 to U.S. Nuclear Regulatory Commission, October 31, 2019, ADAMS Accession No. ML19304B653.

19. Application to Revise LaSalle County Station Technical Specifications to Adopt Risk Informed Completion Times TSTF-505, Revision 2, "Provide Risk-Informed Extended Completion Times - RITSTF Initiative 4b," Exelon Generation Letter RS-20-009 to U.S. Nuclear Regulatory Commission, January 31, 2020, ADAMS Accession No. ML20035E577.

20. Clinton Power Station, Unit No. 1 – Issuance of Amendment No. 238 RE: Technical Specifications Task Force Traveler TSTF-505, Revision 2, “Provide Risk-Informed Extended Completion Times – RITSTF Initiative 4B” (EPID L-2020-LLA-0097), Dated June 28, 2021, ADAMS Accession No. ML21132A288.

Background

Following the accident at the Fukushima Daiichi Nuclear Power Plant resulting from the March 11, 2011, Great Tohoku Earthquake, the NRC NTTF developed a set of recommendations intended to clarify and strengthen the regulatory framework for protection against natural phenomena such as earthquakes. Subsequently, the NRC issued a 50.54(f) letter (Reference 7) that requested licensees to reevaluate the seismic hazards at their sites against present-day NRC requirements and guidance.

In response to the 50.54(f) letter, a BNP site-specific seismic hazard estimate has been developed (Reference 3) using EPRI guidance (i.e., the SPID) (Reference 8). The NRC further requested that interim actions be taken for plants whose updated ground motion response spectrum (GMRS) exceeds the design basis safe shutdown earthquake (SSE) in the spectral frequency range from 1 to 10 Hz. The GMRS for BNP exceeds the SSE at higher frequencies (as shown in Figure 1), so an evaluation of beyond design basis ground motions was performed utilizing data from the IPEEE (Reference 5). The IPEEE was reviewed for adequacy utilizing the guidance provided in the SPID, and the IPEEE plant-level HCLPF response spectrum (IHS) was included for screening purposes. The SSE, RLE, and the resulting IHS are plotted against the GMRS in Figure 1.

In nearly the entire 1-10 Hz region, the IHS at the plant control point exceeds the GMRS. There is a minor narrow band exceedance of the GMRS over the IHS in the 9.7-10 Hz region. At 10 Hz, the GMRS exceeds the IHS by approximately 9% which is within the 10% limit required by the SPID. The SPID also requires that the average ratio in the adjacent 1/3 octave bandwidth (1/6 on either side) is less than unity. Since the seismic risk evaluation screening in the SPID is limited to the 1-10 Hz region, only the 1/6 octave bandwidth below 10 Hz was evaluated. The area created between the IHS and the GMRS from 8.91 Hz to approximately 9.7 Hz is greater than the area created between the GMRS and the IHS from approximately 9.7 Hz to 10 Hz. Therefore, the average ratio of the GMRS to IHS is less than unity and this exceedance is considered acceptable (Reference 3).

The RLE response spectra anchored to 0.3g PGA was used as the seismic demand response curve in the IPEEE. The GI-199 assessment used this RLE demand curve as the lower bound on the actual HCLPF capacity of the plant level fragility curve (per table C-1 of GI-199 [Reference 4]) in order to establish the basis of plant level fragility curve parameters from the IPEEE information.

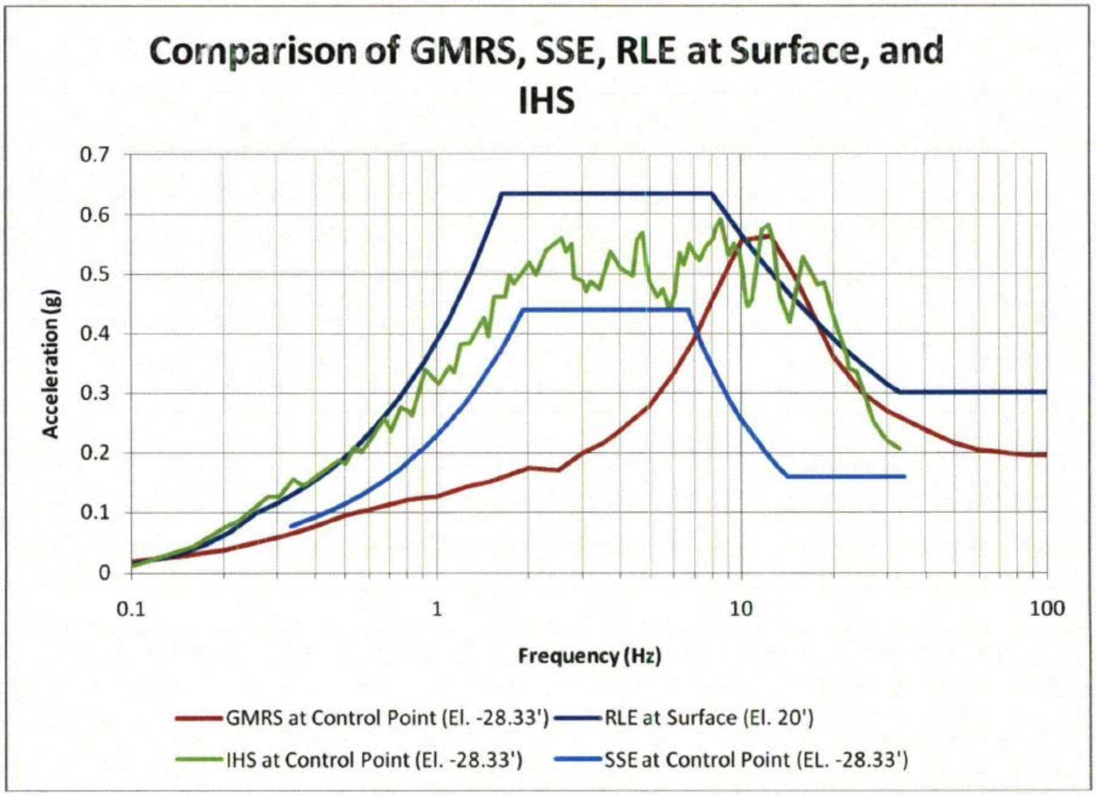

Figure 1 – Comparison of BNP GMRS to the Safe Shutdown Earthquake (SSE), the Review Level Earthquake (RLE) at the Surface, and the IPEEE HCLPF Response Spectra (IHS) at the Control Point Assessed in the IPEEE.

Seismic Hazard

In accordance with the 50.54(f) letter (Reference 7) and following the guidance in the SPID (Reference 8), an updated, site-specific probabilistic seismic hazard analysis (PSHA) was developed for BNP (Reference 3). Seismic hazard is typically expressed as a function of annual frequency of exceedance versus a seismic ground motion parameter. The most common ground motion parameters are:

- Peak ground acceleration (PGA)
- Spectral acceleration (SA)

PGA is occasionally more descriptively termed peak "free-field" ground acceleration. PGA is the average of the maximum ground surface accelerations in orthogonal directions. In contrast to the "free-field" nature of the PGA motion parameter, spectral acceleration, as may be measured on a concrete pad by whip-like instruments tuned to various natural frequencies (e.g., 1 Hz, 2.5 Hz, 5 Hz, 10 Hz, 25 Hz, etc.), reflect the response motion of single-degree-of-freedom structures. PGA is also a spectral acceleration metric but corresponds to higher frequencies (e.g., 100 Hz) at the ground surface.

PGA has been used as the ground motion metric in most industry seismic PRAs (SPRAs) performed to date. Although it has been asserted by some seismic fragility experts (Reference 9) that 5-10 Hz may be a more accurate motion metric for the calculation of seismic-induced damage risk at a nuclear power plant than is the PGA ground motion, the EPRI SPRA guidelines (Reference 6) and ASME/ANS PRA Standard (Reference 10) appropriately allow use of either PGA or other frequency to characterize the seismic hazard input to the SPRA models.

Whichever ground motion parameter is used, the hazard curve and the seismic fragilities need to be in the same motion units (i.e., both based on PGA, or both based on the same spectral acceleration) to result in a coherent risk result. The BNP SCDF and SLERF calculations are developed and quantified using the hazard curve in terms of PGA and the fragilities in terms of PGA.

The BNP seismic hazard in units of g (PGA, peak ground acceleration) is shown in Table 1 below (from Reference 3). The mean fractile annual exceedance frequencies of Table 1 are used here; use of mean values is a typical and expected PRA practice. The frequency of each data point on the curve is the frequency of that specific g-level or higher. The seismic hazard curve progresses from extremely low magnitude earthquakes well below the Brunswick operating basis earthquake of 0.08g to extremely large magnitude earthquakes well beyond the Brunswick safe shutdown earthquake of 0.16g PGA (Reference 5)

Table 1 – BNP Mean and Fractile Seismic Hazard Curves for 100 Hz (PGA)

AMPS(g)	MEAN	0.05	0.16	0.50	0.84	0.95
0.0005	3.29E-02	1.69E-02	2.68E-02	3.33E-02	3.95E-02	4.31E-02
0.001	2.49E-02	1.13E-02	1.90E-02	2.46E-02	3.14E-02	3.57E-02
0.005	8.12E-03	3.68E-03	5.27E-03	7.55E-03	1.05E-02	1.57E-02
0.01	4.54E-03	1.84E-03	2.64E-03	4.13E-03	6.09E-03	9.37E-03
0.015	3.17E-03	1.07E-03	1.67E-03	2.84E-03	4.50E-03	6.73E-03
0.03	1.56E-03	3.14E-04	5.66E-04	1.27E-03	2.53E-03	3.90E-03
0.05	8.00E-04	9.51E-05	1.90E-04	5.35E-04	1.40E-03	2.46E-03
0.075	4.17E-04	3.05E-05	6.93E-05	2.22E-04	7.34E-04	1.51E-03
0.1	2.45E-04	1.25E-05	3.23E-05	1.10E-04	4.13E-04	9.79E-04
0.15	1.05E-04	3.23E-06	1.05E-05	4.07E-05	1.57E-04	4.37E-04
0.3	1.99E-05	2.13E-07	1.46E-06	7.45E-06	2.76E-05	7.13E-05
0.5	5.13E-06	2.13E-08	3.01E-07	1.98E-06	7.66E-06	1.79E-05
0.75	1.67E-06	3.47E-09	8.12E-08	6.45E-07	2.72E-06	6.26E-06
1	7.32E-07	9.11E-10	2.92E-08	2.68E-07	1.23E-06	2.92E-06
1.5	2.17E-07	1.72E-10	5.83E-09	6.93E-08	3.68E-07	9.11E-07
3	2.15E-08	8.12E-11	2.53E-10	4.13E-09	3.28E-08	9.37E-08
5	3.09E-09	5.05E-11	8.12E-11	3.84E-10	3.95E-09	1.34E-08
7.5	5.56E-10	4.01E-11	5.27E-11	8.85E-11	6.09E-10	2.35E-09
10	1.48E-10	4.01E-11	5.05E-11	8.12E-11	1.77E-10	6.54E-10

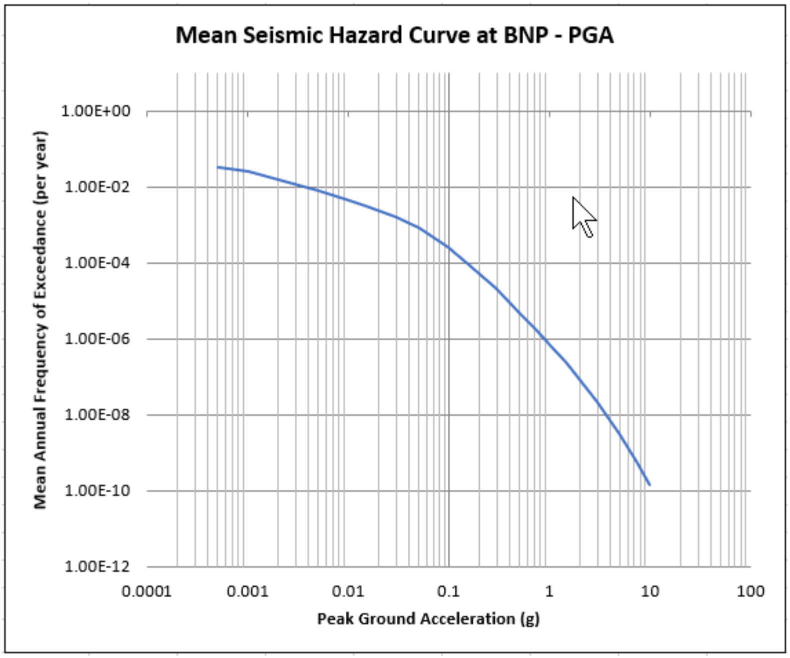

Figure 2 – BNP Mean Seismic Hazard Curve (PGA)

<u>Plant Level Fragility</u>

The original seismic design of BNP was conducted to a SSE with a NUREG/CR-0098 (Reference 11) spectral shape anchored to 0.16g PGA. The most recent seismic evaluation at BNP is the seismic margin assessment (SMA) performed for the BNP IPEEE (Reference 5). The RLE used for the SMA was a RG 1.60 spectrum anchored to a 0.3g PGA. The SMA conservatively concluded that BNP has a plant-level HCLPF capacity of at least 0.3 PGA for the identified success path and the components included in the path.

The plant level seismic fragility is the conditional probability of plant damage at a given seismic hazard input level. The BNP plant-level fragility curve was developed by the NRC as part of the GI-199 assessment (Reference 4) based on information provided in the BNP IPEEE submittal. Appendix C of the GI-199 report defines the methods the NRC used to estimate a plant-level fragility from information reported in the IPEEE. Since BNP conducted a focused-scope SMA for the 0.3g RLE as part of the IPEEE, the NRC estimated the plant-level fragility based on the reported plant-level HCLPF values of assessed components, and an estimate of the composite variability, βc, from the SMA components. The HCLPF is related to the median seismic capacity by:

$$C_{50} = \text{HCLPF} \times \exp(2.3264 \times \beta_c)$$

where:

- HCLPF is the limiting seismic capacity of a component (from the SMA) whose seismic failure would lead directly to core damage,
- C_{50} (or a_m) is the median (50th percentile) plant-level acceleration capacity (g), and
- β_c is the composite variability in the plant-level acceleration capacity.

The GI-199 report states that the RLE demand curve is the lower bound on the actual HCLPF capacity of the plant level fragility curve, where:

HCLPF = 0.3g
C_{50} (or a_m) = 0.76g, and
β_c = 0.4.

The plant level seismic fragility is modeled as a cumulative log-normal distribution function for each acceleration:

$$P_f(a) = \Phi\left(\ln(a/a_m) / \beta_c \right)$$

where:

- $P_f(a)$ is the conditional probability of failure for a given acceleration, a,
- Φ is the cumulative normal distribution function in Excel (NORMSDIST or NORM.S.DIST),
- a is the given seismic acceleration demand of interest (g),
- a_m (or C_{50}) is the median (50th percentile) plant-level acceleration capacity (g) at each spectral frequency, and
- β_c is the composite variability in the mean fragility curve.

The BNP plant level fragilities at PGA for the RLE were calculated and are plotted in Figure 3 below. The cumulative probability of failure is 1.0 for ground accelerations greater than 5g. These values are inherently conservative as they represent the lower bound HCLPF capacity based on the most limiting component in the plant, and they are used as both the seismic conditional core damage probabilities (SCCDPs) and the seismic conditional large early release probabilities (SCLERP) for the SCDF/SLERF calculations.

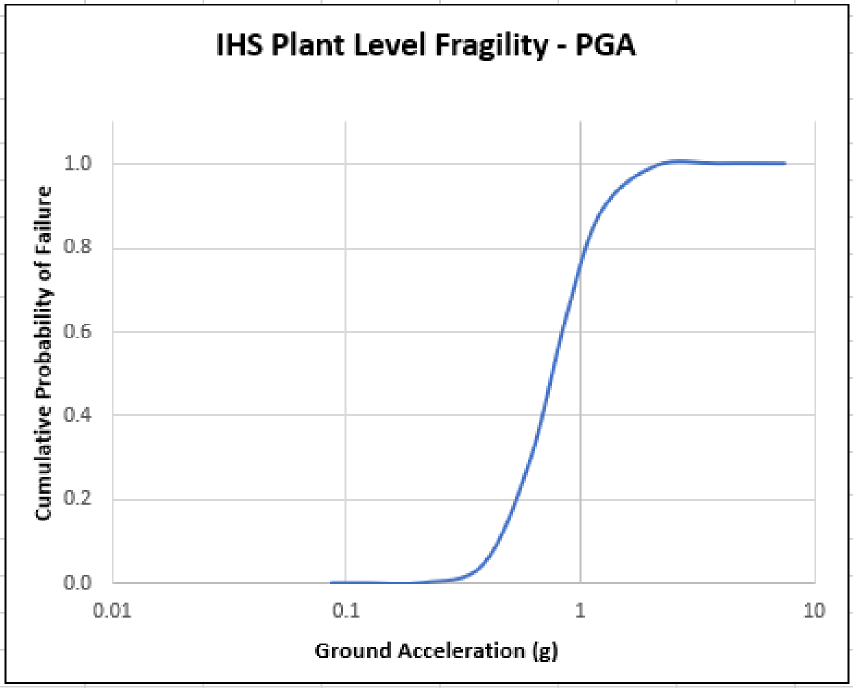

Figure 3 – BNP Plant Level Fragility for the Review Level Earthquake (RLE) (0.3g)

Civil structures, equipment, and subsystems were screened in the IPEEE following the methodology for focused and full -scope plants. The screening methodology followed the applicable guidance, so it can be concluded that the screening of BNP components is adequate for IPEEE screening purposes. In addition, walkdowns to address NRC Fukushima NTTF Recommendation 2.3 have been completed in accordance with the EPRI seismic walkdown guidance (Reference 12). There were no vulnerabilities identified, and identified enhancements were reviewed and found to be complete. BNP confirmed through walkdowns that the existing monitoring and maintenance procedures keep the plant consistent with the design basis.

In order to validate that the components included in the SMA are representative of the as-built, as-operated plant, the components on the Seismic Safe Shutdown Equipment List (SSEL) were assessed (Reference 13) to support the BNP 10 CFR 50.69 LAR. The intent of the assessment was to validate that the equipment credited in the SMA success paths still perform the credited function, and to determine if any new equipment in the success paths have been added to the list. Engineering changes (ECs) generated from 1990 to April 26, 2017, were identified and reviewed to validate the equipment credited in the success paths described in the SMA.

The EDG starting air receivers that would have been on the SSEL if they had been installed at the time of the IPEEE analysis have been installed since the SMA was completed. This equipment has been added to the SSEL. In addition, a set of equipment (15 items – primarily valves – listed in Attachment 2 of Reference 13) that have been removed, spared, or abandoned in place and that do not impact the SMA success paths has been removed from the SSEL. No major changes have been made to the plant since the assessment was completed, and there have been no Internal Events Model of Record updates for BNP since 2017. This provides high confidence that the components from the SMA used to determine the plant level fragility are representative of the as-built, as-operated plant. The results of the review demonstrated the design changes to the plant since issuance of the IPEEE have not invalidated the Seismic Margins Analysis and that the risk insights obtained from the IPEEE are still valid under the current plant configuration.

Estimating SCDF and SLERF

The approach to estimation of the SCDF for use as the seismic penalty in RICT calculations is to perform a numerical convolution calculation of the BNP seismic hazard curve with the BNP plant level seismic fragility curve. Convolution is a mathematical term that refers to combining (e.g., multiplying) two or more inter-related functions. In the case of seismic risk estimation, the inter-related functions are the seismic hazard curve and SSC fragility curves. The hazard curve is a function of increasing magnitude of the hazard load with corresponding reduction in occurrence frequency. The SSC fragility function is increasing probability of SSC failure with increasing magnitude of the hazard load. Convolution is a basic aspect of SPRA (as well as other hazard risk models, e.g., high winds and tornadoes).

This is a commonly used approach to estimate SCDF when a seismic PRA is not available. This approach is the same as that used in past LAR submittals. The NRC used this approach in the GI-199 risk assessment (Reference 4), and this method is also discussed in sections 10-B.9-3 and 10-B.9-4 of the ASME/ANS PRA Standard (Reference 10).

The convolution calculation of the seismic hazard curve with the Brunswick PGA-based plant level seismic fragility curve is performed by dividing the hazard curve into seismic magnitude range intervals. In the case of the seismic hazard curve in Table 1, ten seismic hazard intervals are explicitly used in this convolution calculation and are defined by the magnitude data points which is consistent with the intervals typically used in SPRAs. The very low magnitude data points and the very high magnitude data points are non-significant to the convolved SCDF estimate because of very low likelihood of damage and very low likelihood of occurrence, respectively.

To facilitate calculation of the BNP plant fragility probability at each seismic hazard interval, a representative g-level is calculated for each interval. The representative g-level for the seismic hazard intervals is calculated using a geometric mean approach (i.e., the square root of the product of the g-level values at the beginning and end of a given interval). For the last open-ended seismic interval greater than 5g, the representative g-level is estimated as 1.5X the exceedance frequency (5g) per SPRA convention. However, this point is immaterial given that the calculated conditional failure probability at a g-level >5g is 1.0 and the contribution from this final interval has a negligible contribution to the overall SCDF estimate.

The seismic hazard interval annual initiating event frequency is calculated (except for the final interval) by subtracting the mean exceedance frequency associated with the g-interval (high) end point from the mean exceedance frequency associated with the g-interval beginning point. The frequency of the last seismic hazard interval is the exceedance frequency at the beginning point of that interval. This is common practice in industry SPRAs (Reference 6).

The SCDF for each hazard interval is the product of the hazard interval initiating event frequency (/yr) and the plant level fragility failure probability for that same hazard interval. The results per hazard interval are then straight summed to produce the overall total SCDF across the entire hazard curve. The SCDF convolution calculation determined that the total estimated SCDF is 3.02E-06/yr.

The BNP IPEEE provides no quantitative information regarding the LERF risk metric. For development of a seismic penalty estimate for RICT calculations, the SCLERPs are conservatively represented by convolving the obtained SCCDP with the plant level fragility for the various seismic hazard bins. This is a conservative, but reasonable approach as the plant level fragility HCLPF also represents the lower bound HCLPF capacity of the containment. This is a meaningful, bounding estimate because structural capacity is also the lower bound fragility. The seismic LERF estimate was determined by the convolution of the seismic CDF with the SCLERP using the same HCLPF value of 0.3g PGA as the SCDP. All analyses were performed using seismic hazard data and the plant level fragilities described previously. Table 2 provides a summary and description of the convolution calculations, respectively.

Table 2 – SCDF/SLERF Calculations for Peak Ground Acceleration (PGA)

Ground Acceleration (g)	Cumulative Mean Annual Frequency of Exceedance (MAFE) (per year)	Bin Number	Bin Mean Acceleration (g)	Delta-Exceedance Frequency of Bin	CDF Fragility at Bin Mean Acceleration	LERF Fragility at Bin Mean Acceleration	Bin CDF (per year)	Bin LERF (per year)
0.0005	3.29E-02		0.0007	8.00E-03	0.00	0.00	-	-
0.001	2.49E-02		0.002	1.68E-02	0.00	0.00	-	-
0.005	8.12E-03		0.007	3.58E-03	0.00	0.00	-	-
0.01	4.54E-03		0.012	1.37E-03	0.00	0.00	-	-
0.015	3.17E-03		0.021	1.61E-03	0.00	0.00	-	-
0.03	1.56E-03		0.039	7.60E-04	0.00	0.00	-	-
0.05	8.00E-04		0.061	3.83E-04	0.00	0.00	-	-
0.075	4.17E-04	1	0.0866	1.72E-04	2.8E-08	2.8E-08	4.85E-12	1.37E-19
0.1	2.45E-04	2	0.1225	1.40E-04	2.5E-06	2.5E-06	3.52E-10	8.85E-16
0.15	1.05E-04	3	0.2121	8.51E-05	7.1E-04	7.1E-04	6.05E-08	4.30E-11
0.3	1.99E-05	4	0.3873	1.48E-05	0.046	0.046	6.79E-07	3.12E-08
0.5	5.13E-06	5	0.6124	3.46E-06	0.295	0.295	1.02E-06	3.00E-07
0.75	1.67E-06	6	0.8660	9.38E-07	0.628	0.628	5.89E-07	3.70E-07
1	7.32E-07	7	1.2247	5.15E-07	0.884	0.884	4.55E-07	4.02E-07
1.5	2.17E-07	8	2.1213	1.96E-07	0.995	0.995	1.94E-07	1.93E-07
3	2.15E-08	9	3.8730	1.84E-08	1.000	1.000	1.84E-08	1.84E-08
5	3.09E-09	10	7.5000	3.09E-09	1.000	1.000	3.09E-09	3.09E-09
7.5	5.56E-10	-	-	-	-	-	-	-
10	1.48E-10	-	-	-	-	-	-	-
						SCDF:	**3.02E-06**	
						SLERF:		**1.32E-06**

Results

The calculated results of the SCDF and SLERF estimates for the BNP are:

- $SCDF_{avg}$ = 3.02E-06 (per year),
- $SLERF_{avg}$ = 1.32E-06 (per year), and
- SLERF/SCDF Ratio: 0.44.

