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

June 24, 2020

Mr. Daniel G. Stoddard
Senior Vice President and
Chief Nuclear Officer
Dominion Nuclear
Innsbrook Technical Center
5000 Dominion Boulevard
Glen Allen, VA 23060-6711

SUBJECT: MILLSTONE POWER STATION, UNIT NO. 2 – ISSUANCE OF AMENDMENT NO. 339 RE: EXTENSION OF TECHNICAL SPECIFICATION 3.8.1.1, "A.C. SOURCES – OPERATING," ALLOWED OUTAGE TIME (EPID L-2019-LLA-0177)

Dear Mr. Stoddard:

The U.S. Nuclear Regulatory Commission (the Commission) has issued the enclosed Amendment No. 339 to Renewed Facility Operating License No. DPR-65 for the Millstone Power Station (Millstone), Unit No. 2, in response to your application dated August 14, 2019, as supplemented by letters dated October 22, 2019; February 11, 2020; March 19, 2020; and April 14, 2020.

The amendment revises Technical Specification 3.8.1.1, ''A.C. Sources – Operating,'' to add a permanent Required Action a.3 that provides an option to extend the allowed outage time (AOT) from 72 hours to 10 days for one inoperable offsite circuit. In addition, the amendment adds a one-time exception to the Required Action a.3 that extends the AOT to 35 days for one inoperable offsite circuit. One-time use of the 35-day AOT will allow the replacement of the Millstone, Unit No. 3, 'A' reserve station service transformer, its associated equipment, and other 345 kV south bus switchyard components that are nearing the end of their dependable service life.

A copy of the related Safety Evaluation is also enclosed. Notice of Issuance will be included in the Commission's biweekly *Federal Register* notice.

Sincerely,

/RA/

Richard V. Guzman, Senior Project Manager
Plant Licensing Branch I
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket No. 50-336

Enclosures:
1. Amendment No. 339 to DPR-65
2. Safety Evaluation

cc: Listserv

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

DOMINION ENERGY NUCLEAR CONNECTICUT, INC.

DOCKET NO. 50-336

MILLSTONE POWER STATION, UNIT NO. 2

AMENDMENT TO RENEWED FACILITY OPERATING LICENSE

Amendment No. 339
Renewed License No. DPR-65

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

   A. The application for amendment by Dominion Energy Nuclear Connecticut, Inc. (the licensee) dated August 14, 2019, as supplemented by letters dated October 22, 2019; February 11, 2020; March 19, 2020; and April 14, 2020, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations set forth in 10 CFR Chapter I;

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

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

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

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

2. Accordingly, the license is amended by changes to the Technical Specifications as indicated in the attachment to this license amendment, and paragraph 2.C.(2) of Renewed Facility Operating License No. DPR-65 is hereby amended to read as follows:

    (2) <u>Technical Specifications</u>

    The Technical Specifications contained in Appendix A, as revised through Amendment No. 339 are hereby incorporated in the renewed license. The licensee shall operate the facility in accordance with the Technical Specifications.

3. This license amendment is effective as of the date of issuance and shall be implemented within 90 days of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

James G. Danna

Digitally signed by James G. Danna
Date: 2020.06.24 09:55:30 -04'00'

James G. Danna, Chief
Plant Licensing Branch I
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

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

Date of Issuance: June 24, 2020

ATTACHMENT TO LICENSE AMENDMENT NO. 339

MILLSTONE POWER STATION, UNIT NO. 2

RENEWED FACILITY OPERATING LICENSE NO. DPR-65

DOCKET NO. 50-336

Replace the following page of the Renewed Facility Operating License with the attached revised page. The revised page is identified by amendment number and contains a marginal line indicating the area of change.

Remove	Insert
3	3

Replace the following pages of the Appendix A Technical Specifications with the attached revised pages. The revised pages are identified by amendment number and contain a marginal line indicating the area of change.

Remove	Insert
3/4 8-1	3/4 8-1
3/4 8-1a	3/4 8-1a
---	3/4 8-1b

Connecticut, in accordance with the procedures and limitations set forth in this renewed operating license;

(2) Pursuant to the Act and 10 CFR Part 70, to receive, possess and use at any time special nuclear material as reactor fuel, in accordance with the limitations for storage and amounts required for reactor operation, as described in the Final Safety Analysis Report, as supplemented and amended;

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

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

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

C. This renewed operating license shall be deemed to contain and is subject to the conditions specified in the following Commission regulations in 10 CFR Chapter 1: Part 20, Section 30.34 of Part 30, Section 40.41 of Part 40, Section 50.54 and 50.59 of Part 50, and Section 70.32 of Part 70; and is subject to all applicable provisions of the Act and the rules, regulations, and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified or incorporated below:

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

The licensee is authorized to operate the facility at steady-state reactor core power levels not in excess of 2700 megawatts thermal.

(2) <u>Technical Specifications</u>

The Technical Specifications contained in Appendix A, as revised through Amendment No. 339 are hereby incorporated in the renewed license. The licensee shall operate the facility in accordance with the Technical Specifications.

3/4.8 ELECTRICAL POWER SYSTEMS

3/4.8.1 A.C. SOURCES

OPERATING

LIMITING CONDITION FOR OPERATION

3.8.1.1 As a minimum, the following A.C. electrical power sources shall be OPERABLE:

a. Two physically independent circuits between the offsite transmission network and the onsite Class 1E distribution system, and

b. Two separate and independent diesel generators each with a separate fuel oil supply tank containing a minimum of 12,000 gallons of fuel.

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

Inoperable Equipment	Required ACTION
a. One offsite circuit	a.1 Perform Surveillance Requirement 4.8.1.1.1. for remaining offsite circuit within 1 hour prior to or after entering this condition, and at least once per 8 hours thereafter. AND a.2 Restore the inoperable offsite circuit to OPERABLE status within 72 hours (within 10 days* if Required ACTION a.3 is met) or be in HOT STANDBY within the next 6 hours and COLD SHUTDOWN within the following 30 hours. AND

ACTION (Continued)

Inoperable Equipment	Required ACTION
a. One offsite circuit	a.3 With MPS3 in MODE 5, 6, or defueled, the MPS3 'A' RSST inoperable, and the MPS3 'A' NSST energized with breaker 15G-13T-2 (13T) and associated disconnect switches closed, restore either offsite circuit to OPERABLE status within 10 days* if the following requirements are met: - Within 30 days prior to entering the 10-day* AOT, the availability of the supplemental power source (MPS3 SBO diesel generator) shall be verified. - During the 10-day*AOT, the availability of the supplemental power source shall be checked once per shift. If the supplemental power source becomes unavailable at any time during the 10-day*AOT, restore to available status within 24 hours or be in HOT STANDBY within the next 6 hours and COLD SHUTDOWN within the following 30 hours. - The risk management actions contained in DENC letter 20-109, Attachment 4 (also provided in TS Bases 3/4.8), shall remain in effect during the 10-day*AOT.

* To facilitate replacement of the MPS3 'A' RSST and associated equipment, use of a one-time 35-day allowed outage time is permitted provided the requirements of Required ACTION a.3 are met. The work shall be completed no later than the end of MPS3 Refueling Outage 22 (fall 2023).

ACTION (Continued)

Inoperable Equipment	Required ACTION
b. One diesel generator	b.1 Perform Surveillance Requirement 4.8.1.1.1 for the offsite circuit within 1 hour prior to or after entering this condition, and at least once per 8 hours thereafter. AND b.2 Demonstrate OPERABLE diesel generator is not inoperable due to common cause failure within 24 hours or perform Surveillance Requirement 4.8.1.1.2.a.2 for the OPERABLE diesel generator within 24 hours. AND b.3 Verify the steam-driven auxiliary feedwater pump is OPERABLE (MODES 1, 2, and 3 only). If this condition is not satisfied within 2 hours, be in at least HOT STANDBY within the next 6 hours and HOT SHUTDOWN within the following 6 hours. AND b.4 (Applicable only if the 14 day allowed outage time specified in ACTION Statement b.5 is to be used.) Verify the required Millstone Unit No. 3 diesel generator(s) is/are OPERABLE and the Millstone Unit No. 3 SBO diesel generator is available within 1 hour prior to or after entering this condition, and at least once per 24 hours thereafter. Restore any inoperable required Millstone Unit No. 3 diesel generator to OPERABLE status and/or Millstone Unit No. 3 SBO diesel generator to available status within 72 hours or be in HOT STANDBY within the next 6 hours and COLD SHUTDOWN within the following 30 hours. AND b.5 Restore the inoperable diesel generator to OPERABLE status within 72 hours (within 14 days if ACTION Statement b.4 is met) or be in HOT STANDBY within the next 6 hours and COLD SHUTDOWN within the following 30 hours.

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NO. 339

TO RENEWED FACILITY OPERATING LICENSE NO. DPR-65

DOMINION ENERGY NUCLEAR CONNECTICUT, INC.

MILLSTONE POWER STATION, UNIT NO. 2

DOCKET NO. 50-336

1.0 INTRODUCTION

By letter dated August 14, 2019 (Reference 1), as supplemented by letters dated October 22, 2019 (Reference 2); February 11, 2020 (Reference 3); March 19, 2020 (Reference 4); and April 14, 2020 (Reference 5), Dominion Energy Nuclear Connecticut, Inc. (DENC or the licensee) submitted a license amendment request (LAR or application) for the Millstone Power Station, Unit No. 2 (MPS2).

The LAR proposes to revise Technical Specification (TS) 3.8.1.1, "A.C. [Alternating Current] Sources – Operating," to add a new Required Action a.3 that provides an option to extend the allowed outage time (AOT) from 72 hours to 10 days for one inoperable offsite circuit. The new required action is needed to complete periodic maintenance and testing of the Millstone Power Station, Unit No. 2 (MPS3) 'A' reserve station service transformer (RSST) and other 345 kilovolt (kV) south bus switchyard components. Since periodic maintenance and testing of these components cannot typically be completed by the licensee within the current 72-hour AOT, the licensee proposed an extended AOT which reduces (1) the number of switching evolutions required to complete the work, (2) equipment unavailability time, and (3) potential for equipment failures or human performance events. The licensee stated that the use of this 10-day AOT will be limited to no more than once per 18-month refueling interval for MPS3.

