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

January 25, 2019

Mr. Peter P. Sena, III
President and Chief Nuclear Officer
PSEG Nuclear LLC - N09
Salem Nuclear Generating Station
P.O. Box 236
Hancocks Bridge, NJ 08038

SUBJECT: SALEM NUCLEAR GENERATING STATION, UNIT NOS. 1 AND 2 – ISSUANCE OF AMENDMENT NOS. 326 AND 307 RE: REVISE TECHNICAL SPECIFICATIONS TO INCREASE VITAL INSTRUMENT BUS INVERTER ALLOWED OUTAGE TIME (EPID L-2018-LLA-0140)

Dear Mr. Sena:

The U.S. Nuclear Regulatory Commission (the Commission) has issued the enclosed Amendment Nos. 326 and 307 to Renewed Facility Operating License Nos. DPR-70 and DPR-75 for the Salem Nuclear Generating Station, Unit Nos. 1 and 2, respectively. These amendments consist of changes to the Technical Specifications in response to your application dated May 16, 2018, as supplemented by letters dated June 14, 2018; October 18, 2018; October 20, 2018; and October 30, 2018.

The amendments revise Technical Specification 3.8.2.1, "A.C. Distribution - Operating," to increase the vital instrument bus inverters allowed outage time from 24 hours for the A, B, and C inverters to 7 days, and from 72 hours for the D inverter to 7 days. The proposed extended allowed outage time is based on application of the Salem Nuclear Generating Station probabilistic risk assessment in support of a risk-informed extension, and on additional considerations and compensatory actions.

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

Sincerely,

James S. Kim

James S. Kim, Project Manager
Plant Licensing Branch I
Division of Operating Reactor Licensing
Office of Nuclear Reactor Regulation

Docket Nos. 50-272 and 50-311

Enclosures:
1. Amendment No. 326 to DPR-70
2. Amendment No. 307 to DPR-75
3. Safety Evaluation

cc: Listserv

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

PSEG NUCLEAR LLC

EXELON GENERATION COMPANY, LLC

DOCKET NO. 50-272

SALEM NUCLEAR GENERATING STATION, UNIT NO. 1

AMENDMENT TO RENEWED FACILITY OPERATING LICENSE

Amendment No. 326
Renewed License No. DPR-70

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

   A. The application for amendment filed by PSEG Nuclear LLC, acting on behalf of itself and Exelon Generation Company, LLC (the licensees), dated May 16, 2018, as supplemented by letters dated June 14, 2018; October 18, 2018; October 20, 2018; and October 30, 2018, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations set forth in 10 CFR Chapter I;

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

   C. There is reasonable assurance: (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations 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 amended by changes to the Technical Specifications as indicated in the attachment to this license amendment, and paragraph 2.C.(2) of Renewed Facility Operating License No. DPR-70 is hereby amended to read as follows:

    (2) Technical Specifications and Environmental Protection Plan

    The Technical Specifications contained in Appendix A, as revised through Amendment No. 326, and the Environmental Protection Plan contained in Appendix B, are hereby incorporated in the renewed license. PSEG Nuclear LLC 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 within 60 days of the date of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

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

Attachment:
Changes to Renewed Facility Operating
License and Technical Specifications

Date of Issuance: January 25, 2019

ATTACHMENT TO LICENSE AMENDMENT NO. 326

SALEM NUCLEAR GENERATING STATION, UNIT NO. 1

RENEWED FACILITY OPERATING LICENSE NO. DPR-70

DOCKET NO. 50-272

Replace the following page of Renewed Facility Operating License No. DPR-70 with the attached revised page as indicated. The revised page is identified by amendment number and contains a marginal line indicating the area of change.

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Page 3	Page 3

Replace the following page of the Appendix A, Technical Specifications, with the attached revised page as indicated. The revised page is identified by amendment number and contains marginal lines indicating the areas of change.

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instrumentation and radiation monitoring equipment calibration, and as fission detectors in amounts as required;

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

(6) PSEG Nuclear LLC, 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, Sections 50.54 and 50.59 of Part 50, and Section 70.32 of Part 70; and is subject to all applicable provisions of the Act and to the rules, regulations, and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified or incorporated below:

(1) Maximum Power Level

PSEG Nuclear LLC is authorized to operate the facility at a steady state reactor core power level not in excess of 3459 megawatts (one hundred percent of rated core power).

(2) Technical Specifications and Environmental Protection Plan

The Technical Specifications contained in Appendix A, as revised through Amendment No. 326, and the Environmental Protection Plan contained in Appendix B, are hereby incorporated in the renewed license. PSEG Nuclear LLC shall operate the facility in accordance with the Technical Specifications, and the Environmental Protection Plan.

(3) Deleted Per Amendment 22, 11-20-79

(4) Less than Four Loop Operation

PSEG Nuclear LLC shall not operate the reactor at power levels above P-7 (as defined in Table 3.3-1 of Specification 3.3.1.1 of Appendix A to this renewed license) with less than four (4) reactor coolant loops in operation until safety analyses for less than four loop operation have been submitted by the licensees and approval for less than four loop operation at power levels above P-7 has been granted by the Commission by Amendment of this renewed license.

(5) PSEG Nuclear LLC shall implement and maintain in effect all provisions of the approved fire protection program as described in the Updated Final Safety

ELECTRICAL POWER SYSTEMS

3/4.8.2 ONSITE POWER DISTRIBUTION SYSTEMS

A.C. DISTRIBUTION - OPERATING

LIMITING CONDITION FOR OPERATION

3.8.2.1 The following A.C. electrical busses shall be OPERABLE and energized from sources of power other than the diesel generators:

4 kvolt	Vital Bus # 1A	
4 kvolt	Vital Bus # 1B	
4 kvolt	Vital Bus # 1C	
460 volt	Vital Bus # 1A and associated control centers	
460 volt	Vital Bus # 1B and associated control centers	
460 volt	Vital Bus # 1C and associated control centers	
230 volt	Vital Bus # 1A and associated control centers	
230 volt	Vital Bus # 1B and associated control centers	
230 volt	Vital Bus # 1C and associated control centers	
115 volt	Vital Instrument Bus # 1A and Inverter	*
115 volt	Vital Instrument Bus # 1B and Inverter	*
115 volt	Vital Instrument Bus # 1C and Inverter	*
115 volt	Vital Instrument Bus # 1D and Inverter	*

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

a. With less than the above complement of A.C. busses OPERABLE or energized, restore the inoperable bus to OPERABLE and energized status within 8 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

b. With one inverter inoperable, energize the associated A.C. Vital Bus within 8 hours; restore the inoperable inverter to OPERABLE and energized status within 7 days or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.8.2.1 The specified A.C. busses shall be determined OPERABLE and energized from A.C. sources other than the diesel generators in accordance with the Surveillance Frequency Control Program by verifying correct breaker alignment and indicated power availability.

(*) An inverter may be disconnected from its DC source for up to 24 hours for the purpose of performing an equalizing charge on its associated battery bank provided (1) its vital bus is OPERABLE and energized, and (2) the vital busses associated with the other battery banks are OPERABLE and energized.