The SCDF/SLERF calculation results are shown included in Appendix A. These results are inherently conservative because the seismic initiating frequencies are convolved with the plant level fragility whose HCLPF capacity is based on the most limiting component in the SMA. As such, the plant level fragility represents a SCCDP that is more conservative than a CCDP estimate calculated from a plant support model. No credit is taken for systems modeling, accident mitigation strategies, including FLEX, or for operator actions. Similarly, the conservative SCDF is an input to the SLERF computations, and the screening or lower bound capacity from the RLE is used as the controlling containment fragility (0.3g PGA) for the SLERF calculations. This results in conservatively biased SCLERP and SLERF calculations.

For any RICT with a 30-day backstop, the seismic ICDP and seismic ILERP would be:

- ICDP = 2.48E-07 (per 30 days), and
- ILERP = 1.08E-07 (per 30 days).

Comparison of SCDF Estimates with BSEP Historic and Other Plant Evaluations

The SCDF PGA point estimate for BNP is compared in Table 3 with the SCDF estimates developed by the NRC in 2010 using the 2008 U.S. Geological Survey (USGS) and the 1994 Lawrence Livermore National Laboratory (LLNL) seismic hazard curves. These were the most recent seismic hazard assessment available at the time of the 2010 study. The assessment with the 1989 EPRI hazard curves was used by the NRC in its review of seismic evaluations submitted with the IPEEEs.

Several other Boiling Water Reactors (BWRs) (Hatch, Peach Bottom, and Columbia) have previously completed SPRAs for NTTF submittals while others (Limerick, Nine Mile Point, LaSalle, and Clinton) have completed seismic evaluations based on IPEEE analyses to support LARs for TSTF-505. The average SCDF/SCLERF for each of these plants are shown in Table 4. To account for potential uncertainties in the SCLERP calculations for use in RICT calculations, the seismic assessment plants (i.e., Limerick, Nine Mile Point, LaSalle, and Clinton) assumed SCLERPs to be used as a conservative value to provide additional safety margin for use in the SLERF “penalties” for the RICT calculation. The conservative SCLERP estimate for BNP is 0.44 and is one of the most limiting estimates observed for those plants with seismic PRAs or plants that performed a bounding seismic assessment for the purpose of TSTF-505.

Table 3 – Comparison of SCDF for the Historical BNP Seismic Hazard Evaluations

BNP	SCDF (PGA)	Reference
2014 NTTF Seismic Hazard Evaluation	3.02E-06	See above: From BNP-PSA-120
2008 USGS Seismic Hazard Curves	9.50E-06	Reference 4
1994 LLNL Seismic Hazard Curves	1.40E-05	Reference 4
1989 EPRI Seismic Hazard Curves	3.30E-06	Reference 4

Table 4 – Seismic Risk Estimates for BWRs

Plant	SCDF (per year)	SLERF (per year)	SCLERP	Reference
Seismic PRA's				
Hatch	U1: 3.88E-07 U2: 2.45E-07	U1: 1.38E-07 U2: 1.35E-07	U1: 0.36 U2: 0.55	Reference 14
Peach Bottom	U2: 2.1E-05 U3: 2.1E-05	U2: 4.0E-06 U3: 4.1E-06	U2/U3: 0.19	Reference 15
Columbia	2.0E-05	8.80E-06	0.44	Reference 16
Seismic Assessment for TSTF-505				
Limerick	3.70E-06	1.85E-06	0.48 (estimated) 0.50 (assumed for conservatism)	Reference 17
Nine Mile Point	6.40E-07	3.2E-07	0.32 (estimated) 0.50 (assumed for conservatism)	Reference 18
Lasalle	1.1E-05	2.2E-06	0.02 (estimated) 0.20 (assumed for conservatism)	Reference 19
Clinton	6.4E-06	1.6E-06	0.25	Reference 20
Brunswick	3.02E-06	1.32E-06	0.44	See above: From BNP-PSA-120

<u>Seismic Conclusions</u>

The results from this calculation provide the technical basis for addressing seismic risk in BNP's TSTF-505 application. The updated site-specific seismic hazard information from BNP's 50.54(f) submittal to the NRC have been used to estimate the BNP seismic risk based on NRC/EPRI methodologies.

The estimate of BNP's seismic CDF is 3.02E-06/yr, and the estimate of the seismic LERF is 1.32E-06/yr. These results are inherently conservative because the seismic initiating frequencies are convolved with the plant level fragility whose HCLPF capacity is based on the most limiting component in the SMA. As such, the plant level fragility represents a seismic CCDP that is more conservative than a CCDP estimate calculated from a plant support model. No credit is taken for systems modeling, accident mitigation strategies, including FLEX, or for operator actions. Similarly, the conservative SCDF is an input to the SLERF computations, and the CCDP is used as the CLERP or lower bound capacity for the SLERF calculations. This results in a conservatively biased seismic CLERP and a conservative SLERF calculation.

These results can be used in each RICT calculation under TSTF-505 by adding a seismic penalty value of 3.02E-06/year to the CDF and 1.32E-06/year to the seismic LERF. This method ensures that an incremental seismic CDF/LERF risk for every RICT includes a reasonably conservative estimate of SCDF/SLERF risk that does not exceed the estimated annual maximum seismic risk.

Electrical Engineering Branch (EEEB) Audit Questions

EEEB Q2 – LCO 3.8.1

Address the following inquiries regarding TS LCO 3.8.1:

a. *Explain the applicability of Insert 2 in TS LCO 3.8.1, Condition D.4.*

Duke Energy Response to EEEB Q2, Part a

INSERT 2 from the original LAR for both the Unit 1 and Unit 2 TS markups states:

> 7 days
>
> OR
>
> In accordance with
> the Risk-Informed Completion Time
> Program

Prior to the issuance of Brunswick license amendments 264 and 292, the front stop Completion Time for Condition D ("One DG inoperable for reasons other than Condition B."), Required Action D.4 (currently Required Action D.5; "Restore DG to OPERABLE status.") was 7 days. Upon issuance of those risk-informed license amendments the Completion Time could be extended to 14 days provided the SUPP-DG is available. For the proposed Brunswick RICT Program, the intent of INSERT 2 from the original LAR is to eliminate the 14-day risk-informed Completion Time and restore the 7-day Completion Time for one inoperable DG, as that was the acceptable and approved licensing basis Completion Time prior to the issuance of Amendments 264 and 292. With INSERT 2 from the original LAR applied, the structure of the Completion Time for one inoperable DG will more closely resemble NUREG-1433 STS and allow for easy application of a RICT. Elimination of the existing 14-day risk-informed Completion Time and restoration of the 7-day Completion Time is consistent with NRC guidance regarding implementation of TSTF-505, Revision 2.

It is noted that the SUPP-DG is removed from Technical Specifications in the proposed TS markups. The SUPP-DG will no longer be required to be available for the 7-day front stop Completion Time to apply. However, the SUPP-DG will remain available for defense-in-depth and is also incorporated into the PRA.

b. The LAR states that TS LCO 3.8.1, Required Action D.2 was added as part of amendment numbers 264 and 292 to support extension of the completion time for Required Action D.1 (restoration of an inoperable EDG). The justification for this amendment denoted that the Supplemental Diesel Generator (SUPP-DG) provided additional defense-in-depth. Please provide justification for the use of RICT with the proposed removal of the Supplemental DG from LCO 3.8.1, Required Action D.2.

Duke Energy Response to EEEB Q2, Part b

With INSERT 2 from the original LAR applied as discussed above in Part a, there will no longer be a 14-day Completion Time, which is dependent upon SUPP-DG availability, for an inoperable DG. The front stop Completion Time will be 7 days with no regard for the status of the SUPP-DG availability. It is true that the SUPP-DG will continue to be available as defense-in-depth, but it would not be needed to exceed the 7-day Completion Time (i.e., front stop). The justification for a RICT being applied to Required Action D.4 ("Restore DG to OPERABLE status.") with a front stop of 7 days is that Brunswick Required Action D.4 directly correlates to Required Action B.4 of TSTF-505/NUREG-1433. The DGs are also explicitly modeled in the BSEP PRA and thus a RICT can directly be calculated in the real-time risk model (i.e., Phoenix).

c. For Table E1-1 in LAR, LCO 3.8.1 Conditions C, D, E, and F, please explain why each of these require three emergency buses to be available for all events. Additionally, please discuss what "all events" refers to in the context of this inquiry.

d. Please explain why in table E1-1, for TS 3.8.1, Condition D, it is stated that an "An EDG is adequate for each bus. Three emergency buses are adequate for all events" when only three emergency buses are needed.

Duke Energy Response to EEEB Q2, Parts c and d

Each unit has four (4) 1000 hp RHR pumps and four (4) 800 hp RHRSW pumps. There is one Unit 1 RHR pump and one Unit 1 RHRSW pump fed from each of the 4 kV emergency buses (E1, E2, E3 and E4). Similarly, there is one Unit 2 RHR pump and one Unit 2 RHRSW pump fed from each of the 4 kV emergency buses. For this reason, the design basis of the emergency power system is that any three of the four 4 kV emergency buses (including associated EDGs and downstream distribution networks) are capable of powering equipment necessary for mitigating an accident on one unit while bringing the other unit to a safe shutdown condition.

"All events" refers to all analyzed events up to and including the worst-case design basis event.

EEEB Q4 – Electric Distribution Systems Design Success Criteria

The design success criteria column in Table E1-1 of Enclosure 1 to the LAR includes short descriptions of the existing assumptions of "success" for each of the TS LCO conditions proposed for inclusion into the RICT program, including those relative to the electrical distribution system. Address the following as they relate to the design success criteria for the LCOs below:

a. *Please explain the need for "three trains of DC power" per unit, as discussed in Table E1-1 for LCO 3.8.4, Condition A*

b. *Please explain need for "three of four DC distribution systems" as discussed in Table E1-1 for LCO 3.8.7, Conditions C and D.*

c. *Please explain need for "three of four load groups" as discussed in Table E1-1 for LCO 3.8.7, Condition A.*

<u>Duke Energy Response to EEEB Q4, Parts a and b</u>

The reason that "three trains of DC power" for TS 3.8.4, Condition A and "three of four DC distribution systems" for TS 3.8.7, Conditions C and D are needed as discussed in Table E1-1 of the LAR is that each Brunswick unit requires the other unit's DC sources and distribution. However, the unit can meet all safety functions with a loss of one source or loss of one distribution subsystem.

As discussed, and presented during the September 2021 regulatory audit, the following from the TS Bases further elaborates on the design success criteria for TS 3.8.4 and TS 3.8.7.

Per the TS 3.8.4 Bases (Unit 2 is shown):

> The Unit 2 Division I and Division II DC electrical power subsystems, with each DC subsystem consisting of two 125 V batteries (Batteries 2A-1 and 2A-2 for Division I and Batteries 2B-1 and 2B-2 for Division II), two battery chargers (one per battery) and the corresponding control equipment and interconnecting cabling supplying power to the associated bus are required to be OPERABLE to ensure the availability of the required power to shut down the reactor and maintain it in a safe condition after an anticipated operational occurrence (AOO) or a postulated DBA. In addition, DC control power for operation of two of the four 4.16 kV emergency buses and two of the four 480 V emergency buses, as well as control power for two of the four DGs, is provided by the Unit 1 DC electrical power subsystems. Therefore, Unit 1 Division I and Division II DC electrical power subsystems are also required to be OPERABLE. Unit 1 DC electrical power subsystem OPERABILITY requirements are the same as those required for a Unit 2 DC electrical power subsystem. Loss of any DC electrical power subsystem does not prevent the minimum safety function from being performed (Ref. 1).

Per the TS 3.8.7 Bases:

> With one or more DC electrical power distribution subsystems inoperable due to loss of normal DC source, the remaining DC electrical power distribution subsystem(s) are capable of supporting the minimum safety functions necessary to shutdown the reactor and maintain it in a safe shutdown condition, provided safety function is not lost and assuming no single failure. However, the overall reliability is reduced because a single failure in the DC electrical power distribution system could result in a loss of two of four AC electrical load groups and the minimum required ESF functions not being supported. Therefore, action must be immediately initiated to transfer the DC electrical power distribution system to its alternate source and the affected supported equipment immediately declared inoperable. Upon completion of the transfer of the affected supported equipment's DC electrical power distribution subsystem to its OPERABLE alternate DC source, the affected supported equipment may be declared OPERABLE again. The ESS logic cabinets transfer automatically upon loss of the normal source. For an ESS logic cabinet, verification that the automatic transfer has occurred and alternate power is available to the ESS logic cabinet will satisfy Required Action C.2.

Duke Energy Response to EEEB Q4, Part c

Each unit has four (4) 1000 hp RHR pumps and four (4) 800 hp RHR Service Water (RHRSW) pumps. There is one Unit 1 RHR pump and one Unit 1 RHRSW pump fed from each of the 4 kV emergency buses (E1, E2, E3 and E4). Similarly, there is one Unit 2 RHR pump and one Unit 2 RHRSW pump fed from each of the 4 kV emergency buses. For this reason, the design basis of the emergency power system is that any three of the four 4 kV emergency buses (including associated EDGs and downstream distribution networks) are capable of powering equipment necessary for mitigating an accident on one unit while bringing the other unit to a safe shutdown condition.

The Class 1E AC electrical distribution system is divided into four load groups. Each load group consists of a primary emergency bus, its downstream secondary emergency bus, 120 VAC vital bus, and transformers and interconnecting cables. The buses associated with each of the four load groups are defined as follows:

Load group E1 consists of 4.16 kV bus E1, 480 V bus E5, and 120 VAC vital bus 1E5.
Load group E2 consists of 4.16 kV bus E2, 480 V bus E6, and 120 VAC vital bus 1E6.
Load group E3 consists of 4.16 kV bus E3, 480 V bus E7, and 120 VAC vital bus 2E7.
Load group E4 consists of 4.16 kV bus E4, 480 V bus E8, and 120VAC vital bus 2E8.

Thus, the need for 3 of 4 load groups.

<u>EEEB Q5 – Conservatism in RICT Estimates</u>

Note 3 in Table E1-2 of Enclosure 1 to the LAR indicates that the RICT estimates for certain TS action statements were derived from "the most limiting RICT calculation based on the most limiting component." For action statements in Table E1-2 where Note 3 is applicable, provide the configurations of the associated SSCs and identify limiting components including their RICT estimates.

The licensee has outlined several scenarios where a Risk-Informed Completion Time (RICT) could not be applied for electrical equipment in the context of Technical Specification (TS) Section 3.8 (e.g., Limiting Condition for Operation (LCO) 3.8.1, LCO 3.8.4). The licensee stated in its License Amendment Request (LAR) and during the audit that in the worst cases (i.e., the bounding scenarios), a RICT could not be applied for some of the conditions. This is also acknowledged by Note 1 to Table E1-2. Were there other scenarios (equipment configurations) beyond the worst cases where the licensee determined that a RICT could not be applied to LCOs in Section 8 of the TSs?

<u>Duke Energy Response to EEEB Q5</u>

For Condition A of TS 3.3.6.1, a conservative surrogate was used to cover all possible SSCs and Note 3 is no longer appliable to this condition. A revised LAR Table E1-2 entry for TS 3.3.6.1, Condition A is provided as follows.

Technical Specification Action Statements	BSEP Technical Specification Condition	BSEP Technical Specification Required Action	RICT Estimate (days)
<u>Primary Containment Isolation Instrumentation</u> TSTF-505: LCO 3.3.6.1, Condition A, RA A.1 BNP: LCO 3.3.6.1, Condition A, RA A.1	A. One or more required channels inoperable.	A.1 Place channel in trip.	N/A[1]

For Condition A of TS 3.8.4, the 4 cases evaluated for the sample calculations were Battery 1A-1, Battery 1A-2, Battery 1B-1 and Battery 1B-2 out of service. The results of the sample calculations showed that the limiting cases were Battery 1A1 and Battery 1B-2 out of service, which resulted in a CDF > 1E-3 and those results were reported in Table E1-2 of the original LAR. The other two cases from Battery 1A-2 and Battery 1B-1 have RICT estimates beyond the 30-day backstop.

For Condition B of TS 3.8.7, the 2 cases evaluated for the sample calculations were AC BUS E1 and AC BUS E2 out of service. The results of the sample calculations showed that the limiting case was AC BUS E1 out of service, but both cases resulted in a CDF > 1E-3 and those results were reported in Table E1-2 of the original LAR.

For Condition C of TS 3.8.7, the 4 cases evaluated for the sample calculations were Charger 1A-1, Charger 1A-2, Charger 1B-1 and Charger 1B-2 out of service. The results of the sample calculations showed that the limiting cases were Charger 1A1 and Charger 1B-2 out of service, resulting in a CDF > 1E-3. Those results were reported in Table E1-2 of the original LAR. The other two cases from Charger 1A-2 and Charger 1B-1 have RICT estimates beyond the 30-day backstop.

For Condition D of TS 3.8.7, the 4 cases evaluated for the sample calculations were 125V DC SWITCHBOARD 1A BUS P, 125V DC SWITCHBOARD 1A BUS N, 125V DC SWITCHBOARD 1B BUS P and 125V DC SWITCHBOARD 1B BUS N out of service. The results of the sample calculations showed that the limiting cases were 125V DC SWITCHBOARD 1A BUS P and 125V DC SWITCHBOARD 1B BUS N out of service, resulting in a CDF > 1E-3. Those results were reported in Table E1-2 of the original LAR. The other two cases from Charger 125V DC SWITCHBOARD 1A BUS N and 125V DC SWITCHBOARD 1B BUS P have RICT estimates beyond the 30-day backstop.

There were no other scenarios (equipment configurations) beyond the worst cases where it was determined that a RICT could not be applied to LCOs in Section 8 of the TS.

EEEB Q6 – TS Markup for LCO 3.8.4

Table E1-1 of Enclosure 1 to the LAR indicates that LCO 3.8.4 Conditions B and C will be included as part of the RICT program. However, the TS markups in Attachments 2 and 3 of the LAR do not include these TS conditions. Clarify whether LCO 3.8.4 Conditions B and C are within scope of the LAR and, if so, whether a note for loss of function is necessary for the proposed insert relative to TS 3.8.4 Condition C.

Duke Energy Response to EEEB Q6

TS 3.8.4, Actions B and C were listed in Table E1-1 of the original LAR inadvertently. Those TS Actions are not proposed to be in the scope of the Brunswick RICT Program. The TS 3.8.4 markup for Units 1 and 2 included in Attachments 1 and 2 of this submittal is reflective of what is proposed for the Brunswick RICT Program (i.e., Condition A, Required Action A.1 only and not Conditions B and C). A revised LAR Table E1-1 in Attachment 3 of this submittal also reflects that Actions B and C are not in scope of the proposed change.

EEEB Q7 – Modeling of Electric Plant for LCO 3.8.7

The proposed insert to Section 5.5 of the BNP TSs includes the following statement "A RICT may only be utilized in MODE 1 and 2" (see Attachments 2 and 3 of the LAR). Attachment 1 of the LAR on page 6 indicates, in part, that LCO 3.8.7 Condition A is a variation from the LCOs referenced in TSTF-505, Revision 2 (i.e., Standard TSs in NUREG-1433). The description of this variation indicates with the "opposite unit" (i.e., the shutdown unit) in MODE 4 or 5 and one AC electrical power distribution subsystem inoperable for planned status maintenance, the remaining AC electrical power distribution load groups can support the minimum safety functions necessary to shut down the operating unit and maintain both reactors in a safe condition. If the "opposite unit" (Unit 1 or Unit 2) is in MODE 1, 2 or 3, then LCO 3.8.7 Required Action A.1 for the opposite unit requires restoration of the associated AC electrical power distribution subsystem within 8 hours of the inoperability.

Clarify whether the configuraitons associated with TS 3.8.7 Condition A for the opposite unit are explicitly modeled in the BNP PRA and whether the opposite unit (either operating or shutdown) is modeled in PRA when affected unit is in the RICT program for this TS Condition.

Duke Energy Response to EEEB Q7

Configurations associated with TS 3.8.7 Condition A for the opposite unit are explicitly modeled in the Brunswick PRA. Also, the opposite unit (either operating or shutdown) is modeled in the PRA for scenarios when the affected unit would be in the proposed RICT program for this TS Condition.

EEEB Q8 – Emergency Bus Crossite Actions

Relative to Audit Request R14, provide the relevant portion(s) (high level steps) of Procedure 0AOP-36.1 that would address a worst-case loss of a 4.16 kV emergency bus due to its Emergency Diesel Generator (EDG) being in a RICT (EDG not recoverable) assuming a station Loss of Offsite Power (LOOP) and a Loss of Coolant Accident (LOCA) on the opposite unit, including any cross connections between 4.16 kV buses that would be directed by the procedure.

Duke Energy Response to EEEB Q8

As requested by the NRC staff during the September 2021 regulatory audit, Duke Energy confirms that the 4160 V power supplies and loads are explicitly modeled in the PRA.

Scenario/Initial Conditions for Response to EEEB Q8:

Both Units are in MODE 1, 100% power.
EDG #1 is out of service and is in a RICT.
A site LOOP occurs.
Unit 2 experiences a LOCA.

Response:

As requested by the NRC staff during the September 2021 regulatory audit, Duke Energy confirms that the 4160 V power supplies and loads are explicitly modeled in the PRA.

The Shift Manager and Control Room Supervisor (i.e., Senior Reactor Operator licensed individuals) would evaluate plant conditions and utilize generic guidance from BNP procedure AD-OP-BNP-1001, “Conduct of Abnormal Operations,” to determine whether a cross-tie of E3 to E1 would be desired. Another option available for use in this scenario is the SUPP-DG. The decision would be based upon resources and time.

BNP CONDUCT OF ABNORMAL OPERATIONS	AD-OP-BNP-1001
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5.3.1 General Strategies for Effective Control (continued)

- Starting/stopping loads that are being powered from a diesel generator should be coordinated with other ROs. This is of particular importance for loads on:
  - ◊ A diesel generator on the opposite unit.
  - ◊ A diesel generator operating in MANUAL.
- Consideration should be given to the performance of E-Bus cross-ties if the cross-ties will provide additional injection sources, provide critical RPV level and containment monitoring instrumentation, allow for the isolation of leakage pathways or performance of EOP actions. The benefits of the action(s) to be taken should be weighed against the of potential detrimental effect of cross-tying.

Further, the operator executing Brunswick procedure 0AOP-36.1, “Loss of Any 4160V Buses or 480V E-Buses,” would execute step 6 (depicted below) once directed by the Control Room Supervisor to cross-tie E3 to E1.

LOSS OF ANY 4160V BUSES OR 480V E-BUSES	0AOP-36.1
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6. **IF AT ANY TIME** during performance of this procedure, additional power is needed to support the EOPs,
THEN perform Section 4.2.11 on page 62 to cross-tie E buses

4.2.1 Actions Determination (continued)

7. **IF AT ANY TIME** during performance of this procedure, additional power is needed to support the EOPs and it is desired to utilize the Supplemental Diesel Generator,
THEN perform Section 4.2.12 on page 69 concurrently with this section. .... ☐

The basis for the cross-tie is as follows:

	E3	E4	E1	E2
RHR	1A 2A	1B 2B	1C 2C	1D 2D
RHR SW	1A 2A	1B 2B	1C 2C	1D 2D
Core Spray	2A	2B	1A	1B
CRD	2A	2B	1A	1B
NSW	2A	2B	1A	1B
CSW	— 2A	1A 2B	1B 2C	1C —
Fire Pump		Alt		Norm

Note that the Unit 2 RHR A loop injection valves are powered from E1-E5-MCC 2XA-2. Without a cross-tie, both Unit 2 divisions of Core Spray are available for low pressure injection; however, only Division 2 RHR is available. With a LOCA in progress on Unit 2, the operating crew would choose to cross-tie in order to have redundancy in low pressure ECCS.