The LAR also proposes a one-time allowance to the new proposed Required Action a.3 that extends the AOT to 35 days for one inoperable offsite circuit and states that use of the 35-day AOT allows replacement of the MPS3 'A' RSST, its associated equipment, and other 345 kV south bus switchyard components that are nearing the end of their dependable service life. The licensee stated that this work is planned to take place no later than the fall 2023 outage for MPS3 (3R22) and that the replacement of these components is necessary to ensure continued safe and dependable generation of electric power.

Additionally, the licensee stated that the permanent 10-day AOT and one-time 35-day AOT is only entered if the conditions specified in TS Required Action a.3 are met and that certain compensatory and risk management actions will be met during both the permanent 10-day AOT and the one-time 35-day AOT, which are provided in the TS Bases in support of this amendment request.

The supplemental letters dated October 22, 2019; February 11, 2020; March 19, 2020; and April 14, 2020, provided additional information that clarified the application, did not expand the scope of the application as originally noticed, and did not change the U.S. Nuclear Regulatory Commission (NRC or the Commission) staff's original proposed no significant hazards consideration determination as published in the *Federal Register* on December 31, 2019 (84 FR 72387).

2.0 REGULATORY EVALUATION

2.1 System Description

Millstone Power Station is a three-unit site with two operating reactors, MPS2 and MPS3. Millstone Power Station is connected to the transmission system by four 345 kV circuits. The 345 kV switchyard buses together four 345 kV transmission line circuits, two generator circuits, and two station service circuits. The breaker arrangement allows the isolation of any of the four transmission lines without affecting the integrity of the switchyard.

MPS2 Offsite Power Sources

The MPS2 design provides two offsite circuits between the switchyard and the 4,160 volt (V) Class 1E buses. The normal supply to MPS2 with the unit online is the MPS2 normal station service transformer (NSST), which supplies power to emergency 4,160 V buses 24C and 24D by normal buses 24A and 24B, respectively. If this source is lost due to a plant trip, a fast bus transfer scheme connects the plant electrical system to the MPS2 RSST, which supplies power to buses 24C and 24D. The second or alternate source of offsite power is available by manual controls to MPS3 bus 34A or 34B for 4,160 V power. This power source directly feeds bus 24E, which can then be directed to either bus 24C or 24D.

MPS2 Onsite AC Power System

The 6,900 V system is a reliable source of power for the reactor coolant and condensate pumps. The system consists of two buses – 25A and 25B, each capable of being fed from the 6,900 V winding of either MPS2 NSST or RSST. The 4,160 V system consists of five buses – 24A, 24B, 24C, 24D, and 24E. The 4,160 V system provides a reliable source of power to large AC motors and to 480 V load centers. During plant operation, power is supplied to buses 24A and 24B from the MPS2 NSST. Bus ties connect buses 24A and 24B to buses 24C and 24D, respectively. During other periods such as startup and shutdown when the MPS2 NSST is not used, power is supplied from the MPS2 RSST directly to buses 24C and 24D and by bus ties to buses 24A and 24B. The 24E bus may be fed from either bus 24C or 24D, or from the MPS3 'A' RSST, or 'A' NSST by the MPS3 to MPS2 cross-tie. Buses 24C, 24D, and 24E are emergency buses that supply power to equipment required for a loss-of-coolant accident or other transients and conform to the requirements for Class 1E equipment. MPS2 has two diesel generators, 'A' and 'B.' Diesel generator 'A' connects to bus 24C, and diesel generator 'B' connects to bus 24D.

MPS2 Emergency AC Power System

The emergency power system includes the electrical distribution equipment required to support the safe shutdown and post-accident operations for MPS2. Included in the emergency power system are the two diesel generators, emergency 4,160 V switchgear, and all extensions except

those going to the normal switchgear and the MPS2 RSST. The emergency power system and equipment are Class 1 E and safety-related.

MPS3 Onsite AC Power System

The MPS3 Class 1E 4,160 V system consists of two redundant emergency buses – 34C and 34D. Each bus can be supplied from the MPS3 ‘A’ NSST, MPS3 ‘A’ RSST, or an MPS3 diesel generator. The MPS3 ‘A’ NSST supplies power to emergency 4,160 V buses 34C and 34D by normal buses 34A and 34B, respectively. During normal operation, power is supplied through the MPS3 ‘A’ NSST from the unit generator with the generator breaker closed. During other periods, when the MPS3 ‘A’ NSST is not used, power is supplied from the MPS3 ‘A’ RSST directly to buses 34C and 34D and by bus ties to buses 34A and 34B.

2.2 Proposed TS Changes

The current MPS2 Required Action a.2 of TS 3.8.1.1 allows 72 hours to restore an inoperable offsite circuit to operable status. The licensee proposes to revise TS 3.8.1.1 to add a new Required Action a.3, which provides an option to extend the AOT from 72 hours to 10 days. The proposed TS required actions are shown below (added text is italicized and in bold).

a.2 Restore the inoperable offsite circuit to OPERABLE status within 72 hours ***(within 10 days* if Required ACTION a.3 is met)*** or be in HOT STANDBY within the next 6 hours and COLD SHUTDOWN within the following 30 hours.

AND

a.3 With MPS3 in MODE 5, 6, or defueled, the MPS3 ‘A’ RSST inoperable, and the MPS3 ‘A’NSST energized with breaker 15G-13T-2 (13T) and associated disconnect switches closed, restore either offsite circuit to OPERABLE status within 10 days* if the following requirements are met:

- Within 30 days prior to entering the 10-day* AOT, the availability of the supplemental power source (MPS3 SBO diesel generator) shall be verified.

- During the 10-day* AOT, the availability of the supplemental power source shall be checked once per shift. If the supplemental power source becomes unavailable at any time during the 10-day* AOT, restore to available status within 24 hours or be in HOT STANDBY within the next 6 hours and COLD SHUTDOWN within the following 30 hours.

- The risk management actions contained in DENC letter 20-109, Attachment 4 (also provided in TS Bases 3/4.8), shall remain in effect during the 10-day* AOT.

A footnote denoted by * is added as a one-time exception to the new proposed Required Action a.3 that extends the AOT to 35 days to allow replacement of the MPS3 ‘A’ RSST and 345 kV south bus switchyard components.

* ***To facilitate replacement of the MPS3 ‘A’ RSST and associated equipment, use of a one-time 35-day allowed outage time is permitted provided the requirements of Required ACTION a.3 are met. The work shall be completed no later than the end of MPS3 Refueling Outage 22 (fall 2023).***

2.3 Regulatory Requirements and Guidance

The following NRC requirements and guidance are applicable to the NRC staff’s review of the LAR:

Section 182a of the Atomic Energy Act, as amended, requires applicants for nuclear power plant operating licenses to include TSs as part of the license application. The TSs, among other things, help to ensure the operational capability of structures, systems, and components (SSCs) that are required to protect the health and safety of the public. Title 10 of the *Code of Federal Regulations* (10 CFR) Section 50.36(c)(2)(i) states, in part:

> Limiting conditions for operation are the lowest functional capability or performance levels of equipment required for safe operation of the facility. When a limiting condition for operation of a nuclear reactor is not met, the licensee shall shut down the reactor or follow any remedial action permitted by the technical specifications until the condition can be met.

This LAR contains changes to the remedial actions, also known as required actions or actions, permitted by TS 3.8.1.1.

Appendix A, “General Design Criteria for Nuclear Power Plants” (GDC), to 10 CFR Part 50, GDC 5, “Sharing of structures, systems, and components,” requires that SSCs important to safety shall not be shared among nuclear power units unless it can be shown that such sharing will not significantly impair their ability to perform their safety functions, including, in the event of an accident in one unit, an orderly shutdown and cooldown of the remaining units. The offsite power system switchyard is common to both MPS2 and MPS3.

GDC 17, “Electric power systems,” requires, in part, that an onsite electric power system and an offsite electric power system be provided to permit functioning of SSCs important to safety. The safety function for each system (assuming the other system is not functioning) shall be to provide sufficient capacity and capability to assure that: (1) specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded as a result of anticipated operational occurrences, and (2) the core is cooled and containment integrity and other vital functions are maintained in the event of postulated accidents.

GDC 18, “Inspection and testing of electric power systems,” requires that electric power systems that are important to safety be designed to permit appropriate periodic inspection and testing of important areas and features such as wiring, insulation, connections, and switchboards to assess the continuity of the systems and the condition of their components.

The regulation at 10 CFR 50.63, “Loss of all alternating current power,” requires, in part, that a nuclear power plant shall be able to withstand for a specified duration and recover from a complete loss of offsite and onsite AC sources (i.e., a station blackout (SBO)).
The regulation at 10 CFR 50.65, “Requirements for monitoring the effectiveness of maintenance at nuclear power plants,” requires, in part, that the licensee shall monitor the performance or

condition of SSCs in a manner sufficient to provide reasonable assurance that these SSCs are capable of fulfilling their intended functions.

Regulatory Guide (RG) 1.174, Revision 3, “An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis” (Reference 6), describes an acceptable risk-informed approach for assessing the nature and impact of proposed permanent licensing basis changes by considering engineering issues and applying risk insights. This RG provides risk acceptance guidelines for evaluating the results of such evaluations.

RG 1.177, Revision 1, “An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications” (Reference 7), describes an acceptable risk-informed approach specifically for assessing proposed one-time TS changes in completion time (CT), which is equivalent to AOT. This RG provides risk acceptance guidelines for evaluating the results of such assessments. Section C.2.4 of RG 1.177 provides a three-tiered TS acceptance guideline for evaluating the risk associated with the AOT changes.

RG 1.200, Revision 2, “An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities” (Reference 8), describes one acceptable approach for determining whether the technical acceptability of the probabilistic risk assessment (PRA), in total or the parts, that is used to support an application is sufficient to provide confidence in the results such that the PRA can be used in regulatory decisionmaking for light-water reactors.

NUREG-0800, Branch Technical Position (BTP) 8-8, “Onsite (Emergency Diesel Generators) and Offsite Power Sources Allowed Outage Time Extensions” (Reference 9), provides guidance to the NRC staff in reviewing LARs for licensees proposing a permanent or one-time TS change to extend an emergency diesel generator (EDG) AOT beyond 72 hours.

3.0 TECHNICAL EVALUATION

The NRC staff evaluates AOT extension requests from licensees for offsite power sources to allow online maintenance of offsite power source(s) such as a transformer or bus. The NRC staff reviewed the proposed LAR, as supplemented, from a deterministic, as well as a PRA perspective. Section 3.1 of this safety evaluation (SE) provides the staff’s deterministic evaluation of the proposed changes. Specifically, the NRC staff evaluated defense-in-depth aspects for electric power sources in accordance with the guidance provided in BTP 8-8 (or hereafter referred to as “the BTP”).

