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

September 18, 2020

Ms. Cheryl A. Gayheart
Regulatory Affairs Director
Southern Nuclear Operating Co., Inc.
3535 Colonnade Parkway
Birmingham, AL 35243

SUBJECT: EDWIN I. HATCH NUCLEAR PLANT, UNIT NOS. 1 AND 2 - ISSUANCE OF AMENDMENTS NOS. 307 AND 252, REGARDING LICENSE AMENDMENT REQUEST TO REVISE THE REQUIRED ACTIONS OF TECHNICAL SPECIFICATIONS 3.8.1, "AC [ALTERNATING CURRENT] SOURCES – OPERATING," FOR ONE-TIME EXTENSION OF COMPLETION TIME FOR UNIT 1 AND SWING EMERGENCY DIESEL GENERATORS (EPID L-2020-LLA-171)

Dear Ms. Gayheart:

The Nuclear Regulatory Commission (NRC) has issued the enclosed Amendment No. 307 to Renewed Facility Operating License No. DPR-57 and Amendment No. 252 to Renewed Facility Operating License No. NPF-5 for the Edwin I. Hatch Nuclear Plant (Hatch), Unit Nos 1 and 2, respectively. The amendments consist of changes to the Technical Specifications (TSs) in response to your application dated July 31, 2020, as supplemented August 23, 2020.

The amendments revise TS 3.8.1, "AC Sources – Operating," to provide a one-time extension of the completion time of Required Action B.4 for Hatch, Unit 1, TS and Required Actions B.4 and C.4 for Hatch, Unit 2, TS for each Hatch, Unit 1, emergency diesel generator (EDG) and the swing EDG from 14 days to 19 days.

The amendment is risk-informed and follows the guidance in NRC Regulatory Guide (RG) 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," Revision 3, and NRC RG 1.177, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications," Revision 1.

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

If you have questions, you can contact via phone at 301-415-3100 or via email at John.Lamb@nrc.gov.

Sincerely,

/RA/

John G. Lamb, Senior Project Manager
Plant Licensing Branch II-1
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket Nos. 50-321 and 50-366

Enclosures:
1. Amendment No. 307 to DPR-57
2. Amendment No. 252 to NPF-5
3. Safety Evaluation

cc: Listserv

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NUCLEAR REGULATORY COMMISSION
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SOUTHERN NUCLEAR OPERATING COMPANY, INC.

GEORGIA POWER COMPANY

OGLETHORPE POWER CORPORATION

MUNICIPAL ELECTRIC AUTHORITY OF GEORGIA

CITY OF DALTON, GEORGIA

DOCKET NO. 50-321

EDWIN I. HATCH NUCLEAR PLANT, UNIT NO. 1

AMENDMENT TO RENEWED FACILITY OPERATING LICENSE

Amendment No. 307
Renewed License No. DPR-57

1. The Nuclear Regulatory Commission (NRC, the Commission) has found that:

   A. The application for amendment to the Edwin I. Hatch Nuclear Plant, Unit No. 1 (the facility) Renewed Facility Operating License No. DPR-57 filed by Southern Nuclear Operating Company, Inc. (the licensee), acting for itself, Georgia Power Company, Oglethorpe Power Corporation, Municipal Electric Authority of Georgia, and City of Dalton, Georgia (the owners), dated July 31, 2020, as supplemented August 23, 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 as 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 set forth in 10 CFR Chapter I;

   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 hereby amended by page 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-57 is hereby amended to read as follows:

(2) Technical Specifications

The Technical Specifications (Appendix A) and the Environmental Protection Plan (Appendix B), as revised through Amendment No. 307, are hereby incorporated in the renewed license. Southern Nuclear shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

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

FOR THE NUCLEAR REGULATORY COMMISSION

Glenn E. Miller

Digitally signed by Glenn E. Miller
Date: 2020.09.18 16:40:38 -04'00'

Michael T. Markley, Chief
Plant Licensing Branch II-1
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Attachment:
Changes to Renewed Facility Operating License No. DPR-57 and Technical Specifications

Date of Issuance: September 18, 2020

ATTACHMENT TO LICENSE AMENDMENT NO. 307

EDWIN I. HATCH NUCLEAR PLANT, UNIT NO. 1

RENEWED FACILITY OPERATING LICENSE NO. DPR-57

DOCKET NO. 50-321

Replace the following pages of the License and the Appendix A Technical Specifications (TSs) with the attached revised pages. The revised pages are identified by amendment number and contain marginal lines indicating the areas of change.

Remove Pages	Insert Pages
License	License
4	4
TSs	TSs
3.8-3	3.8-3
3.8-4	3.8-4a
-------	3.8-4b

for sample analysis or instrumentation calibration, or associated with radioactive apparatus or components

(6) Southern Nuclear, 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 license shall be deemed to contain, and is subject to, the conditions specified in the following Commission regulations in 10 CFR Chapter I: Part 20, Section 30.34 of Part 30, Section 40.41 of Part 40, Section 50.54 of Part 50, and Section 70.32 of Part 70; all applicable provisions of the Act and the rules, regulations, and orders of the Commission now or hereafter in effect; and the additional conditions[2] specified or incorporated below:

(1) Maximum Power Level

Southern Nuclear is authorized to operate the facility at steady state reactor core power levels not in excess of 2804 megawatts thermal.

(2) Technical Specifications

The Technical Specifications (Appendix A) and the Environmental Protection Plan (Appendix B); as revised through Amendment No. 307 are hereby incorporated in the renewed license. Southern Nuclear shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

The Surveillance Requirement (SR) contained in the Technical Specifications and listed below, is not required to be performed immediately upon implementation of Amendment No. 195. The SR listed below shall be successfully demonstrated before the time and condition specified:

SR 3.8.1.18 shall be successfully demonstrated at its next regularly scheduled performance.

(3) Fire Protection

Southern Nuclear shall implement and maintain in effect all provisions of the fire protection program, which is referenced in the Updated Final Safety Analysis Report for the facility, as contained in the updated Fire Hazards Analysis and Fire Protection Program for the Edwin I. Hatch Nuclear Plant, Units 1 and 2, which was originally submitted by letter dated July 22, 1986. Southern Nuclear may make changes to the fire protection program without prior Commission approval only if the changes

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. (continued)	B.2	Declare required feature(s), supported by the inoperable DG, inoperable when the redundant required feature(s) are inoperable.	4 hours from discovery of Condition B concurrent with inoperability of redundant required feature(s)
	AND		
	B.3.1	Determine OPERABLE DG(s) are not inoperable due to common cause failure.	24 hours
	OR		
	B.3.2	Perform SR 3.8.1.2.a for OPERABLE DG(s).	24 hours
	AND		
	B.4.1	Restore DG to OPERABLE status.	72 hours for a Unit 1 DG with the swing DG not inhibited or maintenance restrictions not met AND 14 days for a Unit 1 DG with the swing DG inhibited from automatically aligning to Unit 2 and maintenance restrictions met AND 72 hours for the swing diesel with maintenance restrictions not met
			(continued)

ACTIONS

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

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. One required Unit 2 DG inoperable	C.1	Perform SR 3.8.1.1 for OPERABLE required offsite circuit(s).	1 hour AND Once per 8 hours thereafter
	AND		
	C.2	Declare required feature(s), supported by the inoperable DG, inoperable when the redundant required feature(s) are inoperable.	4 hours from discovery of Condition C concurrent with inoperability of redundant required feature(s)
	AND		
	C.3.1	Determine OPERABLE DG(s) are not inoperable due to common cause failure.	24 hours
	OR		
	C.3.2	Perform SR 3.8.1.2.a for OPERABLE DG(s).	24 hours
			(continued)

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SOUTHERN NUCLEAR OPERATING COMPANY, INC.

GEORGIA POWER COMPANY

OGLETHORPE POWER CORPORATION

MUNICIPAL ELECTRIC AUTHORITY OF GEORGIA

CITY OF DALTON, GEORGIA

DOCKET NO. 50-366

EDWIN I. HATCH NUCLEAR PLANT, UNIT NO. 2

AMENDMENT TO RENEWED FACILITY OPERATING LICENSE

Amendment No. 252
Renewed License No. NPF-5

1. The Nuclear Regulatory Commission (NRC, the Commission) has found that:

    A. The application for amendment to the Edwin I. Hatch Nuclear Plant, Unit No. 2 (the facility) Renewed Facility Operating License No. NPF-5 filed by Southern Nuclear Operating Company, Inc. (the licensee), acting for itself, Georgia Power Company, Oglethorpe Power Corporation, Municipal Electric Authority of Georgia, and City of Dalton, Georgia (the owners), dated July 31, 2020, as supplemented August 23, 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 as 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 set forth in 10 CFR Chapter I;

    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 hereby amended by page 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. NPF-5 is hereby amended to read as follows:

(2) Technical Specifications

The Technical Specifications (Appendix A) and the Environmental Protection Plan (Appendix B), as revised through Amendment No. 252 are hereby incorporated in the renewed license. Southern Nuclear shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

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

FOR THE NUCLEAR REGULATORY COMMISSION

Glenn E. Miller

Digitally signed by Glenn E. Miller
Date: 2020.09.18 16:41:05 -04'00'

Michael T. Markley, Chief
Plant Licensing Branch II-1
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Attachment:
Changes to Renewed Facility Operating License No. NPF-5 and Technical Specifications

Date of Issuance: September 18, 2020

ATTACHMENT TO LICENSE AMENDMENT NO. 252

EDWIN I. HATCH NUCLEAR PLANT, UNIT NO. 2

RENEWED FACILITY OPERATING LICENSE NO. NPF-5

DOCKET NO. 50-366

Replace the following pages of the License and the Appendix A Technical Specifications (TSs) with the attached revised pages. The revised pages are identified by amendment number and contain marginal lines indicating the areas of change.

