UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION I
2100 RENAISSANCE BLVD., SUITE 100
KING OF PRUSSIA, PA 19406-2713

February 2, 2017

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

SUBJECT: SALEM NUCLEAR GENERATING STATION, UNIT NOS. 1 AND 2 – INTEGRATED INSPECTION REPORT 05000272/2016004 AND 05000311/2016004

Dear Mr. Sena:

On December 31, 2016, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at Salem Nuclear Generating Station, Units 1 and 2. On January 18, 2017, the NRC inspectors discussed the results of this inspection with Mr. Charles McFeaters, Salem Vice President, and other members of your staff. The results of this inspection are documented in the enclosed report.

NRC inspectors documented two findings of very low safety significance (Green) in this report. One of these findings involved a violation of NRC requirements. Further, inspectors documented a licensee-identified violation which was determined to be of very low safety significance in this report. The NRC is treating these violations as non-cited violations (NCVs) consistent with Section 2.3.2.a of the Enforcement Policy.

If you contest the violations or significance of these NCVs, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001; with copies to the Regional Administrator, Region I; the Director, Office of Enforcement; and the NRC Resident Inspector at Salem Nuclear Generating Station. In addition, if you disagree with a cross-cutting aspect assignment or a finding not associated with a regulatory requirement in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your disagreement, to the U. S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001; with copies to the Regional Administrator, Region I, and the NRC Resident Inspector at Salem Nuclear Generating Station.

This letter, its enclosure, and your response (if any) will be made available for public inspection and copying at http://www.nrc.gov/reading-rm/adams.html and the NRC Public Document Room in accordance with 10 CFR 2.390, "Public Inspections, Exemptions, Requests for Withholding."

Sincerely,

/RA/

Fred L. Bower, III, Chief
Reactor Projects Branch 3
Division of Reactor Projects

Docket Nos. 50-272 and 50-311
License Nos. DPR-70 and DPR-75

Enclosure:
Inspection Report 05000272/2016004 and
05000311/2016004
w/Attachment: Supplementary Information

cc w/encl: Distribution via ListServ

Letter to Peter P. Sena from Fred L. Bower

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U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket Nos.	50-272 and 50-311
License Nos.	DPR-70 and DPR-75
Report Nos.	05000272/2016004 and 05000311/2016004
Licensee:	PSEG Nuclear LLC (PSEG)
Facility:	Salem Nuclear Generating Station, Units 1 and 2
Location:	P.O. Box 236 Hancocks Bridge, NJ 08038
Dates:	October 1, 2016 through December 31, 2016
Inspectors:	P. Finney, Senior Resident Inspector A. Ziedonis, Resident Inspector J. DeBoer, Emergency Preparedness Specialist J. Hawkins, Hope Creek Senior Resident Inspector J. Kulp, Senior Reactor Inspector P. Ott, Operations Engineer
Approved By:	Fred L. Bower, III, Chief Reactor Projects Branch 3 Division of Reactor Projects

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SUMMARY

Inspection Report (IR) 05000272/2016004, 05000311/2016004; 10/01/2016 – 12/31/2016; Salem Nuclear Generating Station Units 1 and 2; Maintenance Effectiveness; Follow-Up of Events and Notices of Enforcement Discretion.

This report covered a three-month period of inspection by resident inspectors and announced inspections performed by regional inspectors. The inspectors identified two self-revealing findings, both of very low safety significance (Green), one of which was a non-cited violation (NCV). The significance of most findings is indicated by their color (i.e., greater than Green, or Green, White, Yellow, Red) and determined using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process (SDP)," dated April 29, 2015. Cross-cutting aspects are determined using IMC 0310, "Aspects Within Cross-Cutting Areas," dated December 4, 2014. All violations of NRC requirements are dispositioned in accordance with the NRC's Enforcement Policy, dated November 1, 2016. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 6.