3.1 Permanent TS Required Action with Extended AOT (10 Day)

Currently, Required Action a.2 of TS 3.8.1.1, “A.C. Sources – Operating,” allows 72 hours to restore an inoperable offsite circuit to operable status. In LAR Attachment 1, Section 4.1.1, “Permanent TS Required Action with Extended AOT (10 Day),” the licensee provides a description of the proposed changes related to extending the AOT from 72 hours to 10 days for an inoperable offsite power circuit. The NRC staff’s guidance in BTP 8-8 for extending an AOT from the plant’s current TS states that a supplemental power source should be available as a backup to the inoperable offsite power source to maintain the defense-in-depth design philosophy of the electrical system to meet its intended safety function. The licensee proposed to use the MPS3 SBO diesel generator as the supplemental power source for the inoperable

offsite circuit to mitigate a postulated loss-of-offsite power (LOOP) or SBO event since MPS3 will be in Mode 5, 6, or defueled.

The NRC staff verified the licensee conformed to the staff positions provided in BTP 8-8 for determining the adequacy of the AOT extension request. The BTP states that for multi-unit sites that would use their existing Class 1E EDGs as a supplemental AC source, the adjacent unit must have excess capacity to meet its unit's LOOP safe shutdown loads (without load shedding) while complying with the single failure criteria and have spare capacity to support the other unit in maintenance to bring the plant to cold shutdown without any load shedding. The licensee proposed to modify TS 3.8.1.1 Required Action a.2 to allow restoration of the offsite circuit to operable status within 10 days as long as Required Action a.3 is met. TS 3.8.1.1 Required Action a.3 requires that in order to be able to use the extended AOT for 10 days, MPS3 must be in Mode 5, 6, or defueled.. Based on the above, the NRC staff finds the use of the MPS3 SBO diesel generator is acceptable and is in accordance with BTP 8-8.

Duration of the 10-Day AOT

The NRC staff requires the licensee to provide justification for the duration of the requested AOT, including actual hours plus margin based on plant-specific past operating experience. LAR Attachment 1 Section 4.1.1 provides details of how the licensee justifies the duration of the AOT. LAR Attachment 1, Table 1-1, "Normal Preventative Maintenance Schedule for MPS3 'A' RSST," provides a detailed description of the duration of the AOT, including margins for weather considerations for performing testing of the transformer. The proposed durations of these activities are based on plant operating experiences of performing maintenance activities, as provided in Section 4.1.1 of the LAR. The details provided in Table 1-1 also include durations of the testing of the transformer, relays, disconnect switches, cables, voltage transformers, and lightning arrestors, which will cover most of the scope of work for the AOT. The NRC staff finds the licensee has provided sufficient justification for extending the current AOT; therefore, the NRC staff concludes the licensee's request for extending the current AOT to 10 days to perform these activities is acceptable.

The guidance in BTP 8-8 states that the time to make the supplemental power source available, including accomplishing the cross-connection, should be approximately 1 hour to enable restoration of battery chargers and control reactor. The NRC staff noted that Section 4.2.4, "Operator Actions (for 10-Day/35-Day AOTs)," of the LAR states:

> Aligning the MPS3 SBO to MPS2 electrical buses and starting a charging pump is a time critical operator action and is completed within one hour of event initiation. This action ensures power is supplied to battery chargers and RCS [reactor coolant system] makeup, within the assumptions of the Station Blackout Analysis.

The NRC staff finds this acceptable because it ensures the restoration of the battery chargers and reactor coolant system inventory.

The BTP states the extended AOT will be used no more than once in a 24-month period (or refueling interval) on a per diesel basis to perform EDG maintenance activities or any major maintenance on offsite power transformer and bus. The licensee states that the use of this 10-day AOT will be limited to no more than once per 18-month refueling interval for MPS3. The NRC staff finds this condition acceptable, as it meets the BTP staff position.

Availability of the Supplemental Power Source

In addition, BTP 8-8 states that the availability of the supplemental power source should be verified within the last 30 days before entering extended AOT by operating or bringing the power source to its rated voltage and frequency for 5 minutes and ensuring all its auxiliary support systems are available or operational. The NRC staff noted that LAR Section 4.2.2, "Initial Conditions - Electrical Power Configuration (for 10-Day/35-Day AOTs)," states, in part, that the availability of the supplemental power source (MPS3 SBO diesel generator) shall be verified within 30 days prior to entering the configuration and then checked once per shift. The licensee also included it as part of the conditions within TS 3.8.1.1 Required Action a.3. Therefore, the NRC staff concludes the licensee conforms with the availability of the supplemental power source as stated in the BTP.

Also, the BTP states that the TSs must contain required actions and CTs to verify that the supplemental AC source is available before entering extended AOT. The licensee added TS 3.8.1.1 Required Action a.3, which provides the required actions and CTs before entering the AOT. The required actions and CTs are in accordance with BTP 8-8.

The BTP states that the licensee verifies the availability of alternate alternating current (AAC) is checked every 8-12 hours or once per shift. The NRC staff noted that TS 3.8.1.1 a.3 states:

> During the 10-day AOT, the availability of the supplemental power source shall be checked once per shift. If the supplemental power source becomes unavailable at any time during the 10-day AOT, restore to available status within 24 hours or be in HOT STANDBY within the next 6 hours and COLD SHUTDOWN within the following 30 hours.

The NRC staff finds that the availability of AAC is verified in accordance with the BTP staff position and is, therefore, acceptable.

Equipment Capacity

The NRC staff verified that the plant has formal engineering calculations for equipment sizing and protection and has approved procedures for connecting the AAC or supplemental power sources to the safety buses. LAR Section 4.2.5, "SPS Sizing," provides a detailed description of the MPS3 SBO diesel generator to be used as the supplemental power source. The licensee states:

> The AAC can also provide power to MPS2 in the event of a Station Blackout at that unit by means of a 4160 V cross-tie between the AAC output breaker and MPS2 Bus 24E. The AAC is also credited to supply alternate AC power to MPS2 via the same tie in the event of a fire in specifically identified MPS2 Appendix R areas.

The licensee states that the AAC voltage and frequency limits are within the requirements of the MPS2 and MPS3 4,160 V emergency buses. The licensee's calculations show the AAC power source has adequate capacity to bring the plant to a cold shutdown, if needed, for a potential SBO condition at Unit 2 if the remaining power sources fail. Therefore, the NRC staff finds the licensee has provided sufficient justification for the equipment sizing for the supplemental power source.

Compensatory Measures and Risk Management Actions

The BTP states that the staff expects that the licensee will provide compensatory measures and risk management actions. LAR Attachment 4, as supplemented in Reference 5, and TS 3.8.1.1 Required Action a.3 include compensatory measures and risk management actions to assure safe shutdown during inoperability of one offsite circuit. To provide additional defense in depth during the AOT, the following actions will be taken:

1. The AOT will be used no more than once every 18-month refueling interval for MPS3 to perform maintenance on the MPS 'A' RSST and/or 345 kV south bus switchyard components.

2. The AOT will not be scheduled when adverse or inclement weather and/or unstable grid conditions are predicted or present.

3. The load dispatcher will be contacted once per day to ensure no significant grid perturbations are expected during the AOT.

4. Component testing or maintenance of safety systems and important non-safety equipment in the offsite power systems that can increase the likelihood of a plant trip will be avoided. No elective maintenance within the switchyard that could challenge offsite power availability will be scheduled other than 345 kV south bus switchyard maintenance and repairs.

5. During concurrent maintenance and repair activities on 345 kV south bus switchyard components, the 345 kV offsite line 310 will be removed from service to prevent a loss of load trip of MPS2 from a 310 line fault.

6. The Tier 2 equipment listed below will be verified to be operable/functional, and positive measures will be provided to preclude subsequent testing or maintenance activities on this equipment (except for testing required to restore or maintain operability/functionality):

    - MPS2 EDGs H7A and H7B
    - MPS3 SBO Diesel Generator 3BGS-EG1
    - MPS3 Diesel-driven Fire Water Pump M7-7 (which is common to MPS2 and MPS3)
    - MPS2 Service Water Pumps P5A, P5B, and P5C
    - MPS2 Auxiliary Feedwater Pumps P9A, P9B, and P4
    - MPS2 High Pressure Safety Injection (HPSI) Pumps P41A, P41B, and P41C (and associated equipment)

7. The MPS2 turbine-driven auxiliary feedwater pump will be controlled as protected equipment.

8. The status of the MPS2 EDGs will be verified once per shift.

The NRC staff determined that the above proposed compensatory measures and risk management actions are consistent with the staff's position in BTP 8-8, which identifies appropriate actions to ensure maintenance of defense in depth during an extended AOT. Therefore, the NRC staff finds the above compensatory measures and risk management actions are acceptable.

3.1.1 TS Required Action with One-Time AOT Request to 35 Days

The licensee also proposes a one-time exception to the new proposed Required Action a.3 that would extend the AOT to 35 days for one inoperable offsite circuit. Use of the 35-day AOT would permit replacement of the MPS3 'A' RSST, its associated equipment, and other 345 kV south bus switchyard components that are nearing the end of their dependable service life. This work is planned to take place no later than the fall 2023 outage (3R22) for MPS3. Replacement of these components is necessary to ensure continued safe and dependable generation of electric power.

The staff's deterministic evaluation applies to the one-time 35-day AOT extension request, as the proposed use of the one-time AOT is permitted only if the supplemental power source requirements of Required Action a.3 for the 10-day AOT are met, and the related risk management actions specified in LAR Attachment 4 are taken. Since the licensee's request goes beyond the maximum 14-day duration specified in the BTP 8-8 staff position, the acceptability of the one-time AOT duration is based on a risk evaluation of this configuration, which is provided in Section 3.2 of this SE.

3.1.2 Compliance with 10 CFR 50.36(c)(2)(i)

TS 3.8.1.1 Required Action a.2 is revised to include the phrase "within 10 days* if Required ACTION a.3 is met." The addition of this phrase to Required Action a.2 allows the AOT to be extended from 72 hours to 10 days when the requirements within Required Action a.3 are met.