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PSEG NUCLEAR LLC

EXELON GENERATION COMPANY, LLC

DOCKET NO. 50-311

SALEM NUCLEAR GENERATING STATION, UNIT NO. 2

AMENDMENT TO RENEWED FACILITY OPERATING LICENSE

Amendment No. 307
Renewed License No. DPR-75

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

   A. The application for amendment filed by PSEG Nuclear LLC, acting on behalf of itself and Exelon Generation Company, LLC (the licensees), dated May 16, 2018, as supplemented by letters dated June 14, 2018; October 18, 2018; October 20, 2018; and October 30, 2018, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's rules and regulations set forth in 10 CFR Chapter I;

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

   C. There is reasonable assurance: (i) that the activities authorized by this amendment can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations 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 amended by changes to the Technical Specifications as indicated in the attachment to this license amendment, and paragraph 2.C.(2) of Renewed Facility Operating License No. DPR-75 is hereby amended to read as follows:

    (2) Technical Specifications and Environmental Protection Plan

    The Technical Specifications contained in Appendix A, as revised through Amendment No. 307, and the Environmental Protection Plan contained in Appendix B, are hereby incorporated in the renewed license. PSEG Nuclear LLC 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 within 60 days of the date of issuance.

FOR THE NUCLEAR REGULATORY COMMISSION

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

Attachment:
Changes to Renewed Facility Operating License and Technical Specifications

Date of Issuance: January 25, 2019

ATTACHMENT TO LICENSE AMENDMENT NO. 307

SALEM NUCLEAR GENERATING STATION, UNIT NO. 2

RENEWED FACILITY OPERATING LICENSE NO. DPR-75

DOCKET NO. 50-311

Replace the following page of Renewed Facility Operating License No. DPR-75 with the attached revised page as indicated. The revised page is identified by amendment number and contains a marginal line indicating the area of change.

Remove	Insert
Page 3	Page 3

Replace the following page of the Appendix A, Technical Specifications, with the attached revised page as indicated. The revised page is identified by amendment number and contains marginal lines indicating the areas of change.

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

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

(6) PSEG Nuclear LLC, pursuant to the Act and 10 CFR Parts 30, 40 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 Commission's regulations set forth in 10 CFR Chapter I and is subject to all applicable provisions of the Act and to the rules, regulations and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified or incorporated below:

(1) Maximum Power Level

PSEG Nuclear LLC is authorized to operate the facility at steady state reactor core power levels not in excess of 3459 megawatts (thermal).

(2) Technical Specifications and Environmental Protection Plan

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

3/4.8.2 ONSITE POWER DISTRIBUTION SYSTEMS

A.C. DISTRIBUTION - OPERATING

LIMITING CONDITION FOR OPERATION

3.8.2.1 The following A.C. electrical busses shall be OPERABLE and energized from sources of power other than the diesel generators:

4 kvolt	Vital Bus # 2A	
4 kvolt	Vital Bus # 2B	
4 kvolt	Vital Bus # 2C	
460 volt	Vital Bus # 2A and associated control centers	
460 volt	Vital Bus # 2B and associated control centers	
460 volt	Vital Bus # 2C and associated control centers	
230 volt	Vital Bus # 2A and associated control centers	
230 volt	Vital Bus # 2B and associated control centers	
230 volt	Vital Bus # 2C and associated control centers	
115 volt	Vital Instrument Bus # 2A and Inverter	*
115 volt	Vital Instrument Bus # 2B and Inverter	*
115 volt	Vital Instrument Bus # 2C and Inverter	*
115 volt	Vital Instrument Bus # 2D and Inverter	*

APPLICABILITY: MODES 1, 2, 3 and 4.

ACTION:

a. With less than the above complement of A.C. busses OPERABLE or energized, restore the inoperable busses to OPERABLE and energized status within 8 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

b. With one inverter inoperable, energize the associated A.C. Vital Bus within 8 hours; restore the inoperable inverter to OPERABLE and energized status within 7 days or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

SURVEILLANCE REQUIREMENTS

4.8.2.1 The specified A.C. busses and inverters shall be determined OPERABLE and energized from A.C. sources other than the diesel generators in accordance with the Surveillance Frequency Control Program by verifying correct breaker alignment and indicated voltage on the busses.

* An inverter may be disconnected from its D.C. source for up to 24 hours for the purpose of performing an equalizing charge on its associated battery bank provided (1) its vital bus is OPERABLE and energized, and (2) the vital busses associated with the other battery banks are OPERABLE and energized.

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

SAFETY EVALUATION BY THE OFFICE OF NUCLEAR REACTOR REGULATION

RELATED TO AMENDMENT NOS. 326 AND 307 TO

RENEWED FACILITY OPERATING LICENSE NOS. DPR-70 AND DPR-75

PSEG NUCLEAR LLC

EXELON GENERATION COMPANY, LLC

SALEM NUCLEAR GENERATING STATION, UNIT NOS. 1 AND 2

DOCKET NOS. 50-272 AND 50-311

1.0 INTRODUCTION

By letter dated May 16, 2018 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML18136A866), as supplemented by letters dated June 14, 2018; October 18, 2018; October 20, 2018; and October 30, 2018 (ADAMS Accession Nos. ML18169A218, ML18291B033, ML18295A399, and ML18304A131, respectively), PSEG Nuclear LLC (PSEG, the licensee), submitted a license amendment request (LAR) to revise the Salem Nuclear Generating Station (Salem), Unit Nos. 1 and 2, Technical Specification (TS) 3.8.2.1, "A.C. [Alternating Current] Distribution - Operating," to increase the vital instrument bus (VIB) inverter allowed outage time (AOT) from 24 hours to 7 days for the A, B, and C inverters, and from 72 hours to 7 days for the D inverter. The licensee stated that the proposed change will allow increased flexibility in the scheduling and performance of corrective maintenance, allow better control and allocation of resources, and reduce the potential for unplanned plant shutdowns.

2.0 REGULATORY EVALUATION

2.1 Regulatory Criteria and Guidance

The U.S. Nuclear Regulatory Commission (NRC or the Commission) staff's evaluation is based on the following guidance and regulations:

Title 10 of the *Code of Federal Regulations* (10 CFR) Section 50.36, "Technical specifications," identifies the requirements for the TS categories for operating power plants: (1) safety limits, limiting safety system settings, and limiting control settings, (2) limiting conditions for operation (LCOs), (3) surveillance requirements, (4) design features, (5) administrative controls, (6) decommissioning, (7) initial notification, and (8) written reports.

For LCOs, 10 CFR 50.36(c)(2)(i) states, in part:

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

The regulations at 10 CFR 50.65, "Requirements for monitoring the effectiveness of maintenance at nuclear power plants," requires that preventive maintenance activities must be sufficient to provide reasonable assurance that structures, systems, and components (SSCs) are capable of fulfilling their intended functions and that such activities be balanced against the objective of minimizing the unavailability of SSCs. Paragraph 50.65(a)(4) of 10 CFR requires licensees to assess and manage the increase in risk that may result from proposed maintenance activities.

Salem, Unit Nos. 1 and 2, were designed in accordance with the Atomic Industrial Forum General Design Criteria (GDC). In addition to the Atomic Industrial Forum GDC, Salem was designed to comply with PSEG's understanding of the intent of the Atomic Energy Commission's (AEC's) proposed GDCs published in July 1967. The application of AEC's proposed GDC to Salem is discussed in Section 3.1.2 of the Salem Updated Final Safety Analysis Report (UFSAR). The design criteria relevant to the proposed changes are stated below:

<u>Criterion 14 - Core Protection Systems</u>
Core protection systems, together with associated equipment, shall be designed to act automatically to prevent or to suppress conditions that could result in exceeding acceptable fuel damage limits.