The cross-tie procedural steps from 0AOP-36.1 are as follows:

4.2.11 Emergency Bus Cross-Tie

NOTE

If cross-tying E-buses, Technical Specification 3.8.7 or 3.8.8 should be consulted. ☐

1. **IF** desired to cross-tie a 4160V E bus,
   THEN: ☐
   a. **Confirm** using Attachment 5, 4160V E Bus Lockout Indications, indications of a lockout, **OR** phase overcurrent trip do **NOT** exist. ☐
   b. **Confirm** availability of diesel generator(s) **OR** off-site power on the opposite unit ☐
   c. **Obtain** permission from both Units' CRS to close the 4160V E bus cross-tie breakers. ☐

NOTE

- Placing SS-B, local cross-tie breaker (Control Selector Switch), to MAINT with a LOCA signal present initiates a 10 minute delay before breaker closure is permitted. ☐
- E bus cross-tie breaker keys (TEM30), will be needed to allow closing the breakers addressed in this section. ☐

   d. **Place** the selected bus cross-tie keylock control switches to MAINT:

      Cross-tie E1 and E3:

      - 1-E1-AG0-SS-B (Row-O1) (Local Sel SW For Tie Bkr To Swgr E3) ☐

        AND

      - 2-E3-AJ5-SS-B (Row-N1) (ASSD SW In E3 Tie Bkr To E1 Cub) ☐

      Cross-tie E2 and E4:

      - 1-E2-AH9-SS-B (Row-P1) (Local Sel SW For Tie Bkr To Swgr E4) ☐

        AND

      - 2-E4-AL5-SS-B (Row-Q1) (ASSD SW In E4 Tie Bkr To E2 Cub) ☐

EEEB Q9 – Supplemental Diesel Generator Credit

Discuss whether the Supplemental Diesel Generator (SUPP-DG) is credited for mitigating the consequences of a LOOP coincident with a LOCA.

Duke Energy Response to EEEB Q9

The Brunswick PRA model does not differentiate between SUPP-DG credit between LOCA and non-LOCA initiating events because a LOOP-LOCA is a very low probability event. Thus, credit for the SUPP-DG is given for mitigating the consequences of a LOOP coincident with a LOCA.

A sensitivity was performed removing all credit from the SUPP-DG for LOCA initiating event sequences. This is conservative because the SUPP-DG would be able to support long-term aspects of the LOCA sequences, such as wet-well cooling. The base case results showed no difference in results because any credit given for the SUPP-DG for LOCAs fell below truncation. The sensitivity was also performed on the most limiting condition for the “AC Sources – Operating: LCO 3.8.1, Condition F” Case (One DG inoperable and One offsite circuit inoperable). The original RICT was calculated well beyond the 30-day backstop Completion Time. This sensitivity showed that the RICT would decrease by 0.1 days if no credit was given for the SUPP-DG for LOCA sequences. The other Technical Specifications proposed to be scoped into the RICT Program are not expected to be impacted by removing any credit for the SUPP-DG for LOCAs based on these sensitivities.

A PRA issue tracker was created to address removing credit of the SUPP-DG for LOCA sequences in the Brunswick PRA model.

EEEB Q10 – Actions and Plant Response to the Unavailability of a DC Subsystem

State the procedure(s) that address unavailability of one DC subsystem (125/250 Vdc battery) due to maintenance (and hypothetical use of a RICT). Additionally, state the plant response to a station LOOP and LOCA on the opposite unit, assuming the unavailability of the DC subsystem.

Duke Energy Response to EEEB Q10

The following procedures are used to remove a battery from service and were provided to the NRC staff to review during the September 2021 regulatory audit:

- 0OWP-51/4, Removal of A Unit 1/2 125/250 Volt DC Switchboard from Service
- 0OWP-51/1, Removal of 125 VDC Battery From Service Including DC Control Power Alignment

Assuming these procedures are executed for U1 Division 1 DC power and then a site LOOP and Unit 2 LOCA occurs, no adverse response is expected to the LOCA unit assuming no additional equipment failures. EDGs 3 and 4 would start and load as designed. There would be no impact on E3 and EDG 3 control power (only back up control power is unavailable). EDG 1 would start and load. This is due to swapping logic power to Unit 2 Division 1 power per procedure. EDG 2 would start as designed. Unit 1 would have several loads supplied by alternate DC power; however, Unit 1 is shutdown in the postulated scenario.

<u>EEEB Q11 – LOOP/LOCA Scenarios with One DG in a RICT</u>

For the two scenarios of (1) small break LOCA in one unit concurrent with station LOOP and (2) large break (or design basis) LOCA in one unit concurrent with station LOOP, please provide the following for each scenario assuming one DG in RICT and is unavailable:

- *<u>Minimum</u> load groups required for safe shutdown of the accident and non-accident units*
- *Any tie breakers for 4.16 kV safety buses required to be closed*
- *<u>Minimum</u> RHR, CS, and RHRSW pumps required per load group*
- *Any load groups where DG loading is required to be closely monitored*
- *Agreement with Table E1-1 of the LAR for applicable TS 3.8.1 conditions*

<u>Duke Energy Response to EEEB Q11</u>

Duke Energy has performed a calculation that addresses loading on the EDGs assuming one EDG is unavailable and a site LOOP occurs concurrent with a LOCA on one unit.

The minimum load groups for a large break LOCA (on Unit 2) with a site LOOP and EDG 4** in a RICT are:

- All E5,6,7 480v loads
- 1A,1B,2A NSW pumps
- 1C,2C*,2D*,2A* RHR pumps
- 2A CS pump *
- 2C,1B,2A CSW pumps
- 1C,2C,2A RHRSW pumps
- 1B Control Rod Drive (CRD) pump

* Pumps would be cycled as needed to maintain adequate core cooling.
** Load groups would be similar for different EDGs in a RICT.

No cross-tie breaker operation is required, however Shift Manager and Control Room Supervisor could make the decision to cross-tie to gain redundancy.

The minimum load groups for a small break LOCA with a site LOOP and EDG 4** in a RICT are:

- All E5,6,7 480v loads
- 1A,1B,2A NSW pumps
- 1C,2C,2A RHR pumps
- 2C,1B,2A CSW pumps
- 1C,2C,2A RHRSW pumps
- 1B CRD pump

HPCI and RCIC will be utilized for reactor water makeup strategy for the LOCA unit instead of low pressure ECCS.

EDG loading is closely monitored when operators manually start equipment powered from the EDG. Operators ensure correct LOCA equipment AUTO starts as required.

Table E1-1 of the original LAR states "The success criteria in the PRA are consistent with the design basis criteria." In general, the design of the plant is a site LOOP concurrent with a LOCA on one unit and an EDG out of service, which is the same as the success criteria.

Technical Specifications Branch (STSB) Audit Questions

STSB Q1 – Technical Specification Markups

Attachments 2 and 3 include markups of the Technical Specifications (TSs) to support the proposed implementation of a RICT program at BNP Unit 1 and Unit 2, respectively. Address the following inquiries and observations relative to these markups:

a. *Example 1.3-8 does not match the formatting in TSTF-505, Revision 2, in some places. In TSTF-505, the title is in all capital letters and underscored, and logical connectors are underscored.*

b. *The proposed administrative controls in TS 5.5.15 paragraph c.2 of Insert 3 states "Action Completion Time" instead of "Required Action Completion Time," the latter which is provided in TSTF-505, Revision 2.*

c. *The proposed administrative controls in TS 5.5.15 paragraph e of Insert 3 include the phrase "this license amendment." In lieu of the phrase "this license amendment," discuss whether the phrases "Amendment # xxx" or, as discussed in the TSTF-505 model SE, "this program" would provide more clarity for this paragraph.*

Duke Energy Response to STSB Q1, Part a

Attachments 1 and 2 of this submittal contain revised TS markups for Units 1 and 2 that supersede the TS markups provided in the original LAR. The logical connectors "AND" and "OR" are now clearly depicted as being underscored. Also, to match the TSTF-505, Revision 2 markup for Example 1.3-8, the title is now marked up as follows: "EXAMPLE 1.3-8."

Duke Energy Response to STSB Q1, Part b

The markup for TS 5.5.15 in Attachments 1 and 2 of this submittal now reflects "Required Action Completion Time" to be consistent with the markup in TSTF-505, Revision 2.

Duke Energy Response to STSB Q1, Part c

The markup for TS 5.5.15 now reflects the phrase "Amendment No. [XXX]" in lieu of "this license amendment."

STSB/SCPB Q2 – Table E1-3 Additional Justifications Required

The proposed RICT program includes LCO 3.7.6 which addresses operability of the BNP main turbine bypass valves (LCO 3.7.7 in Standard TSs). Condition A is entered when the LCO is not met. Table E1-3 in Enclosure 1 of the LAR provides the additional justification required for this LCO consistent with Table 1 in TSTF-505, Revision 2. For Unit 2, discuss further how the common cause failure basic event for all bypass valves proposed for the RICT program ensures that the PRA success criteria bound the design-basis success criteria.

Duke Energy Response to STSB/SCPB Q2

As noted in the additional justification for Unit 1 that was provided in Enclosure 1 of the original LAR, the success criteria in the PRA are more restrictive than the design basis criteria for the turbine bypass valves (TBVs). In the Unit 1 PRA, a failure of any one of the four bypass valves, fails the system. However, for Unit 2, the design basis success criteria is “Eight of Ten U2 Bypass Valves are required to be OPERABLE,” while the PRA success criteria is “Three of its ten turbine bypass valves must open” to support the PRA function. Thus, to account for the difference, the Unit 2 LCO is mapped to a common cause failure (CCF) basic event that fails all ten bypass valves, which fails the system, when any of the Unit 2 turbine bypass components are removed from service for the RICT program. This ensures that the PRA surrogate bounds the design-basis success criteria.

As noted in Section 10.4.4.3 of the Brunswick (see excerpt below), adequate protection exists for all load rejection and turbine trip transients, even with bypass failure. Thus, from a safety evaluation standpoint, even Unit 2’s PRA success criteria bound the safety analysis design criteria for the bypass system.

Design Criteria Function of the PRA Turbine Bypass system

UFSAR 10.4.4.2 System Description

The Unit 2 turbine bypass system consists of ten bypass valves, individually piped to the condenser through a pressure breakdown device (called a trumpet). The steam is delivered to the condenser at 250 psig. The Unit 2 bypass system is capable of accepting approximately 70 percent of rated steam flow at 2923 MWt with all ten bypass valves operable. The Unit 2 Bypass System is still considered operable with two bypass valves out of service. The Unit 2 Bypass System is capable of accepting approximately 55 percent of the rated steam flow at 2923 MWt with two bypass valves out of service. The bypass valves are controlled by the initial pressure regulator to minimize pressure spikes and to compensate for sudden load changes of the turbine.

The Unit 1 (20.6 percent capacity) turbine bypass system consists of four bypass valves individually piped to the condenser through a "trumpet." The steam is delivered to the condenser at 250 psig. The Unit 1 bypass system is capable of accepting up to approximately 20.6 percent of steam flow, which cannot be absorbed by the turbine.

The bypass system also provides a means for utilizing the condenser as a heat sink during startup and shutdown. Heating and loading of the turbine are accomplished by first establishing a flow of steam to the condenser through the bypass system, then gradually transferring this flow to the turbine.

During normal shutdown, steam is released to the main condensers through the bypass system to give the desired rate of cooldown of the reactor.

UFSAR 10.4.4.3 Safety Evaluation

The turbine bypass system is not a safety related system. Adequate protection exists for all load rejection and turbine trip transients, even with bypass failure. These transients have been analyzed and the results are shown in Sections 15.2.1 and 15.2.2.

PRA Function of the PRA Turbine Bypass system

In the PRA, the Turbine Bypass system is credited for condenser cooling through the turbine bypass valves after a reactor trip occurs. The steam flow capacity available to be cooled through the turbine bypass valves by the condenser that is credited in the PRA is the same between both units. The PRA is not concerned with the load rejection capability of the turbine bypass system prior to a reactor trip.

For Unit 2, by using the CCF of all the TBVs as a surrogate, this fails the entire system in the risk model. This is a conservative approach in assuming that all of the TBVs are failed, when in actuality some of the valves may still be able to accomplish the safety function.

STSB/EICB Q3 – Potential Loss of Function

For LCO 3.3.5.1, entry into Condition A (one or more channels inoperable) could be required during scenarios involving a Loss of Function (LOF). For LCO 3.3.5.1, LOF occurs when there is a loss of initiation capability resulting from a loss of one or more required channels. Required Action A.1 directs entry into the conditions listed in Table 3.3.5.1-1. This includes entry into Conditions B, C, D, E and F which are within the scope of the proposed RICT program. Given that TSTF-505, Revision 2, does not allow LOF conditions, discuss how potential LOF scenarios will be treated in the proposed RICT program.

Duke Energy Response to STSB/EICB Q3

As discussed during the September 2021 regulatory audit associated with the proposed amendment, Duke Energy has revised the TS markup for Brunswick TS 3.3.5.1, Conditions B, C, D, E and F (see Attachments 1 and 2) to include the following note above the Completion Time "In accordance with the Risk-Informed Completion Time Program:"

> ------NOTE------
> Not applicable
> when a loss of
> function occurs
> --------------------

This Note is identical to that which was reviewed and approved by the NRC staff for the LaSalle County Station, Unit Nos. 1 and 2 RICT Program (ADAMS Accession No. ML21162A069) and will preclude Brunswick from being in a RICT for scenarios involving a loss of function.

Additionally, consistent with the Lasalle precedent, the markup for Brunswick TS 3.3.5.2 (Reactor Core Isolation Cooling (RCIC) System Instrumentation), Condition B has been revised in Attachments 1 and 2 to reflect the above Note.

STSB/EICB/SNSB Q4 – Table E1-1 Questions

The following inquiries relate to Table E1-1 in Enclosure 1 of the LAR:

a. *For LCO 3.3.5.1 Condition C (functions 1.d, 2.f), state the minimum number of channels required for success.*

b. *For LCO 3.3.5.1 Condition E, the design success criteria (DSC) are not described. Please provide information regarding the DSC for this condition.*

c. *For LCO 3.3.5.1 Condition F, Table 3.3.5.1-1 of the BNP TS indicate that functions 4.b and 5.b have one (1) required channel per function. State the DSC for these functions (i.e., minimum number of channels required).*

d. *For LCO 3.3.5.1 Condition F (functions 4.d, 4.e, 5.d, 5.e), Table 3.3.5.1-1 of the BNP TSs indicates that there are six (6) instrumentation channels used for detection of running Core Spray and Residual Heat Removal (RHR) pumps for each Automatic Depressurization System (ADS) trip system (A and B). Correspondingly, the DSC description for this condition states that 12 channels are provided to ensure that no single instrument failure can preclude ADS initiation. State the DSC (i.e., minimum number of channels required).*

e. *For LCO 3.3.6.1 Condition A (10 rows in Table E1-1 for varying isolation functions), state the minimum number of channels required to meet the DSC applicable to each isolation function.*

f. *For LCO 3.5.1 Condition D, state the minimum equipment required to meet the DSC.*

g. *For LCO 3.5.3 Condition A, state the minimum complement of equipment required to meet the DSC.*

Duke Energy Response to STSB/EICB/SNSB Q4, Part a

The minimum number of channels required for success for TS 3.3.5.1 Condition C (Functions 1.d and 2.f) is provided in Table E1-1c of Attachment 3. Other Functions associated with TS 3.3.5.1 are also addressed in Table E1-1c.

Duke Energy Response to STSB/EICB/SNSB Q4, Part b

The DSC (i.e., minimum number of channels required for success) for TS 3.3.5.1 Condition E are provided in Table E1-1c of Attachment 3. See Functions 4.a, 4.c and 5.a, 5.c.

Duke Energy Response to STSB/EICB/SNSB Q4, Part c

The DSC (i.e., minimum number of channels required) for Functions 4.b and 5.b of TS Table 3.3.5.1-1 are provided in Table E1-1c of Attachment 3.

Duke Energy Response to STSB/EICB/SNSB Q4, Part d

The DSC (i.e., minimum number of channels required) for Functions 4.d, 4.e, 5.d and 5.e of TS Table 3.3.5.1-1 are provided in Table E1-1c of Attachment 3.

Duke Energy Response to STSB/EICB/SNSB Q4, Part e

The DSC (i.e., minimum number of channels required) for each isolation Function associated with TS 3.3.6.1 Condition A are provided in Table E1-1d of Attachment 3.

Duke Energy Response to STSB/EICB/SNSB Q4, Part f

The minimum required equipment to ensure success if HPCI is inoperable (i.e., TS 3.5.1 Condition D) is any (1) low pressure ECCS pump (RHR/CS) and the ADS system. One low pressure ECCS pump exceeds the injection rate of HPCI assuming the reactor pressure vessel is depressurized by the ADS system.

Duke Energy Response to STSB/EICB/SNSB Q4, Part g

TS 3.5.3 Condition A is for the RCIC System inoperable. The RCIC System is not an Engineered Safety Feature System and no credit is taken in the safety analyses for RCIC System operation.

HPCI exceeds RCIC design criteria and fully performs all functions provided by RCIC. Required Action A.1 requires verification that HPCI is OPERABLE with a Completion Time of immediately.

HPCI is the minimum equipment needed for the DSC.

ATTACHMENT 1

PROPOSED TECHNICAL SPECIFICATION CHANGES (MARK-UP) – UNIT 1

1.3 Completion Times

EXAMPLES

EXAMPLE 1.3-7 (continued)

is met after Condition B is entered, Condition B is exited and operation may continue in accordance with Condition A, provided the Completion Time for Required Action A.2 has not expired.

INSERT 1

IMMEDIATE COMPLETION TIME

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

3.1 REACTIVITY CONTROL SYSTEMS

3.1.7 Standby Liquid Control (SLC) System

LCO 3.1.7 Two SLC subsystems shall be OPERABLE.

APPLICABILITY: MODES 1 and 2.

ACTIONS

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

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.7.1	Verify available volume of sodium pentaborate solution is within the limits of Figure 3.1.7-1.	In accordance with the Surveillance Frequency Control Program

(continued)

3.3 INSTRUMENTATION

3.3.1.1 Reactor Protection System (RPS) Instrumentation

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

APPLICABILITY: According to Table 3.3.1.1-1.

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required channels inoperable.	A.1 Place channel in trip.	12 hours INSERT 2
	<u>OR</u>	
	A.2 ---------------NOTE------------- Not applicable for Functions 2.a, 2.b, 2.c, 2.d, or 2.f. ------------------------------------- Place associated trip system in trip.	12 hours INSERT 2

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. ------------NOTE---------------- Not applicable for Functions 2.a, 2.b, 2.c, 2.d, or 2.f. ------------------------------------	B.1 Place channel in one trip system in trip.	6 hours INSERT 2
	<u>OR</u>	
One or more Functions with one or more required channels inoperable in both trip systems.	B.2 Place one trip system in trip.	6 hours INSERT 2
C. One or more Functions with RPS trip capability not maintained.	C.1 Restore RPS trip capability.	1 hour
D. Required Action and associated Completion Time of Condition A, B, or C not met.	D.1 Enter the Condition referenced in Table 3.3.1.1-1 for the channel.	Immediately
E. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	E.1 Reduce THERMAL POWER to < 26% RTP.	4 hours

(continued)

3.3 INSTRUMENTATION

3.3.2.2 Feedwater and Main Turbine High Water Level Trip Instrumentation

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

APPLICABILITY: THERMAL POWER ≥ 23% RTP.

ACTIONS

--NOTE--

Separate Condition entry is allowed for each channel.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One feedwater and main turbine high water level trip channel inoperable.	A.1 Place channel in trip.	7 days INSERT 2
B. Two or more feedwater and main turbine high water level trip channels inoperable.	B.1 Restore feedwater and main turbine high water level trip capability.	4 hours
C. Required Action and associated Completion Time not met.	C.1 Reduce THERMAL POWER to < 23% RTP.	4 hours

3.3 INSTRUMENTATION

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

LCO 3.3.4.1 Two channels per trip system for each ATWS-RPT instrumentation Function listed below shall be OPERABLE:

a. Reactor Vessel Water Level—Low Level 2; and

b. Reactor Vessel Pressure—High.

APPLICABILITY: MODE 1.

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more channels inoperable.	A.1 Restore channel to OPERABLE status. <u>OR</u> A.2 --------------NOTE-------------- Not applicable if inoperable channel is the result of an inoperable breaker. ------------------------------------- Place channel in trip.	14 days INSERT 2 14 days INSERT 2

(continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. (continued)	B.2	--------------NOTE------------- Only applicable for Functions 3.a and 3.b. -----------------------------------	
		Declare High Pressure Coolant Injection (HPCI) System inoperable.	1 hour from discovery of loss of HPCI initiation capability
	AND		
	B.3	Place channel in trip.	24 hours INSERT 3
C. As required by Required Action A.1 and referenced in Table 3.3.5.1-1.	C.1	-------------NOTE--------------- Only applicable for Functions 1.c, 1.d, 2.c, 2.d, and 2.f. ------------------------------------	
		Declare supported feature(s) inoperable when its redundant feature ECCS initiation capability is inoperable.	1 hour from discovery of loss of initiation capability for feature(s) in both divisions
	AND		
	C.2	Restore channel to OPERABLE status.	24 hours INSERT 3

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
D. As required by Required Action A.1 and referenced in Table 3.3.5.1-1.	D.1	--------------NOTE------------- Only applicable if HPCI pump suction is not aligned to the suppression pool. -----------------------------------	
		Declare HPCI System inoperable.	1 hour from discovery of loss of HPCI initiation capability
	AND		
	D.2.1	Place channel in trip.	24 hours INSERT 3
	OR		
	D.2.2	Align the HPCI pump suction to the suppression pool.	24 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. As required by Required Action A.1 and referenced in Table 3.3.5.1-1.	E.1 Declare Automatic Depressurization System (ADS) valves inoperable. AND E.2 Place channel in trip.	1 hour from discovery of loss of ADS initiation capability in both trip systems 96 hours from discovery of inoperable channel concurrent with HPCI or reactor core isolation cooling (RCIC) inoperable INSERT 3 AND 8 days INSERT 3

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
F. As required by Required Action A.1 and referenced in Table 3.3.5.1-1.	F.1 Declare ADS valves inoperable.	1 hour from discovery of loss of ADS initiation capability in both trip systems
	<u>AND</u>	
	F.2 Restore channel to OPERABLE status.	96 hours from discovery of inoperable channel concurrent with HPCI or RCIC inoperable INSERT 3 <u>AND</u> 8 days INSERT 3
G. Required Action and associated Completion Time of Condition B, C, D, E, or F not met.	G.1 Declare associated supported feature(s) inoperable.	Immediately

3.3 INSTRUMENTATION

3.3.5.2 Reactor Core Isolation Cooling (RCIC) System Instrumentation

LCO 3.3.5.2 The RCIC System instrumentation for each Function in Table 3.3.5.2-1 shall be OPERABLE.

APPLICABILITY: MODE 1,

MODES 2 and 3 with reactor steam dome pressure > 150 psig.

ACTIONS

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

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One or more channels inoperable.	A.1	Enter the Condition referenced in Table 3.3.5.2-1 for the channel.	Immediately
B. As required by Required Action A.1 and referenced in Table 3.3.5.2-1.	B.1	Declare RCIC System inoperable.	1 hour from discovery of loss of RCIC initiation capability
	AND		
	B.2	Place channel in trip.	24 hours INSERT 3
C. As required by Required Action A.1 and referenced in Table 3.3.5.2-1.	C.1	Restore channel to OPERABLE status.	24 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
D. As required by Required Action A.1 and referenced in Table 3.3.5.2-1.	D.1	-------------NOTE--------------- Only applicable if RCIC pump suction is not aligned to the suppression pool. ------------------------------------ Declare RCIC System inoperable.	1 hour from discovery of loss of RCIC initiation capability
	AND		
	D.2.1	Place channel in trip.	24 hours INSERT 3
	OR		
	D.2.2	Align RCIC pump suction to the suppression pool.	24 hours
E. Required Action and associated Completion Time of Condition B, C, or D not met.	E.1	Declare RCIC System inoperable.	Immediately

3.3 INSTRUMENTATION

3.3.6.1 Primary Containment Isolation Instrumentation

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

APPLICABILITY: According to Table 3.3.6.1-1.