As discussed in Section 3.1.1 of this SE, a new Required Action a.3 is added to TS 3.8.1.1. Required Action a.3 is applicable when MPS3 is in Modes 5, 6, or defueled, and only for the configuration where MPS3 'A' RSST is inoperable and MPS3 'A' NSST is energized with breaker 15G-13T-2 (breaker 13T) and associated disconnect switches closed. Required Action a.3 requires restoring either offsite circuit to operable status with 10 days if the supplemental power source, which consists of the MPS3 SBO diesel generator, was verified to be available within the previous 30 days before entering Required Action a.3. Required Action a.3 also requires the availability of the supplemental power source to be checked once per shift throughout the duration of the 10-day AOT. If the supplemental power source becomes unavailable at any time during the 10-day AOT, then Required Action a.3 requires it be restored to available status within 24 hours, or MPS2 must be placed in hot standby within the next 6 hours and cold shutdown within the following 30 hours.

The proposed footnote to be added to TS 3.8.1.1 states:

> To facilitate replacement of the MPS3 'A' RSST and associated equipment, use of a one-time 35-day allowed outage time is permitted provided the requirements of Required ACTION a.3 are met. The work shall be completed no later than the end of MPS3 Refueling Outage 22 (fall 2023).

Use of the 10-day AOT allows for performance of MPS3 'A' RSST and/or the 345 kV south bus switchyard component maintenance and repair activities with MPS2 operating and breaker 13T closed.

The NRC staff finds that the extended 35-day AOT will remain in effect from issuance of this license amendment through the MPS3 Refueling Outage 22 in fall of 2023. After this time, the extended AOT will no longer be applicable. During the applicable time period, the licensee may

utilize the 35-day AOT to replace MPS3 'A' RSST, its associated equipment, and 345 kV south bus switchyard components, provided that the supplemental power source has been verified to be available within the previous 30 days before entering Required Action a.3. While the 35-day extended AOT is in effect, the supplemental power source will be verified to be available by the licensee once per shift. If the supplemental power source becomes unavailable at any time during the AOT, then the supplemental power source shall be restored within 24 hours or MPS2 is required to be in hot standby within the next 6 hours and cold shutdown within the following 36 hours.

The NRC staff finds that 10 CFR 50.36(c)(2)(i) will continue to be met because the remedial actions proposed in TS 3.8.1.1 can be completed by the licensee until the LCO can be met. If the remedial actions cannot be met within the AOTs, the licensee will be required to shut down the reactor. The NRC staff finds the proposed changes to the remedial actions in TS 3.8.1.1 are acceptable. Therefore, the staff concludes, based on the evaluations above, that the requirements of 10 CFR 50.36(c)(2)(i) for TS LCO 3.8.1.1 and its associated remedial actions will continue to be met following implementation of the changes to the TSs described in this SE.

3.1.2 <u>Deterministic Conclusion</u>

Based on the NRC staff's review of the licensee's compensatory measures and risk management actions and the deterministic technical evaluation above, the NRC staff concludes that the proposed changes to TS LCO 3.8.1.1 Required Actions a.2 and a.3 are acceptable and that the requirements of 10 CFR 50.36(c)(2)(i); 10 CFR 50.63; GDC 17; GDC 18; and the position of NUREG-0800, BTP 8-8 for TS LCO 3.8.1.1, and its associated remedial actions, will continue to be met following the implementation of the changes to the TSs as described in this SE.

3.2 <u>Risk Evaluation</u>

3.2.1 <u>Background</u>

The NRC staff evaluated the licensee's proposed one-time AOT extension to determine whether the proposed change is consistent with the regulations, licensing, and design-basis information, and regulatory guidance discussed in Section 2 of this SE.

The LAR, as supplemented, stated that the proposed one-time 35-day extension of TS 3.8.1.1 AOT was evaluated in accordance with the guidance of RG 1.177, Revision 1, and RG 1.174, Revision 3. RG 1.177 describes a risk-informed approach for assessing proposed changes, which is based on meeting the five key principles outlined in RG 1.174 and summarized in Section 2 of this SE. The NRC staff reviewed the proposed one-time 35-day extension of TS 3.8.1.1 AOT against the following five key principles of RG 1.174:

- Principle 1: The proposed licensing basis change meets the current regulations unless it is explicitly related to a requested exemption (i.e., a specific exemption under 10 CFR 50.12).
- Principle 2: The proposed licensing basis change is consistent with the defense-in-depth philosophy.
- Principle 3: The proposed licensing basis change maintains sufficient safety margins.

- Principle 4: When proposed licensing basis changes result in an increase in risk, the increases should be small and consistent with the intent of the Commission's policy statement on safety goals for the operations of nuclear power plants.

- Principle 5: The impact of the proposed licensing basis change should be monitored using performance measurement strategies.

3.2.2 Key Principle 1: Compliance with Current Regulations

As a key principle of risk-informed integrated decisionmaking, Regulatory Position 1 in RG 1.174 states the licensee should affirm that the proposed licensing basis change meets the current regulations, unless the proposed change is explicitly related to a proposed exemption (i.e., a specific exemption under 10 CFR 50.12).

As discussed in Section 2.3 of this SE, the regulations in 10 CFR 50.36(c) specify the requirements of the TSs. The licensee's proposed one-time change to TS LCO 3.8.1.1 Required Action a.3 to increase the AOT affects the maximum allowed time to have an offsite circuit inoperable without shutting down the reactor. The licensee's request does not deviate from the requirements in this regulation or any other regulation. An exemption from regulations was not proposed by the licensee. The licensee also states in Section 5.2 of LAR Attachment 1 that the proposed change will not result in plant operation in a configuration outside the current design basis. The NRC staff finds that the proposed change will continue to meet the requirements of the applicable regulations, including 10 CFR 50.36. Therefore, the NRC staff concludes that the proposed change meets the first key principle of RG 1.174.

3.2.3 Key Principle 2: Evaluation of Defense in Depth

Regulatory Position C.2.1.1 in RG 1.174 states that defense in depth consists of seven elements, and consistency with the defense-in-depth philosophy is maintained if the following occurs:

1. Preserve a reasonable balance among the layers of defense.

2. Preserve adequate capability of design features without an overreliance on programmatic activities as compensatory measures.

3. Preserve system redundancy, independence, and diversity commensurate with the expected frequency and consequences of challenges to the system, including consideration of uncertainty.

4. Preserve adequate defense against potential common cause failures.

5. Maintain multiple fission product barriers.

6. Preserve sufficient defense against human errors.

7. Continue to meet the intent of the plant's design criteria.

The following sections provide the NRC staff's evaluation of each of these seven considerations.

3.2.3.1 Preserve a Reasonable Balance Among the Layers of Defense

In LAR Attachment 1, Section 4.5.1, the licensee discusses the defense in depth for mitigating a breaker 13T failure during the proposed extension.

The NRC staff determined that the following plant and operational attributes continue to provide defense in depth:

- The MPS2 EDGs would be the first line of defense for mitigating the event.
- The MPS3 SBO diesel generator – the operator would initiate action to isolate the faulted breaker 13T.
- The onsite 480 V (Diverse and Flexible Coping Strategies (FLEX)) diesel generator can be deployed from the beyond-design-basis (BDB) storage to bring MPS2 to hot shutdown conditions.
- The compensatory actions to protect the equipment as discussed in Tier 2 (see evaluation in Section 3.2.5.2 of this SE).

The alternative AC power sources listed above have adequate capability to bring MPS2 to a safe and stable shutdown by mitigating a failure of breaker 13T during the extended AOT. The NRC staff's review finds that the proposed change does not significantly impact the ability to prevent plant challenges from progressing to core damage, the containment function, or the effectiveness of emergency response. The NRC staff's evaluation finds that the proposed change continues to preserve a reasonable balance between prevention of core damage, prevention of containment failure, and emergency response, because the proposed change does not significantly reduce the effectiveness of a layer of defense that exists in the plant design and operation before the implementation of the proposed change.

3.2.3.2 Preserve Adequate Capability of Design Features Without an Overreliance on Programmatic Activities as Compensatory Measures

The licensee listed compensatory measures in LAR Attachment 4. The licensee stated that the compensatory measures are intended to reduce the potential of risk-significant configurations. The NRC staff's review determined that the compensatory measures identified by the licensee do not reduce the capability of the design features. The design feature capability remains adequate and preserved by the compensatory measures. Further, the NRC staff's review finds that the compensatory measures are not the basis for requesting the proposed change and are not included in the risk assessment performed in support of the proposed change. Therefore, the NRC staff finds that the proposed change avoids an overreliance on programmatic activities as compensatory measures.

3.2.3.3 Preserve System Redundancy, Independence, and Diversity Commensurate with the Expected Frequency and Consequences of Challenges to the System, Including Consideration of Uncertainty

The NRC staff's review finds that the proposed change does not significantly reduce system redundancy, independence, and diversity because multiple means of achieving system function to mitigate any challenges continue to be available. The NRC staff's review also finds that the proposed change ensures that the ability to provide the system function is commensurate with

the risk of scenarios that could be mitigated by that function, including consideration of uncertainty.

3.2.3.4 Preserve Adequate Defense Against Potential CCFs

The proposed change does not introduce new equipment or system that could degrade defenses against CCFs or introduce new CCF mechanisms. The licensee demonstrated that CCF was not an issue for the change in risk from the proposed change (see Section 3.2.5.1.1.3 of this SE). Based on its review, the NRC staff concludes that the licensee has adequately assessed the potential for the introduction of new CCF mechanisms because the proposed change does not degrade defenses against potential CCFs and does not introduce new CCF mechanisms.

3.2.3.5 Maintain Multiple Fission Product Barriers

The proposed change does not introduce new equipment or system. Further, the licensee stated that the backup AC power sources can bring MPS2 to a safe and stable condition. Based on its review, the NRC staff finds that the proposed change does not directly impact any of the three fission product barriers (fuel cladding, reactor coolant system, containment building) or cause their degradation. The staff's evaluation of the risk assessment supporting the proposed change finds that the risk increase from the proposed modification is small. Further, the staff's evaluation finds that multiple fission product barriers are maintained because the proposed change does not introduce a new event that would simultaneously impact multiple barriers and does not create a significant increase in the likelihood or consequence of an event that simultaneously challenges multiple barriers. The NRC staff finds that the proposed change has negligible impact on the fission product barriers because the increase of core damage frequency (CDF) and large early release frequency (LERF) is very low.