Remove Pages	Insert Pages
License	License
4	4
TSs	TSs
3.8-3	3.8-3
3.8-4	3.8-4a
-------	3.8-4b
3.8-5	3.8-5a
-------	3.8-5b

(6) Southern Nuclear, 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 license shall be deemed to contain, and is subject to, the conditions specified in the following Commission regulations in 10 CFR Chapter I: Part 20, Section 30.34 of Part 30, Section 40.41 of Part 40, Section 50.54 of Part 50, and Section 70.32 of Part 70; all applicable provisions of the Act and the rules, regulations, and orders of the Commission now or hereafter in effect; and the additional conditions[2] specified or incorporated below:

(1) Maximum Power Level

Southern Nuclear is authorized to operate the facility at steady sate reactor core power levels not in excess of 2,804 megawatts thermal, in accordance with the conditions specified herein.

(2) Technical Specifications

The Technical Specifications (Appendix A) and the Environmental Protection Plan (Appendix B); as revised through Amendment No. 252 are hereby incorporated in the renewed license. Southern Nuclear shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

(3) Additional Conditions

The matters specified in the following conditions shall be completed to the satisfaction of the Commission within the stated time periods following the issuance of the renewed license or within the operational restrictions indicated. The removal of these conditions shall be made by an amendment to the license supported by a favorable evaluation by the Commission.

(a) Fire Protection

Southern Nuclear shall implement and maintain in effect all provisions of the fire protection program, which is referenced in the Updated Final Safety Analysis Report for the facility, as contained

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[2] The original licensee authorized to possess, use, and operate the facility with Georgia Power Company (GPC). Consequently, certain historical references to GPC remain in certain license conditions.

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. (continued)	B.2 Declare required feature(s), supported by the inoperable DG, inoperable when the redundant required feature(s) are inoperable.	4 hours from discovery of Condition B concurrent with inoperability of redundant required feature(s)
	AND	
	B.3.1 Determine OPERABLE DG(s) are not inoperable due to common cause failure.	24 hours
	OR	
	B.3.2 Perform SR 3.8.1.2.a for OPERABLE DG(s)	24 hours
	AND	
	B.4.1 Restore DG to OPERABLE status.	72 hours for a Unit 2 DG with the swing DG not inhibited or maintenance restrictions not met AND 14 days for a Unit 2 DG with the swing DG inhibited from automatically aligning to Unit 1 and maintenance restrictions met AND 72 hours for the swing diesel with maintenance restrictions not met
		(continued)

ACTIONS

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

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. One required Unit 1 DG inoperable.	C.1	Perform SR 3.8.1.1 for OPERABLE required offsite circuit(s).	1 hour <u>AND</u> Once per 8 hours thereafter
	<u>AND</u>		
	C.2	Declare required feature(s), supported by the inoperable DG, inoperable when the redundant required feature(s) are inoperable.	4 hours from discovery of Condition C concurrent with inoperability of redundant required feature(s)
	<u>AND</u>		
	C.3.1	Determine OPERABLE DG(s) are not inoperable due to common cause failure.	24 hours
	<u>OR</u>		
	C.3.2	Perform SR 3.8.1.2.a for OPERABLE DG(s).	24 hours
			(continued)

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
C. (continued)	AND	
	C.4.1 Restore required DG to OPERABLE status.	7 days with the swing DG not inhibited or maintenance restrictions not met AND 14 days with the swing DG inhibited from automatically aligning to Unit 2 and maintenance restrictions met
	OR	
	------------------NOTES---------------- 1. Only applicable during diesel engine cylinder liner replacement outage. 2. Only applicable once per DG. 3. Only applicable until June 30, 2021. ---	
	C.4.2.1 Establish compensatory and risk management controls for extended DG outage as specified in Attachment 5 of SNC letter NL-20-1000, dated August 23, 2020.	7 days AND 24 hours thereafter from discovery of compensatory or risk management control not met
	AND	
	C.4.2.2 Inhibit swing DG from automatically aligning to Unit 2.	7 days
	AND	
	C.4.2.3 Restore DG to OPERABLE status.	19 days

(continued)

ACTIONS (continued)

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

(continued)

UNITED STATES
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WASHINGTON, D.C. 20555-0001

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO

AMENDMENT NO. 307 TO FACILITY OPERATING LICENSE NO. DPR-57

AND

AMENDMENT NO. 252 TO FACILITY OPERATING LICENSE NO. NPF-5

SOUTHERN NUCLEAR OPERATING COMPANY

EDWIN I. HATCH NUCLEAR PLANT, UNITS 1 AND 2

DOCKET NOS. 50-321 AND 50-366

1.0 INTRODUCTION AND PROPOSED CHANGE

By application dated July 31, 2020 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML20213C715), as supplemented by letter dated August 23, 2020 (ADAMS Accession No. ML20236S786), Southern Nuclear Operating Company, Inc. (SNC, the licensee), requested changes to the Technical Specifications (TSs) for the Edwin I. Hatch Nuclear Plant (Hatch), Units 1 and 2.

The proposed changes would revise TS 3.8.1, "AC [Alternating Current] Sources – Operating," for Hatch, Units 1 and 2, to provide a one-time extension of the completion time (CT) of Required Action B.4 for the Hatch, Unit 1, TS and Required Actions B.4 and C.4 for the Hatch, Unit 2, TS for each Hatch, Unit 1, emergency diesel generator (EDG) and the swing EDG, from 14 days to 19 days.

The proposed changes are risk-informed and follow the guidance in NRC Regulatory Guide (RG) 1.174, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," Revision 3, and NRC RG 1.177, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications," Revision 1, both of which are described in Section 2.0 below.

The supplement dated August 23, 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, the Commission) staff's original proposed no significant hazards consideration determination as published the *Federal Register* on August 14, 2020 (85 FR 49687).

System Description

The following description of the Hatch AC power system is reproduced from the licensee's July 31, 2020, license amendment request (LAR):

> …Offsite power is supplied to the station from the 230 kV [kilovolt] ring bus by five electrically and physically separate feeds through startup auxiliary transformers (SATs) 1C and 2C (via a common switchyard feed), 1D, 1E, 2D, and 2E, to the respective unit 4.16 kV engineered safety feature (ESF) buses E, F, and G. Each SAT provides the normal source of power to its respective ESF bus. If any 4.16 kV ESF bus loses power, an automatic transfer occurs from the normal offsite power source to its alternate offsite power source. By design, no single SAT can supply more than two 4.16 kV ESF buses simultaneously.
>
> Onsite standby emergency power is supplied by independent DGs [diesel generators], with 4.16 kV ESF Buses E and G each supplied by a dedicated unit DG and the 4.16 kV ESF Bus F on both units supplied by the swing DG (i.e., DG 1B). The swing DG cannot supply both F buses simultaneously. …

Current TSs

The current Hatch, Unit 1, TSs are contained in "Appendix A, Technical Specifications, Unit 1" attached to Renewed Facility Operating License DPR-57 (ADAMS Accession No. ML052930172). The current Hatch, Unit 2, TSs are contained in "Appendix A, Technical Specifications, Unit 2" attached to Renewed Facility Operating License DPF-5 (ADAMS Accession No. ML052930177).

Proposed TS Changes

The proposed TS changes are contained in Attachment 1 of the SNC supplement dated August 23, 2020.

2.0 REGULATORY EVALUATION

The NRC staff considered the following regulatory requirements, guidance, and licensing and design-basis information during its review of the proposed changes.

The regulations at Title 10 of the Code of Federal Regulations (10 CFR), Part 50, Section 36(a)(1) state, in part, that each applicant for an operating license shall include in the application proposed TSs in accordance with the requirements of 10 CFR 50.36, "Technical specifications." Section 50.36(c) of 10 CFR requires that the TSs include items in the following categories related to station operation: (1) safety limits, limiting safety system settings, and limiting control settings; (2) limiting conditions for operation (LCOs); (3) surveillance requirements; (4) design features; and (5) administrative controls. Section 50.36(c)(2) of 10 CFR states, in part, that when an LCO is not met, the licensee shall shut down the reactor or follow any remedial action permitted by the TSs until the condition can be met.

The regulations at 10 CFR 50.63, "Loss of all alternating current power," require, 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 regulations at 10 CFR 50.65(a)(4) require, in part, that before performing maintenance activities, the licensee shall assess and manage the increase in risk that may result from the proposed maintenance activities.

The Hatch, Unit 1, emergency power system was designed to the following applicable Atomic Energy Commission preliminary general design criteria (GDC) identified in *Federal Register* at 32 FR 10213, published July 11, 1967 (ADAMS Accession No. ML043310029):

> Criterion 39 – Emergency Power for Engineered Safety Features (Category A): Alternate power systems shall be provided and designed with adequate Independency, redundancy, capacity, and testability to permit the functioning required of the engineered safety features. As a minimum, the onsite power system and the offsite power system shall each, independently, provide this capacity assuming a failure of a single active component in each power system.

The Hatch, Unit 2, onsite emergency power system was designed to the following 10 CFR Part 50, Appendix A GDC for Nuclear Power Plants:

- GDC 17, "Electric Power Systems," of Appendix A to 10 CFR Part 50, requires, in part, that an onsite electric power system shall be provided to permit functioning of structures, systems, and components important to safety. The onsite electric power supplies and the onsite electric distribution system shall have sufficient independence, redundancy, and testability to perform their safety functions assuming a single failure. In addition, provisions shall be included to minimize the probability of losing electric power from any of the remaining supplies as a result of, or coincident with, the loss of power from the nuclear power unit, the transmission network, or the onsite electric power supplies.

- GDC 18, "Inspection and Testing of Electric Power Systems," requires, in part, that electric power systems important to safety be designed to permit appropriate periodic inspection and testing of important areas and features, to demonstrate operability and functional performance.

The NRC staff also reviewed the LAR based on the following regulatory guidance documents.

Regulatory Guide (RG) 1.93, "Availability of Electric Power Sources" (ADAMS Accession Nos. ML090550661 and ML090550693), provides guidance with respect to operating restrictions or completion time (CT) (referred to as allowed outage time (AOT) in this evaluation) if the number of available AC sources is less than that required by the TS Limiting Condition of Operation (LCO). In particular, this guide recommends a maximum CT of 72 hours for an inoperable onsite or offsite AC source.

RG 1.155, "Station Blackout" (ADAMS Accession No. ML003740034), provides guidance for complying with the requirements of 10 CFR 50.63, which require nuclear power plants to be capable of coping with an SBO event for a specified duration.