<u>Criterion 15 - Engineered Safety Features Protection Systems</u>
Protection systems shall be provided for sensing accident situations and for initiating the operation of necessary engineered safety features.

<u>Criterion 20 - Protection Systems Redundancy and Independence</u>
Redundancy and independence designed into protection systems shall be sufficient to assure that no single failure or removal from service for any component or channel of a system will result in loss of the protection function. The redundancy provided shall include, as a minimum, two channels of protection for each protection function to be served.

<u>Criterion 24 - Emergency Power for Protection Systems</u>
In the event of loss-of-offsite power (LOOP), sufficient alternate sources of power shall be provided to permit the required functioning of the protection systems.

Regulatory Guide (RG) 1.174, Revision 3, "An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," dated January 2018 (ADAMS Accession No. ML17317A256), describes an acceptable risk-informed approach for assessing changes to licensing bases.

RG 1.177, Revision 1, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications," dated May 2011 (ADAMS Accession No. ML100910008), describes an acceptable risk-informed approach for assessing proposed permanent TS changes in AOTs. In addition, this RG provides risk acceptance guidelines for evaluating the results of such assessments.

As noted in RG 1.174, Revision 3, and RG 1.177, Revision 1, a risk-informed application should be evaluated to ensure the proposed changes meet the following five key principles:

- The proposed change meets the current regulations, unless it explicitly relates to a requested exemption or rule change.
- The proposed change is consistent with the defense-in-depth philosophy.
- The proposed change maintains sufficient safety margins.
- When proposed changes result in an increase in core damage frequency (CDF) or risk, the increase(s) should be small and consistent with the intent of the Commission's Safety Goal Policy Statement.
- The impact of the proposed change should be monitored using performance measurement strategies.

RG 1.200, Revision 2, "An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities," dated March 2009 (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, are sufficient to provide confidence in the results such that the PRA models can be used in regulatory decisionmaking for light-water reactors.

NRC Regulatory Issue Summary 2007-06, "Regulatory Guide 1.200 Implementation," dated March 22, 2007 (ADAMS Accession No. ML070650428), describes how the NRC will implement its technical adequacy review of plant-specific PRAs used to support risk-informed licensing actions after the issuance of RG 1.200.

2.2 Proposed TS Change

As described in the LAR, the proposed revision to TS 3.8.2.1 would extend the VIB inverter AOT Action b to 7 days, with applicability in Modes 1, 2, 3, and 4. The 1A, 1B, and 1C inverters would be increased from the current AOT of 24 hours, and the 1D inverter would be increased from an AOT of 72 hours.

The current Salem Unit No. 1, Action b for TS 3.8.2.1 is as follows:

> With one inverter inoperable, energize the associated A.C. Vital Bus within 8 hours; restore the inoperable 1A, 1B, or 1C inverter to OPERABLE and energized status within 24 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours; restore the

> inoperable 1D inverter to OPERABLE and energized status within 72 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

The proposed change would revise Salem Unit No. 1, TS 3.8.2.1 Action b as follows:

> With one inverter inoperable, energize the associated A.C. Vital Bus within 8 hours; restore the inoperable inverter to OPERABLE and energized status within 7 days or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

The current Salem Unit No. 2, Action b for TS 3.8.2.1 is as follows:

> With one inverter inoperable, energize the associated A.C. Vital Bus within 8 hours; restore the inoperable 2A, 2B, or 2C inverter to OPERABLE and energized status within 24 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours; restore the inoperable 1D inverter to OPERABLE and energized status within 72 hours or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

The proposed change would revise Salem Unit No. 2, TS 3.8.2.1 Action b as follows:

> With one inverter inoperable, energize the associated A.C. Vital Bus within 8 hours; restore the inoperable inverter to OPERABLE and energized status within 7 days or be in at least HOT STANDBY within the next 6 hours and in COLD SHUTDOWN within the following 30 hours.

2.3 Purpose of Proposed Change

TS AOTs provide a limited time to restore equipment to operable status. The AOT represents a balance between the risk associated with continued plant operation with less than the required system or component redundancy, and the risk associated with initiating a plant transient while transitioning the unit to a lower power state. Shutdown of the plant involves many plant operator activities and plant evolutions. These activities and evolutions provide challenges to plant equipment, opportunities for operator errors, and an increase in the possibility of a plant trip.

The licensee stated the following:

> The proposed change will allow increased flexibility in the scheduling and performance of corrective maintenance, allow better control and allocation of resources, and reduce the potential for unplanned plant shutdowns.

Increasing the AOT of the inverters to 7 days can increase operational safety by allowing continued steady-state operation and by avoiding additional operator activities and plant evolutions associated with plant shutdown. The AOT extension reduces unnecessary operational burdens by increasing flexibility in the scheduling and performance of corrective maintenance, which can improve the reliability of the inverters. Better control and allocation of resources is also afforded during unplanned maintenance, reducing the potential for unplanned plant shutdowns.

3.0 TECHNICAL EVALUATION

3.1 Traditional Engineering Evaluation

The licensee has requested an increased AOT of 7 days versus the current 24 hours for Required Action b for TS 3.8.2.1 for an inoperable 115 volts (V) A.C. VIB inverter A, B, or C, and 72 hours for inverter D, to troubleshoot and repair, perform post-maintenance testing, and return the inoperable inverter to service. The licensee stated that current AOTs are based on engineering judgment, taking into consideration the time required to repair an inverter and the additional risk to which the unit is exposed because of the inverter inoperability. The 72-hour AOT for the D VIB inverter is based upon allowing increased operating flexibility because it does not affect the operation of any safeguards equipment controller. In LAR Section 2.3, "Reason for the Proposed Change," the licensee stated that:

> Salem performs preventative maintenance on the VIB inverters during refueling outages. There are no current plans to perform routine preventive maintenance on a scheduled basis at power. Should the need for such maintenance be identified as a result of component performance, the necessary preventive maintenance would be planned and scheduled in accordance with PSEG procedures for on-line work management.
>
> Experience both at Salem and at other nuclear power plants has shown that the current AOTs for restoration of an inoperable VIB inverter are insufficient in certain instances to support on-line troubleshooting, corrective maintenance, and post-maintenance testing while the unit is at power. Specifically, Salem has entered TS 3.8.2.1 LCO due to an inoperable inverter 5 times since 2009. The actual times in the LCO were 9 hours 28 minutes in 2009, 16 hours 39 minutes in 2014, 23 hours 33 minutes in 2016, 16 hours 47 minutes in 2017 and 32 hours 50 minutes in 2018 (for the D inverter): however in these instances, the cause of the failures was readily evident. This allowed the troubleshooting process to be minimized thereby allowing for a quick repair and subsequent testing

The NRC staff submitted a request for additional information (RAI), dated September 6, 2018 (ADAMS Accession No. ML18250A313), requesting the licensee provide technical justification for the duration of the requested AOT (actual hours plus margin based on plant-specific past operating experience and vendor recommendations). In its response dated October 18, 2018, the licensee stated that the general maintenance activities on inverters were conducted during refueling outages. The licensee estimated 116 hours to resolve the issue, including time for conducting systematic trouble-shooting activities and post-maintenance tests for failures where root causes are not self-revealing or easily detected. The licensee further stated that preventive maintenance is not scheduled during power operation, but it may be necessitated from performance problems, and that the increased outage time would be beneficial in addressing such situations.