Cornerstone: Initiating Events

- Green. The inspectors determined there was a self-revealing Green non-cited violation (NCV) of Technical Specification (TS) 6.8.1.c, "Surveillance and test activities of safety-related equipment," when PSEG did not establish adequate procedures for restoring service water (SW) to a drained section of discharge piping from the containment fan coil unit (CFCU) following surveillance test activities. Consequently, during restoration of SW to 22 CFCU following testing on August 31, 2016, refilling the voided SW piping created a pressure pulse sufficient to extrude the motor cooler cover plate spacer gasket inside primary containment, resulting in leakage that caused a 21 reactor coolant pump (RCP) cable fault and subsequent reactor trip. PSEG entered the issue in the corrective action program (CAP), performed a root cause evaluation (RCE), and revised applicable procedures for filling and venting SW to the CFCUs on September 19, 2016.

  This issue was more than minor since it was associated with the procedure quality attribute of the Initiating Events cornerstone and adversely impacted its objective to limit the likelihood of events that upset plant stability and challenge critical safety functions. Using IMC 0609, Attachment 4 and Appendix A, Exhibit 1, the inspectors determined that this finding was of very low safety significance, or Green, since mitigating equipment relied upon to transition the plant to stable shutdown remained available. The finding had a cross-cutting aspect in the area of Problem Identification and Resolution, Evaluation, because PSEG did not thoroughly evaluate previous CFCU motor cooler gasket leaks such that the resolution addressed the cause. [P.2] (Section 4OA3)

Cornerstone: Mitigating Systems

- Green. A self-revealing Green finding (FIN) against MA-AA-716-010, "Maintenance Planning Process," step 4.2.3, Revision 18, was identified for PSEG's inadequate maintenance guidance that resulted in 11 steam generator feedwater pump (SGFP) elevated vibrations and required an emergent down power to be taken out of service due to a coupling and shaft failure. PSEG entered this issue in their CAP as notification (NOTF) 20739299, conducted a prompt investigation, troubleshooting, repairs, and a completed a causal evaluation under Order 70189096.

This issue was more than minor since it was associated with the equipment performance attribute of the Mitigating Systems cornerstone and adversely impacted its objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. The finding screened to Green in accordance with IMC 0609, Appendix A, because the finding did not represent an actual loss of function of one or more non-TS equipment trains designated as high safety-significant in accordance with PSEG's Maintenance Rule (MR) program. The finding had a cross-cutting aspect in the area of Problem Identification and Resolution, Operating Experience (OE), because PSEG did not ensure that the organization systematically and effectively collects, evaluates, and implements relevant internal and external operating experience in a timely manner. [P.5] (Section 1R12)

Other Findings

A violation of very low safety significance that was identified by PSEG was reviewed by the inspectors. Corrective actions (CAs) taken or planned by PSEG have been entered into PSEG's CAP. This violation and CA tracking number are listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status

Unit 1 began the inspection period at 100 percent rated thermal power (RTP). On November 9, the unit was reduced to approximately 58 percent power in support of planned turbine valve testing and corrective maintenance. The unit returned to 100 percent RTP on November 12. The unit remained at or near 100 percent RTP for the remainder of the inspection period.

Unit 2 began the inspection period at 100 percent RTP. The unit remained at or near 100 percent RTP for the remainder of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01 – 1 sample)

Readiness for Seasonal Extreme Weather Conditions

a. Inspection Scope

The inspectors reviewed PSEG's preparations for the onset of seasonal winter weather conditions on December 29. The review focused on plant systems that were most susceptible to cold weather challenges. The inspectors reviewed the Updated Final Safety Analysis Report (UFSAR) and TSs to determine what temperatures or other seasonal weather could challenge these systems. The inspectors reviewed station procedures, work orders (WO), and CA notifications to ensure PSEG personnel had adequately prepared for these challenges. The inspectors walked down the SW intake structure, circulating water intake structure, Unit 1 and 2 auxiliary buildings and roofs, Unit 1 and 2 turbine building roofs, Unit 2 SW accumulators and canyon storage area for Mitigating Strategies equipment to ensure station personnel identified issues that could challenge the operability of the systems during cold weather conditions. Documents reviewed for each section of this IR are listed in the Attachment.

b. Findings

No findings were identified.