RG 1.174, Revision 3, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis" (ADAMS Accession No. ML17317A256), describes a risk-informed approach acceptable to the NRC for assessing the nature and impact of proposed licensing-basis changes by considering engineering issues and applying risk insights. This RG also 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” (ADAMS Accession No. ML100910008), describes an acceptable risk-informed approach specifically for assessing proposed one-time TS changes in CTs. This RG also provides risk acceptance guidelines for evaluating the results of such assessments and contains five key principles that TS changes should meet. They are: (1) the proposed change meets the current regulations unless it is explicitly related to a requested exemption or rule change; (2) the proposed change is consistent with the defense-in-depth philosophy; (3) the proposed change maintains sufficient safety margins; (4) when proposed changes result in an increase in core-damage frequency or 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 (Commission’s Safety Goal Policy Statement) (51 FR 28044; August 4, 1986 as corrected and republished at 51 FR 30028; August 21, 1986); and (5) the impact of the proposed change should be monitored using performance measurement strategies.

RG 1.177 provides the following three-tiered TS acceptance guidelines specific to one-time only CT changes for evaluating the risk associated with the revised CT:

1. The licensee has demonstrated that implementation of the one-time only TS CT change impact on plant risk is acceptable (Tier 1):

   - Incremental conditional core damage probability (ICCDP) damage probability of less than $1.0x10^{-6}$ and an incremental conditional large early release probability (ICLERP) of less than $1.0x10^{-7}$, or

   - An ICCDP of less than $1.0x10^{-5}$ and an ICLERP of less than $1.0x10^{-6}$ with effective compensatory measures implemented to reduce the sources of increased risk.

2. The licensee has demonstrated that there are appropriate restrictions on dominant risk-significant configurations associated with the change (Tier 2).

3. The licensee has implemented a risk-informed plant configuration control program. The licensee has implemented procedures to utilize, maintain, and control such a program (Tier 3).

RG 1.200, Revision 2, “An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities” (ADAMS Accession No. ML090410014), describes an acceptable approach for determining whether the quality of the probabilistic risk assessment (PRA) models, in total, or the parts that are used to support an application, is sufficient to provide confidence in the results such that the PRA models can be used in regulatory decision-making for light-water reactors.

NUREG-0800, “Standard Review Plan [SRP] Chapter 16.1, Revision 1, “Risk-Informed Decision Making: Technical Specifications" (ADAMS Accession No. ML070380228), for the Review of Safety Analysis Reports for Nuclear Power Plants: LWR [light-water reactor] Edition states that licensees submitting risk information should address each of the principles of risk-informed regulation addressed in RG 1.177.

NUREG-0800, Branch Technical Position (BTP) 8-8, “Onsite (Emergency Diesel Generators) and Offsite Power Sources Allowed Outage Time Extensions,” dated February 2012 (ADAMS

Accession No. ML113640138), provides guidance to the NRC staff in reviewing LARs for licensees proposing a one-time or permanent TS change to extend an EDG allowed outage time (AOT) beyond 72 hours.

NUREG-0800, “Standard Review Plan [SRP] Chapter 19, Section 19.2, “Review of Risk Information Used to Support Permanent Plant-Specific Changes to the Licensing Basis: General Guidance” (ADAMS Accession No. ML071700658), provides general guidance for evaluating the technical basis for proposed risk-informed changes that envelop one-time changes. Guidance on evaluating PRA technical adequacy is provided in Section 19.1, “Determining the Technical Adequacy of Probabilistic Risk Assessment for Risk-Informed License Amendment Requests After Initial Fuel Load” (ADAMS Accession No. ML12193A107).

Nuclear Management and Resources Council (NUMARC) 87-00, “Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors” (ADAMS Accession No. ML102710587), provides: (1) a set of baseline assumptions concerning the course and nature of a station blackout, (2) guidance for determining the required coping duration category consistent with the NRC Staff’s draft RG 1.155, (3) guidelines for assuring plant specific procedures adequately address station blackout response, and (4) a simplified methodology for reviewing basic plant coping features.

3.0 TECHNICAL EVALUATION

The NRC staff evaluated the licensee’s application to determine if the proposed changes are consistent with the guidance, regulations, and plant-specific design and licensing basis information discussed in Section 2.0 of this safety evaluation (SE).

3.1 Deterministic Evaluation of Proposed Changes and Risk Management Controls Technical Review

Onsite standby emergency power at Hatch, Units 1 and 2, is supplied by five independent EDGs, with 4.16 kV ESF Buses E and G each supplied by a dedicated unit EDG and the 4.16 kV ESF Bus F on both units supplied by the swing EDG (i.e., EDG 1B). In the event of a loss of offsite power (LOOP) or LOOP concurrent with a design basis accident (DBA) with a single failure of an EDG, two EDGs per unit can fully provide the required safety functions to support unit shutdown and cooldown to cold conditions and remain in cold shutdown conditions for 30 days.

The LAR proposes changes to TS 3.8.1, “AC Sources –Operating,” to provide a one-time extension of the CT of Required Action B.4 (Unit 1 TS) and Required Actions B.4 and C.4 (Unit 2 TS) of TS 3.8.1 for each Unit 1 EDG (1A and 1C) and the swing EDG (1B) from 14 days to 19 days. The licensee stated that this one-time TS change is a necessary contingency to support preventative maintenance activities, including replacement of the diesel engine cylinder liners. In addition, since the EDGs are greater than 40 years old, the licensee stated that it is possible that unforeseen engine or generator degradation will be discovered during the disassembly which could require more time to repair and restore the EDG. The current schedule does not provide sufficient margin to support discovery, repair, and restoration of unforeseen EDG component degradations, such as a cracked crank or cam shaft, cracked piston rod, or degraded stator winding. The licensee summarized the maintenance tasks to be performed for EDG 1B and estimated the expected duration for each task. LAR Table 2.3-1 includes contingent tasks with estimated durations to complete these tasks. These tasks and durations are comparable to those expected for the maintenance outages of the Unit 1 EDGs. Based on the past experience and lessons learned, the NRC staff finds that although the proposed CT is beyond the BTP-8-8

14-day limit, the licensee's estimates for the time required to complete the EDG maintenance on the other Unit 1 EDGs is reasonable. The NRC staff finds the licensee's justification for the estimate for the AOT extension duration consistent with the BTP 8-8 guidance.

In the LAR, the licensee stated that the proposed extended EDG CTs for Units 1 and 2 are expected to be performed in operational Mode 1. During the extended CT duration, none of the offsite power sources are affected by the planned EDG maintenance and will remain operable. Also, to improve defense-in-depth and minimize risk of a loss of all offsite power during the extended EDG AOT, offsite electrical power system diversity is maximized by requiring all three circuits (i.e., SATs and associated circuit paths to the 4.16 kV ESF buses) per unit to be maintained operable and automatic transfer capability to all three 4.16 kV ESF buses per unit to be maintained operable. Additionally, to minimize the risk of a LOOP to Hatch during the extended EDG outage, daily communication with the electrical system load dispatcher will be required to ensure multiple line contingencies are available. During the extended EDG outage, Hatch operations management will consider a plant shutdown when offsite electrical system stability has eroded to a single contingency, provided the plant shutdown does not result in a further destabilization of the offsite electrical power system network.

Additionally, the licensee stated that only one EDG will be removed from service at a time. Since the safety analysis assumes a single failure (e.g., failure of an EDG to start or the loss of a single 4.16 kV ESF bus), the one-time extension of the CT for an inoperable EDG has no impact on the system design basis. Also, the licensee stated that the proposed change does not alter the design, operation, or testing acceptance criteria of the EDGs. Minimum AC power sources credited in the accident analyses are not altered by the proposed change. Therefore, the safety analyses acceptance criteria as provided in the Updated Final Safety Analysis Report (UFSAR) are not impacted by this change. Since the minimum number of EDGs and both offsite power sources are available during the proposed one-time AOT (assuming single failures in each unit, two EDGs to support a LOOP/LOCA in one unit and 1 EDG to support LOOP in the second unit), the NRC staff finds the Hatch, Units 1 and 2, would be able to mitigate all design bases events and AOOs as required by their design and licensing basis, discussed in Section 2.0 of this SE.

The NRC staff evaluated the proposed mark-up of the TS provided in LAR Attachments 1 and 2. The staff noted that during an AOT for TS 3.8.1, the LCO is not met due to the inoperable EDG (Conditions B and C) and the redundancy or minimum equipment required by the TS LCO (in operating modes) as specified by GDC 17 or Atomic Energy Commission GDC 39 will not be maintained. The regulation at 10 CFR 50.36(c)(2), permits a limited period of time to restore the inoperable train to OPERABLE status and/or take other remedial measures when the necessary redundancy is not maintained (e.g., one train in a redundant train system is inoperable). If these actions are not completed within the CT, the TS normally require that the plant exit the mode of applicability for the LCO. For Hatch, Unit 1, with EDG 1A or 1C or swing EDG 1B (shared between units) onsite power subsystem inoperable, the TS safety function is accomplished by the remaining OPERABLE EDGs. In the current TS, the specified AOT is a maximum time of 14 days to restore these EDGs to OPERABLE status. The NRC staff noted that the requested AOT extension for 19 days is beyond the guidance provided in RG 1.93, and the NRC staff position established in BTP 8-8, as it reduces the defense-in-depth incorporated in the plant design for 5 days beyond the upper extent specified in these guidance documents.