The NRC staff concerns regarding the potential for the loss of more than one inverter under certain circumstances needed further clarification from the licensee. For example, in the plant configuration where a safety channel on the 1A vital instrument bus is in bypass for testing while the inverter for the 1B vital bus is in a planned or an unplanned AOT, a LOOP could lead to failure of actuation of an engineered safety function (ESF) subsystem in a timely manner. This is possible because ESF actuation requires power for operation. LOOP should not disable a safety function during an AOT. Therefore, in an RAI dated September 20, 2018 (ADAMS Accession No. ML18264A012), the NRC staff requested that the licensee provide a description of the measures taken at Salem to avoid configurations that could result in a system's loss of safety function.

The licensee responded to the request by letter dated October 30, 2018. In its application, dated May 16, 2018, the licensee identified the following compensatory measures to be used during planned inverter outages:

1. Entry into the extended inverter AOT will not be planned concurrent with emergency diesel generator maintenance.

2. Entry into the extended inverter AOT will not be planned concurrent with planned maintenance on another reactor trip system or ESF actuation system instrumentation channel that could result in that channel being in a tripped condition.

Additionally, the licensee stated in its October 30, 2018, response that, in general, loss of instrumentation power to the sensors, instruments, or logic devices in the ESF places that channel in the trip mode. However, the containment spray initiating channels for both units, and the Unit No. 2 refueling water storage tank (RWST) low level logic signals for semi-automatic switchover initiation do require instrument power for actuation.

The containment spray actuation system consists of four actuation channels, and the actuation is initiated with a two-out-of-four logic. Similarly, Unit No. 2 RWST semi-automatic switchover is a four-channel system and is initiated by a two-out-of-four logic. For these two systems, the channel being tested is placed in the trip mode. Hence, if one other channel becomes unavailable on a LOOP or any other reason, only one of the two remaining channels needs to be operable to initiate the actuation of the affected function.

The NRC staff reviewed the licensee's supplemental response dated October 30, 2018, and finds that the licensee's compensatory measures for the inverters are qualitative, prudent actions because the required safety functions will not be adversely affected during testing, should there be total loss of A.C. power.

The licensee provided a list of loads on each of the four 115 V A.C. vital buses, the effect of loss of any single 115 V A.C. bus, and the compensatory measures to be taken. There are three batteries that feed four vital 115 V A.C. buses. Battery B feeds Vital Instrument Buses 1B and 1D. The load on battery B is somewhat greater than the load on batteries A and C. However, according to UFSAR Section 8.3.2.2, all three batteries are sized for 2 hours of operation on a loss of A.C. power. In case of a loss of all A.C. power, it is important to monitor the batteries to ensure that they will continue to perform their safety functions with adequate voltage.

Section 8.3.2.8, "Station Battery Monitoring," of the UFSAR describes monitoring and alarms for the station batteries. The monitoring functions include continuous control room monitoring for voltage and battery load ammeter, ground detectors, undervoltage alarm in the control room, and blown fuse alarm in the control room. The NRC staff finds these monitoring features are adequate to monitor the battery's ability to supply the connected loads.

Monitoring of the 115 V vital buses was not addressed in the amendment request. In its RAI dated September 20, 2018, the NRC staff requested the licensee to describe what type of monitoring and/or alarms are provided for the 115 V vital instrument buses. In its response dated October 30, 2018, the licensee stated that each of the four vital inverters is continuously monitored for voltage and the following other functions:

- undervoltage alarm in the main control room
- uninterruptible power supply A.C. output voltmeter
- uninterruptible power supply A.C. output frequency meter

Based on its review, the NRC staff finds that the indications and alarms are sufficient instrumentation to monitor the status of 115 V vital buses, and are proper remedial actions to be followed until the LCO can be met; therefore, the proposed changes meet 10 CFR 50.36(c)(2).

The core protection systems are designed to act automatically to prevent or suppress conditions that could result in exceeding acceptable fuel damage limits. The NRC staff finds that inverter AOT extension, along with compensatory measures included in the LAR, meet Salem Criterion 14, "Core Protection Systems."

In addition, Salem Criteria 15, "Engineered Safety Features Protection Systems," and 20, "Protection Systems Redundancy and Independence," are met because the protection system design is maintained, and the minimum channels for operation are preserved during the inverter AOT by compensatory measures.

On a LOOP, the emergency diesel generators are available to provide power to the emergency buses. The compensatory measures assure that emergency diesel generator maintenance will not be concurrent with the inverter AOT, and an inverter AOT will not be planned concurrent with a reactor trip system or ESF actuation system instrumentation channel that could result in that channel being in a tripped condition. These actions assure sufficient alternate sources of power to permit required safety functioning of the protection systems.

The proposed changes preserve reasonable balance among the layers of defense. There is no additional reliance on programmatic activities, and the system design independence and redundancies are maintained. No new common cause failures have been introduced due to the proposed changes. Therefore, the NRC staff finds that the Salem plant design maintains sufficient means to perform the safety functions of the vital instrument buses, demonstrating consistency with the defense-in-depth philosophy.

3.2 Risk Evaluation (Key Principle 4)

RG 1.177 outlines a three-tiered approach for evaluating the risk associated with a proposed change to a TS AOT:

- Tier 1 assesses the risk impact of the proposed change in accordance with acceptance guidelines consistent with the Commission's Safety Goal Policy Statement, as documented in RG 1.177. The Tier 1 assessment evaluates the impact of the proposed change on operational plant risk as represented by the change in core damage frequency (CDF or ΔCDF) and the change in large early release frequency (LERF or ΔLERF). In addition to operational plant risk, the Tier 1 assessment evaluates plant risk while equipment covered by the AOT change is out of service, as represented by the incremental conditional core damage probability

(ICCDP) and the incremental conditional large early release probability (ICLERP). The Tier 1 assessment also addresses the quality of the licensee's plant-specific PRA model used to assess the changes in risk.

- Tier 2 identifies and evaluates any potential risk-significant plant configurations that could result if any equipment, in addition to that associated with the proposed license amendment, is taken out of service simultaneously, or if other risk-significant operational factors such as concurrent system or equipment testing, are involved. The purpose of this evaluation is to ensure that there are appropriate restrictions on dominant risk-significant equipment configurations associated with the proposed change.

- Tier 3 addresses the licensee's overall configuration risk management program to ensure that the licensee has established adequate programs and procedures for identifying risk-significant plant configurations resulting from maintenance or other operational activities, and that appropriate compensatory measures are taken to avoid risk-significant configurations that may not have been considered in the Tier 2 evaluation. Compared with Tier 2, Tier 3 provides additional coverage to ensure that the licensee identifies, in a timely manner, any potentially risk-significant equipment outage configurations, and that the licensee evaluates appropriately the risk impact of out-of-service equipment prior to performing any maintenance activity over extended periods of plant operation.