1R04 Equipment Alignment

Partial System Walkdown (71111.04Q – 3 samples)

a. Inspection Scope

The inspectors performed partial walkdowns of the following systems:

- Unit 1, Main turbine overspeed protection with one governor valve out of service (OOS) on November 10,
- Unit 2, CFCUs with 22 CFCU OOS on October 3, and
- Unit 2, SW with 21 and 22 SW pumps unavailable on November 1.

The inspectors selected these systems based on their risk-significance relative to the reactor safety cornerstones at the time they were inspected. The inspectors reviewed

applicable operating procedures, system diagrams, the UFSAR, TSs, WOs, NOTFs, and the impact of ongoing work activities on redundant trains of equipment in order to identify conditions that could have impacted the system's performance of its intended safety functions. The inspectors also performed field walkdowns of accessible portions of the systems to verify system components and support equipment were aligned correctly and were operable. The inspectors examined the material condition of the components and observed operating parameters of equipment to verify that there were no deficiencies. The inspectors also reviewed whether PSEG staff had properly identified equipment issues and entered them into the CAP for resolution with the appropriate significance characterization.

b. Findings

No findings were identified.

1R05 Fire Protection

.1 Resident Inspector Quarterly Walkdowns (71111.05Q – 4 samples)

a. Inspection Scope

The inspectors conducted tours of the areas listed below to assess the material condition and operational status of fire protection features. The inspectors verified that PSEG controlled combustible materials and ignition sources in accordance with administrative procedures. The inspectors verified that fire protection and suppression equipment was available for use as specified in the area pre-fire plan, and passive fire barriers were maintained in good material condition. The inspectors also verified that station personnel implemented compensatory measures for OOS, degraded, or inoperable fire protection equipment, as applicable, in accordance with procedures.

- Unit 1, Mechanical penetration area on October 11
- Unit 2, Auxiliary building ventilation units on October 31
- Unit 2, Relay room following damper test failure on November 18
- Common, Charging pump areas on November 28

b. Findings

No findings were identified.

.2 Fire Protection – Drill Observation (71111.05A – 1 sample)

a. Inspection Scope

The inspectors evaluated specific attributes as follows:

The inspectors observed an unannounced fire brigade drill scenario conducted on October 26 that involved a fire in the circulating water boiler house. The inspectors evaluated the readiness of the plant fire brigade to fight fires. The inspectors verified that PSEG personnel identified deficiencies, openly discussed them at the debrief in a self-critical manner, and took appropriate CAs as required. The inspectors evaluated specific attributes as follows:

- Proper wearing of turnout gear and self-contained breathing apparatus,
- Proper use and layout of fire hoses,
- Employment of appropriate fire-fighting techniques,
- Sufficient fire-fighting equipment brought to the scene,
- Effectiveness of command and control,
- Search for victims and propagation of the fire into other plant areas,
- Smoke removal operations,
- Utilization of pre-planned strategies,
- Adherence to the pre-planned drill scenario, and
- Drill objectives met.

The inspectors also evaluated the fire brigade's actions to determine whether these actions were in accordance with PSEG's fire-fighting strategies.

b. Findings

No findings were identified.

1R06 Flood Protection Measures (71111.06 – 1 sample)

Internal Flooding Review

a. Inspection Scope

The inspectors reviewed the UFSAR, the site flooding analysis, and plant procedures to identify internal flooding susceptibilities for the site. The inspectors review focused on the 4 kilovolt (kV) switchgear and 480V/230V areas following water in a 4kV cable. It verified the adequacy of equipment seals located below the flood line, floor and water penetration seals, watertight door seals, common drain lines and sumps, sump pumps, level alarms, control circuits, and temporary or removable flood barriers. It assessed the adequacy of operator actions that PSEG had identified as necessary to cope with flooding in this area and also reviewed the CAP to determine if PSEG was identifying and correcting problems associated with both flood mitigation features and site procedures for responding to flooding.

b. Findings

No findings were identified.