In consideration of this, the NRC staff reviewed the safe shutdown capability of the remaining operable EDGs to ensure that Hatch's design basis requirements during accident conditions and AOOs are retained. The NRC staff noted that the proposed TS for Unit 1, TS 3.8.1 Condition B (One Unit 1 or the swing EDG inoperable) includes a Note for Required Action (RA) B.4.2 that limits the use of the optional one-time extended CT of 19 days for each EDG (1A, 1B or 1C). A similar Note is added to Unit 2, TS 3.8.1 Condition C, because of one required Unit 1 EDG being inoperable. These notes also include an expiration date of June 30, 2021. This Note ensures the optional 19-day CT will not be used more than once for Unit 1 EDGs 1A and 1C and for swing EDG 1B to perform maintenance or repairs. The NRC staff finds that the expiration date will allow for a reasonable amount of margin in case the last EDG maintenance outage must be delayed due to unforeseen events (e.g. unexpected equipment out of service, unavailability of maintenance personnel, severe weather) while also ensuring that SNC completes the maintenance in a timely manner. The NRC staff noted that Hatch, Unit 2, Condition B will be entered for the swing EDG 1B for each of the three maintenance outages, since the Unit 1 TS will require the swing EDG to be inhibited from aligning to Unit 2 during the EDG 1A and 1C maintenance outages. In addition, TS RAs B.4.2.3 and C.4.2.3 were added to restore the EDGs 1A, 1B, or 1C to OPERABLE status with a CT of 19 days. The NRC staff finds the RAs, Notes, and CTs for performing one-time extended CT maintenance for 1A, 1B, and 1C EDGs acceptable, because they meet the regulatory requirements, the format and content are written in a style consistent with the current Hatch TS, and the compensatory measures and risk management controls specified are consistent with BTP 8-8.

In the LAR, the licensee stated that since two EDGs remain operable for each unit during the extended EDG outage, at least one EDG per unit would be available to support transition to cold shutdown in the highly unlikely event of a LOOP concurrent with an additional failure of an EDG. Also, the licensee stated its belief that this meets the intent of the position presented in BTP 8-8. As stated earlier, the purpose of NRC BTP 8-8 is to provide guidance from a deterministic perspective in reviewing LARs for one-time or permanent AOT extensions for EDGs and offsite power sources to perform online maintenance of EDGs and offsite power sources. The NRC staff requested the licensee to explain how the key criteria specified in BTP 8-8 are addressed. In its response dated August 23, 2020, the licensee provided a table which compared the BTP criteria as addressed in the LAR. The licensee stated that many of the criteria provided in BTP 8-8 do not apply to Hatch, because the objective of BTP 8-8 to avoid a potential extended SBO event during the period of an extended AOT is met with the existing Hatch onsite standby emergency AC power sources. The NRC staff does not address the licensee's assertion that no supplemental source is needed at Hatch to maintain the same level of defense-in-depth of the onsite power source that is present during normal operation during the extended CT when an EDG is inoperable. Rather, the NRC staff finds this condition acceptable because (1) the licensee's CT extension request is only for a short duration, (2) the NRC staff's probabilistic risk assessment indicated that the risk is acceptable for this period, and (3) the FLEX strategies approved by the NRC staff are available to provide reasonable assurance that, in the event of an extended SBO during the proposed one-time AOT for the Unit 1 EDGs and the swing EDG, the long-term core cooling and spent fuel pool cooling will be managed until external resources are available.

The licensee stated in the LAR that during an extended AOT, the licensee will implement risk management controls for various plant maintenance configurations to maintain and manage acceptable risk levels. This is to reduce the duration of risk-sensitive activities and avoid risk sensitive equipment outages or maintenance states that result in high-risk plant configurations.

By letter dated August 23, 2020, the licensee updated certain planned compensatory actions and risk management controls, as described below, for the duration of the extended AOT requested for EDGs 1A, 1B, and 1C.

The compensatory and risk management controls necessary to comply with Unit 1 Technical Specification (TS) 3.8.1, “AC Sources – Operating,” Required Action B.4.2.1 and Unit 2 TS 3.8.1, Required Actions B.4.2.1 and C.4.2.1 are specified herein. Unless otherwise stated, systems and components listed herein are those associated with that specific unit. Any difference between controls for Unit 1 TS and Unit 2 TS are annotated herein.

The following defense-in-depth controls (i.e., compensatory controls) are required to be established and maintained during the extended Completion Time period:

- Three qualified circuits between the offsite transmission network and the onsite Class 1E Electrical Distribution System (i.e., station auxiliary transformers (SATs) and associated circuit paths to the 4.16 kV engineered safety feature (ESF) buses) per unit must be OPERABLE and aligned to their respective 4.16 kV ESF bus and no SAT will supply more than one 4.16 kV ESF bus;

- Feeder lines from the 230 kV switchyard to the primary of each SAT will be protected and no discretionary maintenance or testing will be scheduled on these lines for the duration of the extended Completion Time period; No discretionary maintenance or testing will be scheduled in the 500 kV or 230 kV switchyards that could affect the stability of the feeder lines to the SATs;

- Electrical system load dispatcher will be contacted once per day to verify multiple line contingencies are available and to ensure no significant grid perturbations (i.e., high grid loading unable to withstand a single contingency of line or generation outage) are expected during the extended [E]DG maintenance period;

- Each automatic transfer of unit power supply from the normal offsite circuit to the alternate offsite circuit must be OPERABLE for each Class 1E 4.16 kV ESF bus;

- (Unit 1 TS) At least two DGs must be OPERABLE to Unit 1 (i.e., any combination of Unit 1 [E]DGs (1A and 1C) and the swing [E]DG (1B));

- (Unit 2 TS) Unit 2 DGs (2A and 2C) must be OPERABLE;

- High Pressure Coolant Injection and Reactor Core Isolation Cooling Systems must be OPERABLE;

- For each residual heat removal loop, either the shutdown cooling (SDC) mode must be OPERABLE or the low pressure coolant injection alternate SDC mode must be available; and

- Preplanned maintenance on any sensitive or critical equipment will be rescheduled during periods of severe weather forecasts.

[In addition], the following RG 1.177 Tier 2 risk management controls must be established and maintained during the extended Completion Time period:

- (Applicable to [E]DGs 1A, 1B, and 1C) Systems and components specified in Appendix A of the plant online configuration risk management program will be maintained available and no discretionary maintenance or testing will be scheduled on these systems or components; and

- (Only applicable to [E]DG 1C) No discretionary maintenance or testing, including fire protection surveillances, will be scheduled on any equipment in the cable spreading room during the extended completion time and access will be limited to fire watches, on shift operations personnel; and security personnel for the purposes of required area surveillance and inspection.

In addition, Attachment 6 to the August 23, 2020, letter contains a revised Table 4-6, "Maintenance Events Prohibited by Procedure," which provides a list of equipment that will be considered to have "No Maintenance" as part of Hatch Configuration Risk Management Procedural Restrictions. The licensee also confirmed that no deferrals of TS requirements are forecast for these one-time CT extension maintenance evolutions.

The licensee stated in the LAR that the impact of the proposed change will be monitored for effectiveness in accordance with the existing plant maintenance rule program pursuant to 10 CFR 50.65(a)(4) and the associated implementation guidance in RG 1.160, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." The program requires, in part, that performing maintenance activities shall not reduce the overall availability of SSCs, which are important to safety. This program also ensures that EDG reliability is maintained at or above the SBO target level, and the effectiveness of maintenance of the EDGs and support systems is monitored.

The NRC staff finds the proposed compensatory actions and risk management controls are reasonable to reduce the risk of loss of AC power that is required for safe shutdown of dual units, and they are consistent with the intent of the BTP 8-8 guidance. In addition, while this LAR would allow a single EDG to be out of service for the extended CT period for maintenance, TS Condition F requires the plant to be in Mode 3 within 12 hours if an additional EDG becomes inoperable during the extended CT period.

In Section 4.1 of the LAR dated July 31, 2020, the licensee stated the following:

> In March 2012, the NRC issued Order EA-12-049, "Issuance of Order to Modify Licenses with Regard to Requirements for Mitigation Strategies for Beyond-Design-Basis External Events," (NRC Agencywide Documents Access and Management System (ADAMS) Accession No. ML12054A735). This order directed licensees to develop, implement, and maintain guidance and strategies to maintain or restore core cooling, containment and spent fuel pool cooling capabilities in the event of a beyond-design-basis external event.
>
> In a letter from the NRC to SNC dated August 4, 2017, the NRC provided the results of the staff review of strategies related to the HNP FLEX (NRC ADAMS Accession No. ML17179A286). The NRC determined that SNC's actions during an extended loss of all AC power, including use of portable generators, provides additional defense-in-depth measures. The FLEX strategies provide reasonable assurance that in the event of an extended SBO during the proposed one-time AOT for the Unit 1 [E]DGs and the swing [E]DG, the long-term core cooling and spent fuel pool cooling will be managed until external resources are available.

The NRC staff evaluated the licensee's request to extend the CTs for EDGs 1A, 1B, and 1C to determine whether the decrease in severe accident risk, achieved with the implementation of the SBO requirements in 10 CFR Section 50.63, would be eroded. The request was also evaluated to ensure that the overall availability of onsite and offsite power systems will not be adversely impacted to significantly reduce safe shutdown capability of Units 1 and 2 as a result of extended CTs required to conduct the maintenance activities.

In Section 3.3 of the LAR, dated July 31, 2020, the licensee stated that, at Hatch, the SBO event considers standby EDGs as AAC sources for coping and terminating the SBO event.

The NRC staff noted that since the swing EDG (1B) is the only EDG that can be connected to both Unit 1 and Unit 2 ESF buses (1F and 2F) at the 4.16 kV bus level and that can be used as an AAC power source to mitigate an SBO event at one Hatch unit. As such, the NRC staff questioned how the licensee justified the availability of an AAC power source when EDG 1B is unavailable for 19 days based on the LAR. In response to the NRC staff's question concerning the AAC power source relied upon to mitigate an SBO in one unit (Unit 2) and a LOOP with a single failure of a EDG (Unit 1), the licensee's letter dated August 23, 2020, stated the following:

> [Hatch] HNP does not credit a Unit 1 [E]DG to support a shutdown and cooldown of Unit 2 in an SBO on Unit 2. As stated in Unit 2 FSAR Subsection 8.4.2 and restated in Section 3.3 of the enclosure to the LAR (SBO section 1st and 2nd paragraphs on pg. E-10), the HNP SBO analysis credits the swing [E]DG ([E]DG 1B) or one of the unit [E]DGs as an AAC for the blackout unit (e.g., [E]DG 2A or 2C for an SBO on Unit 2). This represents the current design and licensing basis for SBO coping and HNP compliance with 10 CFR 50.63. Therefore, a single Unit 1 [E]DG is not required to have the capacity and capability to bring both units in cold shut down if an SBO occurs in Hatch Unit 2, and Hatch Unit 1, EDG is assumed to have a single failure.