3.2.3.6 Preserve Sufficient Defense Against Human Errors

As discussed in Section 3.2.3.1 above, the licensee provided three layers of AC sources for mitigation. In Section 4.2.4 of LAR Attachment 1, the licensee provided discussions of operator actions for the one-time 35-day AOT. In a LOOP event, MPS2 EDGs would be the first line of defense for mitigating the event. Plant operators will perform routine logs and monitoring at least every 12 hours to ensure that EDG parameters and conditions are normal and will support operation. Additionally, alarms in the control room will alert operators to abnormal conditions with the EDGs. Operators will respond to the event in accordance with emergency operating procedures to confirm reactor coolant system, secondary system, and containment conditions. In an SBO event, the operators would be directed to request power from MPS3. The MPS3 SBO diesel generator will be available and the emergency operating procedures provide directions to energize MPS2 electrical buses from the MPS3 SBO diesel generator though a 4,160 V AC cross-tie.

In Section 4.2.13 of LAR Attachment 1, the licensee discussed the training on emergency operating procedures during LOOPs and SBO, which are conducted periodically in accordance with the Millstone station licensed and non-licensed operator training program to maintain proficiency energizing MPS2 emergency buses from the MPS3 SBO diesel generator. Prior to entering either proposed permanent TS required action or one-time exception, pre-job briefs

would be conducted to increase awareness of the risk sensitivity associated with the activity. With the plant operation procedures for EDGs and SBO, human errors will be minimized.

Based on its review, the NRC staff finds that the proposed change does not significantly reduce the ability of plant staff to perform actions because the change does not create new human actions that are important to preserving any of the layers of defense and does not significantly increase the probability of existing human errors by significantly affecting performance shaping factors, including mental and physical demands and level of training. Therefore, the NRC staff concludes that the proposed change preserves defenses against human error.

3.2.3.7 Continue to Meet the Intent of the Plant's Design Criteria

Based on the NRC staff's review, the proposed change continues to meet the intent of the plant's design criteria because it does not alter the plant's design criteria or any other aspect of the licensing basis, and the intent and purpose of TS 3.8.1.1 remains unchanged. In addition, the impact of the proposed change is known through the risk assessment supporting the change.

Key Principle 2 Conclusion

In summary, the staff finds that the proposed change does not significantly affect the seven considerations for defense in depth, and the proposed change preserves defense in depth commensurate with the expected frequency and consequence of challenges to the system resulting from the proposed change. The NRC staff finds there is reasonable assurance that the defense-in-depth operation and design philosophy of the electrical system will be maintained during the proposed AOT extension. Therefore, the NRC staff concludes that the proposed change meets the second key principle of RG 1.174.

3.2.4 Key Principle 3: Evaluation of Safety Margins

Regulatory Position C.2.1.2 in RG 1.174 discusses two specific criteria that should be addressed when considering the impact of the proposed change on safety margin:

(1) the codes and standards or their alternatives approved for use by the NRC are met, and

(2) safety analyses acceptance criteria in the licensing basis (e.g., FSAR [final safety analysis report], supporting analyses) are met or proposed revisions provide sufficient margin to account for uncertainty in the analysis and data.

The proposed change does not modify the design and operation of AC sources. Codes or standards approved for use by the NRC relevant to the change are not modified and continue to be met. Further, safety analysis acceptance criteria in the plant's licensing basis continue to be met, and TS safety limits are not affected by the proposed change. In Section 4.5.1 of LAR Attachment 1, the licensee stated that aligning breaker 13T in closed position has no adverse impact on the ability of the MPS3 'A' NSST to supply power to the 4,160 V buses. The risk increase of breaker 13T failure due to the proposed change is evaluated in Section 3.2.5 of this SE, which shows that margin exists to the acceptance guidelines in RG 1.174 and RG 1.177.

Key Principle 3 Conclusion

Based on its review, the NRC staff finds that the proposed change maintains safety margins because (1) codes and standards or their alternatives approved for use by the NRC and relevant to the change continue to be met, (2) safety analyses acceptance criteria in the licensing basis continue to be met, and (3) adequate margin exists to the acceptance guidelines in RG 1.174 and RG 1.177. Therefore, the NRC staff concludes that the proposed change meets the third key principle of RG 1.174.

3.2.5 Key Principle 4: Change in Risk Consistent with the Commission's Policy Statement on Safety Goals

RG 1.177, Revision 1, addresses this principle through a three-tiered approach for evaluating the risk associated with the proposed change to TS CTs:

- Tier 1 assesses the risk impact of proposed TS CT changes in accordance with acceptance guidelines in RG 1.174 and RG 1.177, consistent with the Commission's policy statement on safety goals for the operation of nuclear power plants. The risk impact is evaluated against: (1) operational plant risk as represented by the change in core damage frequency (ΔCDF) and the change in large early release frequency (ΔLERF); and (2) incremental plant risk while equipment covered by the proposed TS CT changes are out of service, as represented by the incremental conditional core damage probability (ICCDP) and the incremental conditional large early release probability (ICLERP). The Tier 1 evaluation also addresses acceptability of the plant-specific PRAs used to assess the changes in risk.

- Tier 2 identifies and evaluates any potential risk-significant plant configurations that could result if any equipment, in addition to that associated with the proposed TS CT changes, will be taken out of service simultaneously or if other risk-significant operational factors, such as concurrent system or equipment testing, are involved.

The purpose of this evaluation is to ensure that there are appropriate restrictions on dominant risk-significant equipment configurations associated with the proposed TS CT changes. In addition, compensatory measures that can mitigate any corresponding increase in risk are identified and evaluated.

- Tier 3 addresses the licensee's overall configuration risk management program to ensure that adequate programs and procedures have been established for identifying risk-significant plant configurations resulting from maintenance or other operational activities, and that appropriate compensatory measures are taken to avoid risk-significant configurations that may not have been considered in the Tier 2 evaluation.

The NRC staff's evaluation of each of the three tiers is presented below.

3.2.5.1 Tier 1 Evaluation – Risk Impact

In accordance with Tier 1 outlined in RG 1.177, the licensee should evaluate the change in risk resulting from the proposed TS CT changes as represented by the ΔCDF, ICCDP, ΔLERF, and ICLERP. As part of this evaluation, the licensee should demonstrate that its PRA (or its qualitative analyses, bounding analyses, detailed analyses, or compensatory measures if a PRA

of sufficient scope is not available) is acceptable for assessing the proposed TS CT changes. Also, uncertainties should be appropriately considered in the analyses and interpretation of the findings. The Tier 1 review involves two aspects: (1) evaluation of the technical acceptability of the MPS2 PRAs used to support this application, and (2) evaluation of the PRA results and insights for the licensee's proposed change. The NRC staff's assessment of these aspects is provided below.

3.2.5.1.1 PRA Acceptability

Section C.2.3 of RG 1.174 states:

> The PRA analysis used to support an application is measured in terms of its appropriateness with respect to scope, level of detail, conformance with the technical elements, and plant representation. These aspects of the PRA are to be commensurate with its intended use and the role the PRA results play in the integrated decision process.

The acceptability of the PRA must be compatible with the safety implications of the TS change being requested and the role that the PRA plays in justifying that change. That is, the more the potential change in risk or the greater the uncertainty in that risk from the requested TS change, or both, the more rigor that must go into ensuring the acceptability of the PRA. This applies to Tier 1, and it also applies to Tier 2 and Tier 3 to the extent that a PRA model is used.

3.2.5.1.1.1 Scope of the PRA

Regulatory Position C.2.3.2 of RG 1.177 states that the licensee should perform evaluations of CDF and LERF to support any risk-informed changes to TS. The scope of the analysis should include all hazard groups (i.e., internal events, internal flooding, fires, seismic events, high winds, and other external hazards) unless it can be shown the contribution from specific hazard groups does not affect the decision. In some cases, a PRA of sufficient scope may not be available. This will have to be compensated for by qualitative arguments, bounding analyses, or compensatory measures.

Based on the LAR, as supplemented, the change in risk (i.e., ΔCDF, ΔLERF, ICCDP, and ICLERP) resulting from the proposed TS 3.8.1.1 CT extension is estimated utilizing PRAs for at-power internal events with internal flooding. For other hazards, qualitative assessments were used to screen these events from further consideration.

RG 1.200 describes one acceptable approach for determining whether the acceptability of the PRA, in total or the parts that are used to support an application, is sufficient to provide confidence in the results such that the PRA can be used in regulatory decisionmaking for light-water reactors. RG 1.200 endorses, with clarifications and qualifications, American Society of Mechanical Engineers/American Nuclear Society (ASME/ANS) PRA standard ASME/ANS RA-Sa-2009, "Addenda to ASME/ANS RA-S-2008, Standard for Level 1/Large Early Release Frequency Probabilistic Risk Assessment for Nuclear Power Plant Applications." The ASME/ANS PRA standard provides technical supporting requirements in terms of three Capability Categories (CCs). The intent of the delineation of the CCs within the supporting requirements is generally that the degree of scope and level of detail, the degree of plant

specificity, and the degree of realism increase from CC I to CC III. Per RG 1.200, CC II of the ASME/ANS standard, is the level of detail that is adequate for the majority of applications.

Internal Events and Internal Flooding PRA

The NRC staff's review of the internal events PRA is based on: (1) the results of the peer review of the internal events PRA and the associated facts and observations (F&Os) closure review described in LAR Attachment 5; and (2) the previously plant-specific docketed information relevant to the NRC staff's review of the internal events PRA for MPS2 adoption of 10 CFR 50.69, "Risk-Informed Categorization and Treatment of SSCs for Nuclear Power Reactors" (Reference 10 and Reference 11).

In LAR Attachment 5, the licensee states that the internal events and internal flooding PRA was subject to focused-scope peer reviews in September 2012, March 2018, and July 2018, in accordance with RG 1.200, Revision 2, and covered all supporting requirements in the ASME/ANS 2009 Standard. In addition, the licensee states that in March 2018, an F&O closure review was performed by an independent team on all internal events and internal flooding finding-level F&Os. This F&O closure review was performed as detailed in Appendix X (Reference 12) to the guidance in NEI 05-04 (Reference 13), NEI 07-12 (Reference 14), and NEI 12-13 (Reference 15) concerning the process, "Close-Out of Facts and Observations." The NRC staff accepted, with conditions, a final version of Appendix X to NEI 05-04, NEI 07-12, and NEI 12-13 by letter dated May 3, 2017 (Reference 16). The NRC staff's review finds that the licensee appropriately implemented the Appendix X guidance as accepted.