3.2.1 Tier 1: PRA Quality and Insights

In accordance with Tier 1 of the three-tiered approach outlined in RG 1.177, the licensee should evaluate the change in plant risk resulting from the TS AOT change as represented by the ΔCDF, ICCDP, ΔLERF, and ICLERP. To support this evaluation, two aspects should to be considered: (1) the validity or quality of the PRA and (2) the PRA insights and findings. The licensee should demonstrate that its PRA is valid for assessing the proposed TS changes and identify the impact of the TS change on plant risk.

3.2.1.1 PRA Quality

In accordance with Section 2.3 of RG 1.177, the quality of a PRA can be determined through an assessment of the scope of the PRA and the technical acceptability of the PRA, with particular attention given to PRA modeling and assumptions and sensitivity and uncertainty analyses.

3.2.1.1.1 Scope of the PRA

Section 2.3.2 of RG 1.177 states that, as a minimum, the licensee should perform evaluations of CDF and LERF to support any risk-informed changes to TSs. The scope of the analysis should include all hazard groups (i.e., internal events, internal flood, internal fires, seismic events, high winds, transportation events, and other external hazards). Section 2.3.1 of RG 1.174 states that a qualitative treatment of the missing modes and hazard groups may be sufficient when the licensee can demonstrate that those risk contributions would not affect the decision.

As stated in the LAR, the licensee performed a quantitative evaluation of the change in risk resulting from the TS AOT using the Salem, Unit No. 1, at-power internal events and internal flooding PRA model of record. The licensee provided evaluations of the change in risk for internal fires, seismic hazards, and external flooding using insights gained from the individual

plant external events examination (IPEEE) and bounding analyses using the internal events PRA. The review of the technical acceptability of the internal events and internal flooding PRA models, and the acceptability of the qualitative and bounding analyses for internal fires, seismic, and external flooding hazards are contained in Section 3.2.1.2 of this safety evaluation.
In its LAR, licensee stated that Salem either screened out or found a negligible impact from the remaining external events indicated in NUREG 1407, "Procedural and Submittal Guidance for the Individual Plant Examination of External Events (IPEEE) for Severe Accident Vulnerabilities, Final Report," published June 1991 (ADAMS Accession No. ML063550238). The licensee screened out the events either by compliance with the 1975 Standard Review Plan criteria or by bounding probabilistic analyses that demonstrated a CDF of less than the IPEEE screening criteria as contained in NUREG-1407. The screening criteria in NUREG-1407 is bounded by the screening criteria contained in the American Society of Mechanical Engineers (ASME)/American Nuclear Society (ANS) RA-Sa–2009, "Standard for Level 1/Large Early Release Frequency Probabilistic Risk Assessment for Nuclear Power Plant Applications," which is endorsed with clarifications and exceptions by the NRC in RG 1.200, Revision 2.

Based on the review of the licensee's LAR, the NRC staff finds that, when compared to the guidance contained in RGs 1.174, 1.177, and 1.200, the licensee's risk assessment is of sufficient scope for use in this specific risk-informed application.

3.2.1.1.2 Technical Acceptability of the PRA

RG 1.200 describes one acceptable approach for determining whether the technical acceptability of a PRA is sufficient for use in regulatory decisionmaking for light-water reactors. The purpose of RG 1.200 is to (a) provide guidance to licensees for use in determining the technical acceptability of the base PRA used in a risk-informed regulatory activity and (b) endorse industry standards and peer-review guidance. In March of 2009, the NRC issued Revision 2 of RG 1.200, which endorsed, with clarifications and exceptions, the industry consensus standards for PRAs for internal events, internal floods, fires, and other external events (i.e., seismic, external flooding, high winds, etc.) contained in ASME/ANS RA-Sa-2009. The NRC staff position provided in NRC Regulatory Issue Summary 2007-06 allows 1 year before the NRC expects a licensee to implement revisions to RG 1.200 in its PRA model that is used as a basis for risk-informed LARs.

Regulatory Position 2.1 of RG 1.200 states that if a licensee demonstrates that the parts of a PRA that are used to support an application comply with the ASME/ANS standard when supplemented to account for the staff's regulatory positions contained in Appendix A of RG 1.200, the NRC would consider the PRA to be adequate to support the applicable risk-informed regulatory application. In general, the staff anticipates that current good practice (i.e., meeting Capability Category II for the supporting requirements in the ASME/ANS standard) is the level of detail that is adequate for the majority of applications.

As discussed in Section 3.2.1.1.1 of this safety evaluation, the scope of the licensee's evaluation should include an assessment of the change in risk for internal events, internal flooding, internal fires, seismic events, and external flooding. The licensee provides a quantitative assessment of the change in risk using an internal events PRA model, which includes an assessment of internal flooding. For internal fires, seismic hazards, and external flooding, the licensee provides qualitative and semi-quantitative assessments of the change in risk that is based on insights the IPEEE, and additional bounding calculations, based on insights from the internal events and flooding PRA model.

Internal Events and Internal Flooding Assessment

In November 2008, the licensee completed a full-scope peer review of its then current base PRA model (Model 4.1) against the industry PRA standard contained in ASME/ANS RA-Sb-2005 in accordance with Nuclear Energy Institute 05-04, Revision 1, "Process for Performing Follow-on PRA Peer Reviews Using the ASME PRA Standard (Internal Events)" (Draft). The peer review assessed the PRA model and all applicable supporting documentation against the applicable high-level requirements and supporting requirements (SRs) indicated in the standard. The PRA peer review resulted in a number of Facts and Observations (F&Os) that indicated some SRs were categorized as "not met" for Capability Category II. Attachment 2 to the May 16, 2018, LAR provides a summary for each of the F&Os identified during the November 2008 peer review and a brief summary of the resolution for each.

In September of 2014, the licensee updated its model of record to model Version SA112A, which addressed several of the F&Os identified in the November 2008 peer review. The licensee stated in the LAR that the changes made during the SA112A model update have been carried through to the SA115A current model of record (SA115A) unless modified by later required changes. In accordance with RG 1.200, Revision 2, the licensee performed a self-assessment to identify and address differences in the high-level requirements and SRs that were revised between the 2005 and the 2009 versions of the ASME/ANS PRA standard. In addition, the licensee performed a gap assessment against the NRC regulatory position on ASME/ANS RA-Sa-2009 contained in Appendix A of RG 1.200 in order to ensure the PRA accounts for the staff's regulatory positions.

The licensee addressed the treatment of update requirement evaluations (UREs) in Section 3.2.1.4, "URE Status," of the LAR. The open URE review identified three UREs with potential impact. Two of the UREs involve logic changes to the PRA and were incorporated into the Salem PRA application-specific model (SA115C), a modified version of the model of record, SA115A. The remaining URE identified two plant changes incorporated in the PRA that may require evaluation as PRA upgrades. This URE was addressed by sensitivity calculations provided in Section 3.2.4.2.4, "Assess Sources of Model Uncertainty in Context of Important Contributors to the Base Model," of the LAR that removed the changes. The following items were identified as significant fault tree modifications made to PRA model SA115A:

- Implementation of mitigating systems performance index pump (4th auxiliary feedwater pump)
- Station blackout event tree enhancements that make use of FLEX equipment for extended loss of A.C. power scenarios

The licensee performed a sensitivity study on the base PRA model, SA115A, by failing both the mitigating systems performance index pump and FLEX diesel generator, and recalculating ΔCDF/ΔLERF for the AOT extension. The results are reported in Table 3-16 of the LAR, "AOT Extension Sensitivity to Model Changes." The calculated values for ΔCDF/ΔLERF were shown to be within Region III of the acceptance guidelines table in RG 1.174, demonstrating a very small change in risk.