The NRC staff noted that, when an SBO is postulated in Unit 2, the two dedicated EDGs are inoperable. Therefore, the licensee's statement that when the swing EDG is not available, either of the two remaining unit EDGs (e.g., EDG 2A or 2C for an SBO on Unit 2) may be used as the AAC source is not consistent with the boundary conditions of an SBO scenario. However, the NRC staff finds this condition acceptable because (1) the licensee's CT extension request is only for a short duration, (2) the NRC staff's probabilistic risk assessment indicated that the risk is acceptable for this period, and (3) the FLEX strategies approved by the NRC staff are available to provide reasonable assurance that, in the event of an extended SBO during the proposed one-time AOT for the Unit 1 EDGs and the swing EDG, the long-term core cooling and spent fuel pool cooling will be managed until external resources are available.

The NRC staff's risk assessment for the extended AOT is discussed below.

3.2 Risk-Informed Evaluation

An acceptable approach for making risk-informed decisions about proposed TS changes, including both permanent and temporary changes, is to show that the proposed changes meet the five key principles stated in RG 1.174, Section 2, and RG 1.177, Section B. These key principles are:

- Principle 1: The proposed licensing basis change meets the current regulations unless it is explicitly related to a requested exemption (i.e., a specific exemption under 10 CFR 50.12).
- Principle 2: The proposed licensing basis change is consistent with the defense-in-depth (DID) 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 cited above.
- Principle 5: The impact of the proposed licensing basis change should be monitored using performance measurement strategies.

3.3 Key Principle 1

The regulations at 10 CFR 50.36(c) specify the requirements for TSs. The licensee's proposed one-time change to TS 3.8.1, "AC [Alternating Current] Sources – Operating," is to provide a one-time extension of the CT of Required Action B.4 For Hatch, Unit 1 TSs and Required Actions B.4 and C.4 for Hatch, Unit 2, TSs, and for each Hatch, Unit 1, EDG and the swing EDG from 14 days to 19 days.

The licensee's request does not deviate from the requirements to comply with this regulation. However, the NRC staff notes that the licensee will have the additional Alternating Current (AAC) power source removed for maintenance for an additional 5 days as requested in the LAR. This short-term removal of equipment for maintenance is allowed by the Commission for performing online maintenance and reducing shutdown risk. The NRC staff determined the licensee's need to perform maintenance online to improve the reliability of the AAC power source (1B EDG) and EDGs 1A and 1C is consistent with 10 CFR 50.65(a)(4). The NRC staff has evaluated the LAR's compliance with existing regulations and has determined that the LAR meets the existing regulations as discussed in Section 3.1 above.

3.4 Key Principle 2

During the implementation of the extended AOT, the licensee will implement compensatory actions and risk management controls for various plant maintenance configurations to maintain and manage acceptable risk levels as well as maintain all offsite power sources operable during the maintenance evolutions for EDGs 1A, 1B, and 1C. The intent of the compensatory measures is to reduce the duration of risk-sensitive activities and avoid high-risk sensitive equipment outages or maintenance states that result in high-risk plant configurations. Since the minimum number of EDGs and both offsite power sources are available during the proposed one-time AOT (assuming single failures in each unit, two EDGs to support a loss of offsite power (LOOP) / loss of coolant accident (LOCA) in one unit and 1 EDG to support LOOP in the second unit), the NRC staff finds that Hatch, Units 1 and 2, would be able to mitigate all design basis events and abnormal operating occurrences (AOOs) as required by their design and licensing basis discussed above. The NRC staff concludes that although the defense-in-depth incorporated in the design of the onsite power system is reduced during the extended AOT, safe shutdown capability for postulated accident conditions and abnormal operational occurrences is retained. Furthermore, although the licensee is not taking credit for the FLEX equipment, the NRC staff notes that FLEX strategies provide reasonable assurance that, in the event of an extended SBO during the proposed one-time AOT for the Unit 1 EDGs and the swing EDG, long-term core cooling and spent fuel pool cooling will be safely managed until external resources are available. For more details, see Section 3.1 above.

3.5 Key Principle 3

The licensee will continue to meet the design basis requirements (assuming no additional failure in safety-related equipment in any other train except those impacted by the 1A, 1B, 1C EDG outage). The NRC staff finds that there will be only a minimal reduction in safety margin during the extended AOT duration.

3.6 Key Principle 4

The evaluation below addresses the NRC staff's philosophy of risk-informed decision making that when the proposed changes result in a change in core damage frequency (CDF) or risk, the increase should be small and consistent with the intent of the Commission's Safety Goal Policy Statement. The NRC staff evaluation of Key Principle 4 for the proposed one-time TS change is described below.

As provided in Commission's Safety Goal Policy Statement, the qualitative safety goals are as follows:

- Individual members of the public should be provided a level of protection from the consequences of nuclear power plant operation such that individuals bear no significant additional risk to life and health.

- Societal risks to life and health from nuclear power plant operation should be comparable to or less than the risks of generating electricity by viable competing technologies and should not be a significant addition to other societal risks.

As further provided in Commission's Safety Goal Policy Statement, the following quantitative objectives are to be used in determining achievement of the above safety goals:

- The risk to an average individual in the vicinity of a nuclear power plant of prompt fatalities that might result from reactor accidents should not exceed one-tenth of one percent (0.1 percent) of the sum of prompt fatality risks resulting from other accidents to which members of the U.S. population are generally exposed.

- The risk to the population in the area near a nuclear power plant of cancer fatalities that might result from nuclear power plant operation should not exceed one-tenth of one percent (0.1 percent) of the sum of cancer fatality risks resulting from all other causes.

3.6.1 Tier 1: PRA Capability and Insights

The first tier evaluates the impact of the proposed change on plant operational risk. The Tier 1 review involves two aspects: (1) evaluation of the technical adequacy of the probabilistic risk assessment (PRA) models and their application to the proposed change, and (2) evaluation of the PRA results and insights based on the licensee's proposed change.

3.6.1.1 Evaluation of PRA Acceptability

RG 1.174 states, in part, that, "[t]he scope, level of detail, and technical adequacy of the PRA are to be commensurate with the application for which it is intended and the role the PRA results play in the integrated decision process." The technical adequacy 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 technical adequacy 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.

RG 1.200, Revision 2, describes one acceptable approach for determining whether the technical elements 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 decision-making for light-water reactors. RG 1.200, Revision 2, endorses, with comments and qualifications, the use of: (1) the 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;" (2) NEI 00-02, Revision 1, "Probabilistic Risk Assessment (PRA) Peer Review Process Guidance" (ADAMS Accession No. ML061510619); and (3) NEI 05-04, Revision 2, "Process for Performing Internal Events PRA Peer Reviews Using the ASME/ANS PRA Standard" (ADAMS Accession No. ML083430462). The ASME/ANS PRA standard provides technical supporting requirements in terms of three Capability Categories (CCs). The intent of the delineation of the Capability Categories 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. In general, the NRC staff anticipates that current good practice (i.e., CC II of the ASME/ANS standard) is adequate for the majority of applications.

On May 3, 2017, the NRC staff transmitted its review results of Appendix X to NEI 05-04, NEI 07-12 and NEI 12-13, "Close-out of Facts and Observations" (F&Os) (ADAMS Accession No. ML17079A427). The NRC accepted Appendix X for use by licensees to close F&Os that were generated during a peer review process.

The licensee's PRA scope for this application includes internal events, internal flooding, fire and seismic events during full power operation. The licensee stated that an external event screening evaluation has eliminated all other hazard groups.

3.6.1.1.2 Internal Events and Internal Flooding PRA

In Attachment 4 of the LAR, dated July 31, 2020, the licensee stated that a full scope peer review of the internal events and internal flooding PRA was completed in November 2009 against RG 1.200, Revision 2, and associated PRA standard ASME/ANS PRA Standard RA-Sa-2009. Additionally, in July 2017, the licensee conducted an F&O closure in accordance with Appendix X to NEI 05-04, NEI 07-12 and NEI 12-13, "Close-out of Facts and Observations" (F&Os). The licensee stated that all but two findings associated with internal flooding were closed. An additional focused-scope peer review was conducted for the internal flooding PRA using the guidance of NEI 05-04/07-12/12-06, and as a result the two open findings from the original peer review were closed.

3.6.1.1.3 Fire PRA

The licensee stated that a full scope peer review of the fire PRA was completed in June 2016. Further, an F&O closure independent assessment was performed per Appendix X of NEI 05-04/07-12/12-06 in October 2017. The licensee stated that all findings were closed per this review.

The NRC previously reviewed the quality of the Hatch PRA against the PRA standard ASME/ANS RA-Sa-2009 and RG 1.200 for transition to 10 CFR 50.48(c), National Fire Protection Association Standard (NFPA) 805. Further, in its response to request for additional information (RAI) 9 in the letter dated August 23, 2020, the licensee confirmed that there are no incomplete implementation items (Table S-3 in the NFPA 805 submittal) that would impact the results of this analysis for this application.

3.6.1.1.4 Seismic PRA

The licensee stated that a peer review of the seismic PRA was completed in September 2016. The F&Os were closed using Appendix X of NEI 05-04/07-12/12-06. The licensee stated that two of the finding resolutions were considered a model upgrade and a subsequent focused-scope peer review was performed on those elements affected with no additional findings issued.

3.6.1.1.5 Plant Representation

RG 1.174 states that, "[t]he PRA results used to support an application are derived from a PRA model that represents the as-built and as-operated plant to the extent needed to support the application." That is, at the time of the application, the PRA should realistically reflect the risk associated with the plant.

The licensee stated in the LAR that the PRA model of record (MOR) incorporated changes identified during the recent transition to 10 CFR 50.48(c) in Amendment Nos. 304 and 249 (ADAMS Accession No. ML20066F592) and to 10 CFR 50.69, Risk Informed Categorization of structures, systems and components for nuclear power reactors, in amendment nos. 305 and 250 (ADAMS Accession No. ML20077J704). The licensee stated that the Hatch PRA models reflect the as-built, as-operated plant, including recent plant modifications such as the installation of a third startup transformer and restricting to the cable bus feeds to the 4.16KV switchgear to address degraded grid concerns.