ACTIONS

--NOTES--

1. Penetration flow paths may be unisolated intermittently under administrative controls.
2. Separate Condition entry is allowed for each channel.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required channels inoperable.	A.1 Place channel in trip. INSERT 2 INSERT 2	12 hours for Functions 2.a, 2.b, 6.b, 7.a, and 7.b <u>AND</u> 24 hours for Functions other than Functions 2.a, 2.b, 6.b, 7.a, and 7.b
B. One or more Functions with isolation capability not maintained.	B.1 Restore isolation capability.	1 hour
C. Required Action and associated Completion Time of Condition A or B not met.	C.1 Enter the Condition referenced in Table 3.3.6.1-1 for the channel.	Immediately

(continued)

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

3.5.1 ECCS—Operating

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

APPLICABILITY: MODE 1,

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

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One low pressure ECCS injection/spray subsystem inoperable. <u>OR</u> One low pressure coolant injection (LPCI) pump in each subsystem inoperable.	A.1 Restore low pressure ECCS injection/spray subsystem to OPERABLE status.	7 days INSERT 2
B. One LPCI pump inoperable. <u>AND</u> One core spray (CS) subsystem inoperable.	B.1 Restore LPCI pump to OPERABLE status. <u>OR</u> B.2 Restore CS subsystem to OPERABLE status.	72 hours INSERT 2 72 hours INSERT 2

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. Required Action and associated Completion Time of Condition A or B not met.	C.1	--------------NOTE-------------- LCO 3.0.4.a is not applicable when entering MODE 3. ------------------------------------ Be in MODE 3.	12 hours
D. HPCI System inoperable.	D.1	Verify by administrative means RCIC System is OPERABLE.	Immediately
	<u>AND</u>		
	D.2	Restore HPCI System to OPERABLE status.	14 days INSERT 2
E. HPCI System inoperable. <u>AND</u> One low pressure ECCS injection/spray subsystem is inoperable.	E.1	Restore HPCI System to OPERABLE status.	72 hours INSERT 2
	<u>OR</u>		
	E.2	Restore low pressure ECCS injection/spray subsystem to OPERABLE status.	72 hours INSERT 2
F. One required ADS valve inoperable.	F.1	Restore required ADS valve to OPERABLE status.	14 days INSERT 2

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
G. One required ADS valve inoperable. AND One low pressure ECCS injection/spray subsystem inoperable.	G.1 Restore required ADS valve to OPERABLE status. OR G.2 Restore low pressure ECCS injection/spray subsystem to OPERABLE status.	72 hours INSERT 2 72 hours INSERT 2
H. One required ADS valve inoperable. AND HPCI System inoperable.	H.1 Restore required ADS valve to OPERABLE status. OR H.2 Restore HPCI System to OPERABLE status.	72 hours INSERT 2 72 hours INSERT 2
I. Required Action and associated Completion Time of Condition D, E, F, G, or H not met.	I.1 --------------NOTE-------------- LCO 3.0.4.a is not applicable when entering MODE 3. ------------------------------------ Be in MODE 3.	 12 hours
J. Two or more required ADS valves inoperable.	J.1 Be in MODE 3. AND J.2 Reduce reactor steam dome pressure to ≤ 150 psig.	12 hours 36 hours

(continued)

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

3.5.3 RCIC System

LCO 3.5.3 The RCIC System shall be OPERABLE.

APPLICABILITY: MODE 1,

MODES 2 and 3 with reactor steam dome pressure > 150 psig.

ACTIONS

--NOTE--

LCO 3.0.4.b is not applicable to RCIC.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. RCIC System inoperable.	A.1 Verify by administrative means High Pressure Coolant Injection System is OPERABLE. <u>AND</u> A.2 Restore RCIC System to OPERABLE status.	Immediately 14 days INSERT 2
B. Required Action and associated Completion Time not met.	B.1 --------------NOTE-------------- LCO 3.0.4.a is not applicable when entering MODE 3. ------------------------------------- Be in MODE 3.	 12 hours

ACTIONS

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

(continued)

3.6 CONTAINMENT SYSTEMS

3.6.1.3 Primary Containment Isolation Valves (PCIVs)

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

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

--NOTES--

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. --------------NOTE-------------- Only applicable to penetration flow paths with two PCIVs. ----------------------------------- One or more penetration flow paths with one PCIV inoperable except for MSIV leakage not within limit.	A.1 Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, blind flange, or check valve with flow through the valve secured. <u>AND</u>	8 hours INSERT 2 (continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
D. Two reactor building-to-suppression chamber vacuum breakers inoperable due to inoperable nitrogen backup subsystems.	D.1	Restore one vacuum breaker to OPERABLE status.	7 days
E. One line with one or more reactor building-to-suppression chamber vacuum breakers inoperable for opening for reasons other than Condition C.	E.1	Restore the vacuum breaker(s) to OPERABLE status.	72 hours INSERT 2
F. Required Action and associated Completion Time of Condition E not met.	F.1	-------------NOTE-------------- LCO 3.0.4.a is not applicable when entering MODE 3. ----------------------------------- Be in MODE 3.	12 hours
G. Two lines with one or more reactor building-to-suppression chamber vacuum breakers inoperable for opening for reasons other than Condition D.	G.1	Restore all vacuum breakers in one line to OPERABLE status.	2 hours
H. Required Action and associated Completion Time of Condition A, B, C, D, F, or G not met.	H.1	Be in MODE 3.	12 hours
	AND		
	H.2	Be in MODE 4.	36 hours

3.6 CONTAINMENT SYSTEMS

3.6.1.6 Suppression Chamber-to-Drywell Vacuum Breakers

LCO 3.6.1.6 Eight suppression chamber-to-drywell vacuum breakers shall be OPERABLE for opening.

AND

Ten suppression chamber-to-drywell vacuum breakers shall be closed, except when performing their intended function.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required suppression chamber-to-drywell vacuum breaker inoperable for opening.	A.1 Restore one vacuum breaker to OPERABLE status.	72 hours INSERT 2
B. Required Action and associated Completion Time of Condition A not met.	B.1 -------------NOTE-------------- LCO 3.0.4.a is not applicable when entering MODE 3. ----------------------------------- Be in MODE 3.	12 hours
C. One suppression chamber-to-drywell vacuum breaker not closed.	C.1 Close the open vacuum breaker.	4 hours
D. Required Action and associated Completion Time of Condition C not met.	D.1 Be in MODE 3. AND D.2 Be in MODE 4.	12 hours 36 hours

3.6 CONTAINMENT SYSTEMS

3.6.2.3 Residual Heat Removal (RHR) Suppression Pool Cooling

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

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

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

3.7 PLANT SYSTEMS

3.7.1 Residual Heat Removal Service Water (RHRSW) System

LCO 3.7.1 Two RHRSW subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One RHRSW pump inoperable.	A.1 Restore RHRSW pump to OPERABLE status.	14 days INSERT 2

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. One RHRSW subsystem inoperable for reasons other than Condition A.	B.1	-------------NOTE-------------- Enter applicable Conditions and Required Actions of LCO 3.4.7, "Residual Heat Removal (RHR) Shutdown Cooling System—Hot Shutdown," for RHR shutdown cooling made inoperable by RHRSW System. ----------------------------------- Restore RHRSW subsystem to OPERABLE status.	7 days INSERT 2
C. Required Action and associated Completion Time of Condition A or B not met.	C.1	-------------NOTE-------------- LCO 3.0.4.a is not applicable when entering MODE 3. ----------------------------------- Be in MODE 3.	12 hours
D. Both RHRSW subsystems inoperable.	D.1	-------------NOTE-------------- Enter applicable Conditions and Required Actions of LCO 3.4.7 for RHR shutdown cooling made inoperable by RHRSW System. ----------------------------------- Restore one RHRSW subsystem to OPERABLE status.	8 hours

(continued)

3.7 PLANT SYSTEMS

3.7.2 Service Water (SW) System and Ultimate Heat Sink (UHS)

LCO 3.7.2 SW System and UHS shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. ---------------NOTE------------- Only applicable when Unit 2 is in MODE 4 or 5. ------------------------------------ One required nuclear service water (NSW) pump inoperable due to an inoperable Unit 2 NSW header.	A.1 --------------NOTE------------- Enter applicable Conditions and Required Actions of LCO 3.8.1, "AC Sources—Operating," for diesel generators (DGs) made inoperable by NSW. ------------------------------------ Restore required NSW pump to OPERABLE status.	14 days INSERT 2

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. One required NSW pump inoperable for reasons other than Condition A.	B.1	--------------NOTE------------- Enter applicable Conditions and Required Actions of LCO 3.8.1 for DGs made inoperable by NSW. ----------------------------------- Restore required NSW pump to OPERABLE status.	 7 days INSERT 2
C. One required conventional service water (CSW) pump inoperable.	C.1	Verify the one OPERABLE CSW pump and one OPERABLE Unit 1 NSW pump are powered from separate 4.16 kV emergency buses.	Immediately
	<u>AND</u>		
	C.2	Restore required CSW pump to OPERABLE status.	7 days INSERT 2

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. Required Action C.1 and associated Completion Time not met.	D.1 Restore required CSW pump to OPERABLE status.	72 hours
E. Two required CSW pumps inoperable.	E.1 --------------NOTE------------- Enter applicable Conditions and Required Actions of LCO 3.7.1, "Residual Heat Removal Service Water (RHRSW) System," for RHRSW subsystems made inoperable by CSW. ----------------------------------- Restore one required CSW pump to OPERABLE status.	72 hours INSERT 2
F. One required NSW pump inoperable. <u>AND</u> One required CSW pump inoperable.	F.1 Restore required NSW pump to OPERABLE status. <u>OR</u> F.2 Restore required CSW pump to OPERABLE status.	72 hours INSERT 2 72 hours INSERT 2

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
G. One required NSW pump inoperable. <u>AND</u> Two required CSW pumps inoperable.	G.1	Verify by administrative means that two Unit 1 NSW pumps are OPERABLE.	Immediately
	<u>AND</u>		
	G.2.1	Restore required NSW pump to OPERABLE status.	72 hours INSERT 2
	<u>OR</u>		
	G.2.2	Restore one required CSW pump to OPERABLE status.	72 hours INSERT 2
H. Water temperature of the UHS > 90.5°F and ≤ 92°F.	H.1	Verify water temperature of the UHS is ≤ 90.5°F averaged over previous 24 hour period.	Once per hour

(continued)

3.7 PLANT SYSTEMS

3.7.6 The Main Turbine Bypass System

LCO 3.7.6 The Main Turbine Bypass System shall be OPERABLE.

<u>OR</u>

The following limits are made applicable:

a. LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)," limits for an inoperable Main Turbine Bypass System, as specified in the COLR;

b. LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)," limits for an inoperable Main Turbine Bypass System, as specified in the COLR; and

c. LCO 3.2.3, "LINEAR HEAT GENERATION RATE (LHGR)," limits for an inoperable Main Turbine Bypass System, as specified in the COLR.

APPLICABILITY: THERMAL POWER ≥ 23% RTP.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Requirements of the LCO not met.	A.1 Satisfy the requirements of the LCO.	4 hours INSERT 2
B. Required Action and associated Completion Time not met.	B.1 Reduce THERMAL POWER to < 23% RTP.	4 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. One offsite circuit inoperable for reasons other than Condition A or B.	C.1	Perform SR 3.8.1.1 for OPERABLE offsite circuit(s).	2 hours <u>AND</u> Once per 12 hours thereafter
	<u>AND</u>		
	C.2	Declare required feature(s) with no offsite power available inoperable when the redundant required feature(s) are inoperable.	24 hours from discovery of no offsite power to one 4.16 kV emergency bus concurrent with inoperability of redundant required feature(s)
	<u>AND</u>		
	C.3	Restore offsite circuit to OPERABLE status.	72 hours INSERT 2

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
D. One DG inoperable for reasons other than Condition B.	D.1	Perform SR 3.8.1.1 for OPERABLE offsite circuit(s).	2 hours AND Once per 12 hours thereafter
	AND		
	~~D.2~~	~~Evaluate availability of supplemental diesel generator (SUPP-DG)~~	~~2 hours~~ ~~AND~~ ~~Once per 12 hours thereafter~~
	~~AND~~		
D.2	~~D.3~~	Declare required feature (s), supported by the inoperable DG, inoperable when the redundant required feature (s) are inoperable.	4 hours from discovery of Condition D concurrent with inoperability of redundant required feature (s)
	AND		
D.3.1	~~D.4.1~~	Determine OPERABLE DG(s) are not inoperable due to common cause failure.	24 hours
	OR		
D.3.2	~~D.4.2~~	Perform SR 3.8.1.2 for OPERABLE DG(s).	24 hours
	AND		

(continued)

INSERT 4

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. (continued) D.4	~~D.5~~ Restore DG to OPERABLE status.	~~7 days from discovery of unavailability of SUPP-DG~~ ~~AND~~ ~~24 hours from discovery of Condition D entry ≥ 6 days concurrent with unavailability of SUPP-DG~~ ~~AND~~ ~~14 days~~
E. Two or more offsite circuits inoperable for reasons other than Condition B.	E.1 Declare required feature(s) inoperable when the redundant required feature(s) are inoperable. AND E.2 Restore all but one offsite circuit to OPERABLE status.	12 hours from discovery of Condition E concurrent with inoperability of redundant required feature(s) 24 hours INSERT 2

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
F. One offsite circuit inoperable for reasons other than Condition B. AND One DG inoperable for reasons other than Condition B.	---------------------NOTE------------------ Enter applicable Conditions and Required Actions of LCO 3.8.7, "Distribution Systems—Operating," when Condition F is entered with no AC power source to any 4.16 kV emergency bus. --- F.1 Restore offsite circuit to OPERABLE status. OR F.2 Restore DG to OPERABLE status.	 12 hours INSERT 2 12 hours INSERT 2
G. Two or more DGs inoperable.	G.1 Restore all but one DG to OPERABLE status.	2 hours
H. Required Action and associated Completion Time of Condition A, B, C, D, E, F or G not met.	H.1 -------------NOTE------------- LCO 3.0.4.a is not applicable when entering MODE 3. ----------------------------------- Be in MODE 3.	 12 hours
I. One or more offsite circuits and two or more DGs inoperable. OR Two or more offsite circuits and one DG inoperable for reasons other than Condition B.	I.1 Enter LCO 3.0.3.	Immediately

3.8 ELECTRICAL POWER SYSTEMS

3.8.4 DC Sources—Operating

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

a. Unit 1 Division I and Division II DC electrical power subsystems; and

b. Unit 2 Division I and Division II DC electrical power subsystems.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One DC electrical power subsystem inoperable.	A.1	--------------NOTE-------------- Enter applicable Conditions and Required Actions of LCO 3.8.7, "Distribution Systems—Operating," when Condition A results in de-energization of an AC electrical power distribution subsystem or a DC electrical power distribution subsystem. ------------------------------------ Restore DC electrical power subsystem to OPERABLE status.	7 days INSERT 2

(continued)

3.8 ELECTRICAL POWER SYSTEMS

3.8.7 Distribution Systems—Operating

LCO 3.8.7 Division I and Division II AC and DC electrical power distribution subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One AC electrical power distribution subsystem inoperable for planned maintenance due to either inoperable load group E3 bus(es) or inoperable load group E4 bus(es).	A.1	Restore affected load group bus(es) to OPERABLE status.	7 days INSERT 2
B. One or more AC electrical power distribution subsystems inoperable for reasons other than Condition A.	B.1	Restore AC electrical power distribution subsystems to OPERABLE status.	8 hours INSERT 2

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. One or more DC electrical power distribution subsystems inoperable due to loss of normal DC source.	C.1	Declare required feature(s), supported by the inoperable DC electrical power distribution subsystem, inoperable.	Immediately
	AND		
	C.2	Initiate action to transfer DC electrical power distribution subsystem to its alternate DC source.	Immediately
	AND		
	C.3	Declare required feature(s) supported by the inoperable DC electrical power distribution subsystem OPERABLE.	Upon completion of transfer of the required feature's DC electrical power distribution subsystem to its OPERABLE alternate DC source
	AND		
	C.4	Restore DC electrical power distribution subsystem to OPERABLE status.	7 days INSERT 2

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
D. One or more DC electrical power distribution subsystems inoperable for reasons other than Condition C.	D.1	Restore DC electrical power distribution subsystems to OPERABLE status.	7 days INSERT 2
E. Required Action and associated Completion Time of Condition A, B, C, or D not met.	E.1	-------------NOTE-------------- LCO 3.0.4.a is not applicable when entering MODE 3. ----------------------------------- Be in MODE 3.	12 hours
F. Two or more electrical power distribution subsystems inoperable that result in a loss of function.	F.1	Enter LCO 3.0.3.	Immediately

5.5 Programs and Manuals

5.5.14 Surveillance Frequency Control Program (continued)

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

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

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

INSERT 5

Brunswick Technical Specifications Inserts (applicable to both Units 1 and 2 TS)

INSERT 1

EXAMPLE 1.3-8

ACTIONS

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

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

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

If the 7 day Completion Time clock of Condition A has expired and subsequent changes in plant condition result in exiting the applicability of the Risk-Informed

Completion Time Program without restoring the inoperable subsystem to OPERABLE status, Condition B is also entered and the Completion Time clocks for Required Actions B.1 and B.2 start.

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

INSERT 2

OR

In accordance with the Risk-Informed Completion Time Program

INSERT 3

OR

-----NOTE-----
Not applicable when a loss of function occurs

In accordance with the Risk-Informed Completion Time Program

INSERT 4

7 days

OR

In accordance with the Risk-Informed Completion Time Program

INSERT 5

5.5.15 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 and 2;

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

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

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

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

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

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

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

e. The risk assessment approaches and methods shall be acceptable to the NRC. The plant PRA shall be based on the as-built, as-operated, and maintained plant; and reflect the operating experience at the plant, as specified in Regulatory Guide 1.200, Revision 2. Methods to assess the risk from extending the Completion Times must be PRA methods used to support 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 2

PROPOSED TECHNICAL SPECIFICATION CHANGES (MARK-UP) – UNIT 2

1.3 Completion Times

EXAMPLES

EXAMPLE 1.3-7 (continued)

is met after Condition B is entered, Condition B is exited and operation may continue in accordance with Condition A, provided the Completion Time for Required Action A.2 has not expired.

INSERT 1

IMMEDIATE COMPLETION TIME

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

3.1 REACTIVITY CONTROL SYSTEMS

3.1.7 Standby Liquid Control (SLC) System

LCO 3.1.7 Two SLC subsystems shall be OPERABLE.

APPLICABILITY: MODES 1 and 2.

ACTIONS

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

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.1.7.1	Verify available volume of sodium pentaborate solution is within the limits of Figure 3.1.7-1.	In accordance with the Surveillance Frequency Control Program

(continued)

3.3 INSTRUMENTATION

3.3.1.1 Reactor Protection System (RPS) Instrumentation

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

APPLICABILITY: According to Table 3.3.1.1-1.

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required channels inoperable.	A.1 Place channel in trip.	12 hours INSERT 2
	<u>OR</u>	
	A.2 ---------------NOTE------------- Not applicable for Functions 2.a, 2.b, 2.c, 2.d, or 2.f. ------------------------------------- Place associated trip system in trip.	12 hours INSERT 2

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. ------------NOTE---------------- Not applicable for Functions 2.a, 2.b, 2.c, 2.d, or 2.f. ------------------------------------	B.1	Place channel in one trip system in trip.	6 hours INSERT 2
	<u>OR</u>		
One or more Functions with one or more required channels inoperable in both trip systems.	B.2	Place one trip system in trip.	6 hours INSERT 2
C. One or more Functions with RPS trip capability not maintained.	C.1	Restore RPS trip capability.	1 hour
D. Required Action and associated Completion Time of Condition A, B, or C not met.	D.1	Enter the Condition referenced in Table 3.3.1.1-1 for the channel.	Immediately
E. As required by Required Action D.1 and referenced in Table 3.3.1.1-1.	E.1	Reduce THERMAL POWER to < 26% RTP.	4 hours

(continued)

3.3 INSTRUMENTATION

3.3.2.2 Feedwater and Main Turbine High Water Level Trip Instrumentation

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

APPLICABILITY: THERMAL POWER ≥ 23% RTP.

ACTIONS

--NOTE--

Separate Condition entry is allowed for each channel.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One feedwater and main turbine high water level trip channel inoperable.	A.1 Place channel in trip.	7 days INSERT 2
B. Two or more feedwater and main turbine high water level trip channels inoperable.	B.1 Restore feedwater and main turbine high water level trip capability.	4 hours
C. Required Action and associated Completion Time not met.	C.1 Reduce THERMAL POWER to < 23% RTP.	4 hours

3.3 INSTRUMENTATION

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

LCO 3.3.4.1 Two channels per trip system for each ATWS-RPT instrumentation Function listed below shall be OPERABLE:

a. Reactor Vessel Water Level—Low Level 2; and

b. Reactor Vessel Pressure—High.

APPLICABILITY: MODE 1.

ACTIONS

--NOTE--

Separate Condition entry is allowed for each channel.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more channels inoperable.	A.1 Restore channel to OPERABLE status.	~~14 days~~ INSERT 2
	<u>OR</u>	
	A.2 --------------NOTE-------------- Not applicable if inoperable channel is the result of an inoperable breaker. ------------------------------------- Place channel in trip.	~~14 days~~ INSERT 2

(continued)

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. (continued)	B.2	-------------NOTE-------------- Only applicable for Functions 3.a and 3.b. -----------------------------------	
		Declare High Pressure Coolant Injection (HPCI) System inoperable.	1 hour from discovery of loss of HPCI initiation capability
	AND		
	B.3	Place channel in trip.	24 hours INSERT 3
C. As required by Required Action A.1 and referenced in Table 3.3.5.1-1.	C.1	------------NOTE--------------- Only applicable for Functions 1.c, 1.d, 2.c, 2.d, and 2.f. -----------------------------------	
		Declare supported feature(s) inoperable when its redundant feature ECCS initiation capability is inoperable.	1 hour from discovery of loss of initiation capability for feature(s) in both divisions
	AND		
	C.2	Restore channel to OPERABLE status.	24 hours INSERT 3

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
D. As required by Required Action A.1 and referenced in Table 3.3.5.1-1	D.1	--------------NOTE-------------- Only applicable if HPCI pump suction is not aligned to the suppression pool. -------------------------------------	
		Declare HPCI System inoperable.	1 hour from discovery of loss of HPCI initiation capability
	<u>AND</u>		
	D.2.1	Place channel in trip.	24 hours INSERT 3
	<u>OR</u>		
	D.2.2	Align the HPCI pump suction to the suppression pool.	24 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
E. As required by Required Action A.1 and referenced in Table 3.3.5.1-1.	E.1 Declare Automatic Depressurization System (ADS) valves inoperable. AND E.2 Place channel in trip.	1 hour from discovery of loss of ADS initiation capability in both trip systems 96 hours from discovery of inoperable channel concurrent with HPCI or reactor core isolation cooling (RCIC) inoperable INSERT 3 AND 8 days INSERT 3

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
F. As required by Required Action A.1 and referenced in Table 3.3.5.1-1.	F.1	Declare ADS valves inoperable.	1 hour from discovery of loss of ADS initiation capability in both trip systems
	AND		
	F.2	Restore channel to OPERABLE status.	96 hours from discovery of inoperable channel concurrent with HPCI or RCIC inoperable INSERT 3 AND 8 days INSERT 3
G. Required Action and associated Completion Time of Condition B, C, D, E, or F not met.	G.1	Declare associated supported feature(s) inoperable.	Immediately

3.3 INSTRUMENTATION

3.3.5.2 Reactor Core Isolation Cooling (RCIC) System Instrumentation

LCO 3.3.5.2 The RCIC System instrumentation for each Function in Table 3.3.5.2-1 shall be OPERABLE.

APPLICABILITY: MODE 1,

MODES 2 and 3 with reactor steam dome pressure > 150 psig.

ACTIONS

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more channels inoperable.	A.1 Enter the Condition referenced in Table 3.3.5.2-1 for the channel.	Immediately
B. As required by Required Action A.1 and referenced in Table 3.3.5.2-1.	B.1 Declare RCIC System inoperable.	1 hour from discovery of loss of RCIC initiation capability
	<u>AND</u>	
	B.2 Place channel in trip.	24 hours INSERT 3
C. As required by Required Action A.1 and referenced in Table 3.3.5.2-1.	C.1 Restore channel to OPERABLE status.	24 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. As required by Required Action A.1 and referenced in Table 3.3.5.2-1.	D.1 -------------NOTE--------------- Only applicable if RCIC pump suction is not aligned to the suppression pool. ------------------------------------	
	Declare RCIC System inoperable.	1 hour from discovery of loss of RCIC initiation capability
	AND	
	D.2.1 Place channel in trip.	24 hours INSERT 3
	OR	
	D.2.2 Align RCIC pump suction to the suppression pool.	24 hours
E. Required Action and associated Completion Time of Condition B, C, or D not met.	E.1 Declare RCIC System inoperable.	Immediately

3.3 INSTRUMENTATION

3.3.6.1 Primary Containment Isolation Instrumentation

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

APPLICABILITY: According to Table 3.3.6.1-1.