Attachment 2 to the May 16, 2018, LAR provided Tables A-1 through A-11, which included the capability category and each applicable SR with the summary assessment and resolution for the associated F&Os identified during the peer review that was performed in November 2008. The self-assessment tables identified and addressed all applicable differences between ASME/ANS

RA-Sb-2005 and RA-Sa-2009. The summary of resolution for item (I) associated with SR number QU-F2 in Table A-7 of Attachment 2 notes that the Salem PRA model of record (SA115A) was only completed for Salem, Unit No. 1, and it relies on Unit No. 2 equipment for certain support functions. In its October 20, 2018, response to the NRC RAI dated September 21, 2018 (ADAMS Accession No. ML18267A171), the licensee summarized and assessed the major differences between Salem, Units No. 1 and 2. The licensee's assessment justified that the equipment differences and dependences were small, not related to the vital bus inverters, or did not impact the inverters such that there was no risk difference. Training for operations personnel was noted to be conducted such that no differences in the human reliability analysis exists between the units or is conservative with respect to Unit No. 2. The licensee also addressed Unit No. 2 support systems that have been modeled in the PRA for Unit No. 1.

Attachment 2, Table A-12, to the May 16, 2018, LAR summarizes the comments resulting from the gap assessment performed against the NRC clarifications and qualifications in Appendix A of RG 1.200, Revision 2. Only the changes in the clarifications and comments between Revision 1 and Revision 2 of RG 1.200 were evaluated, since the peer review already included the RG 1.200, Revision 1, clarifications and qualifications when assessing the technical adequacy of the model.

Per Section 3.2.7.2, "PRA Model," of the LAR, the licensee performed the quantitative evaluation of risk metrics for the proposed change using the SA115C Salem PRA application-specific model. SA115C included the following changes to SA115A:

- Addition of inverter maintenance terms.
- Addition of inverter common cause failure terms.
- Emergency diesel generator electrical support dependencies are more accurately modeled.
- The mutually exclusive file has been edited to exclude concurrent maintenance of inverters.

Based on the review of the licensee's LAR, the NRC staff finds that the licensee, in accordance with RG 1.200, has identified and addressed all applicable differences between ASME/ANS RA-Sb-2005 and RA-Sa-2009 with the applicable regulatory positions contained in RG 1.200, Appendix A. In addition, the NRC staff finds that the F&Os associated with SRs that did not meet at least Capability Category II of the ASME/ANS standard either did not have an impact on this application or the licensee dispositioned and/or resolved them sufficiently for use in this application. As such, in accordance with Regulatory Position 2.1 of RG 1.200, the NRC staff finds that the technical acceptability of the licensee's PRA for internal events and internal flooding, as described in the LAR, is sufficient for use in supporting this specific risk-informed regulatory application. The NRC staff also finds that the cross-unit support functions, as well as Unit Nos. 1 and 2, asymmetries, are adequately accounted for in the Salem PRA SA115A model of record such that application to Salem, Unit No. 2, as well as Unit No. 1, is appropriate.

3.2.1.2 Fires, Seismic, and External Flood Events Assessment

In accordance with RGs 1.174 and 1.177, a licensee may qualitatively evaluate hazards or use bounding analyses, provided that the qualitative assessment or bounding analysis is of sufficient quality to demonstrate that the contribution to the risk increase is insignificant enough that it would not affect the NRC staff's decision. Per Section 3.2.3.1 of the licensee's LAR, Salem does not have a separate PRA for fire, seismic, and external flooding events. Salem completed an IPEEE in 1996 in accordance with NUREG-1407. However, Section 3.2.3.3 of the LAR notes that the IPEEE assessment was consistent with state of the practice in the 1990s such that it cannot be used for quantitative PRA insights. Because the licensee's PRA model of record does not account for the risk associated with internal fires, seismic, or external flooding events, the licensee provided bounding analyses for these hazards.

Per Section 3.2.3.1 of the LAR, the licensee stated that an internal fire PRA (FPRA) is currently under development for Salem but has not yet undergone an industry peer review as required by RG 1.200 for use in risk-informed regulatory applications. The current Salem FPRA follows the methodology of NUREG/CR-6850, "EPRI/NRC-RES Fire PRA Methodology for Nuclear Power Facilities: Detailed Methodology, Volume 1: Summary and Overview," dated September 2005 (ADAMS Accession No. ML15167A401), with some incorporation of more recent data and methods. The licensee recognizes that while the current FPRA can be used to provide valuable PRA insights, it cannot provide quantitative information. Therefore, in addition to qualitative information derived from the IPEEE fire assessment utilizing the EPRI Fire Induced Vulnerability Evaluation (FIVE) methodology, the licensee developed a set of stand-alone calculations to quantify the potential impact of fire events on the risk assessment.

As noted above, Section 3.2.3.3 of the LAR notes that the IPEEE assessment was consistent with state of the practice in the 1990s such that it cannot be used for quantitative PRA insights. Therefore, the licensee performed a bounding analysis to assess the potential impact of seismic events associated with the proposed VIB inverter AOT. The licensee based this assessment on current seismic hazard evaluations, plant walkdowns, and the Salem internal events PRA model. Per Section 3.2.3.4 of the LAR, the licensee addressed external flooding using a bounding analysis with insights from the Salem IPEEE screening and reevaluated flood hazard, as well as inputs from the Salem internal events PRA. The licensee developed an upper bound estimate of external flooding hazards by comparing external flooding events to a LOOP.

Based on the review of the licensee's LAR, the NRC staff finds that the bounding analyses are of sufficient quality to demonstrate that the contribution to the risk increase from internal fires, seismic events, and external flooding events is insignificant such that it would not affect the staff's decision. As such, in accordance with RGs 1.174 and 1.177, the licensee's assessment of the risk contribution from internal fires, seismic, and external flooding events is sufficient for use in this specific risk-informed application.

3.2.1.3 PRA Insights

Based on the quantitative assessment of internal events and internal flooding provided in the LAR, and taking into account the consideration of compensatory measures as described in Section 3.2.5 of the LAR, the licensee calculated the ΔCDF, ΔLERF, ICCDP, and ICLERP for the proposed 7-day AOTs. The licensee quantified for five cases – one base case and one for each channel's inverters set out of service. The licensee's calculations for ΔCDF/ICCDP and ΔLERF/ICLERP assume the inverter outage occurs once in a 12-month period. As a result, the value of ΔCDF will equal the ICCDP, and ΔLERF will equal the ICLERP, with ΔCDF/ΔLERF having units of per reactor-year and ICCDP/ICLERP being a unit-less probability. The results of the quantitative evaluations are presented in the tables below and compared to the acceptance guidelines of RG 1.174 and RG 1.177.