The licensee further described in the LAR, dated July 31, 2020, its PRA maintenance procedure. The licensee stated that risk management procedures provide the guidance for PRA documentation quality and maintenance activities. The licensee stated that, according to the risk management procedures, potential impacts to the PRA models are identified and entered into the PRA Model Change log. The entry in the change log requires an evaluation of the impact of the individual change, as well as an evaluation of the cumulative impact for unincorporated changes. This results in a continuous change tracking process so that the difference between the models and the plant can be quickly determined and evaluated.

Based on the description of the PRA model update process, the NRC staff concludes that the licensee's PRA maintenance and change process ensure that the PRA model would be updated as necessary to reflect the as-built and as-operated plant.

3.6.1.1.6 Technical Acceptability Conclusion

The NRC staff previously reviewed the technical acceptability of the Hatch internal events, internal flooding, fire, and seismic PRA against the PRA standard ASME/ANS RA-Sa-2009 and RG 1.200 in the licensee's applications for transition to 10 CFR 50.48(c), National Fire Protection Association Standard (NFPA) 805 (ADAMS Accession Nos. ML20066F592) and to 10 CFR 50.69, "Risk-informed categorization and treatment of structures, systems and components for nuclear power reactors" (ADAMS Accession No. ML20077J704). The extensive PRA reviews by the licensee as summarized above, as reviewed by the NRC staff in its safety evaluations of the applications for 10 CFR 50.69 and NFPA-805, provides reasonable assurance that the licensee's PRA is generally acceptable and is capable to support the specific calculation as required by this LAR for one-time EDG AOT extension.

3.6.1.1.7 Other external hazards

The licensee stated that Hatch performed external events screening per ASME/ANS PRA Standard Ra-Sa-2009, Section 6 and all external events hazards other than seismic screened out.

High Winds

The licensee screened out the High Winds hazard based on compliance with the design basis and the low contribution to CDF. The licensee stated that compliance with design basis was demonstrated by a comprehensive walkdown and is documented in the Hatch Tornado Missile Project Summary Report. The licensee stated that any non-compliant items discovered during those walkdowns were documented and corrected using the plant design change process. Further, the licensee estimated that the CDF resulting from the high winds hazards would be less than $1x10^{-6}$/year. The licensee estimated a probability of a F2 or greater Tornado induced LOOP at $3.4x10^{-6}$. The licensee estimated the conditional cored damage probability (CCDP) for LOOP with no offsite power recovery and EDG 1C out of service to $8.7x10^{-3}$. Therefore, the resulting CDF is estimated at $3.0x10^{-8}$, below the $1Ex10^{-6}$ criteria in the PRA Standard. The NRC staff finds the licensee adequately used the screening out criteria from the PRA standard, and adequately justified screening the high winds hazards for the application.

External Flooding

The licensee stated that several of the proposed EDG outages are scheduled during the typical peak of hurricane season, and therefore, it re-examined the Local Intense Precipitation (LIP) screening. The licensee stated that the LIP analysis utilized a 1-hour/1-square mile Probable Maximum Precipitation (PMP) approach to determine local flood levels across a grid. The licensee stated that some doors were identified where the maximum LIP exterior water surface elevation would be greater than the finished floor elevation for a given duration. The licensee stated that calculations showed that the water ingress from the LIP event is insufficient to damage key SSCs. The LIP analysis credits only passive mitigation features; thus, the screening of the flooding event is not impacted by removing an EDG from service. The NRC staff notes that the other external flooding mechanisms were discussed and reviewed in the NRC staff's safety evaluation associated with the licensee's application for 10 CFR 50.69, "Risk-informed categorization and treatment of structures, systems and components for nuclear power reactors" (ADAMS Accession No. ML20077J704). Based on the NRC staff's review of external flooding screening performed during the review of the licensee's application for 50.69 and the additional information provided in the LAR for LIP, the NRC staff finds that the licensee adequately justified screening out the external flooding hazard for this application.

3.6.1.2 PRA Modeling

To calculate the risk due to the proposed one-time EDG AOT extension, the licensee stated that it created an application specific model (ASM) based on the model of record (MOR). The licensee stated that the ASM was prepared for all hazards for Unit 1, and for fire and seismic only for Unit 2, which is conservative as discussed later in this section. In its LAR, dated July 31, 2020, Attachment 4, the licensee summarized the changes performed for the ASM, which included, for the internal events and internal flooding PRA model, model changes to reflect a recent plant modification with installation of a third startup transformer and various model and recovery rules changes to adjust credit for offsite power and EDG failure recovery. For the fire PRA, the licensee stated it refined the model to remove an unlocated conduit as target from transient fires in the cable spreading room and added a human failure event to secure an EDG on loss of Plant Service Water (PSW) during a fire scenario in a specific fire compartment. The licensee stated in the LAR that the FLEX EDGs are not credited as compensatory actions in the risk analysis for the extended EDG AOT.

In the LAR, dated July 31, 2020, as supplemented by the licensee's response to RAI 5.a and 5.b, dated August 23, 2020, the licensee further explained the credit for recovery of offsite power. The licensee clarified that the offsite power recovery is only credited in the internal events and internal flooding PRA, and that the fire PRA does not credit offsite power recovery. The licensee explained that the LOOP probabilities are obtained through Bayesian updating, with plant specific experience, of the LOOP initiators in NUREG/CR-6890, "Reevaluation of Station Blackout Risk at Nuclear Power Plants," 2015 update. As described in the LAR, dated July 31, 2020, the ASM model adjustments for internal events and internal flooding PRA included: adding credit for recovery of AC power given a consequential LOOP and a single EDG failure; recovery rule changes to apply credit for offsite power recovery for reactor core isolation cooling (RCIC) success to those scenarios that do not have a hardware failure; and recovery rule changes to adjust offsite power recovery probability for long-term loss of decay heat removal scenarios based on the time to reach the primary containment vent pressure. In response to RAI 4.d, dated August 23, 2020, the licensee also explained how the consequential LOOP probabilities were derived using industry data and plant specific experience. Further, the licensee addressed the impact of uncertainty in consequential LOOP probability. The licensee explained that consequential LOOP events contributes approximately 5-percent of the internal events risk and 70-percent of the internal flooding risk, but internal flooding is a small overall contribution to total risk.

In response to RAI 5.c, dated August 23, 2020, the licensee explained that the EDG failure recovery is applied only in the internal events and internal flooding PRA and is applied to failure of an EDG to start or for failure of an EDG output breaker to close. The licensee explained how the failure probability was derived based on plant specific historical data. The licensee derived a recovery probability of 0.59.

The NRC staff finds that the licensee's ASM model changes for internal events and internal flooding PRA are reasonable, because the licensee used industry generic and plant specific experience to derive credit for power recovery. The NRC staff notes that the licensee does not appear to have used industry experience to estimate the EDG recovery probability, and therefore, this could be a source of uncertainty. However the NRC staff notes that in the highest risk scenario, the EDG 1C 19 day outage, as discussed in Section 3.4.1.3, the risk is dominated by fire events, and therefore, any uncertainty in credit for offsite power or EDG recovery taken in the internal events PRA is unlikely to present a challenge to meeting the RG 1.177 acceptance criteria for this one time change.

For the fire PRA, the licensee explained in the LAR, dated July 31, 2020, as supplemented in its response to RAI 8, dated August 23, 2020, that it identified an unlocated conduit in the Cable Spreading Room that was leading to high risk results due to a cable that was assumed failed for all fire scenarios in the room. The licensee stated that the conduit was determined to be outside of the zone of influence (ZOI) of the transient fire scenarios, and therefore, the ASM removed this target from all transient fires in the cable spreading room.

Further, the licensee added, in the fire PRA, a human failure event (HFE) to secure an EDG on loss of PSW, manually close the PSW isolation valves, and restart the EDG. The licensee explained that a fire scenario in fire compartment 1101J would lead to automatic closure of PSW isolation valves, leading to a PSW flow diversion, therefore resulting in assumed failure of the associated EDG due to insufficient cooling. The licensee explained that this fire HFE includes tripping the EDG within 15 minutes, locally closing one of the two valves to stop the flow diversion, and then re-establishing EDG cooling from PSW. The licensee explained that this HFE is applied through recovery rules to any cut set pertaining to a fire in 1101J that propagates to SBO sequences, and which does not contain a separate operator action or PSW system failures. In response to RAI 5.e, dated August 23, 2020, the license confirmed that the operator action was fully developed for the ASM by using feasibility studies and operator interviews. The licensee provided details of the feasibility studies and operator interviews in Attachment 4 to the RAI, dated August 23, 2020. Because the licensee confirmed that the HFE was fully developed consistent with the PRA standard, the NRC staff finds this change acceptable for the application.

The NRC staff finds that the licensee sufficiently justified the refinements performed to the fire PRA model, and therefore, the NRC staff finds these model changes are acceptable to support the risk assessments performed by the licensee for this application.

In addition, the licensee explained that the PRA model locked the swing EDG 1B alignment to Unit 1 during the applicable EDG outage for Internal Events, Internal Flooding, Fire, and seismic PRA. The licensee stated in the LAR, dated July 31, 2020, as further clarified in its response to RAI 6.d, dated August 23, 2020, that the PRA models captures the alignment of the reactor protection system (RPS) bus alternate supply to a source supplied by the EDG 1A during the EDG 1C outage, and this alignment is consistent with the existing plant procedures.

The licensee explained that the common cause failure (CCF) terms were not modified for this analysis. The licensee explained that modifying the CCF events would have minimal impact on the results and no impact on the conclusions of this analysis, because the licensee’s model maintains all combinations of CCF from the common cause group of five diesels. Full implementation of RG 1.177 guidance for preventative maintenance would require that the licensee remove all non-applicable failure combinations (i.e., all common cause failure combinations including the inoperable component) and modify all the remaining basic event probabilities to reflect the reduced number of redundant components. This would mean that any CCF events pertaining to the inoperable EDG should be set to FALSE, and all other EDG CCF terms would be adjusted to consider four EDGs instead of five, which would reduce the number of CCF terms from 120 to 60. The NRC staff finds that following RG 1.177 with regards to adjusting CCF terms for preventative maintenance would result in minimal changes to the results, and therefore, the NRC staff finds the licensee's approach for CCF acceptable for the application.