The licensee submitted a list of all the open F&Os from peer reviews, including the F&Os that remained open after the F&O closure review, in LAR Attachment 5. It listed eight F&Os with their dispositions for this application. The NRC staff reviewed the licensee's resolution of all the peer review findings and assessed the potential impact of the findings on the categorization. Seven of the F&Os were dispositioned as documentation updates (which have been resolved) that would not impact this LAR application. The remaining F&O affects the steam generator tube rupture accident sequence, which does not impact this application.

Based on its review, the NRC staff finds that the licensee has (1) followed the guidance in RG 1.200 for determining the technical acceptability of the internal events and internal flooding PRA, and (2) the dispositions of the open finding-level F&Os are appropriate for this application because they do not impact this application. Therefore, the NRC staff finds the licensee's internal events and internal flooding PRA to be technically acceptable for this application.

Internal Fire Risk

The licensee stated that MPS2 does not have an internal fire PRA model, and the risk impact for this hazard group was assessed qualitatively. The licensee stated that the offsite power sources are not listed on the fire safe shutdown equipment list and, therefore, are not considered fire safe shutdown equipment. In its request for additional information (RAI) letter dated February 19, 2020 (Reference 17), the NRC staff questioned the impact of fires in the transformers, as well as other switchyard equipment, and the absence of fire watches in the risk management actions listed in LAR Attachment 4.

The licensee stated that a single transformer fire would not impact both MPS2 RSST and MPS3 NSST transformer, and any other switchyard components (Reference 4). The licensee further explained that a fire event is not expected to impact breaker 13T and the MPS2 offsite sources

without impacting the entire switchyard. The licensee analyzed two postulated fire scenarios: (1) a fire that initiates within breaker 13T causing an internal fault that propagates to the MPS2 RSST and MPS3 ‘A’ NSST, rendering them both unavailable, and (2) a fire that impacts the ability of breaker 13T to perform its active function to maintain electrical separation of the MPS2 offsite sources. The analytical results showed that the risk from a fire that impacts the 13T breaker is much lower than the risk from the random breaker internal fault considered in the LAR.

Based on the discussion above, the NRC staff finds that the licensee’s justification for internal fire risk is acceptable for this application because (1) a fire in the switchyard would cause other switchyard damages in addition to causing the breaker to trip open, and (2) the fire frequencies that impact the proposed change are much lower than the random breaker internal fault value used in this application. Therefore, the internal fire risk does not need to be quantitatively included in the risk assessment supporting this application.

High Winds Risk

The licensee evaluated the impacts from high wind and tornado in LAR Attachment 5 (under extreme wind or tornado and hurricane) and screened out high wind and tornado, based on a frequency of occurrence less than 1.0×10^{-6} per year. Further, several potential failures caused by tornado-generated missiles are also excluded based on their being bounded by the 1.0×10^{-6} frequency of occurrence. However, the basis for the frequency of occurrence cited by the licensee, as well as the frequency being bounding for tornado-generated missile risks, are not provided.

In response to the NRC’s RAI 02 (Reference 4), the licensee stated that a likely scenario of a high winds event will cause breaker 13T to open or a loss of all four offsite transmission lines and that the high winds configuration risk increase associated with maintaining switchyard breaker 13T closed coincident with the MPS3 ‘A’ RSST out of service is considered negligible. In addition, risk is managed by risk management action item 2 in LAR Attachment 4, which does not allow scheduling entry into the action statement when adverse or inclement weather is predicted or present.

Based on the discussion above, the NRC staff finds that the licensee’s justification for high wind risk is acceptable for this application, because a high winds event would cause other switchyard damages in addition to causing the breaker to trip open. Therefore, high wind risk does not need to be quantitatively included in the risk assessment supporting this application.

External Flooding Impact

LAR Attachment 6 provides a qualitative evaluation for the external flooding hazard and concludes that this hazard has no impact on risk for this application. The licensee stated that the offsite power is expected to be lost as a result of a storm surge that introduces external flooding risk to MPS2. However, the impact is expected to the entire plant and is not just associated with this proposed LAR.

The NRC staff’s review determined that there is a high probability of LOOP during an external flooding event large enough to challenge the plant. Further, the NRC staff finds that such an external flooding-initiated LOOP will impact the entire plant, and its impact will not change because of the proposed change. Further, as discussed in Section 3.4.1.2 of this SE, margin exists to the acceptance guidelines in RG 1.177. Therefore, the NRC staff concludes that

external flooding risk does not need to be quantitatively included in the risk assessment supporting this application.

Seismic Risk

The licensee stated that MPS2 does not have a seismic PRA model, and the risk impact for this hazard group is assessed qualitatively. The licensee stated that the offsite power is expected to be lost as a result of a seismic event. However, the impact is expected to the entire plant and is not just associated with this proposed LAR.

The NRC staff's review determined that there is a high probability of LOOP during a seismic event. Further, the NRC staff finds that a seismically-induced LOOP will impact the entire plant, and its impact will not change because of the proposed change. Further, as discussed in Section 3.4.1.2 of this SE, margin exists to the acceptance guidelines in RG 1.177. Therefore, the NRC staff concludes that the seismic risk does not need to be quantitatively included in the risk assessment supporting this application.

Other External Event Hazards

The LAR evaluated other external hazards to determine whether they impact the application.

The licensee provided a qualitative evaluation of external hazards other than seismic, high winds, and external flooding listed in Table 4-1 of NUREG 1855, Revision 1, "Guidance on the Treatment of Uncertainties Associated with PRAs in Risk-Informed Decision Making" (Reference 18). Each of those hazards was screened from further consideration based on the screening criteria in Section 6 of ASME/ANS RA-Sa-2009.

The NRC staff finds the licensee has appropriately evaluated other external hazards to the extent needed to support this application in accordance with the guidance in RG 1.177 and the 2009 PRA standard endorsed by the NRC in RG 1.200. Therefore, the NRC staff finds that external hazards other than seismic, high winds, and external flooding do not impact this application.

Conclusions for PRA Technical Elements and Acceptability of External Hazard Analyses

Based on its review, as discussed above, the NRC staff finds: (1) the MPS2 internal events and internal flooding PRAs are technically acceptable for this application and conform to the applicable technical elements in ASME/ANS RA-Sa-2009, as endorsed by RG 1.200, to the extent needed to predict the change in CDF and LERF for use in this risk-informed application, and (2) the risk from internal fire, high winds, external flooding, seismic events, and other external hazards does not impact this application.

3.2.5.1.1.2 Level of Detail in PRA

Section C.2.3.3 of RG 1.174 states that the level of detail required of the PRA should be sufficient to model the risk impact of the proposed change. If the impacts of the proposed change to the plant cannot be associated with elements of the PRA, the PRA should be modified accordingly, or the impact of the change should be evaluated qualitatively as part of the integrated decisionmaking process. In any case, the licensee should properly account for the effects of the changes on the reliability and unavailability of SSCs or on operator actions.

In Section 4.4.1 of LAR Attachment 1, the licensee explained the approach used to modify its PRA to reflect the risk from the proposed change. The licensee stated that the proposed change could increase the frequency of grid-related LOOP due to the failure of breaker 13T. The licensee used industry data from NUREG/CR-6928 and updated through 2015 to quantitatively determine the increase in the grid-related LOOP occurrence frequency. This increased frequency was used, in conjunction with the licensee's full power internal events PRA, to determine the change in risk from the proposed request.

The licensee stated that a list of MPS2 PRA model assumptions and sources of uncertainty were reviewed to identify those significant to this application. However, the LAR did not provide the detailed description of the identification process. In response to RAI 03 (Reference 4), the licensee confirmed that the approach used for identifying "key" assumptions and sources of uncertainty is identical to that found acceptable by the NRC staff for the licensee's LAR to adopt 10 CFR 50.69, "Risk-informed categorization of structures, systems, and components" (Reference 11). The licensee applied that approach to the parameters used in the calculation of the increased grid-related LOOP frequency and the modeling of the LOOP as well as an SBO accident scenario. The licensee provided some examples of dispositions made for model assumptions and sources of uncertainty for this application in response to RAI 03.

The NRC staff's review determined that licensee identified the impact of the proposed change, used updated data to quantify the impact, modified the PRA model appropriately to reflect the change, and used a systematic approach to identify key assumptions and sources of uncertainty relevant to this application. Therefore, the NRC staff finds, in conjunction with its finding on the technical acceptability of the internal events PRA for this application, that there is appropriate level of detail in the licensee's internal events PRA to determine the change in risk for this application. The NRC staff's review of the impact of identified key assumptions and sources of uncertainty on this application is evaluated in Section 3.4.1.3 of this SE.

3.2.5.1.1.3 Plant Representation in PRA

Section C.2.3.4 of RG 1.174 states that the PRA results used to support an application should be derived from a PRA that represents the as-built and as-operated plant to the extent needed to support the application. Consequently, the PRA should have been maintained and updated, where necessary, to ensure it represents the as-built and as-operated plant.

In response to RAI 4 for the LAR to adopt 10 CFR 50.69, "Risk-informed categorization of structures, systems, and components" (Reference 19), the licensee stated that FLEX equipment is credited in the MPS2 internal events and internal flooding PRA. The licensee also stated that the FLEX equipment failure data is considered as a source of uncertainty. The human error probability for FLEX actions, especially related to deployment of portable equipment, can also be a source of uncertainty.

In response to NRC's RAI 04 (Reference 4), the licensee explained that the PRA model does credit a portable beyond-design-basis transfer pump to refill the condensate storage tank by the primary water storage tank after the condensate storage tank depletes 8-10 hours following the extended loss of AC power event. Crediting this strategy ensures that the PRA models the as-built, as-operated response, to an SBO scenario. However, the impact of FLEX equipment and human actions results in a minimal increase in LOOP frequency and negligible increase in SBO frequency given that both MPS2 EDGs and the SBO DG will be maintained operable/available per risk management action item 6 of LAR Attachment 4.

The licensee's determination of the increased grid LOOP occurrence frequency did not appear to include common cause failures (CCFs). In response to NRC's RAI 06 (Reference 4), the licensee explained that a CCF of the two transformers, MPS2 RSST and MPS3 'A' NSST, is independent of the breaker 13T position. The licensee provided the fault tree model developed to calculate the increased grid LOOP occurrence frequency and demonstrated that common cause failure was not an issue in this application. Therefore, common cause failure is not considered in the increased grid LOOP occurrence frequency calculation.