ACTIONS

--NOTES--

1. Penetration flow paths may be unisolated intermittently under administrative controls.
2. Separate Condition entry is allowed for each channel.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One or more required channels inoperable.	A.1 Place channel in trip. INSERT 2 INSERT 2	12 hours for Functions 2.a, 2.b, 6.b, 7.a, and 7.b AND 24 hours for Functions other than Functions 2.a, 2.b, 6.b, 7.a, and 7.b
B. One or more Functions with isolation capability not maintained.	B.1 Restore isolation capability.	1 hour
C. Required Action and associated Completion Time of Condition A or B not met.	C.1 Enter the Condition referenced in Table 3.3.6.1-1 for the channel.	Immediately

(continued)

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

3.5.1 ECCS—Operating

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

APPLICABILITY: MODE 1,

MODES 2 and 3, except high pressure coolant injection (HPCI) and ADS valves are not required to be OPERABLE with reactor steam dome pressure $\leq$ 150 psig.

ACTIONS

--NOTE--

LCO 3.0.4.b is not applicable to HPCI.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One low pressure ECCS injection/spray subsystem inoperable. <u>OR</u> One low pressure coolant injection (LPCI) pump in each subsystem inoperable.	A.1 Restore low pressure ECCS injection/spray subsystem to OPERABLE status.	7 days INSERT 2
B. One LPCI pump inoperable. <u>AND</u> One core spray (CS) subsystem inoperable.	B.1 Restore LPCI pump to OPERABLE status. <u>OR</u> B.2 Restore CS subsystem to OPERABLE status.	72 hours INSERT 2 72 hours INSERT 2

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. Required Action and associated Completion Time of Condition A or B not met.	C.1 --------------NOTE-------------- LCO 3.0.4.a is not applicable when entering MODE 3. ------------------------------------ Be in MODE 3.	12 hours
D. HPCI System inoperable.	D.1 Verify by administrative means RCIC System is OPERABLE.	Immediately
	AND	
	D.2 Restore HPCI System to OPERABLE status.	14 days INSERT 2
E. HPCI System inoperable. AND One low pressure ECCS injection/spray subsystem is inoperable.	E.1 Restore HPCI System to OPERABLE status.	72 hours INSERT 2
	OR	
	E.2 Restore low pressure ECCS injection/spray subsystem to OPERABLE status.	72 hours INSERT 2
F. One required ADS valve inoperable.	F.1 Restore required ADS valve to OPERABLE status.	14 days INSERT 2

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
G. One required ADS valve inoperable. AND One low pressure ECCS injection/spray subsystem inoperable.	G.1 Restore required ADS valve to OPERABLE status. OR G.2 Restore low pressure ECCS injection/spray subsystem to OPERABLE status.	72 hours INSERT 2 72 hours INSERT 2
H. One required ADS valve inoperable. AND HPCI System inoperable.	H.1 Restore required ADS valve to OPERABLE status. OR H.2 Restore HPCI System to OPERABLE status.	72 hours INSERT 2 72 hours INSERT 2
I. Required Action and associated Completion Time of Condition D, E, F, G, or H not met.	I.1 --------------NOTE-------------- LCO 3.0.4.a is not applicable when entering MODE 3. ------------------------------------ Be in MODE 3.	 12 hours
J. Two or more required ADS valves inoperable.	J.1 Be in MODE 3. AND J.2 Reduce reactor steam dome pressure to $\leq$ 150 psig.	12 hours 36 hours

(continued)

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

3.5.3 RCIC System

LCO 3.5.3 The RCIC System shall be OPERABLE.

APPLICABILITY: MODE 1,

MODES 2 and 3 with reactor steam dome pressure > 150 psig.

ACTIONS

---NOTE---

LCO 3.0.4.b is not applicable to RCIC.

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. RCIC System inoperable.	A.1 Verify by administrative means High Pressure Coolant Injection System is OPERABLE. <u>AND</u> A.2 Restore RCIC System to OPERABLE status.	Immediately 14 days INSERT 2
B. Required Action and associated Completion Time not met.	B.1 --------------NOTE-------------- LCO 3.0.4.a is not applicable when entering MODE 3. ------------------------------------ Be in MODE 3.	12 hours

ACTIONS

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

(continued)

3.6 CONTAINMENT SYSTEMS

3.6.1.3 Primary Containment Isolation Valves (PCIVs)

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

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

---NOTES---

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

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. --------------NOTE------------- Only applicable to penetration flow paths with two PCIVs. ----------------------------------- One or more penetration flow paths with one PCIV inoperable except for MSIV leakage not within limit.	A.1 Isolate the affected penetration flow path by use of at least one closed and de-activated automatic valve, closed manual valve, blind flange, or check valve with flow through the valve secured. <u>AND</u>	8 hours INSERT 2 (continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
D. Two reactor building-to-suppression chamber vacuum breakers inoperable due to inoperable nitrogen backup subsystems.	D.1	Restore one vacuum breaker to OPERABLE status.	7 days
E. One line with one or more reactor building-to-suppression chamber vacuum breakers inoperable for opening for reasons other than Condition C.	E.1	Restore the vacuum breaker(s) to OPERABLE status.	72 hours INSERT 2
F. Required Action and associated Completion Time of Condition E not met.	F.1	-------------NOTE-------------- LCO 3.0.4.a is not applicable when entering MODE 3. ----------------------------------- Be in MODE 3.	12 hours
G. Two lines with one or more reactor building-to-suppression chamber vacuum breakers inoperable for opening for reasons other than Condition D.	G.1	Restore all vacuum breakers in one line to OPERABLE status.	2 hours
H. Required Action and associated Completion Time of Condition A, B, C, D, F, or G not met.	H.1 <u>AND</u> H.2	Be in MODE 3. Be in MODE 4.	12 hours 36 hours

3.6 CONTAINMENT SYSTEMS

3.6.1.6 Suppression Chamber-to-Drywell Vacuum Breakers

LCO 3.6.1.6 Eight suppression chamber-to-drywell vacuum breakers shall be OPERABLE for opening.

AND

Ten suppression chamber-to-drywell vacuum breakers shall be closed, except when performing their intended function.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required suppression chamber-to-drywell vacuum breaker inoperable for opening.	A.1 Restore one vacuum breaker to OPERABLE status.	72 hours INSERT 2
B. Required Action and associated Completion Time of Condition A not met.	B.1 -------------NOTE-------------- LCO 3.0.4.a is not applicable when entering MODE 3. ----------------------------------- Be in MODE 3.	12 hours
C. One suppression chamber-to-drywell vacuum breaker not closed.	C.1 Close the open vacuum breaker.	4 hours
D. Required Action and associated Completion Time of Condition C not met.	D.1 Be in MODE 3. AND D.2 Be in MODE 4.	12 hours 36 hours

3.6 CONTAINMENT SYSTEMS

3.6.2.3 Residual Heat Removal (RHR) Suppression Pool Cooling

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

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

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

3.7 PLANT SYSTEMS

3.7.1 Residual Heat Removal Service Water (RHRSW) System

LCO 3.7.1 Two RHRSW subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One RHRSW pump inoperable.	A.1	Restore RHRSW pump to OPERABLE status.	14 days INSERT 2

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. One RHRSW subsystem inoperable for reasons other than Condition A.	B.1	-------------NOTE------------- Enter applicable Conditions and Required Actions of LCO 3.4.7, "Residual Heat Removal (RHR) Shutdown Cooling System—Hot Shutdown," for RHR shutdown cooling made inoperable by RHRSW System. ---------------------------------- Restore RHRSW subsystem to OPERABLE status.	7 days INSERT 2
C. Required Action and associated Completion Time of Condition A or B not met.	C.1	-------------NOTE------------- LCO 3.0.4.a is not applicable when entering MODE 3. ---------------------------------- Be in MODE 3.	12 hours
D. Both RHRSW subsystems inoperable.	D.1	-------------NOTE------------- Enter applicable Conditions and Required Actions of LCO 3.4.7 for RHR shutdown cooling made inoperable by RHRSW System. ---------------------------------- Restore one RHRSW subsystem to OPERABLE status.	8 hours

(continued)

3.7 PLANT SYSTEMS

3.7.2 Service Water (SW) System and Ultimate Heat Sink (UHS)

LCO 3.7.2 SW System and UHS shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. ---------NOTE------------------- Only applicable when Unit 1 is in MODE 4 or 5. ------------------------------------ One required nuclear service water (NSW) pump inoperable due to an inoperable Unit 1 NSW header.	A.1 ---------------NOTE------------- Enter applicable Conditions and Required Actions of LCO 3.8.1, "AC Sources—Operating," for diesel generators (DGs) made inoperable by NSW. ------------------------------------ Restore required NSW pump to OPERABLE status.	14 days INSERT 2

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. One required NSW pump inoperable for reasons other than Condition A.	B.1	--------------NOTE------------- Enter applicable Conditions and Required Actions of LCO 3.8.1 for DGs made inoperable by NSW. ----------------------------------- Restore required NSW pump to OPERABLE status.	7 days INSERT 2
C. One required conventional service water (CSW) pump inoperable.	C.1	Verify the one OPERABLE CSW pump and one OPERABLE Unit 2 NSW pump are powered from separate 4.16 kV emergency buses.	Immediately
	<u>AND</u>		
	C.2	Restore required CSW pump to OPERABLE status.	7 days INSERT 2

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
D. Required Action C.1 and associated Completion Time not met.	D.1	Restore required CSW pump to OPERABLE status.	72 hours
E. Two required CSW pumps inoperable.	E.1	--------------NOTE------------- Enter applicable Conditions and Required Actions of LCO 3.7.1, "Residual Heat Removal Service Water (RHRSW) System," for RHRSW subsystems made inoperable by CSW. ----------------------------------- Restore one required CSW pump to OPERABLE status.	72 hours INSERT 2
F. One required NSW pump inoperable. AND One required CSW pump inoperable.	F.1	Restore required NSW pump to OPERABLE status.	72 hours INSERT 2
	OR		
	F.2	Restore required CSW pump to OPERABLE status.	72 hours INSERT 2

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
G. One required NSW pump inoperable. AND Two required CSW pumps inoperable.	G.1 Verify by administrative means that two Unit 2 NSW pumps are OPERABLE. AND G.2.1 Restore required NSW pump to OPERABLE status. OR G.2.2 Restore one required CSW pump to OPERABLE status.	Immediately ~~72 hours~~ INSERT 2 ~~72 hours~~ INSERT 2
H. Water temperature of the UHS > 90.5°F and ≤ 92°F.	H.1 Verify water temperature of the UHS is ≤ 90.5°F averaged over previous 24 hour period.	Once per hour

(continued)

3.7 PLANT SYSTEMS

3.7.6 The Main Turbine Bypass System

LCO 3.7.6 The Main Turbine Bypass System shall be OPERABLE.

<u>OR</u>

The following limits are made applicable:

a. LCO 3.2.1, "AVERAGE PLANAR LINEAR HEAT GENERATION RATE (APLHGR)," limits for an inoperable Main Turbine Bypass System, as specified in the COLR;

b. LCO 3.2.2, "MINIMUM CRITICAL POWER RATIO (MCPR)," limits for an inoperable Main Turbine Bypass System, as specified in the COLR; and

c. LCO 3.2.3, "LINEAR HEAT GENERATION RATE (LHGR)," limits for an inoperable Main Turbine Bypass System, as specified in the COLR.

APPLICABILITY: THERMAL POWER ≥ 23% RTP.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. Requirements of the LCO not met.	A.1 Satisfy the requirements of the LCO.	4 hours INSERT 2
B. Required Action and associated Completion Time not met.	B.1 Reduce THERMAL POWER to < 23% RTP.	4 hours

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. One offsite circuit inoperable for reasons other than Condition A or B.	C.1	Perform SR 3.8.1.1 for OPERABLE offsite circuit(s).	2 hours AND Once per 12 hours thereafter
	AND		
	C.2	Declare required feature(s) with no offsite power available inoperable when the redundant required feature(s) are inoperable.	24 hours from discovery of no offsite power to one 4.16 kV emergency bus concurrent with inoperability of redundant required feature(s)
	AND		
	C.3	Restore offsite circuit to OPERABLE status.	72 hours INSERT 2

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
D. One DG inoperable for reasons other than Condition B.	D.1	Perform SR 3.8.1.1 for OPERABLE offsite circuit(s).	2 hours AND Once per 12 hours thereafter
	AND		
	~~D.2~~	~~Evaluate availability of supplemental diesel generator (SUPP-DG)~~	~~2 hours~~ ~~AND~~ ~~Once per 12 hours thereafter~~
	~~AND~~		
	D.2 ~~D.3~~	Declare required feature (s), supported by the inoperable DG, inoperable when the redundant required feature (s) are inoperable.	4 hours from discovery of Condition D concurrent with inoperability of redundant required feature (s)
	AND		
	D.3.1 ~~D.4.1~~	Determine OPERABLE DG(s) are not inoperable due to common cause failure.	24 hours
	OR		
	D.3.2 ~~D.4.2~~	Perform SR 3.8.1.2 for OPERABLE DG(s).	24 hours
	AND		

(continued)

INSERT 4

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
D. (continued) D.4	~~D.5~~	Restore DG to OPERABLE status.	~~7 days from discovery of unavailability of SUPP-DG~~ ~~AND~~ ~~24 hours from discovery of Condition D entry ≥ 6 days concurrent with unavailability of SUPP-DG~~ ~~AND~~ ~~14 days~~
E. Two or more offsite circuits inoperable for reasons other than Condition B.	E.1	Declare required feature(s) inoperable when the redundant required feature(s) are inoperable.	12 hours from discovery of Condition E concurrent with inoperability of redundant required feature(s)
	AND		
	E.2	Restore all but one offsite circuit to OPERABLE status.	24 hours INSERT 2

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
F. One offsite circuit inoperable for reasons other than Condition B. AND One DG inoperable for reasons other than Condition B.	---------------------NOTE----------------- Enter applicable Conditions and Required Actions of LCO 3.8.7, "Distribution Systems—Operating," when Condition F is entered with no AC power source to any 4.16 kV emergency bus. ---	
	F.1 Restore offsite circuit to OPERABLE status.	12 hours INSERT 2
	OR	
	F.2 Restore DG to OPERABLE status.	12 hours INSERT 2
G. Two or more DGs inoperable.	G.1 Restore all but one DG to OPERABLE status.	2 hours
H. Required Action and associated Completion Time of Condition A, B, C, D, E, F or G not met.	H.1 -------------NOTE------------- LCO 3.0.4.a is not applicable when entering MODE 3. ----------------------------------- Be in MODE 3.	12 hours
I. One or more offsite circuits and two or more DGs inoperable. OR Two or more offsite circuits and one DG inoperable for reasons other than Condition B.	I.1 Enter LCO 3.0.3.	Immediately

3.8 ELECTRICAL POWER SYSTEMS

3.8.4 DC Sources—Operating

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

a. Unit 2 Division I and Division II DC electrical power subsystems; and

b. Unit 1 Division I and Division II DC electrical power subsystems.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One DC electrical power subsystem inoperable.	A.1 --------------NOTE-------------- Enter applicable Conditions and Required Actions of LCO 3.8.7, "Distribution Systems—Operating," when Condition A results in de-energization of an AC electrical power distribution subsystem or a DC electrical power distribution subsystem. ------------------------------------ Restore DC electrical power subsystem to OPERABLE status.	7 days INSERT 2

(continued)

3.8 ELECTRICAL POWER SYSTEMS

3.8.7 Distribution Systems—Operating

LCO 3.8.7 Division I and Division II AC and DC electrical power distribution subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, and 3.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One AC electrical power distribution subsystem inoperable for planned maintenance due to either inoperable load group E1 bus(es) or inoperable load group E2 bus(es).	A.1 Restore affected load group bus(es) to OPERABLE status.	7 days INSERT 2
B. One or more AC electrical power distribution subsystems inoperable for reasons other than Condition A.	B.1 Restore AC electrical power distribution subsystems to OPERABLE status.	8 hours INSERT 2

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. One or more DC electrical power distribution subsystems inoperable due to loss of normal DC source.	C.1	Declare required feature(s), supported by the inoperable DC electrical power distribution subsystem, inoperable.	Immediately
	<u>AND</u>		
	C.2	Initiate action to transfer DC electrical power distribution subsystem to its alternate DC source.	Immediately
	<u>AND</u>		
	C.3	Declare required feature(s) supported by the inoperable DC electrical power distribution subsystem OPERABLE.	Upon completion of transfer of the required feature's DC electrical power distribution subsystem to its OPERABLE alternate DC source
	<u>AND</u>		
	C.4	Restore DC electrical power distribution subsystem to OPERABLE status.	7 days INSERT 2

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
D. One or more DC electrical power distribution subsystems inoperable for reasons other than Condition C.	D.1	Restore DC electrical power distribution subsystems to OPERABLE status.	7 days INSERT 2
E. Required Action and associated Completion Time of Condition A, B, C, or D not met.	E.1	-------------NOTE-------------- LCO 3.0.4.a is not applicable when entering MODE 3. ----------------------------------- Be in MODE 3.	12 hours
F. Two or more electrical power distribution subsystems inoperable that result in a loss of function.	F.1	Enter LCO 3.0.3.	Immediately

5.5 Programs and Manuals

5.5.14 Surveillance Frequency Control Program (continued)

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

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

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

INSERT 5

Brunswick Technical Specifications Inserts (applicable to both Units 1 and 2 TS)

INSERT 1

EXAMPLE 1.3-8

ACTIONS

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

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

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

If the 7 day Completion Time clock of Condition A has expired and subsequent changes in plant condition result in exiting the applicability of the Risk-Informed

Completion Time Program without restoring the inoperable subsystem to OPERABLE status, Condition B is also entered and the Completion Time clocks for Required Actions B.1 and B.2 start.

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

INSERT 2

<u>OR</u>

In accordance with the Risk-Informed Completion Time Program

INSERT 3

<u>OR</u>

-----NOTE-----
Not applicable when a loss of function occurs

In accordance with the Risk-Informed Completion Time Program

INSERT 4

7 days

<u>OR</u>

In accordance with the Risk-Informed Completion Time Program

INSERT 5

5.5.15 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 and 2;

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

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

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

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

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

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

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

e. The risk assessment approaches and methods shall be acceptable to the NRC. The plant PRA shall be based on the as-built, as-operated, and maintained plant; and reflect the operating experience at the plant, as specified in Regulatory Guide 1.200, Revision 2. Methods to assess the risk from extending the Completion Times must be PRA methods used to support 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

REVISED TABLE E1-1, "IN-SCOPE TS ACTIONS TO CORRESPONDING PRA FUNCTIONS"

TABLE E1-1 – IN-SCOPE TS LCOS TO CORRESPONDING PRA FUNCTIONS

BSEP TS	TS Condition	SSCs Covered by TS Condition	Function Covered by TS LCO Condition	Design Success Criteria	SSCs Modeled in PRA	PRA Success Criteria	Comments
Standby Liquid Control (SLC) System 3.1.7	3.1.7 Condition A. One SLC subsystem inoperable.	Two SLC subsystems	Provide a backup capability for bringing the reactor from full power to a cold, Xenon-free shutdown	One SLC pump and corresponding flow path	Yes	Same	SSCs are modeled consistently with the TS scope and so can be directly evaluated by the CRMP. The success criteria in the PRA are consistent with the design basis criteria.
Reactor Protection System (RPS) Instrumentation 3.3.1.1	3.3.1.1 Condition A. One or more required channels inoperable.	The RPS instrumentation in TS Table 3.3.1.1-1 For additional details see Table E1-1a	Trip the reactor trip based on plant parameters	Generally, one-out-of-two taken twice logic For additional details see Table E1-1a	Not explicitly	Same	Individual RPS instrumentation inputs to the RPS logic system are not modeled in the PRA. A surrogate is chosen and it represents the common cause failure of the RPS electrical system. This is conservative and represents failure of the RPS. This event covers both Condition A and Condition B of TS 3.3.1.1.
Reactor Protection System (RPS) Instrumentation 3.3.1.1	3.3.1.1 Condition B. One or more Functions with one or more required channels inoperable in both trip systems.	The RPS instrumentation in TS Table 3.3.1.1-1 For additional details see Table E1-1a	Trip the reactor trip based on plant parameters	Generally, one-out-of-two taken twice logic For additional details see Table E1-1a	Not explicitly	Same	Individual RPS instrumentation inputs to the RPS logic system are not modeled in the PRA. A surrogate is chosen and it represents the common cause failure of the RPS electrical system. This is conservative and represents failure of the RPS. This event covers both Condition A and Condition B of TS 3.3.1.1.

BSEP TS	TS Condition	SSCs Covered by TS Condition	Function Covered by TS LCO Condition	Design Success Criteria	SSCs Modeled in PRA	PRA Success Criteria	Comments
Feedwater and Main Turbine High Water Level Trip Instrumentation 3.3.2.2	3.3.2.2 Condition A. One feedwater and main turbine high water level trip channel inoperable.	Three transmitters and the digital feedwater control system	Provide a reactor high level trip to the two feedwater pump turbines and the main turbine.	Two-out-of-three logic	Yes	Same	SSCs are modeled consistently with the TS scope and so can be directly evaluated by the CRMP. The success criteria in the PRA are consistent with the design basis criteria.
Anticipated Transient Without Scram Recirculation Pump Trip (ATWS-RPT) Instrumentation 3.3.4.1	3.3.4.1 Condition A. One or more channels inoperable.	Two channels of each Function in each of two trip systems. For additional details see Table E1-1b	Trip the recirculation pumps to add negative reactivity on Reactor Low Level 2 or Reactor High Pressure.	Two-out-of-two logic for each Function in either of two trip systems. For additional details see Table E1-1b	Yes	Same	SSCs are modeled consistently with the TS scope and so can be directly evaluated by the CRMP. The success criteria in the PRA are consistent with the design basis criteria.

BSEP TS	TS Condition	SSCs Covered by TS Condition	Function Covered by TS LCO Condition	Design Success Criteria	SSCs Modeled in PRA	PRA Success Criteria	Comments
Emergency Core Cooling System (ECCS) Instrumentation 3.3.5.1	3.3.5.1 Condition B. One or more channels inoperable	Applicable ECCS instrumentation from Table 3.3.5.1-1, see comment For additional details see Table E1-1c	Provide ECCS initiation signals based on plant parameters	One-out-of-two-taken-twice logic For additional details see Table E1-1c	Yes	Same	SSCs are BSEP Table 3.3.5.1-1 Condition B instrumentation with One-out-of-two-taken-twice logic: -Reactor low level 3 CS and RHR initiation (1.a, 2.a) -Drywell high pressure CS, RHR an HPCI initiation (1.b, 2.b, 3.b) -Reactor low level 2 HPCI initiation (3.a) SSCs are modeled consistently with the TS scope and so can be directly evaluated by the CRMP. The success criteria in the PRA are consistent with the design basis criteria.

BSEP TS	TS Condition	SSCs Covered by TS Condition	Function Covered by TS LCO Condition	Design Success Criteria	SSCs Modeled in PRA	PRA Success Criteria	Comments
	3.3.5.1 Condition B. One or more channels inoperable	Applicable ECCS instrumentation from Table 3.3.5.1-1, see comment For additional details see Table E1-1c	Provide ECCS logic signals based on plant parameters	One-out-of-one logic for each RHR loop For additional details see Table E1-1c	Not explicitly	Same	SSCs are BSEP Table 3.3.5.1-1 Condition B instrumentation with One-out-of-one logic for Reactor shroud level input to each division RHR logic (2.e) Individual instrumentation with One-out-of-one logic for Reactor shroud level input to each division RHR logic inputs to the RHR fails to run logic system are not modeled in the PRA. Common cause failure of the RHR pumps surrogates are chosen and they represent the failure of the RHR initiation system. This treatment represents failure of these ECCS logic signals to the RHR loops. These events cover Condition B of TS 3.3.5.1.