The licensee stated that procedure limitations prohibit scheduled maintenance during extended EDG outages, and that it set these associated maintenance events for FALSE for the EDG outage case, but not for the base case. The licensee provided a list of the prohibited maintenance events and protected components in the LAR, dated July 31, 2020, Tables 4-6 and 4-7, as updated in response to RAI 6.b and associated Attachment 6 to letter dated August 23, 2020. In its response to RAI 6.c, dated August 23, 2020, the licensee stated that per SNC's on-line configuration risk management program, these maintenance restrictions would apply to both units.

The licensee confirmed in its response to RAI 6.b, dated August 23, 2020, that these prohibited maintenance events are captured in Appendix A of the plant online configuration risk management program, and therefore, are captured in the compensatory measures specified in Attachment 5 of the licensee's letter, dated August 23, 2020:

> Systems and components specified in Appendix A of the plant online configuration risk management program will be maintained available and no discretionary maintenance or testing will be scheduled on these systems or components.

Proposed TS 3.8.1.B.4.2.1 establishes compensatory and risk management controls for the extended EDG outage as specified in Attachment 5 of SNC letter, dated August 23, 2020.

The NRC staff finds that the licensee adequately described and justified the changes performed to the PRA model to support the risk analysis for the EDG one-time AOT extension.

3.6.1.3 PRA Results and Insights

The licensee provided the table below, to summarize the licensee's calculated Incremental Conditional Core Damage Probability/Incremental Conditional Large Early Release Probability (ICCDP/ICLERP) for the proposed 19-day AOT for each of the Unit 1 EDG and swing EDG.

Metric			**EDG 1A**	**EDG 1B (Swing EDG)**	**EDG 1C**
ICCDP	Unit 1	Internal Events	3.07x10^{-7}	1.67x10^{-7}	3.07x10^{-7}
		Internal Flooding	1.10x10^{-8}	0.00	4.28x10^{-8}
		Internal Fires	5.73x10^{-8}	7.29x10^{-8}	8.80x10^{-7}
		Seismic	4.01x10^{-9}	4.53x10^{-9}	0.0
		Total U1 ICCDP	**3.79x10^{-7}**	**2.45x10^{-7}**	**1.23x10^{-6}**
	Unit 2	Internal Events	1.74x10^{-7}	1.85x10^{-7}	1.74x10^{-7}
		Internal Flooding	1.76x10^{-8}	1.76x10^{-8}	2.28x10^{-8}
		Internal Fires	4.27x10^{-7}	5.67x10^{-7}	4.27x10^{-7}
		Seismic	4.95x10^{-9}	6.66x10^{-9}	6.98x10^{-9}
		Total U2 ICCDP	**6.24x10^{-7}**	**7.77x10^{-7}**	**6.31x10^{-7}**
ICLERP	Unit 1	Internal Events	1.46x10^{-8}	2.08x10^{-9}	1.43x10^{-8}
		Internal Flooding	2.78x10^{-10}	0.00	9.14x10^{-10}

Metric			EDG 1A	EDG 1B (Swing EDG)	EDG 1C
		Internal Fires	$4.16x10^{-9}$	0.00	$2.13x10^{-8}$
		Seismic	0.00	$7.81x10^{-10}$	0.00
		Total U1 ICLERP	**$1.91x10^{-8}$**	**$2.86x10^{-9}$**	**$3.65x10^{-8}$**
	Unit 2	Internal Events	$1.56x10^{-10}$	0.00	0.00
		Internal Flooding	$1.36x10^{-9}$	$1.13x10^{-9}$	$1.49x10^{-9}$
		Internal Fires	$2.39x10^{-8}$	$2.55x10^{-8}$	$2.39x10^{-8}$
		Seismic	$9.89x10^{-10}$	$8.33x10^{-10}$	$1.61x10^{-9}$
		Total U1 ICLERP	**$2.65x10^{-8}$**	**$2.75x10^{-8}$**	**$2.70x10^{-8}$**

The licensee explained that the largest increase in risk was due to the EDG 1C impact on the fire PRA model. The licensee explained that this is because Division 2 components, which are fed by EDG 1C, are the primary fire safe shutdown path in the deterministic fire safe shutdown analysis for fires in the control room and the cable spreading room. Additionally, the licensee explained that the remote shutdown panels contains mostly Division 2 components with circuits routed outside the cable spreading and control rooms.

The NRC staff noticed that the risk results for Unit 2 reported by the licensee are higher than for Unit 1, which was unexpected. The licensee explained that the Unit 2 results for EDG 1A and 1C are conservative due to the assumption that swing EDG 1B cannot be aligned to Unit 2 while Unit 1 EDG 1A and 1C are in maintenance. Also, the licensee explained that the internal events PRA model was not updated for Unit 2, and therefore the ASM model changes described above are not captured in the Unit 2 risk results. In cases where the reduction in risk due to setting prohibited maintenance terms to zero was greater than the increase in risk with the EDG out of service, the ICCDP and/or ICLERP terms were set to zero.

The licensee also conducted and provided the results of a sensitivity analysis to evaluate the risk impact due to an increase in weather-related LOOP frequency during the EDG 1C outage. The licensee stated that the EDG outages are scheduled to occur during the Atlantic hurricane season. The licensee increased the weather-related LOOP initiating event frequency to the 95-percent upper bound weather-related LOOP initiating event frequency, in place of the annual mean weather-related frequency. The licensee demonstrated minimal impact on the risk results for the EDG 1C case (ICCDP of $1.62x10^{-6}$), therefore the increased LOOP frequency is unlikely to present a challenge to meeting the RG 1.177 acceptance criteria.

RG 1.177 provides sets of acceptance criteria for one-time AOT extensions. The first is an ICCDP of less than $1.0x10^{-6}$ and an ICLERP of less than $1.0x10^{-7}$. The licensee stated in the LAR that the calculated ICCDP and ICLERP meet (i.e., are lower than) these thresholds for all cases except the EDG 1C outage. The second set of criteria is when the ICCDP is greater than $1.0X10^{-6}$ but less than $1.0x10^{-5}$ and the ICLERP is greater than $1.0x10^{-7}$ but less than $1.0x10^{-6}$, in which case a licensee must implement effective compensatory measures to reduce the sources of increased risk. For the EDG 1C outage, the licensee stated in the LAR that the calculated ICCDP and ICLERP meet these thresholds, and compensatory measures are therefore required. The NRC staff found that the licensee's proposed compensatory measures are acceptable as discussed in Section 3.6.2 of this SE.

3.6.2 Tier 2: Avoidance of Risk-Significant Plant Configurations

A licensee must provide reasonable assurance that risk significant plant equipment outage configurations will not occur when specific plant equipment is out-of-service in accordance with the proposed TS change. 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 TS change, is simultaneously removed from service or other risk-significant operational factors such as concurrent system or equipment testing are involved. Therefore, Tier 2 helps ensure that appropriate restrictions are placed on dominant risk-significant configurations relevant to the proposed TS change.

The licensee performed a Tier 2 evaluation in the LAR. The licensee stated that the risk insights from this configuration were examined and it identified the necessary Compensatory Measures. These were further clarified in the licensee's response to RAI 6 in Attachment 6 of licensee's letter dated August 23, 2020:

> The compensatory and risk management controls necessary to comply with Unit 1 Technical Specification (TS) 3.8.1, "AC Sources – Operating," Required Action B.4.2.1 and Unit 2 TS 3.8.1, Required Actions B.4.2.1 and C.4.2.1 are specified herein. Unless otherwise stated, systems and components listed herein are those associated with that specific unit. Any difference between controls for Unit 1 TS and Unit 2 TS are annotated herein.
>
> The following defense-in-depth controls (i.e., compensatory controls) are required to be established and maintained during the extended Completion Time:
>
> - Three qualified circuits between the offsite transmission network and the onsite Class 1E Electrical Distribution System (i.e., station auxiliary transformers (SATs) and associated circuit paths to the 4.16 kV engineered safety feature (ESF) buses) per unit must be OPERABLE and aligned to their respective 4.16 kV ESF bus and no SAT will supply more than one 4.16 kV ESF bus;
> - Feeder lines from the 230 kV switchyard to the primary of each SAT will be protected and no discretionary maintenance or testing will be scheduled on these lines for the duration of the extended Completion Time period; no discretionary maintenance or testing will be scheduled in the 500 kV or 230 kV switchyards that could affect the stability of the feeder lines to the SATs;
> - Electrical system load dispatcher will be contacted once per day to verify multiple line contingencies are available and to ensure no significant grid perturbations (i.e., high grid loading unable to withstand a single contingency of line or generation outage) are expected during the extended [E]DG maintenance period;
> - Each automatic transfer of unit power supply from the normal offsite circuit to the alternate offsite circuit must be OPERABLE for each Class 1E 4.16 kV ESF bus;
> - (Unit 1 TS) At least two [E]DGs must be OPERABLE to Unit 1 (i.e., any combination of Unit 1 [E]DGs (1A and 1C) and the swing [E]DG (1B));
> - (Unit 2 TS) Unit 2 [E]DGs (2A and 2C) must be OPERABLE;

- High Pressure Coolant Injection and Reactor Core Isolation Cooling Systems must be OPERABLE;
- For each residual heat removal loop, either the shutdown cooling (SDC) mode must be OPERABLE or the low pressure coolant injection alternate SDC mode must be available; and
- Preplanned maintenance on any sensitive or critical equipment will be rescheduled during periods of severe weather forecasts.

The following RG 1.177 Tier 2 risk management controls must be established and maintained during the extended Completion Time period:

- (Applicable to [E]DGs 1A, 1B, and 1C) Systems and components specified in Appendix A of the plant online configuration risk management program will be maintained available and no discretionary maintenance or testing will be scheduled on these systems or components; and
- (Only applicable to [E]DG 1C) No discretionary maintenance or testing, including fire protection surveillances, will be scheduled on any equipment in the cable spreading room during the extended completion time and access will be limited to fire watches, on shift operations personnel; and security personnel for the purposes of required area surveillance and inspection.