As described in Section 3.2.6 of the MPS2 50.69 LAR, the licensee has administrative controls in place to ensure that the PRA models used to support the categorization reflect the as-built, as-operated plant over time. The licensee's process includes regularly scheduled and interim (as needed) PRA model updates. The process includes provisions for monitoring issues affecting the PRA models (e.g., due to changes in the plant, errors or limitations identified in the model, industry operational experience) for assessing the risk impact of unincorporated changes and for controlling the model and associated computer files.

The NRC staff concludes, based on a review of the LAR, as supplemented, that the licensee's PRA model reflects the as-built, as-operated plant to support this application. Based on the licensee's PRA configuration and control program to maintain and update the PRA, the NRC staff finds the PRA results used to support this application are derived from an integrated PRA that represents the as-built and as-operated plant to the extent needed to support the application.

<u>PRA Acceptability Conclusion</u>

Based on its evaluation of the MPS2 TS 3.8.1.1 LAR, as supplemented, the NRC staff concludes the MPS2 internal events and internal flooding PRAs and non-PRA analysis are acceptable for assessing risk to the extent needed to support this application. The NRC staff based this conclusion for this risk-informed application and to the extent needed to support the application, on the findings that: (1) the licensee's risk assessment is of sufficient scope; (2) the MPS2 internal events and internal flooding PRAs appropriately conform to the applicable technical elements in ASME/ANS RA-Sa-2009, as endorsed by RG 1.200, to the extent needed to predict the change in CDF and LERF; (3) the risk from internal fire, high winds, external flooding, seismic events, and other external hazards not addressed using PRA do not impact this application; (4) the level of detail in the PRA models and the PRA assumptions are appropriate to evaluate the risk impact for this application; and (5) the PRAs represent the as-built and as-operated plant.

3.2.5.1.2 PRA Results

Based on Section C.2.5.2 of RG 1.174, the mean values of the risk metrics (i.e., CDF, LERF, ICCDP, ICLERP, ΔCDF, and ΔLERF) should be compared against the applicable risk acceptance guidelines. The mean values referred to are the means of the risk metric's probability distributions that result from the propagation of the uncertainties on the PRA input parameters.

The licensee evaluated the risk impact of the proposed change using the MPS2 PRA models for internal events and internal flooding in Section 4.4.1 of LAR Attachment 1. The licensee calculated a total CDF and LERF of 1.95×10^{-5} per year and 1.33×10^{-6} per year, respectively,

based on the CT configuration case. The licensee calculated a ΔCDF and ΔLERF for the proposed TS CT extension as follows:

ΔCDF = 2×10^{-9}/year (RG 1.174 Acceptance Guideline: 1×10^{-6} /year, Region III in Figure 4 of RG 1.174)

ΔLERF = 2×10^{-10}/year (RG 1.174 Acceptance Guideline: 1×10^{-7} /year, Region III in Figure 5 of RG 1.174)

The NRC staff finds that the licensee meets the acceptance guidelines of RG 1.174, Section C.2.4.

The licensee calculated the ICCDP and ICLERP for the proposed TS CT extension as follows:

ICCDP = 9×10^{-9} (RG 1.177 Acceptance Guideline: 1×10^{-6})

ICLERP = 1×10^{-9} (RG 1.177 Acceptance Guideline: 1×10^{-7})

The NRC staff finds that the licensee meets the acceptance guidelines of RG 1.177, Section C.2.4, for the proposed one-time change to the AOT.

The risk results provided by the licensee represent point estimate values (obtained by quantification of the cutset probabilities using mean values for each basic event probability) and are not true mean values for these risk metrics. In general, the point estimate values of these risk metrics obtained by quantification of the cutset probabilities using mean values for each basic event probability does not produce a true mean value for these risk metrics. However, due to the margin between the point estimate values and the acceptance guidelines in RG 1.174 and RG 1.177, the NRC staff concludes that use of the corresponding true mean values would not change the staff's conclusions on the proposed change.

The NRC staff concludes the risk increase for the proposed TS 3.8.1.1 CT extension meets the acceptance guidelines in RG 1.174 and RG 1.177, and is, therefore, acceptable for this application.

3.2.5.1.2.1 Sensitivity and Uncertainty Analyses

RG 1.174, Section C.2.5, identifies the following types of uncertainty that affect the results of PRAs: parameter uncertainty, model uncertainty, and completeness uncertainty. In accordance with regulatory positions in RG 1.174 and RG 1.177, uncertainties should be appropriately considered in the analysis and interpretation of findings. Also, RG 1.174 states that the results of the sensitivity studies should confirm the acceptance guidelines are still met, even under the alternative assumptions.

In LAR Attachment 5, the licensee addressed three types of PRA uncertainty. For the parameter uncertainty, the licensee (1) increased the failure rates by a factor of 3 for the switchyard bus failure rate, offsite power transformer failure rate, and switchyard breaker failure rate; (2) evaluated the conditional CDF and LERF; and (3) calculated ICCDF and ICLERF for the one-time 35-day AOT. However, the identified parameter uncertainties, as well as the approach for the corresponding sensitivity, appear to be similar to the model uncertainty identified by the licensee.

In response to RAI 05 (Reference 4), the licensee justified the selection of the three parameters – switchyard bus failure rate, offsite power transformer failure rate, and switchyard breaker failure rate, because these three parameters were used in the calculation to determine the LOOP frequency increase. The PRA model uncertainty was assessed using the model uncertainty parameter LOOP non-recovery probability, which affects base case as well as application-specific risk values. The licensee provided a new sensitivity study that combines the parameter and model uncertainties into one study. The results for ICCDP and ICLERP values are 4.4E-08 and 5.9E-09, respectively, which meet the RG 1.177 acceptance criteria with margin.

The NRC staff finds that the results are robust considering the uncertainty and, therefore, are acceptable to the extent needed to support this application.

Based on the review of the licensee's LAR, as supplemented, the NRC staff finds the licensee performed its Tier 1 risk evaluation in accordance with the regulatory position specified in RG 1.177 and is acceptable to the extent needed to support this application.

3.2.5.2 Tier 2 Evaluation – Avoidance of Risk-Significant Plant Configurations

Section C.2.3 of RG 1.177 discusses Tier 2 of the three-tiered approach for evaluating risk associated with the proposed change to TS CT. According to Tier 2, the avoidance of risk-significant plant configurations limits potentially high-risk configurations that could exist if equipment, in addition to that associated with the proposed change, is simultaneously removed from service or other risk-significant operational factors such as concurrent system or equipment testing, are involved. Therefore, a licensee's Tier 2 evaluation should identify the dominant risk-significant configurations relevant to the proposed TS CT change and ensure appropriate restrictions are placed on these configurations (e.g., assess whether certain enhancements to the TSs or procedures are needed to avoid these plant configurations). In addition, compensatory measures that can mitigate any corresponding increase in risk should be identified and evaluated.

Based on configuration-specific insights provided in LAR Attachment 1, Section 4.4.1, the licensee performed analyses to identify risk-significant combinations of equipment out of service during the extended time and identified further compensatory actions and restrictions for entry into the extended CT to avoid high-risk equipment out-of-service combinations during that time. In addition, the licensee provided a list of SSCs whose unavailability should be minimized during the CT based upon a review of the quantification results to identify significant equipment outage contributors to CDF and LERF. However, the approach used by the licensee to identify the compensatory actions was not provided initially in the LAR. In response to NRC's RAI 07 (Reference 4), the licensee provided the approach, which used risk importance measures from the PRA model, to determine the equipment for Tier 2 restrictions. The licensee's discussion included examples of the correspondence between the identified compensatory actions and the parameters used for identification. Based on configuration-specific insights, the licensee provided a list of SSCs whose unavailability should be minimized during the CT based upon Fussell-Vesely importance measures. In response to RAI 05 (Reference 4), the licensee indicated there are no additional Tier 2 restrictions or any additional compensatory actions beyond those identified in the LAR. The licensee further updated the risk management action item 6 to ensure that the identified Tier 2 equipment will be verified to be operable/functional, and positive measures will be provided to preclude subsequent testing or maintenance activities on the equipment (Reference 5).

The NRC staff finds that the licensee provided adequate analyses of risk-significant configurations during the extended CT and identified appropriate compensatory actions that can mitigate corresponding increases in risk. Therefore, the NRC staff concludes that the licensee's analysis of risk-significant combinations and identification of compensatory actions is consistent with RG 1.177 and provides reasonable assurance that risk-significant plant equipment outage configurations will be avoided during the extended CT.

3.2.5.3 Tier 3 Evaluation – Risk-Informed Configuration Risk Management

Section C.2.3 of RG 1.177 discusses Tier 3 of the three-tiered approach for evaluating risk associated with the proposed change to TS CT. Tier 3 is the establishment of an overall configuration risk management program to ensure other potentially lower probability, but nonetheless, risk-significant configurations resulting from maintenance and other operational activities are identified and managed. Because the Maintenance Rule, as codified in 10 CFR 50.65(a)(4) requires licensees to assess and manage the potential increase in risk that may result from activities, such as surveillance testing and corrective and preventive maintenance, a licensee may use its existing Maintenance Rule program to satisfy Tier 3.

The licensee stated in LAR Attachment 1, Section 4.4.1, that MPS2 has an established configuration risk management program that implements 10 CFR 50.65(a)(4) requirements. DENC has implemented real-time risk assessment technology utilizing Electric Power Research Institute-developed software. The software is run continuously with a unit at-power by the on-shift shift technical advisor to ensure that risk appropriately managed prior to entering any plant configuration and when emergent equipment failure occur. Thus, plant risk will be effectively managed prior to and during the extended CT.

Based on its review, the NRC staff finds the licensee's Tier 3 program is consistent with the guidance in RG 1.177 and, thus, is acceptable.

Key Principle 4 Conclusion

In summary, the NRC staff finds that the licensee has demonstrated that the MPS2 PRA models are technically acceptable to the extent needed to support this application. The risk increase from the proposed change meets the acceptance guidelines in RG 1.177. The NRC staff finds that the licensee has followed the three-tiered approach outlined in RG 1.177 to evaluate the risk associated with the proposed TS CT change and, therefore, the proposed TS change satisfies the fourth key principle of RG 1.174.