BSEP TS	TS Condition	SSCs Covered by TS Condition	Function Covered by TS LCO Condition	Design Success Criteria	SSCs Modeled in PRA	PRA Success Criteria	Comments
Emergency Core Cooling System (ECCS) Instrumentation 3.3.5.1	3.3.5.1 Condition C. One or more channels inoperable	Applicable ECCS instrumentation from Table 3.3.5.1-1, see comment For additional details see Table E1-1c	Provide ECCS logic signals based on plant parameters	One-out-of-two-taken-twice logic For additional details see Table E1-1c	Yes	Same	SSCs are BSEP Table 3.3.5.1-1 Condition C instrumentation with One-out-of-two-taken-twice logic: -Reactor low pressure - CS and RHR injection valve permissive (1.c, 2.c) - Reactor low pressure for recirculation pump discharge valve closure (2.d) SSCs are modeled consistently with the TS scope and so can be directly evaluated by the CRMP. The success criteria in the PRA are consistent with the design basis criteria.

BSEP TS	TS Condition	SSCs Covered by TS Condition	Function Covered by TS LCO Condition	Design Success Criteria	SSCs Modeled in PRA	PRA Success Criteria	Comments
	3.3.5.1 Condition C. One or more channels inoperable	Applicable ECCS instrumentation from Table 3.3.5.1-1, see comment For additional details see Table E1-1c	Provide CS and RHR load sequence time delay	A failure of a 5 second CS time delay relay can only prevent initiation of one CS pump. For each EDG, there are redundant 10 second time delay relays such that a single failure of one of these relays will not prevent any pump starts. For additional details see Table E1-1c	Yes	Same	SSCs are BSEP Table 3.3.5.1-1 Condition C instrumentation for CS and RHR start time delay (1.d, 2.f) SSCs are modeled consistently with the TS scope and so can be directly evaluated by the CRMP. The success criteria in the PRA are consistent with the design basis criteria.

BSEP TS	TS Condition	SSCs Covered by TS Condition	Function Covered by TS LCO Condition	Design Success Criteria	SSCs Modeled in PRA	PRA Success Criteria	Comments
	3.3.5.1 Condition C. One or more channels inoperable	Applicable ECCS instrumentation from Table 3.3.5.1-1, see comment For additional details see Table E1-1c	Trip HPCI on high reactor level	Two-out-of-two logic for trip. For additional details see Table E1-1c	Yes	Same	SSCs are BSEP Table 3.3.5.1-1 Condition C instrumentation for high Reactor level (3.c) SSCs are modeled consistently with the TS scope and so can be directly evaluated by the CRMP. The success criteria in the PRA are consistent with the design basis criteria.
Emergency Core Cooling System (ECCS) Instrumentation 3.3.5.1	3.3.5.1 Condition D. One or more channels inoperable	Applicable ECCS instrumentation from Table 3.3.5.1-1, see comment For additional details see Table E1-1c	Transfer HPCI suction to the Suppression pool	One-out-of-two-logic for either function For additional details see Table E1-1c	Yes	Same	SSCs are BSEP Table 3.3.5.1-1 Condition D instrumentation: - CST low level (3.d) - Suppression pool high level (3.e) SSCs are modeled consistently with the TS scope and so can be directly evaluated by the CRMP. The success criteria in the PRA are consistent with the design basis criteria.

BSEP TS	TS Condition	SSCs Covered by TS Condition	Function Covered by TS LCO Condition	Design Success Criteria	SSCs Modeled in PRA	PRA Success Criteria	Comments
Emergency Core Cooling System (ECCS) Instrumentation 3.3.5.1	3.3.5.1 Condition E. One or more channels inoperable	Applicable ECCS instrumentation from Table 3.3.5.1-1, see comment For additional details see Table E1-1c	Initiate ADS to depressurize the Reactor	See comment on the conservative surrogate. For additional details see Table E1-1c	Not explicitly	Same	SSCs are BSEP Table 3.3.5.1-1 Condition E instrumentation: - Reactor low level 3 initiation (4.a, 5.a) - Reactor low level 1 confirmation (4.c, 5.c) Depressurization of the Reactor through ADS is not credited in the model. Thus individual unique ADS inputs to the ADS logic system are not modeled in the PRA. A surrogate is chosen and it represents the failure of the Reactor depressurization. This is conservative and represents failure of the automatic and manual depressurization. This event covers both Condition E and Condition F of TS 3.3.5.1.

BSEP TS	TS Condition	SSCs Covered by TS Condition	Function Covered by TS LCO Condition	Design Success Criteria	SSCs Modeled in PRA	PRA Success Criteria	Comments
Emergency Core Cooling System (ECCS) Instrumentation 3.3.5.1	3.3.5.1 Condition F. One or more channels inoperable	Applicable ECCS instrumentation from Table 3.3.5.1-1, see comment For additional details see Table E1-1c	Provide time delay for ADS initiation	Two channels are required to be OPERABLE to ensure that no single instrument failure can preclude ADS initiation. For additional details see Table E1-1c	Not explicitly	Same	SSCs are BSEP Table 3.3.5.1-1 Condition F instrumentation for ADS timer (4.b, 5.b) Depressurization of the Reactor through ADS is not credited in the model. Thus individual unique ADS inputs to the ADS logic system are not modeled in the PRA. A surrogate is chosen and it represents the failure of the Reactor depressurization. This is conservative and represents failure of the automatic and manual depressurization. This event covers both Condition E and Condition F of TS 3.3.5.1.

BSEP TS	TS Condition	SSCs Covered by TS Condition	Function Covered by TS LCO Condition	Design Success Criteria	SSCs Modeled in PRA	PRA Success Criteria	Comments
	3.3.5.1 Condition F. One or more channels inoperable	Applicable ECCS instrumentation from Table 3.3.5.1-1, see comment For additional details see Table E1-1c	CS and RHR running logic for ADS initiation	Twelve channels are provided to ensure that no single instrument failure can preclude ADS initiation. For additional details see Table E1-1c	Not explicitly	Same	SSCs are BSEP Table 3.3.5.1-1 Condition F instrumentation for low pressure ECCS pump high discharge pressure (4.d, 4.e, 5.d, 5.e) Depressurization of the Reactor through ADS is not credited in the model. Thus individual unique ADS inputs to the ADS logic system are not modeled in the PRA. A surrogate is chosen and it represents the failure of the Reactor depressurization. This is conservative and represents failure of the automatic and manual depressurization. This event covers both Condition E and Condition F of TS 3.3.5.1.
Reactor Core Isolation Cooling (RCIC) System Instrumentation 3.3.5.2	3.3.5.2 Condition B. One or more channels inoperable	Reactor level instrumentation, Table 3.3.5.2-1 item 1	Initiate RCIC system on Reactor low level 2	One-out-of-two-taken-twice logic	~~Not explicitly~~ Yes	Same	SSCs are modeled consistently with the TS scope and so can be directly evaluated by the CRMP. The success criteria in the PRA are consistent with the design basis criteria.~~Individual instrumentation to initiate RCIC system on Reactor low level 2 are not modeled in the PRA. Simultaneous surrogates are chosen and they represents the common cause failure of the RCIC initiation system. This is~~

BSEP TS	TS Condition	SSCs Covered by TS Condition	Function Covered by TS LCO Condition	Design Success Criteria	SSCs Modeled in PRA	PRA Success Criteria	Comments
							~~conservative and represents failure of these RCIC logic signals. This event covers both Condition B of TS 3.3.5.2~~
Reactor Core Isolation Cooling (RCIC) System Instrumentation 3.3.5.2	3.3.5.2 Condition D. One or more channels inoperable	CST level instrumentation, Table 3.3.5.2-1 item 3	Transfer RCIC suction to Suppression Pool	One-out-of-two logic	Yes	Same	SSCs are modeled consistently with the TS scope and so can be directly evaluated by the CRMP. The success criteria in the PRA are consistent with the design basis criteria.

BSEP TS	TS Condition	SSCs Covered by TS Condition	Function Covered by TS LCO Condition	Design Success Criteria	SSCs Modeled in PRA	PRA Success Criteria	Comments
Primary Containment Isolation Instrumentation 3.3.6.1	3.3.6.1 Condition A. One or more channels inoperable	Primary Containment Isolation instrumentation, Table 3.3.6.1-1, see comment For additional details see Table E1-1d	Main Steam Line Isolation (Group 1)	Adequate channels are provided to ensure that no single instrument failure can preclude the isolation function. For additional details see Table E1-1d	Not explicitly	Same	SSCs are BSEP Table 3.3.6.1 instrumentation: - Reactor Vessel Level - Low Level 3 (1.a) - Main Steam Line Pressure - Low (1.b) - Main Steam Line Flow - High (1.c) - Condenser Vacuum - Low (1.d) - MSIV Pit Temperature - High (1.e) Individual PCI instrumentation inputs to the PCI logic system are not modeled in the PRA. A surrogate is chosen and it represents the common cause failure of the ~~PCI electrical system~~PCI electrical signal. This is conservative and represents failure of the PCI instrumentation. This event covers both Condition A of TS 3.3.6.1.

BSEP TS	TS Condition	SSCs Covered by TS Condition	Function Covered by TS LCO Condition	Design Success Criteria	SSCs Modeled in PRA	PRA Success Criteria	Comments
	3.3.6.1 Condition A. One or more channels inoperable	Primary Containment Isolation instrumentation, Table 3.3.6.1-1, see comment For additional details see Table E1-1d	Primary Containment Isolation see comment	Adequate channels are provided to ensure that no single instrument failure can preclude the isolation function. For additional details see Table E1-1d	Not explicitly	Same	SSCs are BSEP Table 3.3.6.1 instrumentation: - Reactor Vessel Level - Low Level 1 for Group 2, 6 and 8 valves (2.a) - Drywell Pressure - High for Group 2 and 6 valves (2.b) - Reactor Building Exhaust Radiation - High for Group 6 valves (2.d) Individual PCI instrumentation inputs to the PCI logic system are not modeled in the PRA. A surrogate is chosen and it represents the common cause failure of the ~~PCI electrical system~~PCI electrical signal. This is conservative and represents failure of the PCI instrumentation. This event covers both Condition A of TS 3.3.6.1.

BSEP TS	TS Condition	SSCs Covered by TS Condition	Function Covered by TS LCO Condition	Design Success Criteria	SSCs Modeled in PRA	PRA Success Criteria	Comments
	3.3.6.1 Condition A. One or more channels inoperable	Primary Containment Isolation instrumentation, Table 3.3.6.1-1, see comment For additional details see Table E1-1d	Primary Containment Isolation, containment vent and purge valves.	This single channel function is not assumed in any accident or transient analysis in the UFSAR because other leakage paths (e.g., MSIVs) are more limiting. For additional details see Table E1-1d	Not explicitly	Same	SSCs are BSEP Table 3.3.6.1 - Main Stack Radiation - High (2.c) Individual PCI instrumentation inputs to the PCI logic system are not modeled in the PRA. A surrogate is chosen and it represents the common cause failure of the ~~PCI electrical system~~PCI electrical signal. This is conservative and represents failure of the PCI instrumentation. This event covers both Condition A of TS 3.3.6.1.

BSEP TS	TS Condition	SSCs Covered by TS Condition	Function Covered by TS LCO Condition	Design Success Criteria	SSCs Modeled in PRA	PRA Success Criteria	Comments
	3.3.6.1 Condition A. One or more channels inoperable	Primary Containment Isolation instrumentation, Table 3.3.6.1-1, see comment For additional details see Table E1-1d	HPCI System Isolation	Adequate channels are provided to ensure that no single instrument failure can preclude the isolation function. For additional details see Table E1-1d	Not explicitly	Same	SSCs are BSEP Table 3.3.6.1 instrumentation: - HPCI Steam Line Flow - High (3.a) - HPCI Steam Line Flow - High Time Delay Relay (3.b) - HPCI Steam Supply Line Pressure - Low (3.c) - HPCI Turbine Exhaust Diaphragm Pressure - High (3.d) - Drywell Pressure - High (3.e) - Area Temperature (3.f, 3.g, 3.h, 3.i) Individual PCI instrumentation inputs to the PCI logic system are not modeled in the PRA. A surrogate is chosen and it represents the common cause failure of the ~~PCI electrical system~~PCI electrical signal. This is conservative and represents failure of the PCI instrumentation. This event covers both Condition A of TS 3.3.6.1.

BSEP TS	TS Condition	SSCs Covered by TS Condition	Function Covered by TS LCO Condition	Design Success Criteria	SSCs Modeled in PRA	PRA Success Criteria	Comments
	3.3.6.1 Condition A. One or more channels inoperable	Primary Containment Isolation instrumentation, Table 3.3.6.1-1, see comment For additional details see Table E1-1d	RCIC System Isolation	Adequate channels are provided to ensure that no single instrument failure can preclude the isolation function. For additional details see Table E1-1d	Not explicitly	Same	SSCs are BSEP Table 3.3.6.1 instrumentation: - RCIC Steam Line Flow - High (4.a) - RCIC Steam Line Flow - High Time Delay Relay (4.b) - RCIC Steam Supply Line Pressure - Low (4.c) - RCIC Turbine Exhaust Diaphragm Pressure - High (4.d) - Drywell Pressure - High (4.e) - Area Temperature (4.f, 4.g, 4.h, 4.i, 4.j, 4.k) Individual PCI instrumentation inputs to the PCI logic system are not modeled in the PRA. A surrogate is chosen and it represents the common cause failure of the ~~PCI electrical system~~PCI electrical signal. This is conservative and represents failure of the PCI instrumentation. This event covers both Condition A of TS 3.3.6.1.

BSEP TS	TS Condition	SSCs Covered by TS Condition	Function Covered by TS LCO Condition	Design Success Criteria	SSCs Modeled in PRA	PRA Success Criteria	Comments
	3.3.6.1 Condition A. One or more channels inoperable	Primary Containment Isolation instrumentation, Table 3.3.6.1-1, see comment For additional details see Table E1-1d	RWCU System Isolation	The high differential flow signals are compared in a common summer and the output is sent to two high flow trip units. Two channels are provided to ensure that no single instrument failure downstream of the common summer can preclude the isolation function. For additional details see Table E1-1d	Not explicitly	Same	SSCs are BSEP Table 3.3.6.1 instrumentation: - Differential Flow - High (5.a) - Differential Flow - High Time Delay (5.b) Individual PCI instrumentation inputs to the PCI logic system are not modeled in the PRA. A surrogate is chosen and it represents the common cause failure of the ~~PCI electrical system~~PCI electrical signal. This is conservative and represents failure of the PCI instrumentation. This event covers both Condition A of TS 3.3.6.1.

BSEP TS	TS Condition	SSCs Covered by TS Condition	Function Covered by TS LCO Condition	Design Success Criteria	SSCs Modeled in PRA	PRA Success Criteria	Comments
	3.3.6.1 Condition A. One or more channels inoperable	Primary Containment Isolation instrumentation, Table 3.3.6.1-1, see comment For additional details see Table E1-1d	RWCU System Isolation	Adequate channels are provided to ensure that no single instrument failure can preclude the isolation function. For additional details see Table E1-1d	Not explicitly	Same	SSCs are BSEP Table 3.3.6.1 instrumentation: - Area temperature (5.c, 5.d, 5.e) - Reactor Vessel Water Level - Low Level 2 (5.g) Individual PCI instrumentation inputs to the PCI logic system are not modeled in the PRA. A surrogate is chosen and it represents the common cause failure of the ~~PCI electrical system~~PCI electrical signal. This is conservative and represents failure of the PCI instrumentation. This event covers both Condition A of TS 3.3.6.1.

BSEP TS	TS Condition	SSCs Covered by TS Condition	Function Covered by TS LCO Condition	Design Success Criteria	SSCs Modeled in PRA	PRA Success Criteria	Comments
	3.3.6.1 Condition A. One or more channels inoperable	Primary Containment Isolation instrumentation, Table 3.3.6.1-1, see comment For additional details see Table E1-1d	RWCU System Isolation	One channel is provided. This function is only required to close one of the RWCU isolation valves For additional details see Table E1-1d	Not explicitly	Same	SSCs are BSEP Table 3.3.6.1 instrumentation: - SLC System Initiation (5.f) Individual PCI instrumentation inputs to the PCI logic system are not modeled in the PRA. A surrogate is chosen and it represents the common cause failure of the ~~PCI electrical system~~PCI electrical signal. This is conservative and represents failure of the PCI instrumentation. This event covers both Condition A of TS 3.3.6.1.

BSEP TS	TS Condition	SSCs Covered by TS Condition	Function Covered by TS LCO Condition	Design Success Criteria	SSCs Modeled in PRA	PRA Success Criteria	Comments
	3.3.6.1 Condition A. One or more channels inoperable	Primary Containment Isolation instrumentation, Table 3.3.6.1-1, see comment For additional details see Table E1-1d	RHR Shutdown Cooling Isolation	Adequate channels are provided to ensure that no single instrument failure can preclude the isolation function. For additional details see Table E1-1d	Not explicitly	Same	SSCs are BSEP Table 3.3.6.1 instrumentation: - Reactor Steam Dome Pressure - High (6.a) - Reactor Vessel Water Level - Low Level 1 (6.b) Individual PCI instrumentation inputs to the PCI logic system are not modeled in the PRA. A surrogate is chosen and it represents the common cause failure of the ~~PCI electrical system~~PCI electrical signal. This is conservative and represents failure of the PCI instrumentation. This event covers both Condition A of TS 3.3.6.1.

BSEP TS	TS Condition	SSCs Covered by TS Condition	Function Covered by TS LCO Condition	Design Success Criteria	SSCs Modeled in PRA	PRA Success Criteria	Comments
	3.3.6.1 Condition A. One or more channels inoperable	Primary Containment Isolation instrumentation, Table 3.3.6.1-1, see comment For additional details see Table E1-1d	TIP Isolation	Adequate channels are provided to ensure that no single instrument failure can preclude the isolation function. For additional details see Table E1-1d	Not explicitly	Same	SSCs are BSEP Table 3.3.6.1 instrumentation: - Reactor Vessel Water Level – Low Level 1 (7.a) - Drywell Pressure - High (7.b) Individual PCI instrumentation inputs to the PCI logic system are not modeled in the PRA. A surrogate is chosen and it represents the common cause failure of the ~~PCI electrical system~~PCI electrical signal. This is conservative and represents failure of the PCI instrumentation. This event covers both Condition A of TS 3.3.6.1.

BSEP TS	TS Condition	SSCs Covered by TS Condition	Function Covered by TS LCO Condition	Design Success Criteria	SSCs Modeled in PRA	PRA Success Criteria	Comments
ECCS—Operating 3.5.1	3.5.1 Condition A. One low pressure ECCS injection/spray subsystem inoperable. OR One low pressure coolant injection (LPCI) pump in each subsystem inoperable.	Low pressure ECCS consists of two CS Systems and two loops of RHR operating in (LPCI) mode. Each loop of RHR has two pumps	The ECCS uses flooding and/or spraying to cool the core during a LOCA. For medium and small line breaks, reactor depressurization is required to allow adequate cooling flow using the low pressure pumps.	Cooling for a Recirculation suction line break is adequate with four pumps after a single failure disables two pumps. Cooling for all other breaks is adequate with ADS and either two CS pumps or one CS pump and one LPCI pump.	Yes	LOCA PRA success criteria shows sufficient cooling is one CS pump or one RHR pump in LPCI mode.	SSCs are modeled consistently with the TS scope and so can be directly evaluated by the CRMP. The PRA success criteria differ from the design basis criteria in not requiring multiple CS or RHR pumps for LOCAs. Success criteria in PRA are based on plant-specific realistic analyses consistent with the PRA standards for capability category II.

BSEP TS	TS Condition	SSCs Covered by TS Condition	Function Covered by TS LCO Condition	Design Success Criteria	SSCs Modeled in PRA	PRA Success Criteria	Comments
ECCS— Operating 3.5.1	3.5.1 Condition B. One LPCI pump inoperable. AND One core spray (CS) subsystem inoperable.	Low pressure ECCS consists of two CS Systems and two loops of RHR operating in (LPCI) mode. Each loop of RHR has two pumps	The ECCS uses flooding and/or spraying to cool the core during a LOCA. For medium and small line breaks, reactor depressurization is required to allow adequate cooling flow using the low pressure pumps.	Cooling for a Recirculation suction line break is adequate with four pumps after a single failure disables two pumps. Cooling for all other breaks is adequate with ADS and either two CS pumps or one CS pump and one LPCI pump.	Yes	LOCA PRA success criteria shows sufficient cooling is one CS pump or one RHR pump in LPCI mode.	SSCs are modeled consistently with the TS scope and so can be directly evaluated by the CRMP. The PRA success criteria differ from the design basis criteria in not requiring multiple CS or RHR pumps for LOCAs. Success criteria in PRA are based on plant-specific realistic analyses consistent with the PRA standards for capability category II. VARIATION: BSEP TS 3.5.1 contains a Condition B for one LPCI pump inoperable AND one core spray subsystem inoperable. This Condition and associated RAs are not in TSTF-505, Rev. 2. However, the SSCs associated with BSEP LCO 3.5.1, Condition B are directly modeled in the PRA and thus a RICT can be calculated.

BSEP TS	TS Condition	SSCs Covered by TS Condition	Function Covered by TS LCO Condition	Design Success Criteria	SSCs Modeled in PRA	PRA Success Criteria	Comments
ECCS—Operating 3.5.1	3.5.1 Condition D. HPCI System inoperable.	One HPCI System	Reactor coolant makeup for small line breaks with reactor pressure between 150 psig and 1164 psig. HPCI also provides backup to the RCIC function.	HPCI operation for small breaks can prevent the need for ADS actuation and low pressure pump injection. HPCI operation is adequate for coolant makeup for non-LOCA events.	Yes	Same	SSCs are modeled consistently with the TS scope and so can be directly evaluated by the CRMP. The success criteria in the PRA are consistent with the design basis criteria.
ECCS—Operating 3.5.1	3.5.1 Condition E. HPCI System inoperable. AND One low pressure ECCS injection/spray subsystem is inoperable.	CS, LPCI and HPCI	HPCI injection for small breaks or use of a low pressure ECCS pump (after vessel depressurization) for small breaks where HPCI does not operate.	HPCI operation or one low pressure ECCS pump.	Yes	The HPCI PRA success criteria are consistent with the design basis. LOCA PRA success criteria shows sufficient cooling is one CS pump or one RHR pump in LPCI mode.	SSCs are modeled consistently with the TS scope and so can be directly evaluated by the CRMP. The HPCI success criteria in the PRA are consistent with the design basis criteria. The low pressure ECCS pump PRA success criteria differ from the design basis criteria in not requiring multiple CS or RHR pumps for LOCAs. Success criteria in PRA are based on plant-specific realistic analyses consistent with the PRA standards for capability category II.

BSEP TS	TS Condition	SSCs Covered by TS Condition	Function Covered by TS LCO Condition	Design Success Criteria	SSCs Modeled in PRA	PRA Success Criteria	Comments
ECCS—Operating 3.5.1	3.5.1 Condition F. One required ADS valve inoperable.	Six of Seven ADS valves are required to be operable	Automatic or manual reactor depressurization for events with inadequate high pressure coolant makeup	Five ADS valves	Yes	At least three Safety Relief Valves (including ADS valves) for depressurization. ~~At least three Safety Relief Valves (including ADS valves) for non-ATWS scenarios; At least ten SRVs (including ADS valves) for ATWS scenarios~~	SSCs are modeled consistently with the TS scope and so can be directly evaluated by the CRMP. The PRA success criteria differ from the design basis criteria in the number of valves required for reactor depressurization. Success criteria in PRA are based on plant-specific realistic analyses consistent with the PRA standards for capability category II.
ECCS—Operating 3.5.1	3.5.1 Condition G. One required ADS valve inoperable. AND One low pressure ECCS injection/spray subsystem inoperable.	CS, LPCI and ADS	Automatic or manual reactor depressurization for events with inadequate high pressure coolant makeup	Five ADS valves and one low pressure ECCS pump	Yes	Manual~~/ automatic~~ depressurization using at least three Safety Relief Valves and one low pressure ECCS pump.	SSCs are modeled consistently with the TS scope and so can be directly evaluated by the CRMP. The ADS valve PRA success criteria differ from the design basis criteria in the number of valves required for reactor depressurization. Success criteria in PRA are based on plant-specific realistic analyses consistent with the PRA standards for capability category II.