7-day unavailability for 115V A.C. inverter A		
Risk Metric	Acceptance Guideline	PRA Results
ΔCDF	RG 1.174, Figure 4 (Region II or III)	7.85E-10 (Region III)
ΔLERF	RG 1.174, Figure 5 (Region II or III)	1.10E-10 (Region III)
ICCDP	RG 1.177, < 1.0E-6	7.85E-10
ICLERP	RG 1.177, < 1.0E-7	1.10E-10

7-day unavailability for 115V A.C. inverter B		
Risk Metric	Acceptance Guideline	PRA Results
ΔCDF	RG 1.174, Figure 4 (Region II or III)	2.56E-09 (Region III)
ΔLERF	RG 1.174, Figure 5 (Region II or III)	1.70E-10 (Region III)
ICCDP	RG 1.177, < 1.0E-6	2.56E-09
ICLERP	RG 1.177, < 1.0E-7	1.70E-10

7-day unavailability for 115V A.C. inverter C		
Risk Metric	Acceptance Guideline	PRA Results
ΔCDF	RG 1.174, Figure 4 (Region II or III)	7.49E-09 (Region III)
ΔLERF	RG 1.174, Figure 5 (Region II or III)	6.90E-10 (Region III)
ICCDP	RG 1.177, < 1.0E-6	7.49E-09
ICLERP	RG 1.177, < 1.0E-7	6.90E-10

7-day unavailability for 115V A.C. inverter D		
Risk Metric	Acceptance Guideline	PRA Results
ΔCDF	RG 1.174, Figure 4 (Region II or III)	0.0E-00 (Region III)
ΔLERF	RG 1.174, Figure 5 (Region II or III)	0.0E-00 (Region III)
ICCDP	RG 1.177, < 1.0E-6	0.0E-00
ICLERP	RG 1.177, < 1.0E-7	0.0E-00

The risk values in the tables above are well below the RG 1.174 and RG 1.177 acceptance guidelines for an acceptable change in risk (i.e., ΔCDF and ΔLERF) and incremental increase in risk (i.e., ICCDP and ICLERP).

The licensee addressed internal fire hazards with an assessment based on insights from the Salem IPEEE, as well as an upper bound estimate of fire risk utilizing inputs from the full-power internal events PRA. The licensee developed an upper bound estimate of fire risk using the fire LOOP initiating event frequencies calculated from Supplement 1 of NUREG/CR-6850 (Frequently Asked Question 08-0048) and NUREG-2169, the change in inverter unavailability, and the probability of failure of the backup power supply. The LOOP event was chosen as the case of interest since the proposed extended AOT of the 115 V A.C. inverters will have the greatest impact during this event. The upper bound estimate assumes that the fire event damages all but one VIB inverter. The result is a surrogate ΔCDF for fire risk.

In its response dated October 20, 2018, to NRC RAI dated September 21, 2018, the licensee stated that the unavailability values for the inverters utilized in the risk calculations were derived from the existing failure rate determined for the inverters and the requested extended outage time (i.e., 7 days). The licensee noted that this approach is consistent with past Salem operating experience and planned plant operation. The licensee concluded that the above approach to quantify inverter unavailability bounds the risk increase due to other conservatisms used in the risk calculations, including the assumption that every maintenance action uses the full 7-day AOT. Therefore, the NRC staff finds that the licensee's quantitative approach to determine the potential impact of fire events is appropriate.

The surrogate ΔCDF from internal fire risk for each inverter is listed in the table below.

Risk Calculation for Fire Events

Inverter	A	B	C	D
ΔCDF	8.48E-08	6.60E-08	8.48E-08	3.49E-08

The license's calculated surrogate ΔCDF demonstrates that the change in CDF is well below the acceptance criteria in RG 1.174 and is negligible for fire scenarios, which indicates that the LERF impact will also be negligible.

For seismic events, the licensee reasoned that it can be quantitatively inferred that there would be no significant impact on seismic risk due to extending the VIB inverter AOT when the corresponding opposite train was out of service. This conclusion was based on the observation that damage to equipment during seismic events usually occurs across trains. Therefore, the licensee concluded that if a component is failed during a particular seismic event, its corresponding opposite train component is also likely to fail. In this circumstance, the operational status (in/out of service) of the opposite train equipment is irrelevant, as both trains would be expected to incur similar damage due to the seismic event. Nevertheless, the licensee developed an upper bound estimate of seismic risk using a seismic LOOP probability calculated using values from PSEG's Response to 10 CFR 50.54(f) Recommendation 2.1 of the Near-Term Task Force Review of the Fukushima Accident – Salem Generating Station, as well as inputs from the full-power internal events PRA. The upper bound estimate assumes a 7-day per year VIB inverter AOT and that LOOP recovery is not possible. The result is surrogate values for ICCDP and ICLERP. Over a 1-year period, ICCDP and ICLERP are generally equivalent to a change in CDF and LERF, respectively.

The surrogate ICCDP and ICLERP, as provided in Table 3-11 of the LAR, are shown below.

Risk Calculation for Seismic Events

Inverter	ICCDP	ICLERP
A	5.39E-12	2.06E-12
B	3.10E-11	3.44E-12
C	1.39E-11	1.43E-12
D	0.00E+00	0.00E+00

The licensee's calculated surrogate ICCDP and ICLERP values demonstrate that the impacts are estimated to be very low for a seismic scenario that only damages one component. As described above, cross-train impacts are not relevant for seismic scenarios that would damage multiple trains of equipment.

The licensee addressed external flooding with a qualitative assessment using insights from the "Salem Generating Station's Flood Hazards Mitigating Strategies Assessment (MSA) Report Submittal," dated December 30, 2016 (ADAMS Accession No. ML16365A151); current PSEG procedures, including OP-AA-108-111-1001, "Severe Weather and Natural Disaster Guidelines," and SC.OP-AB.ZZ-0001, "Adverse Environmental Conditions"; results of the Flooding Walkdown of the Near-Term Task Force Review of Insights from the Fukushima Dai-ichi Accident (ADAMS Accession Nos. ML15364A073, ML14140A307, and ML14071A401); as well as an upper bound assessment of the change in risk from flooding.

Similar to the seismic hazard evaluation, the licensee's upper bound assessment for flooding uses the weather-related loop frequency (which bounds external flooding frequencies), as well as other inputs from the full-power internal events PRA. The result is surrogate values for ICCDP and ICLERP. Over a 1-year period, ICCDP and ICLERP are generally equivalent to a change in CDF and LERF, respectively. The flooding surrogate values for ICCDP and ICLERP, as provided in Table 3-12 of the LAR, are shown below.

Risk Calculation for External Flooding Events

Inverter	ICCDP	ICLERP
A	1.01E-09	3.84E-10
B	5.79E-09	6.43E-10
C	2.60E-09	2.67E-10
D	0.00E+00	0.00E+00

The values in the table above are several orders of magnitude below the RG 1.177 decision criteria of ICCDP < 1.0E-6 and ICLERP < 1.0E-7. Therefore, the results of the bounding calculation demonstrate that the risk impact associated with external flooding is small enough that changes to extend the VIB AOT, as proposed in the LAR, do not have a significant effect on the overall risk.

Based on the review of the licensee's qualitative, quantitative, and bounding assessments provided in the LAR dated May 16, 2018, as supplemented, the NRC staff finds that the licensee performed its Tier 1 risk evaluation in accordance with the guidance outlined in RG 1.177 and is acceptable for use in this specific risk-informed application.