The NRC staff finds that the licensee provided adequate analyses of risk-significant configurations while one EDG is out-of-service and proposed adequate compensatory measures. Therefore, the NRC staff concludes that the licensee's analysis of risk significant combinations and its identification of compensatory actions are consistent with RG 1.177 and provide reasonable assurance that risk-significant plant equipment outage configurations will not occur during the extended AOT.

3.6.3 Tier 3: Risk-Informed Configuration Risk Management

A Tier 3 program ensures that while an EDG is inoperable, additional activities will not be performed that could further degrade the capability of the plant to respond to adverse conditions, and as a result, increase plant risk beyond that assumed by the risk-informed licensing action. A Tier 3 program: (1) ensures that additional maintenance does not increase the likelihood of an initiating event intended to be mitigated by the out-of-service equipment such as redundant or associated systems or components, (2) evaluates the effects of additional equipment out-of-service during EDG maintenance activities that would adversely impact risk, and (3) evaluates the impact of maintenance on equipment or systems assumed to remain operable by the EDG AOT analysis.

Accordingly, a licensee should develop a Configuration Risk Management Program (CRMP) to ensure that it appropriately evaluates the risk impact of out-of-service equipment before performing a maintenance activity. Licensees can utilize the overall CRMP (as referenced in RG 1.177) through the Maintenance Rule (10 CFR 50.65(a)(4)). Specifically, the rule requires that, before performing any maintenance activity, the licensee must assess and manage the potential risk increase that may result from a proposed maintenance activity. A licensee's submittal must include a discussion of the licensee's CRMP for assessing the risk associated with the removal of an EDG from service and its conformance to the requirements of 10 CFR

50.65(a)(4), and the additions and clarifications outlined in Section 2.3.7.2 of RG 1.177, as they relate to the proposed extended EDG AOT.

In LAR Attachment 4, dated July 31, 2020, the licensee stated that Hatch has a mature on-line configuration risk management process. In its response to RAI 7, dated August 23, 2020, the licensee clarified that the CRMP includes internal events, internal fires, internal flooding and seismic hazards and that the CRMP can provide importance reports for basic events, operator actions and fire areas for use in developing configuration specific risk management actions. The licensee stated that the ASM changes will be captured in the CRMP prior to the first EDG outage.

Based on the above, the NRC staff finds the licensee's Tier 3 program is consistent with the guidance of RG 1.177, and therefore, is acceptable.

3.6.4 Key Principle 4 Conclusion

The NRC staff finds the licensee has demonstrated that the scope, level of detail, and technical adequacy of its PRA models are sufficient to support the proposed one-time AOT change. The risk metrics used to support the LAR are consistent with RG 1.177. The NRC staff further finds that the licensee has followed the three-tiered approach outlined in RG 1.177 to evaluate the risk associated with the proposed change, and therefore, the proposed change satisfies the fourth key safety principle of RG 1.177.

3.7 Key Principle 5

Guidance in RG 1.177 establishes the need for an implementation and monitoring program to ensure that extensions to TS AOTs do not degrade operational safety over time and that no adverse degradation occurs due to unanticipated degradation or common cause mechanisms.

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 structures, systems, and components (SSCs) impacted by the change. RG 1.174 states that monitoring performed in conformance with the Maintenance Rule, 10 CFR 50.65, can be used when the monitoring performed is sufficient for the SSCs affected by the risk-informed application.

In the LAR, dated July 31, 2020, the licensee stated that the impact of the proposed change will be monitored for effectiveness in accordance with the existing plant maintenance rule program pursuant to 10 CFR 50.65(a)(4) and the associated implementation guidance, in RG 1.160, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants"

Based on the above, the NRC staff concludes that the implementation and monitoring program for the proposed one-time EDG AOT extension satisfies the fifth key safety principle of RG 1.177.

3.8 Review of TS Changes

The licensee stated in LAR Section 2.4 of its submittal dated July 31, 2020, that the TS change would add optional proposed requirements to Hatch, Unit 1, TS 3.8.1 Condition B, and Hatch, Unit 2, TS 3.8.1 Conditions B and C. In addition, current Required Actions B.4 and C.4 are renumbered to B.4.1 (C.4.1), and an "OR" is added to support the following contingent Required Actions. In response to NRC staff's request for additional information (RAI), the licensee provided additional clarifications to the Required Actions and Notes as shown in Attachment 1 of the letter dated August 23, 2020.

The NRC staff finds the licensee has demonstrated that the scope, level of detail, and technical adequacy of its PRA models are sufficient to support the proposed one-time AOT change. Further, the NRC staff finds that the licensee will implement risk management controls for various plant maintenance configurations to maintain and manage acceptable risk levels, to reduce the duration of risk-sensitive activities and avoid risk sensitive equipment outages or maintenance states that result in high-risk plant configurations, for the duration of the extended AOT. Therefore, the NRC staff finds the proposed TS changes acceptable.

3.9 Technical Conclusion

The NRC staff concludes that the LAR meets the regulatory requirements and NRC staff guidance as discussed in Section 2.0 above. The NRC staff has determined the licensee's intent to perform online maintenance to improve the reliability of the AAC power source (1B EDG) and EDGs 1A and 1C is consistent with the requirements specified in 10 CFR 50.65(a)(4). Therefore, the NRC staff concludes that the licensee's proposed change complies with existing regulations.

4.0 FINAL NO SIGNIFICANT HAZARDS CONSIDERATION

The NRC's regulation in 10 CFR 50.92(c) states that the NRC may make a final determination, under the procedures in 10 CFR 50.91, that a license amendment involves no significant hazards consideration if operation of the facility, in accordance with the amendment, would not: (1) involve a significant increase in the probability or consequences of an accident previously evaluated; or (2) create the possibility of a new or different kind of accident from any accident previously evaluated; or (3) involve a significant reduction in a margin of safety.

The licensee's determination of no significant hazards consideration is presented below:

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

   Response: No.

   The proposed change provides a one-time extension of the DG restoration time allowed by TS. This change will have no effect on accident probabilities since the DGs are not considered accident initiators. The proposed DG AOT extension does not require any physical plant modifications. Since no individual precursors of an accident are affected, the proposed amendment does not increase the probability of a previously analyzed event. The consequences of an evaluated accident are determined by the operability of plant systems designed to mitigate those consequences. The consequences of an evaluated accident with an inoperable DG is not altered by the proposed change and will not affect the consequences of an accident previously evaluated.

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

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

   Response: No.

   The proposed change does not involve a physical alteration of the plant (i.e., no new or different type of equipment will be installed). Operation in accordance with the revised TS and its limits precludes new challenges to systems, structures, or components that might introduce a new type of accident. Applicable design and performance criteria will continue to be met and no new single failure mechanisms will be created. The proposed change to extend the DG restoration time does not involve the alteration of plant equipment or introduce unique operational modes or accident precursors.

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

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

   Response: No.

   The margin of safety is related to the ability of the fission product barriers to perform their design functions during and following an accident. These barriers include the fuel cladding, the reactor coolant system, and the containment. The performance of these fission product barriers is not adversely affected by the proposed change.

   The proposed change provides a risk-informed, one-time extension of the DG restoration time allowed by TS. A deterministic evaluation of the proposed completion time extension demonstrates there is sufficient margin to safety during the extended DG AOT period. During the extended DG AOT period, sufficient controls will be established to maintain the defense-in-depth design philosophy to ensure the electrical power system meets its design safety function and risk management actions will be established to maintain the risk as low as reasonably achievable within the regulatory acceptance guidelines.

   Operation in accordance with the revised TS ensures that the assumptions for initial conditions of key parameter values in the safety analyses remain valid. This ensures that applicable design and performance criteria associated with the safety analysis will continue to be met and that the margin of safety is not adversely affected.

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

Based on the above evaluation, the NRC staff concludes that the three standards of 10 CFR 50.92(c) are satisfied. Therefore, the NRC staff has made a final determination that no significant hazards consideration is involved for the proposed amendment and that the amendment should be issued in accordance with the criteria contained in 10 CFR 50.91.

5.0 STATE CONSULTATION

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

6.0 ENVIRONMENTAL CONSIDERATION

The amendments change a requirement with respect to the installation or use of facility components located within the restricted area as defined in 10 CFR Part 20 and change surveillance requirements. The NRC staff has determined that the amendments involve 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 that the amendments involve no significant hazards consideration on August 14, 2020 (85 FR 49687), and there has been no public comment on such finding. Accordingly, the amendments meet the eligibility criteria for categorical exclusion set forth in 10 CFR 51.22(c)(9). Pursuant to 10 CFR 51.22(b) no environmental impact statement or environmental assessment need be prepared in connection with the issuance of the amendments.

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 amendments will not be inimical to the common defense and security or to the health and safety of the public.

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Date: September 18, 2020

SUBJECT: EDWIN I. HATCH NUCLEAR PLANT, UNIT NOS. 1 AND 2 - ISSUANCE OF AMENDMENTS NOS. 307 AND 252, REGARDING LICENSE AMENDMENT REQUEST TO REVISE THE REQUIRED ACTIONS OF TECHNICAL SPECIFICATIONS 3.8.1, “AC [ALTERNATING CURRENT] SOURCES – OPERATING,” FOR ONE-TIME EXTENSION OF COMPLETION TIME FOR UNIT 1 AND SWING EMERGENCY DIESEL GENERATORS (EPID L-2020-LLA-171)

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Amendment Nos.:
ML20254A067 (Package);
ML20254A057 (Letter);
ML20254A075 (Safety Evaluation) ***via e-mail** ****via memo**

OFFICE	NRR/DORL/LPL2-1/PM*	NRR/DORL/LPL2-1/LA*	NRR/DE/EEOB/BC**	NRR/DRA/APLB/BC*
NAME	JLamb	KGoldstein	BTitus	JBorromeo
DATE	09/10/2020	09/11/2020	09/09/2020	09/10/2020
OFFICE	NRR/DSS/STSB/BC*	OGC – NLO*	NRR/DORL/LPL2-1/BC*	NRR/DORL/LPL2-1/PM*
NAME	VCusumano	STurk	MMarkley (GEMiller for)	JLamb
DATE	09/14/2020	09/18/2020	09/18/2020	09/18/2020

OFFICIAL RECORD COPY