BSEP TS	TS Condition	SSCs Covered by TS Condition	Function Covered by TS LCO Condition	Design Success Criteria	SSCs Modeled in PRA	PRA Success Criteria	Comments
ECCS—Operating 3.5.1	3.5.1 Condition H. One required ADS valve inoperable. AND HPCI System inoperable.	ADS and HPCI	HPCI injection for small breaks, or reactor depressurization (to allow low pressure ECCS pump injection) for small breaks where HPCI does not operate.	HPCI operation or five ADS valves	Yes	The HPCI success criteria are consistent with the design basis. At least three Safety Relief Valves (including ADS valves) for depressurization. ~~At least three Safety Relief Valves (including ADS valves) for non-ATWS scenarios; At least ten SRVs (including ADS valves) for ATWS scenarios~~	SSCs are modeled consistently with the TS scope and so can be directly evaluated by the CRMP. The HPCI success criteria are consistent with the design basis. The ADS valve PRA success criteria differ from the design basis criteria in the number of valves required for reactor depressurization. Success criteria in PRA are based on plant-specific realistic analyses consistent with the PRA standards for capability category II.
RCIC System 3.5.3	3.5.3 Condition A. RCIC System inoperable.	RCIC	RCIC provides reactor coolant makeup with reactor pressures 150 psig to 1164 psig.	Provide required coolant makeup for events with loss of normal makeup	Yes	Same	SSCs are modeled consistently with the TS scope and so can be directly evaluated by the CRMP. The success criteria in the PRA are consistent with the design basis criteria.

BSEP TS	TS Condition	SSCs Covered by TS Condition	Function Covered by TS LCO Condition	Design Success Criteria	SSCs Modeled in PRA	PRA Success Criteria	Comments
Primary Containment Air Lock 3.6.1.2	3.6.1.2 Condition C Primary containment air lock inoperable for reasons other than Condition A or B.	One air lock with two doors and an interlock mechanism	Maintain containment integrity and leakage within limits	One air lock with one door closed	No	N/A	PRA models using a surrogate basic event. Additional technical justification is required for this TS Action per TSTF-505, Rev. 2 Table 1. The airlocks are not modeled so a large pre-existing leak failure will be used as a conservative surrogate for the RICT calculation.
Primary Containment Isolation Valves (PCIVs) 3.6.1.3	3.6.1.3 Condition A. One or more penetration flow paths with one of two PCIVs inoperable (except for MSIV leakage not within limit	Primary Containment Isolation Valves (PCIVs)	Maintain containment integrity and leakage within limits	One of two PCIVs per penetration isolate within required stroke time	Not explicitly	Same	EDITORIAL: TSTF-505, Rev. 2 includes a 4 hour CT for flow paths except the main steam line and a 8 hour CT for the main steam line. BSEP has a single 8 hour CT to isolate the affected penetration flow path. Not all primary containment isolation valves are modeled. Therefore, a surrogate of a pre-existing containment failure is chosen.

BSEP TS	TS Condition	SSCs Covered by TS Condition	Function Covered by TS LCO Condition	Design Success Criteria	SSCs Modeled in PRA	PRA Success Criteria	Comments
Reactor Building-to-Suppression Chamber Vacuum Breakers 3.6.1.5	3.6.1.5 Condition E. One line with one or more reactor building-to suppression chamber vacuum breakers inoperable for opening for reasons other than Condition C.	Reactor Building-to-Suppression Chamber Vacuum Breakers consist of a check valve and an air operated valve located in series in each of two lines	Protect primary containment from negative pressure	one line	Yes	Same	SSCs are modeled consistently with the TS scope and so can be directly evaluated by the CRMP. The success criteria in the PRA are consistent with the design basis criteria.
Suppression Chamber-to-Drywell Vacuum Breakers 3.6.1.6	3.6.1.6 Condition A. One required suppression chamber-to-drywell vacuum breaker inoperable for opening.	Eight of ten internal vacuum breakers (check valves) are required to be operable	Allow flow from the suppression chamber atmosphere to the drywell	Seven vacuum breakers	Not explicitly	Same	The opening function of the suppression chamber to drywell vacuum breakers is not modeled in the PRA. The vapor suppression function is modeled and is used as a surrogate here. The success criteria in the PRA are consistent with the design basis.

BSEP TS	TS Condition	SSCs Covered by TS Condition	Function Covered by TS LCO Condition	Design Success Criteria	SSCs Modeled in PRA	PRA Success Criteria	Comments
Residual Heat Removal (RHR) Suppression Pool Cooling 3.6.2.3	3.6.2.3 Condition A. One RHR suppression pool cooling subsystem inoperable.	Two loops of RHR with two pumps and one heat exchanger in each loop	Remove heat for primary containment cooling following a LOCA or other event with reactor heat transferred to the suppression pool.	One RHR loop with two pumps and one heat exchanger	Yes	One RHR loop with one pump and one heat exchanger	SSCs are modeled consistently with the TS scope and so can be directly evaluated by the CRMP. The RHR PRA success criteria differ from the design basis criteria in the number of pumps required. Success criteria in PRA are based on plant-specific realistic analyses consistent with the PRA standards for capability category II.
Residual Heat Removal Service Water (RHRSW) System 3.7.1	3.7.1 Condition A. One RHRSW pump inoperable.	Two trains with two RHRSW pumps in each train	RHRSW provides cooling water for the RHR heat exchangers following a LOCA or other event with reactor heat transferred to the suppression pool	One train with two pumps	Yes	One train with one pump	EDITORIAL: The BSEP existing Completion Time for RA A.1 is 14 days whereas the BWR/4 STS Completion Time is 30 days. SSCs are modeled consistently with the TS scope and so can be directly evaluated by the CRMP. The RHRSW PRA success criteria differ from the design basis criteria in the number of pumps required. Success criteria in PRA are based on plant-specific realistic analyses consistent with the PRA standards for capability category II.

BSEP TS	TS Condition	SSCs Covered by TS Condition	Function Covered by TS LCO Condition	Design Success Criteria	SSCs Modeled in PRA	PRA Success Criteria	Comments
Residual Heat Removal Service Water (RHRSW) System 3.7.1	3.7.1 Condition B. One RHRSW subsystem inoperable for reasons other than Condition A.	Two trains of with two RHRSW pumps in each train	RHRSW provides cooling water for the RHR heat exchangers following a LOCA or other event with reactor heat transferred to the suppression pool	One train with two pumps	Yes	One train with one pump	SSCs are modeled consistently with the TS scope and so can be directly evaluated by the CRMP. The RHRSW PRA success criteria differ from the design basis criteria in the number of pumps required. Success criteria in PRA are based on plant-specific realistic analyses consistent with the PRA standards for capability category II.

BSEP TS	TS Condition	SSCs Covered by TS Condition	Function Covered by TS LCO Condition	Design Success Criteria	SSCs Modeled in PRA	PRA Success Criteria	Comments
Service Water (SW) System and Ultimate Heat Sink (UHS) 3.7.2	3.7.2 Condition A. (Note: Only applicable when Unit 2 is in MODE 4 or 5.) One required nuclear service water (NSW) pump inoperable due to an inoperable Unit 2 NSW header.	See 3.7.2 Condition B	See 3.7.2 Condition B	See 3.7.2 Condition B	Yes	See 3.7.2 Condition B.	SSCs are modeled consistently with the TS scope and so can be directly evaluated by the CRMP. The PRA does not differentiate reasons a NSW pump is unavailable regarding the opposite units modes. However, taking a NSW pump out of service in the PRA encompasses the condition described in this portion of the TS. The success criteria in the PRA are consistent with the design basis criteria. See 3.7.2 Condition B Comments for expanded PRA success criteria discussion. VARIATION: This is a site-specific Condition and RA for one NSW pump inoperable due to an inoperable opposite unit NSW header. The opposite unit is also in MODE 4 or 5 for this condition. One NSW pump is explicitly modeled in the BNP PRA models and thus a RICT can be directly calculated.

BSEP TS	TS Condition	SSCs Covered by TS Condition	Function Covered by TS LCO Condition	Design Success Criteria	SSCs Modeled in PRA	PRA Success Criteria	Comments
<u>Service Water (SW) System and Ultimate Heat Sink (UHS)</u> 3.7.2	3.7.2 Condition B. One required NSW pump inoperable for reasons other than Condition A.	Each unit has Two NSW pumps. Three site NSW pumps are required to be OPERABLE.	Provide normal, transient and accident cooling water for EDGs, RHRSW, Room Coolers, RBCCW, RHR Seal Coolers. If the unit specific NSW header can not provide EDG cooling, this function can be provided by the opposite unit NSW header.	For accident responses, the two NSW and three CSW pumps combine to provide the required cooling. With one specific single failure (loss of Div. II emergency bus), one NSW pump provides EDG cooling and two CSW pumps provide cooling to all other equipment. For other single failures, two of three available SW pumps are adequate.	Yes	Similar to the Design Success Criteria three SW pumps functioning to provide SW system loads. Successful throttling of the TBCCW heat exchanger reduces the required number of CSW pumps in the PRA. See comments for expanded PRA success criteria discussion.	SSCs are modeled consistently with the TS scope and so can be directly evaluated by the CRMP. VARIATION: TSTF-505, Rev.2 TS 3.7.2, Condition A is for one SW pump inoperable with a CT of 30 days. Therefore, it was excluded from the scope of the TSTF traveler. However, the equivalent BSEP TS Action (i.e., Condition B) has a CT of 7 days and is therefore proposed to be in the scope of the RICT Program. The success criteria in the PRA are consistent with the design basis criteria. However, the Service Water PRA success criteria credits the following alignments. During normal operation one NSW and two CSW pumps are functioning to provide SWS loads. Following the transient, the pump configuration remains the same, so loads normally supplied from the NSW header still require a single NSW pump. Given a running NSW pump, then one CSW pump can be sufficient for the CSW header during shutdown if the TBCCW heat exchanger throttle valve

BSEP TS	TS Condition	SSCs Covered by TS Condition	Function Covered by TS LCO Condition	Design Success Criteria	SSCs Modeled in PRA	PRA Success Criteria	Comments
							functions to reduce flow through the TBCCW heat exchanger. Successful throttling of the TBCCW heat exchanger reduces the required number of CSW pumps to one (for CSW header supply). If the nuclear header is to be supplied from CSW because the NSW supply is failed, then an additional CSW pump is required, so either all three CSW pumps must function, or two of three with successful throttling of TBCCW flow. This logic applies to loads supplied by the NSW header. In order for the diesel generator to be supplied from CSW, one additional CSW pump must be available to provide the required flow for both the EDG and the RHR system, so the success criteria is two CSW pumps with successful throttling. The success criterion also addresses the potential for using pumps from the opposite unit to supply the diesel generators. Success criteria in PRA are based on plant-specific realistic analyses consistent with the PRA standards for capability

BSEP TS	TS Condition	SSCs Covered by TS Condition	Function Covered by TS LCO Condition	Design Success Criteria	SSCs Modeled in PRA	PRA Success Criteria	Comments
							category II.

BSEP TS	TS Condition	SSCs Covered by TS Condition	Function Covered by TS LCO Condition	Design Success Criteria	SSCs Modeled in PRA	PRA Success Criteria	Comments
Service Water (SW) System and Ultimate Heat Sink (UHS) 3.7.2	3.7.2 Condition C. One required conventional service water (CSW) pump inoperable.	See comment	When aligned to the CSW header, the pumps provide normal, transient and accident cooling water for RHRSW, Room Coolers, TBCCW, RBCCW, RHR Seal Coolers. When aligned to the NSW header, CSW pumps provide the NSW function.	See 3.7.2 Condition B	Yes	See 3.7.2 Condition B	SSCs are modeled consistently with the TS scope and so can be directly evaluated by the CRMP. The success criteria in the PRA are consistent with the design basis criteria. See 3.7.2 Condition B Comments for expanded PRA success criteria discussion. SSCs: The three CSW pumps can be aligned to either the CSW header or the NSW header as needed. Two specific CSW pumps are required to be OPERABLE to supply the CSW header for events with one specific single failure (Loss of Div II power). This failure disables both the flow path from the NSW header to the RHRSW pumps and it disables the CSW pump fed from Div. II. VARIATION: BSEP Condition C of TS 3.7.2 is plant-specific and there is no corresponding ACTION statement in TSTF-505, Revision 2 for one required Conventional Service Water (CSW) pump inoperable. However, one CSW pump is explicitly modeled in the BSEP

BSEP TS	TS Condition	SSCs Covered by TS Condition	Function Covered by TS LCO Condition	Design Success Criteria	SSCs Modeled in PRA	PRA Success Criteria	Comments
							PRA models and thus a RICT can be directly calculated.

BSEP TS	TS Condition	SSCs Covered by TS Condition	Function Covered by TS LCO Condition	Design Success Criteria	SSCs Modeled in PRA	PRA Success Criteria	Comments
Service Water (SW) System and Ultimate Heat Sink (UHS) 3.7.2	3.7.2 Condition E. Two required CSW pumps inoperable.	See 3.7.2 Condition C	See 3.7.2 Condition C	See 3.7.2 Condition B	Yes	See 3.7.2 Condition B	SSCs are modeled consistently with the TS scope and so can be directly evaluated by the CRMP. The success criteria in the PRA are consistent with the design basis criteria. See 3.7.2 Condition B Comments for expanded PRA success criteria discussion. VARIATION: BSEP Condition E of TS 3.7.2 is plant-specific and there is no corresponding ACTION statement in TSTF-505, Revision 2 for two Conventional Service Water (CSW) pump inoperable. However, two CSW pumps out of service is explicitly modeled in the BSEP PRA models and thus a RICT can be directly calculated. Also, two inoperable CSW pumps does not represent a loss of safety function.

BSEP TS	TS Condition	SSCs Covered by TS Condition	Function Covered by TS LCO Condition	Design Success Criteria	SSCs Modeled in PRA	PRA Success Criteria	Comments
Service Water (SW) System and Ultimate Heat Sink (UHS) 3.7.2	3.7.2 Condition F. One required NSW pump inoperable. AND One required CSW pump inoperable.	See 3.7.2 Condition B and 3.7.2 Condition C	See 3.7.2 Condition B and 3.7.2 Condition C	See 3.7.2 Condition B	Yes	See 3.7.2 Condition B	SSCs are modeled consistently with the TS scope and so can be directly evaluated by the CRMP. The success criteria in the PRA are consistent with the design basis criteria. See 3.7.2 Condition B Comments for expanded PRA success criteria discussion. VARIATION: BSEP Condition F of TS 3.7.2 is plant-specific and there is no corresponding ACTION statement in TSTF-505, Revision 2 for one CSW Pump inoperable and one NSW pump inoperable. However, the BSEP PRA Models directly model this Condition F and thus a RICT can be directly calculated. Also, one CSW pump inoperable and one NSW pump inoperable does not represent a loss of safety function.

BSEP TS	TS Condition	SSCs Covered by TS Condition	Function Covered by TS LCO Condition	Design Success Criteria	SSCs Modeled in PRA	PRA Success Criteria	Comments
Service Water (SW) System and Ultimate Heat Sink (UHS) 3.7.2	3.7.2 Condition G. One required NSW pump inoperable. AND Two required CSW pumps inoperable.	See 3.7.2 Condition B and 3.7.2 Condition C	See 3.7.2 Condition B and 3.7.2 Condition C	See 3.7.2 Condition B	Yes	See 3.7.2 Condition B	SSCs are modeled consistently with the TS scope and so can be directly evaluated by the CRMP. The success criteria in the PRA are consistent with the design basis criteria. See 3.7.2 Condition B Comments for expanded PRA success criteria discussion. VARIATION: BSEP Condition G of TS 3.7.2 is plant-specific and there is no corresponding ACTION statement in TSTF-505, Revision 2 for two CSW Pumps inoperable and one NSW pump inoperable. However, the BSEP PRA Models directly model this Condition G and thus a RICT can be directly calculated. Also, two CSW pump inoperable and one NSW pump inoperable does not represent a loss of safety function. Required Action G.1 requires verification of 2 unit-specific NSW pumps to perform the cooling safety function.

BSEP TS	TS Condition	SSCs Covered by TS Condition	Function Covered by TS LCO Condition	Design Success Criteria	SSCs Modeled in PRA	PRA Success Criteria	Comments
The Main Turbine Bypass System 3.7.6 (Unit 1)	3.7.6 Condition A. (Unit 1) Requirements of the LCO not met.	Three of Four U1 Bypass Valves are required to be OPERABLE	Limit peak pressure during events that cause rapid reactor pressurization, so that the Safety Limit MCPR is not exceeded.	Three U1 Bypass Valves	Yes	At unit 1, all four turbine bypass valves must open to support condenser cooling.	SSCs are modeled consistently with the TS scope and so can be directly evaluated by the CRMP. The success criteria in the PRA are more restrictive with the design basis criteria.
The Main Turbine Bypass System 3.7.6 (Unit 2)	3.7.6 Condition A. (Unit 2) Requirements of the LCO not met.	Eight of Ten U2 Bypass Valves are required to be OPERABLE	Limit peak pressure during events that cause rapid reactor pressurization, so that the Safety Limit MCPR is not exceeded.	Eight U2 Bypass Valves	Yes	For the same amount of steam flow at unit 2 as unit 1, only three of its ten turbine bypass valves must open.	SSCs are modeled consistently with the TS scope and so can be directly evaluated by the CRMP. The success criteria in the PRA are different than the design basis criteria. The PRA success criteria was developed for the TBV function credited in the PRA model. The unit 2 PRA only credits the same amount of bypass steam flow as unit 1 and thus only three unit 2 bypass valves are required for success. However, in order to ensure the unit 2 PRA success criteria sufficiently bounds the design basis success criteria the basic event chosen to represent the unit 2 configuration is the common cause failure basic event for all bypass valves.

BSEP TS	TS Condition	SSCs Covered by TS Condition	Function Covered by TS LCO Condition	Design Success Criteria	SSCs Modeled in PRA	PRA Success Criteria	Comments
AC Sources—Operating 3.8.1	3.8.1 Condition C. One offsite circuit inoperable for reasons other than Condition A or B.	Two offsite power supplies for each of the four emergency buses	Provide AC power to the Engineered Safety Feature (ESF) systems.	Either offsite supply is adequate for each bus. Three emergency buses are adequate for all events	Yes	As needed to supply supported functions.	SSCs are modeled consistently with the TS scope and so can be directly evaluated by the CRMP. The success criteria in the PRA are consistent with the design basis criteria.
AC Sources—Operating 3.8.1	3.8.1 Condition D. One DG inoperable for reasons other than Condition B.	One EDG for each of the four emergency buses	Provide AC power to the Engineered Safety Feature (ESF) systems.	An EDG is adequate for each bus. Three emergency buses are adequate for all events	Yes	As needed to supply supported functions.	SSCs are modeled consistently with the TS scope and so can be directly evaluated by the CRMP. The success criteria in the PRA are consistent with the design basis criteria.
AC Sources—Operating 3.8.1	3.8.1 Condition E. Two or more offsite circuits inoperable for reasons other than Condition B.	Two offsite power supplies for each of the four emergency buses	Provide AC power to the Engineered Safety Feature (ESF) systems.	Either offsite supply is adequate for each bus. Three emergency buses are adequate for all events	Yes	As needed to supply supported functions.	SSCs are modeled consistently with the TS scope and so can be directly evaluated by the CRMP. The success criteria in the PRA are consistent with the design basis criteria.

BSEP TS	TS Condition	SSCs Covered by TS Condition	Function Covered by TS LCO Condition	Design Success Criteria	SSCs Modeled in PRA	PRA Success Criteria	Comments
AC Sources—Operating 3.8.1	3.8.1 Condition F. One offsite circuit inoperable for reasons other than Condition B. AND One DG inoperable for reasons other than Condition B.	Two offsite power supplies and one EDG for each of the four emergency buses	Provide AC power to the Engineered Safety Feature (ESF) systems.	Either offsite supply or one EDG is adequate for each bus. Three emergency buses are adequate for all events	Yes	As needed to supply supported functions.	SSCs are modeled consistently with the TS scope and so can be directly evaluated by the CRMP. The success criteria in the PRA are consistent with the design basis criteria.
DC Sources—Operating 3.8.4	3.8.4 Condition A. One DC electrical power subsystem inoperable.	Four trains (two per Unit)	Provide: - Control power for AC emergency power system - Motive and control power to safety related equipment - Power to UPS system	Three trains of DC power are adequate	Yes	As needed to supply supported functions.	SSCs are modeled consistently with the TS scope and so can be directly evaluated by the CRMP. The success criteria in the PRA are consistent with the design basis criteria. EDITORIAL: BSEP TS 3.8.4 does not distinguish separate actions for different causes of inoperability, but applies the limiting 7 day CT for any cause of inoperability of a DC electrical power subsystem.

BSEP TS	TS Condition	SSCs Covered by TS Condition	Function Covered by TS LCO Condition	Design Success Criteria	SSCs Modeled in PRA	PRA Success Criteria	Comments
~~DC Sources—Operating 3.8.4~~	~~3.8.4 Condition B.~~ ~~Required Action and associated Completion Time of Condition A not met.~~	~~Four trains (two per Unit)~~	~~Provide:~~ ~~- Control power for AC emergency power system~~ ~~- Motive and control power to safety related equipment~~ ~~- Power to UPS system~~	~~Three trains of DC power are adequate~~	~~Yes~~	~~As needed to supply supported functions.~~	~~SSCs are modeled consistently with the TS scope and so can be directly evaluated by the CRMP.~~ ~~The success criteria in the PRA are consistent with the design basis criteria.~~ ~~EDITORIAL: BSEP TS 3.8.4 does not distinguish separate actions for different causes of inoperability, but applies the limiting 7 day CT for any cause of inoperability of a DC electrical power subsystem.~~
~~DC Sources—Operating 3.8.4~~	~~3.8.4 Condition C.~~ ~~Two or more DC electrical power subsystems inoperable.~~	~~Four trains (two per Unit)~~	~~Provide:~~ ~~- Control power for AC emergency power system~~ ~~- Motive and control power to safety related equipment~~ ~~- Power to UPS system~~	~~Three trains of DC power are adequate~~	~~Yes~~	~~As needed to supply supported functions.~~	~~SSCs are modeled consistently with the TS scope and so can be directly evaluated by the CRMP.~~ ~~The success criteria in the PRA are consistent with the design basis criteria.~~ ~~EDITORIAL: BSEP TS 3.8.4 does not distinguish separate actions for different causes of inoperability, but applies the limiting 7 day CT for any cause of inoperability of a DC electrical power subsystem.~~

BSEP TS	TS Condition	SSCs Covered by TS Condition	Function Covered by TS LCO Condition	Design Success Criteria	SSCs Modeled in PRA	PRA Success Criteria	Comments
Distribution Systems—Operating 3.8.7	3.8.7 Condition B. One or more AC electrical power distribution subsystems inoperable for reasons other than Condition A.	Load groups E1 and E2 have mostly U1 loads but do have some required U2 loads. Load groups E3 and E4 have mostly U2 loads but do have some required U1 loads.	Provide electrical distribution for required emergency loads	Three of four load groups are adequate	Yes	As needed to supply supported functions.	SSCs are modeled consistently with the TS scope and so can be directly evaluated by the CRMP. The success criteria in the PRA are consistent with the design basis criteria.

BSEP TS	TS Condition	SSCs Covered by TS Condition	Function Covered by TS LCO Condition	Design Success Criteria	SSCs Modeled in PRA	PRA Success Criteria	Comments
<u>Distribution Systems—Operating</u> 3.8.7 (Unit 1)	3.8.7 Condition A (Unit 1). One AC electrical power distribution subsystem inoperable for planned maintenance due to either inoperable load group E3 bus(es) or inoperable load group E4 bus(es).	Load groups E3 and E4 have mostly U2 loads but do have some required U1 loads.	Provide electrical distribution for required emergency loads	Three of four load groups are adequate	Yes	As needed to supply supported functions.	SSCs are modeled consistently with the TS scope and so can be directly evaluated by the CRMP. The success criteria in the PRA are consistent with the design basis criteria. VARIATION: This is a site-specific Condition and RA for one electrical power distribution subsystem inoperable for planned maintenance either due to inoperable load group E3 bus(es) or inoperable load group E4 bus(es). The configurations associated with the ACTION statement are explicitly modeled in the PRA and thus a RICT can be directly calculated.

BSEP TS	TS Condition	SSCs Covered by TS Condition	Function Covered by TS LCO Condition	Design Success Criteria	SSCs Modeled in PRA	PRA Success Criteria	Comments
Distribution Systems— Operating 3.8.7 (Unit 2)	3.8.7 Condition A (Unit 2). One AC electrical power distribution subsystem inoperable for planned maintenance due to either inoperable load group E1 bus(es) or inoperable load group E2 bus(es).	Load groups E1 and E2 have mostly U1 loads but do have some required U2 loads.	Provide electrical distribution for required emergency loads	Three of four load groups are adequate	Yes	As needed to supply supported functions.	SSCs are modeled consistently with the TS scope and so can be directly evaluated by the CRMP. The success criteria in the PRA are consistent with the design basis criteria. VARIATION: This is a site-specific Condition and RA for one electrical power distribution subsystem inoperable for planned maintenance either due to inoperable load group E3 bus(es) or inoperable load group E4 bus(es). The configurations associated with the ACTION statement are explicitly modeled in the PRA and thus a RICT can be directly calculated.