3.2.6 Key Principle 5: Performance Measurement Strategies – Implementation and Monitoring Program

RG 1.174 and RG 1.177 establish the need for an implementation and monitoring program to ensure that no adverse safety degradation occurs because of the changes to the TSs. An implementation and monitoring program is intended to ensure that the impact of the proposed TS change continues to reflect the reliability and availability of SSCs impacted by the change.

RG 1.177 states that the licensee is to use a three-tiered approach in implementing the proposed TS CT change. Application of the three-tiered approach is in keeping with the fundamental principle that the proposed change is consistent with the defense-in-depth philosophy. Application of the three-tiered approach provides assurance that defense in depth will not be significantly impacted by the proposed change. Furthermore, RG 1.177 states that,

to ensure that extension of a TS CT does not degrade operational safety over time, the licensee should ensure, as part of its Maintenance Rule (10 CFR 50.65), that when equipment does not meet its performance criteria, the evaluation required under the Maintenance Rule includes prior related TS changes in its scope.

The licensee provides an evaluation of the proposed TS change against the three-tiered approach in Section 4.4.1 of LAR Attachment 1. The licensee proposes a list of equipment to be protected during the proposed TS change. The identified equipment is protected in accordance with the protected equipment procedures for MPS2 and MPS3. These procedures provide instructions for usage of barriers, signs, logs, walkdowns, and other considerations for protecting equipment.

Key Principle 5 Conclusion

Based on its review, the staff finds the licensee's implementation and monitoring program ensures that the impact of the proposed TS change continues to reflect the reliability and availability of SSCs impacted by the change. The proposed change is consistent with the defense-in-depth philosophy and meets the acceptance guidelines in RG 1.177. The NRC staff finds that the licensee has followed the three-tiered approach outlined in RG 1.177 such that the defense-in-depth will not be significantly impacted by the proposed TS CT change.. Therefore, the NRC staff concludes that the implementation and monitoring program for the proposed TS change described by the licensee satisfies the fifth key principle of RG 1.174.

3.2.7 Risk Evaluation Conclusion

The NRC staff reviewed the proposed change to MPS2 TS 3.8.1.1 in the LAR to add a one-time exception to the new proposed Required Action a.3 that would extend the AOT to 35 days for one inoperable offsite circuit.

Based on its evaluation of the proposed change to MPS2 TS 3.8.1.1 in the LAR, as supplemented, the NRC staff concludes that the licensee's request to revise MPS2 TS 3.8.1.1 for a one-time exception of AOT for 35 days follows the three-tiered approach and performance monitoring programs outlined in RG 1.177 and meets the five key principles of risk-informed decisionmaking outlined in RG 1.174. The NRC staff concludes that there is reasonable assurance that the proposed one-time change to the TS AOT will have minimal impact on the licensee's ability to continue to comply with the requirements of 10 CFR 50.36, GDC 5, GDC 17, and GDC 18.

4.0 REGULATORY COMMITMENT

The licensee submitted the following regulatory commitment in the October 22, 2019, supplemental LAR (Reference 2):

> DENC will add steps to emergency operating procedure(s) (EOP(s)) for Station Blackout response to specifically direct operators to the appropriate EOP for reaching cold shutdown with AC power supplied by the Station Blackout diesel generator, before this LAR is fully implemented.

The NRC staff does not rely on regulatory commitments in its basis for the regulatory approval of the proposed change. Regulatory commitments specify the items for which the licensees volunteer to perform in support of their licensing applications. Regulatory commitments do not

require prior NRC approval of subsequent changes and, therefore, they are not enforceable licensing requirements. Section 3.2.3.6 of this SE provides a discussion of the staff's defense-in-depth evaluation in terms of the operator response for the SBO event scenario as applied to emergency operating procedures.

5.0 STATE CONSULTATION

In accordance with the Commission's regulations, the Connecticut State official was notified of the proposed issuance of the amendment on May 7, 2020. The State official had no comments.

6.0 ENVIRONMENTAL CONSIDERATION

The amendment changes a requirement with respect to the installation or use of facility components located within the restricted area as defined in 10 CFR Part 20 or changes surveillance requirements. The NRC staff has determined that the amendment involves no significant increase in the amounts and no significant change in the types of any effluents that may be released offsite and that there is no significant increase in individual or cumulative occupational radiation exposure. The Commission has previously issued a proposed finding, which was published in the Federal Register on December 31, 2019 (84 FR 72387), that the amendment involves no significant hazards consideration, and there has been no public comment on such finding. Accordingly, the amendment meets the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b), no environmental impact statement or environmental assessment need be prepared in connection with the issuance of the amendment.

7.0 CONCLUSION

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

8.0 REFERENCES

1. Letter from M. D. Sartain, Dominion Energy Nuclear Connecticut, Inc., to U.S. NRC, "Millstone Power Station Unit 2 License Amendment Request to Revise TS 3.8.1.1, "A.C. Sources – Operating," to Support Maintenance and Replacement of the Millstone Unit 3 'A' Reserve Station Service Transformer and 345 kV South Bus Switchyard Components," August 14, 2019 (ADAMS Accession No. ML19234A111).

2. Letter from M. D. Sartain, Dominion Energy Nuclear Connecticut, Inc, to U.S. NRC., "Millstone Power Station Unit 2 Supplement to Proposed License Amendment Request to Revise TS 3.8.1.1, "A.C. Sources – Operating," to Support Maintenance and Replacement of the Millstone Unit 3 'A' Reserve Station Service Transformer and 345 kV South Bus Switchyard Components," October 22, 2019 (ADAMS Accession No. ML19304A294).

3. Letter from M. D. Sartain, Dominion Energy Nuclear Connecticut, Inc., to U.S. NRC, "Response to Request for Additional Information for License Amendment Request to Revise TS 3.8.1.1, "A.C. Sources – Operating," to Support Maintenance and Replacement of the

Millstone Unit 3 ‘A’ Reserve Station Service Transformer and 345 kV South Bus Switchyard Components,” February 11, 2020 (ADAMS Accession No. ML20048A019).

4. Letter from M. D. Sartain, Dominion Energy Nuclear Connecticut, Inc., to U.S. NRC, “Response to Request for Additional Information Regarding License Amendment Request to Revise TS 3.8.1.1, “A.C. Sources – Operating,” to Support Maintenance and Replacement of the Millstone Unit 3 ‘A’ Reserve Station Service Transformer and 345 kV South Bus Switchyard Components,” March 19, 2020 (ADAMS Accession No. ML20079K424).

5. Letter from M. D. Sartain, Dominion Energy Nuclear Connecticut, Inc., to U.S. NRC, “Supplement to License Amendment Request to Revise TS 3.8.1.1, “A.C. Sources – Operating,” to Support Maintenance and Replacement of the Millstone Unit 3 ‘A’ Reserve Station Service Transformer and 345 kV South Bus Switchyard Components,” April 14, 2020 (ADAMS Accession No. ML20105A078).

6. Regulatory Guide 1.174, Revision 3, “An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis,” January 2018 (ADAMS Accession No. ML17317A256).

7. Regulatory Guide 1.177, Revision 1, “An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications,” May 2011 (ADAMS Accession No. ML100910008).

8. Regulatory Guide 1.200, Revision 2, “An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities,” March 2009 (ADAMS Accession No. ML090410014).

9. NUREG-0800, Branch Technical Position 8-8, “Onsite (Emergency Diesel Generators) and Offsite Power Sources Allowed Outage Time Extensions,” February 2012 (ADAMS Accession No. ML113640138).

10. Letter from M. D. Sartain, Dominion Energy Nuclear Connecticut, Inc, to U.S. NRC, “Millstone Power Station Unit 2 Application to Adopt 10 CFR 50.69, Risk-Informed Categorization and Treatment of Structures, Systems, and Components for Nuclear Power Reactors,” January 17, 2019 (ADAMS Accession No. ML19023A427).

11. Letter from R. V. Guzman, U.S. NRC to D. G. Stoddard, Dominion Energy Nuclear Connecticut, Inc, “Millstone Power Station Unit 2 – Issuance of Amendment No. 337 Re: Adoption of 10 CFR 50.69, “Risk-Informed Categorization and Treatment of Structures, Systems and Components of Nuclear Power Reactors,” January 30, 2020 (ADAMS Accession No. ML19340A025).

12. Letter from V. Andersen, Nuclear Energy Institute, to S. Rosenberg, U.S. NRC, “Final Revision of Appendix X to NEI 05-04/07-12/12-16, Close-Out of Facts and Observations (F&Os),” February 21, 2017 (ADAMS Package Accession No. ML17086A431).

13. Nuclear Energy Institute, “Process for Performing Internal Events PRA Peer Reviews Using the ASME/ANS PRA Standard,” NEI 05-04, Revision 2, November 2008 (ADAMS Accession No. ML083430462).

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16. Letter from J. Giitter and M. J. Ross-Lee, U.S. NRC, to G. Krueger, Nuclear Energy Institute, “U.S. Nuclear Regulatory Commission Acceptance on Nuclear Energy Institute Appendix X to Guidance 05-04, 07-12, and 12-13, Close-Out of Facts and Observations (F&Os),” May 3, 2017 (ADAMS Accession No. ML17079A427).

17. Letter from R. V. Guzman, U.S. NRC to S. Sinha, “Millstone Unit 2 – Request for Additional Information: License Amendment Request to Revise TS 3.8.1.1, A.C. Sources – Operating [EPID: L-2019-LLA-0177],” February 19, 2020 (ADAMS Accession No. ML20050F921).

18. NUREG 1855, Revision 1, “Guidance on the Treatment of Uncertainties Associated with PRAs in Risk-Informed Decisionmaking, Final Report,” March 2017 (ADAMS Accession No. ML17062A466).

19. Letter from M. D. Sartain, Dominion Energy Nuclear Connecticut, Inc, to U.S. NRC, “Millstone Power Station Unit 2 License Amendment Request to Adopt 10 CFR 50.69 Response to NRC Request for Additional Information,” October 3, 2019 (ADAMS Accession No. ML19284A397).

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Date: June 24, 2020

SUBJECT: MILLSTONE POWER STATION, UNIT NO. 2 – ISSUANCE OF AMENDMENT NO. 339 RE: EXTENSION OF TECHNICAL SPECIFICATION 3.8.1.1, "A.C. SOURCES – OPERATING," ALLOWED OUTAGE TIME (EPID L-2019-LLA-0177) DATED JUNE 24, 2020

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