3.2.2 Tier 2: Risk-Significant Plant Configurations

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, a licensee's Tier 2 evaluation is expected to ensure that appropriate restrictions are placed on dominant risk-significant configurations relevant to the proposed TS change.

The NRC staff reviewed the risk metrics calculated in Section 3.2.2 and the risk insights discussed in Section 3.2.2.5 of the LAR. The staff determined that the licensee demonstrated that the Salem current configuration is well within the acceptance criteria for the proposed inverter AOT extension and established that there are no equipment outages or plant configurations with extremely high-risk contributions while an inverter is out of service.

The licensee concluded in Section 3.2.5 of the LAR that no plant configuration or equipment outage would require enhancements to TSs or plant procedures. However, the licensee provided a set of additional compensatory measures to improve the plant's defense-in-depth with one inverter in maintenance and further increase the available margin to the acceptance guidelines as described in Section 3.2.1.3 of this safety evaluation. Per Section 3.2.5 of the LAR, the following additional compensatory measures will be implemented:

1. Entry into the extended inverter AOT will not be planned concurrent with emergency diesel generator maintenance.

2. Entry into the extended inverter AOT will not be planned concurrent with planned maintenance on another reactor trip system or ESF actuation system instrumentation channel that could result in that channel being in a tripped condition.

The licensee did not directly credit these additional compensatory actions in the risk metric calculations, and the NRC staff finds that the compensatory actions are appropriate for use in the Salem, Unit Nos. 1 and 2, planned inverter outages.

Based on the review of the licensee's LAR, the NRC staff finds that the licensee performed its Tier 2 risk evaluation in accordance with the guidance outlined RG 1.177 and is acceptable for use in this specific risk-informed application.

3.2.3 Tier 3: Risk-Informed Configuration Risk Management

Consistent with the key principle that changes to TSs result in small increases in the risk to public health and safety (Key Principle 4), the licensee needs to utilize certain configuration controls. Tier 3 is the establishment of an overall configuration risk management program to ensure that other potentially lower probability, but nonetheless risk-significant, configurations resulting from maintenance and other operational activities are identified and compensated for.

The licensee's 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 planned VIB inverter maintenance activities that would adversely impact risk, and (3) evaluates the impact of maintenance on equipment or systems assumed to remain operable by the VIB inverter AOT analysis.

Because the Maintenance Rule, as codified in 10 CFR 50.65(a)(4), requires licensees to assess and manage the potential increase in risk that may result from activities such as surveillance testing and corrective and preventive maintenance, a licensee may use its existing Maintenance Rule program to satisfy Tier 3.

Risk associated with unavailable plant equipment such as VIB inverters is assessed at Salem as required by 10 CFR 50.65(a)(4). The PSEG work management administrative procedure governs on-line risk assessments. The licensee describes the on-line risk assessment as a blended approach using qualitative or defense-in-depth considerations and quantifiable PRA risk insights, when available, to complement the qualitative assessment. The licensee communicates on-line plant risk using three risk tiers (GREEN, YELLOW, and RED).

The licensee's on-line risk assessment shows that the risk level for both Salem units will remain GREEN for an outage of any single VIB inverter train unavailable per the proposed 7-day AOT. At this level, risk is considered close to baseline, and compliance with TS requirements may be considered adequate risk management. In addition, the licensee's station protected equipment program requires protection of the remaining operable VIB inverter trains if one inverter train is unavailable. Protecting equipment entails posting of signs and robust barriers to alert personnel not to approach the protected equipment, and work on protected equipment is generally disallowed. The licensee allows limited exceptions for activities such as inspections, security patrols, or emergency operations. Other exceptions may be authorized by the station shift manager in writing. If additional unplanned equipment unavailability occurs, station procedures direct that the risk be reevaluated, and if found to be unacceptable, compensatory actions are taken until such a time that the risk is reduced to an acceptable level.

Based on the review of the licensee's LAR, the NRC staff finds that the licensee's Tier 3 configuration risk management program is in accordance with the guidance outlined in RG 1.177 and is acceptable for use in this specific risk-informed application.

The NRC staff finds that the licensee's three-tiered approach, as described above, is in accordance with Regulatory Position 2.3 of RG 1.177 and is consistent with Key Principle 4 of RG 1.177.

3.3 Performance Monitoring (Key Principle 5)

To ensure that extension of a TS AOT does not degrade operational safety over time, the licensee should ensure, as part of its Maintenance Rule program (10 CFR 50.65), that when equipment does not meet its performance criteria, the evaluation required under the Maintenance Rule includes prior related TS changes in its scope. If the licensee concludes that the performance or condition of TS equipment affected by a TS change does not meet established performance criteria, appropriate corrective action should be taken in accordance with the Maintenance Rule. Such corrective action could include consideration of another TS change to shorten the revised AOT or imposition of a more restrictive administrative limit, if the licensee determines this to be an important factor in reversing the negative trend.

As described in Section 4.1 of the LAR, the licensee monitors the reliability and availability of the VIB inverters using its Maintenance Rule program. If the pre-established reliability or availability performance criteria are not achieved for the inverters, they are considered for actions specified in 10 CFR 50.65(a)(1), which requires increased management attention and goal setting in order to restore their performance to an acceptable level.

Based on the review of the licensee's LAR, the NRC staff finds that the implementation and monitoring program for the proposed TS change described by the licensee is consistent with Key Principle 5 of RG 1.177

3.4 Conclusion

The NRC staff has evaluated the licensee's proposed amendments to revise TS 3.8.2.1, "A.C. Distribution - Operating," which would increase the VIB Inverter AOT from 24 hours to 7 days for the A, B, and C inverters, and from 72 hours to 7 days for the D inverter. The deterministic evaluation in Section 3.1 of this Safety Evaluation supports the conclusion of continued reasonable assurance of adequate protection. Further, in accordance with the risk-informed considerations of RGs 1.174, 1.177, and 1.200, the staff finds that the risk increase associated with the licensee's proposed changes to TS 3.8.2.1 is small and consistent with the intent of the Commission's Safety Goal Policy Statement and that the licensee has performance measurement strategies in place to monitor the impact of the proposed changes. Therefore, the NRC staff finds that the licensee's proposed changes meet the applicable regulatory requirements and are, therefore, acceptable.

4.0 STATE CONSULTATION

In accordance with the Commission's regulations, the New Jersey State official was notified of the proposed issuance of the amendments on July 10, 2018. The State official had no comments.

5.0 ENVIRONMENTAL CONSIDERATION

The amendments change requirements with respect to the installation or use of facility components located within the restricted area as defined in 10 CFR Part 20. 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, and there has been no public comment on such finding (83 FR 31186; July 3, 2018). 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.

6.0 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: January 25, 2019

SUBJECT: SALEM NUCLEAR GENERATING STATION, UNIT NOS. 1 AND 2 – ISSUANCE OF AMENDMENT NOS. 326 AND 307 RE: REVISE TECHNICAL SPECIFICATIONS TO INCREASE VITAL INSTRUMENT BUS INVERTER ALLOWED OUTAGE TIME (EPID L-2018-LLA-0140) DATED JANUARY 25, 2019

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