BSEP TS	TS Condition	SSCs Covered by TS Condition	Function Covered by TS LCO Condition	Design Success Criteria	SSCs Modeled in PRA	PRA Success Criteria	Comments
Distribution Systems—Operating 3.8.7	3.8.7 Condition C. One or more DC electrical power distribution subsystems inoperable due to loss of normal DC source.	Each of the four site DC distribution systems have mostly unit specific loads and select opposite unit loads	Provide electrical distribution for required emergency loads	Three of four DC distribution systems are adequate	Yes	As needed to supply supported functions.	SSCs are modeled consistently with the TS scope and so can be directly evaluated by the CRMP. The success criteria in the PRA are consistent with the design basis criteria. EDITORIAL: BSEP TS 3.8.7 contains one Action for one or more DC electrical subsystems inoperable due to loss of normal DC source and a separate Action for one or more DC electrical subsystems inoperable for all other reasons. TSTF-505, Rev. 2 TS 3.8.9 does not distinguish between the reasons for inoperability.

BSEP TS	TS Condition	SSCs Covered by TS Condition	Function Covered by TS LCO Condition	Design Success Criteria	SSCs Modeled in PRA	PRA Success Criteria	Comments
Distribution Systems—Operating 3.8.7	3.8.7 Condition D. One or more DC electrical power distribution subsystems inoperable for reasons other than Condition C.	Each of the four site DC distribution systems have mostly unit specific loads and select opposite unit loads	Provide electrical distribution for required emergency loads	Three of four DC distribution systems are adequate	Yes	As needed to supply supported functions.	SSCs are modeled consistently with the TS scope and so can be directly evaluated by the CRMP. The success criteria in the PRA are consistent with the design basis criteria. EDITORIAL: BSEP TS 3.8.7 contains one Action for one or more DC electrical subsystems inoperable due to loss of normal DC source and a separate Action for one or more DC electrical subsystems inoperable for all other reasons. TSTF-505, Rev. 2 TS 3.8.9 does not distinguish between the reasons for inoperability.

TABLE E1-1a – ADDITIONAL DETAILS REGARDING TS 3.3.1.1

Tech Spec 3.3.1.1		*Function Initiation Logic*	*Number of Trip Systems*	*Total Number of Channels Per Trip System*	*Minimum Channels Needed for Function Success*
1. Intermediate Range Monitors		**Need 1 channel from each RPS division: 1.a. OR 1.b.**			
1.a.	Neutron Flux - High	C51-IRM-A, C, E, G AND C51-IRM-B, D, F, H	2	4	2
1.b.	Inop	C51-IRM-A, C, E, G AND C51-IRM-B, D, F, H	2	4	2
2. Average Power Range Monitors		**Need 2 out of 4 APRM trip signals to voters, 1 voter channel from each RPS division: 2.a. OR 2.b. OR 2.c. OR 2.d. OR 2.e. OR 2.f.**			
2.a.	Neutron Flux - High (Setdown)	Need 2 out of 4: C51-APRM1-AR51 C51-APRM2-AR31 C51-APRM3-AR41 C51-APRM4-AR11	4	1	2
2.b.	Simulated Thermal Power - High	Need 2 out of 4: C51-APRM1-AR51 C51-APRM2-AR31 C51-APRM3-AR41 C51-APRM4-AR11	4	1	2

TABLE E1-1a – ADDITIONAL DETAILS REGARDING TS 3.3.1.1

Tech Spec 3.3.1.1		*Function Initiation Logic*	*Number of Trip Systems*	*Total Number of Channels Per Trip System*	*Minimum Channels Needed for Function Success*
2.c.	Neutron Flux - High	Need 2 out of 4: C51-APRM1-AR51 C51-APRM2-AR31 C51-APRM3-AR41 C51-APRM4-AR11	4	1	2
2.d.	Inop	Need 2 out of 4: C51-APRM1-AR51 C51-APRM2-AR31 C51-APRM3-AR41 C51-APRM4-AR11	4	1	2
2.e.	2-out-of-4 Voter	C51-VOTER1-A51 OR C51-VOTER3-A41 AND C51-VOTER2-A31 OR C51-VOTER4-A11	2	2	2
2.f.	OPRM upscale	Need 2 out of 4: C51-APRM1-AR51 C51-APRM2-AR31 C51-APRM3-AR41 C51-APRM4-AR11	4	1	2
3. Reactor Vessel Steam Dome Pressure - High		B21-PT-N023A OR B21-PT-N023C AND B21-PT-N023B OR B21-PT-N023D	2	2	2

TABLE E1-1a – ADDITIONAL DETAILS REGARDING TS 3.3.1.1

Tech Spec 3.3.1.1	*Function Initiation Logic*	*Number of Trip Systems*	*Total Number of Channels Per Trip System*	*Minimum Channels Needed for Function Success*
4. Reactor Vessel Water Level - Low Level 1	B21-LT-N017A OR B21-LT-N017C AND B21-LT-N017B OR B21-LT-N017D	2	2	2
5. Main Steam Isolation Valve - Closure	A1 and A2 or A3 and A4 AND B1 and B2 or B3 and B4 (See Note 1)	2	4	4
6. Drywell Pressure - High	C71(72)-PT-N002A OR C71(72)-PT-N002C AND C71(72)-PT-N002B OR C71(72)-PT-N002D	2	2	2
7. Scram Discharge Volume Water Level - High	[C11(C12)-N013A OR C11(C12)-4516A) OR (C11(12)-N013C OR C11(C12)-4516C)] AND [C11(C12)-N013B OR C11-4516B) OR (C11(C12)-N013D OR C11(C12)-4516D)]	2	4	2

TABLE E1-1a – ADDITIONAL DETAILS REGARDING TS 3.3.1.1

Tech Spec 3.3.1.1	***Function Initiation Logic***	***Number of Trip Systems***	***Total Number of Channels Per Trip System***	***Minimum Channels Needed for Function Success***
8. Turbine Stop Valve - Closure	A1 and A2 or A3 and A4 AND B1 and B2 or B3 and B4 (See Note 2)	2	4	4
9. Turbine Control Valve Fast Closure, Control Oil Pressure - Low	EHC-PSL-1756 OR EHC-PSL-1758 AND EHC-PSL-1757 OR EHC-PSL-1759	2	2	2
10. Reactor Mode Switch - Shutdown Position	C71(72)A-S1 Contacts 9-9C and 57-57C	2	1	2
11. Manual Scram	C71(72)-S3A AND C71(72)-S3B	2	1	2
Note 1:	A1-F022A-LS-3, (U1)F028A-LS-3, (U2)F028A-LS-4 A2-F022B-LS-3, F028B-LS-3 A3-F022C-LS-3 F028C-LS-3 A4-F022D-LS-3 F028D-LS-3	B1-F022A-LS-6 F028A-LS-6 B2-F022C-LS-6 F028C-LS-6 B3-F022B-LS-6 F028B-LS-6 B4-F022D-LS-6 F028D-LS-6		
Note 2:	A1-SVRP-1-1 A4-SVRP-4-1 A2-SVRP-2-1 A3-SVRP-3-1	B1-SVRP-1-2 B4-SVRP-4-2 B2-SVRP-3-2 B3-SVRP-2-2		

TABLE E1-1b – ADDITIONAL DETAILS REGARDING TS 3.3.4.1

Tech Spec 3.3.4.1	*Function Initiation Logic*	*Number of Trip Systems*	*Total Number of Channels Per Trip System*	*Minimum Channels Needed for Function Success*	*Minimum Channels Needed for Initiation Success*
a. Reactor Vessel Water Level - Low Level 2	B21-LT-N025A-2 and B21-LT-N024A-2 OR B21-LT-N025B-2 and B21-LT-N024B-2	2	2	2	2
b. Reactor Vessel Pressure - High	B21-PT-N045A and B21-PT-N045C OR B21-PT-N045B and B21-PT-N045D	2	2	2	2

TABLE E1-1c – ADDITIONAL DETAILS REGARDING TS 3.3.5.1

Tech Spec 3.3.5.1		*Function Initiation Logic*	*Number of Trip Systems*	*Total Number of Channels Per Trip System*	*Minimum Channels Needed for Function Success*
1. Core Spray System		**1.a. OR (1.b. AND 1.c.)**			
1.a.	Reactor Vessel Water Level - Low Level 3	B21-LT-N031A or B AND B21-LT-N031C or D	2	2	2
1.b.	Drywell Pressure - High	E11-PT-N011A or B AND E11-PT-N011C or D	2	2	2
1.c.	Reactor Steam Dome Pressure - Low	B21-PT-N021A or B AND B21-PT-N021C or D	2	2	2
1.d.	Core Spray Pump Start - Time Delay Relay	DGX-STR/2A-1 (2B-1) AND E21-K16A(B) OR DGY-STR/2A-2(2B-2) AND E21-K16A(B) X=U1(1) U2(3) Y=U1(2) U2(4)	2	2	2
2. Low Pressure Coolant Injection (LPCI) System		**2.a. OR (2.b. AND 2.c.)**			
2.a.	Reactor Vessel Water Level - Low Level 3	B21-LT-N031A or B AND B21-LT-N031C or D	2	2	2
2.b.	Drywell Pressure - High	E11-PT-N011A or B AND E11-PT-N011C or D	2	2	2

TABLE E1-1c – ADDITIONAL DETAILS REGARDING TS 3.3.5.1

Tech Spec 3.3.5.1		***Function Initiation Logic***	***Number of Trip Systems***	***Total Number of Channels Per Trip System***	***Minimum Channels Needed for Function Success***
2.c.	Reactor Steam Dome Pressure - Low	B21-PT-N021A or B AND B21-PT-N021C or D	2	2	2
2.d	Reactor Steam Dome Pressure Low (Recirculation Pump Discharge Valve Permissive)	B21-PT-N021A or B AND B21-PT-N021C or D	2	2	2
2.e.	Reactor Vessel Shroud Level	B21-LT-N036 AND B21-LT-N037	2	1	1
2.f.	RHR Pump Start - Time Delay Relay	DGX-STR/2Y-1 OR DGX-STR/2Y-2 Set for each RHR pump X=1,2,3,4	2	1	1 per pump
3. High Pressure Coolant Injection (HPCI) System		**3.a. OR 3.b.**			
3.a.	Reactor Vessel Water Level - Low Level 2	B21-LT-N031A or B AND B21-LT-N031C or D	2	2	2
3.b.	Drywell Pressure - High	E11-PT-N011A or B AND E11-PT-N011C or D	2	2	2
3.c.	Reactor Vessel Water Level - High	B21-LT-N017B-2 AND B21-LT-N017D-2	1	2	2

TABLE E1-1c – ADDITIONAL DETAILS REGARDING TS 3.3.5.1

Tech Spec 3.3.5.1		*Function Initiation Logic*	*Number of Trip Systems*	*Total Number of Channels Per Trip System*	*Minimum Channels Needed for Function Success*
3.d.	Condensate Storage Tank Level - Low	E41-LSL-N002 OR E41-LSL-N003	1	2	1
3.e.	Suppression Chamber Water Level - High	E41-LSH-N015A OR E41-LSH-N015B	1	2	1
4. Automatic Depressurization System (ADS) Trip System A		**4.a. AND 4.b. AND 4.c. AND (4.d. OR 4.e.)**			
4.a.	Reactor Vessel Water Level - Low Level 3	B21-LT-N031B AND B21-LT-N031D	2	1	2
4.b.	ADS Timer	A71-K5A	1	1	1
4.c.	Reactor Vessel Water Level - Low Level 1	B21-LT-N042B	1	1	1
4.d.	Core Spray Pump Discharge Pressure - High	E21-PS-N008B AND E21-PS-N009B	1	2	2
4.e.	RHR (LPCI Mode) Pump Discharge Pressure - High	E11-PS-N020B OR E11-PS-N016B AND E11-PS-N020D OR E11-PS-N016D	2	2	2
5. ADS Trip System B		**5.a. AND 5.b. AND 5.c. AND (5.d. OR 5.e.)**			
5.a.	Reactor Vessel Water Level - Low Level 3	B21-LT-N031A AND B21-LT-N031C	2	1	2
5.b.	ADS Timer	A71-K5B	1	1	1
5.c.	Reactor Vessel Water Level - Low Level 1	B21-LT-N042A	1	1	1

TABLE E1-1c – ADDITIONAL DETAILS REGARDING TS 3.3.5.1

Tech Spec 3.3.5.1		***Function Initiation Logic***	***Number of Trip Systems***	***Total Number of Channels Per Trip System***	***Minimum Channels Needed for Function Success***
5.d.	Core Spray Pump Discharge Pressure - High	E21-PS-N008A AND E21-PS-N009A	1	2	2
5.e.	RHR (LPCI Mode) Pump Discharge Pressure - High	E11-PS-N020A OR E11-PS-N016A AND E11-PS-N020C OR E11-PS-N016C	2	2	2

TABLE E1-1d – ADDITIONAL DETAILS REGARDING TS 3.3.6.1

Tech Spec 3.3.6.1		Function Initiation Logic	Number of Trip Systems	Total Number of Channels Per Trip System	Minimum Channels Needed for Function Success	Function Initiation Logic	Number of Trip Systems	Total Number of Channels Per Trip System	Minimum Channels Needed for Function Success
1. Main Steam Isolation (Group 1) MSIVS and B21-F016/F019		**(1.a. OR 1.b. OR 1.c. OR 1.d. OR 1.e.) MSIVS**				**B21-F016 and B21-F019 (valves in series)**			
1.a.	Reactor Vessel Water Level - Low Level 3	B21-LT-N024A-1 or B21-LT-N025A-1 AND B21-LT-N024B-1 or B21-LT-N025B-1	2	2	2	B21-LT-N024A-1 and B21-LT-N024B-1 OR B21-LT-N025A-1 and B21-LT-N025B-1	2	2	2
1.b.	Main Steam Line Pressure - Low	B21-PT-N015A or B21-PT-N015C AND B21-PT-N015B or B21-PT-N015D	2	2	2	B21-PT-N015A and B21-PT-N015B OR B21-PT-N015C and B21-PT-N015D	2	2	2
1.c.	Main Steam Line Flow - High	B21-PDT-N006(7,8,9)A or B21-PT-N006(7,8,9)C AND B21-PT-N006(7,8,9)B or B21-PT-N006(7,8,9)D	2 per MSL	2	2	B21-PDT-N006(7,8,9)A and B21-PT-N006(7,8,9)B OR B21-PT-N006(7,8,9)C and B21-PT-N006(7,8,9)D	2 per MSL	2	2
1.d.	Condenser Vacuum - Low	B21-PT-N056A or B21-PT-N056C AND B21-PT-N056B or B21-PT-N056D	2	2	2	B21-PT-N056A and B21-PT-N056B OR B21-PT-N056C and B21-PT-N056D	2	2	2

TABLE E1-1d – ADDITIONAL DETAILS REGARDING TS 3.3.6.1

Tech Spec 3.3.6.1		*Function Initiation Logic*	*Number of Trip Systems*	*Total Number of Channels Per Trip System*	*Minimum Channels Needed for Function Success*	*Function Initiation Logic*	*Number of Trip Systems*	*Total Number of Channels Per Trip System*	*Minimum Channels Needed for Function Success*
1.e.	Main Steam Isolation Valve Pit Temperature - High	B21-TS-N010A or B21-TS-N010C AND B21-TS-N010B or B21-TS-N010D	2	2	2	B21-TS-N010A and B21-TS-N010B OR B21-TS-N010C and B21-TS-N010D	2	2	2
1.f.	Main Steam Line Flow—High (Not in Run) (Unit 2 ONLY)	B21-PDT-N006(7,8,9)A or B21-PT-N006(7,8,9)C AND B21-PT-N006(7,8,9)B or B21-PT-N006(7,8,9)D	2	2	2	B21-PDT-N006(7,8,9)A and B21-PT-N006(7,8,9)B OR B21-PT-N006(7,8,9)C and B21-PT-N006(7,8,9)D	2	2	2
2. Primary Containment Isolation (Group 2/Group 6)									
2.a.	Reactor Vessel Water Level - Low Level 1	A1=B21-LT-N017A-1 B1=B21-LT-N017B-1 A2=B21-LT-N017C-1 B2=B21-LT-N017D-1				[redacted]			
	DWED, DWFD, CAC Div 1(Inboard)(V5,6,7,9,49,172 Div 2 (outboard)(V4,8,10,15,22,23,50,58,216)	A1 and B1 closes inboard A2 and B2 closes outboard	2	2	2	[redacted]			
	CAC (remaining valves)	A1 and B1 OR A2 and B2	2	2	2	[redacted]			
	TIP	A1 and B1	1	2	2	[redacted]			

TABLE E1-1d – ADDITIONAL DETAILS REGARDING TS 3.3.6.1

Tech Spec 3.3.6.1		*Function Initiation Logic*	*Number of Trip Systems*	*Total Number of Channels Per Trip System*	*Minimum Channels Needed for Function Success*	*Function Initiation Logic*	*Number of Trip Systems*	*Total Number of Channels Per Trip System*	*Minimum Channels Needed for Function Success*
7.a.	TIP withdrawal is a single Trip System with two Trip Channels. If TIPs are withdrawn with ball valves deactivated CLOSED, the TIP withdrawal function TRIPPED condition is met.					[redacted]			
2.b.	Drywell Pressure - High	A1= C72-PT-N002A B1= C72-PT-N002B A2= C72-PT-N002C B2= C72-PT-N002D							
	DWED, DWFD, CAC Div 1(Inboard)(V5,6,7,9,49,172 Div 2 (outboard)(V4,8,10,15,22,23,50,58,216)	A1 and B1 closes inboard A2 and B2 closes outboard	2	2	2				
	CAC (remaining valves)	A1 and B1 OR A2 and B2	2	2	2				
7.b.	TIP	A1 and B1	1	2	2				
	TIP withdrawal is a single Trip System with two Trip Channels. If TIPs are withdrawn with ball valves deactivated CLOSED, the TIP withdrawal function TRIPPED condition is met.								

TABLE E1-1d – ADDITIONAL DETAILS REGARDING TS 3.3.6.1

	Tech Spec 3.3.6.1	*Function Initiation Logic*	*Number of Trip Systems*	*Total Number of Channels Per Trip System*	*Minimum Channels Needed for Function Success*	*Function Initiation Logic*	*Number of Trip Systems*	*Total Number of Channels Per Trip System*	*Minimum Channels Needed for Function Success*
2.c.	Main Stack Radiation - High	2-D12-RM-80S	2	1	1	[redacted]			
2.d.	Reactor Building Exhaust Radiation - High	D12-RE-N010A/B	2	1	1				
3. High Pressure Coolant Injection (HPCI) System Isolation (Group 4)									
3.a.	HPCI Steam Line Flow - High	E41-PDT-N004-1/-2 OR E41-PDT-N005-1/-2	2	1	1				
3.b.	HPCI Steam Line Flow - High Time Delay Relay	E41-K33 OR E41-K43	2	1	1				
3.c.	HPCI Steam Supply Line Pressure - Low	E41-PS-N001A AND E41-PS-N001C OR E41-PS-N001B AND E41-PS-N001D	2	2	2				
3.d.	HPCI Turbine Exhaust Diaphragm Pressure - High	E41-PSH-N012A and C OR E41-PSH-N012B and D	2	2	2				
3.e.	Drywell Pressure - High	E11-PT-N011C and E41-PS-N001A [3.c.] OR E11-PT-N011D and E41-PS-N001B [3.c.]	2	1	1				
3.f.	HPCI Steam Line Area Temperature - High	B21-XY-5948A OR B21-XY-5948B	2	1	1				
3.g.	HPCI Steam Line Tunnel Ambient Temperature - High	B21-XY-5948A OR B21-XY-5948B	2	2(A)/1(B)	1				

TABLE E1-1d – ADDITIONAL DETAILS REGARDING TS 3.3.6.1

Tech Spec 3.3.6.1		*Function Initiation Logic*	*Number of Trip Systems*	*Total Number of Channels Per Trip System*	*Minimum Channels Needed for Function Success*	*Function Initiation Logic*	*Number of Trip Systems*	*Total Number of Channels Per Trip System*	*Minimum Channels Needed for Function Success*
3.h.	HPCI Steam Line Tunnel Differential Temperature - High	B21-XY-5948A OR B21-XY-5948B	2	1	1	[redacted]			
3.i.	HPCI Equipment Area Temperature - High	B21-XY-5948A OR B21-XY-5948B	2	3(A)/4(B)	1				
4. Reactor Core Isolation Cooling (RCIC) System Isolation (Group 5)									
4.a.	RCIC Steam Line Flow - High	E51-PDTS-N018-2 OR E51-PDTS-N017-2	2	1	1				
4.b.	RCIC Steam Line Flow - High Time Delay Relay	E51-K12 OR E51-K32	2	1	1				
4.c.	RCIC Steam Supply Line Pressure - Low	E51-PS-N019A AND E51-PS-N019C OR E51-PS-N019B AND E51-PS-N019D	2	2	2				
4.d.	RCIC Turbine Exhaust Diaphragm Pressure - High	E51-PSH-N012A AND E51-PSH-N012C OR E51-PSH-N012B AND E51-PSH-N012D	2	2	2				
4.e.	Drywell Pressure - High	E51-PS-N019A and E11-PTS-N011A-2 OR E51-PS-N019B and E11-PTS-N011B-2	2	1	1				
4.f.	RCIC Steam Line Area Temperature - High	B21-XY-5949A OR B21-XY-5949B	2	1	1				

TABLE E1-1d – ADDITIONAL DETAILS REGARDING TS 3.3.6.1

Tech Spec 3.3.6.1		*Function Initiation Logic*	*Number of Trip Systems*	*Total Number of Channels Per Trip System*	*Minimum Channels Needed for Function Success*	*Function Initiation Logic*	*Number of Trip Systems*	*Total Number of Channels Per Trip System*	*Minimum Channels Needed for Function Success*
4.g.	RCIC Steam Line Tunnel Ambient Temperature - High	B21-XY-5949A OR B21-XY-5949B	2	2(A)/1(B)	1	[redacted]			
4.h.	RCIC Steam Line Tunnel and Area Temperature - High Time Delay	B21-XY-5949A OR B21-XY-5949B	2	5(A)/4(B)	1				
4.i.	RCIC Steam Line Tunnel Differential Temperature - High	B21-XY-5949A OR B21-XY-5949B	2	1	1				
4.j.	RCIC Equipment Area Temperature - High	B21-XY-5949A OR B21-XY-5949B	2	3	1				
4.k.	RCIC Equipment Area Differential Temperature - High	B21-XY-5949A OR B21-XY-5949B	2	1	1				
5. Reactor Water Cleanup (RWCU) System Isolation (Group 3)									
5.a.	Differential Flow - High	B21-XY-5949A OR B21-XY-5949B	2	1	1				
5.b.	Differential Flow - High Time Delay	A71-K37 OR A71-K35	2	1	1				
5.c.	Area Temperature - High	B21-XY-5949A OR B21-XY-5949B	2	3(1 per room)	1				
5.d.	Area Ventilation Differential Temperature - High	B21-XY-5949A OR B21-XY-5949B	2	3	1				
5.e.	Piping Outside RWCU Rooms Area Temperature - High	B21-XY-5949A OR B21-XY-5949B	2	1	1				
5.f.	SLC System Initiation (*SLC only inputs into 1 trip sys)	C41-CS-S1	1	1	1				

TABLE E1-1d – ADDITIONAL DETAILS REGARDING TS 3.3.6.1

Tech Spec 3.3.6.1		***Function Initiation Logic***	***Number of Trip Systems***	***Total Number of Channels Per Trip System***	***Minimum Channels Needed for Function Success***	***Function Initiation Logic***	***Number of Trip Systems***	***Total Number of Channels Per Trip System***	***Minimum Channels Needed for Function Success***
5.g.	Reactor Vessel Water Level - Low Level 2	B21-LT-N024A-1 and B21-LT-N024B-1 OR B21-LT-N025A-1 and B21-LT-N025B-1	2	2	2	[redacted]			
6. RHR Shutdown Cooling System Isolation (Group 8)									
6.a.	Reactor Steam Dome Pressure - High	B32-N018A OR B32-N018B	2	1	1				
6.b.	Reactor Vessel Water Level - Low Level 1	B21-LT-N017A-1 and B21-LT-N017B-1 OR B21-LT-N017C-1 and B21-LT-N017D-1	2	2	2				