1R07 Heat Sink Performance (71111.07T – 3 samples)

a. Inspection Scope

Based on risk ranking of safety-related heat exchangers (HXs), a review of past heat sink inspections, and recent operational experience the inspectors selected the ultimate heat sink (UHS), which included Salem Unit 2 SW system piping integrity and intake structure functionality and operation. The inspectors also selected for review the inspection, cleaning, and performance testing methods and frequency used to ensure the heat removal capabilities for the 1A emergency diesel generator (EDG) jacket water (S1DG - 1DAE58) and lube oil (S1DG - 1DAE1) coolers and the 22 component cooling (CC) HX (S2CC - 2CCE6) and compared them to PSEG's commitments made in response to Generic Letter (GL) 89-13, Service Water System Problems Affecting Safety-Related Equipment.

Triennial Review

The inspectors verified that any potential HX deficiencies which could mask degraded performance were being identified. The inspectors reviewed the procedures for maintaining the safety function of the selected HXs and verified that the HXs were effectively monitored by means of inspection, cleaning, and performance testing and verified that these activities were consistent with the Electric Power Research Institute (EPRI) NP-7552, "Heat Exchanger Performance Monitoring Guidelines" and accepted industry practices.

HX Directly Cooled by the SW System

The 1A EDG jacket water and lube oil coolers and the 22 CC HX are directly cooled by SW. The inspectors determined whether testing, inspection, maintenance, and monitoring of biotic fouling and macrofouling programs for these HXs were singularly or in combination adequate to ensure proper heat transfer.

PSEG staff conducted periodic HX performance testing on the 22 CC HX. The inspectors reviewed the test method and a sample of results to verify performance. The inspectors verified the following items:

(a) The selected test methodology is consistent with accepted industry practices, or equivalent,
(b) Test conditions are consistent with the selected methodology,
(c) Test acceptance criteria are consistent with the design basis values,
(d) Test results have appropriately considered differences between testing conditions and design conditions,
(e) Frequency of testing based on trending of test results is sufficient (based on trending data) to detect degradation prior to loss of heat removal capabilities below design basis values, and
(f) Test results have considered test instrument inaccuracies and differences.

PSEG staff conducted periodic HX inspection/cleaning on the in-series EDG jacket water and lube oil coolers and the 22 CC HX. The inspectors reviewed the methods and results of a sample of inspections and cleanings. The inspectors verified the following:

(a) Methods used to inspect and clean HXs are consistent with as-found conditions identified and expected degradation trends and industry standards.
(b) Inspection and cleaning activities have established acceptance criteria, and are consistent with industry standards.
(c) As found results are recorded, evaluated, and appropriately dispositioned such that the as-left condition is acceptable.

Specifically, the inspectors reviewed the HX performance test results, visual inspection records, photographs of the as-found condition, HX specification sheets, HX tube eddy current test reports, and preventative maintenance activities to determine the structural integrity of the HX tubes and to verify that the HXs were maintained consistent with design assumptions in the heat transfer calculations associated with normal, accident, and transient conditions, the description of these components in the UFSAR and in accordance with TS requirements. The inspectors verified that the number of plugged tubes were within pre-established limits, based on heat transfer capability and design

heat transfer assumptions, and were accounted for in the HX performance calculations. The inspectors reviewed flow testing at or near maximum design flow for redundant and infrequently used HXs. The inspectors verified that PSEG staff had controls and operational limits in-place to prevent HX degradation due to excessive flow induced vibration during operation.

Salem Unit 2 SW System

The SW functions as the UHS to provide cooling water flow from the Delaware River to the safety-related HXs during normal operation and loss of offsite power. The inspectors verified that potential common cause heat sink performance problems that have the potential to increase risk were identified, such as potential icing at circulating and SW intake structures. The inspectors verified that the PSEG staff had adequately identified and resolved heat sink performance problems that could result in initiating events or affect multiple HXs in mitigating systems.

The inspectors reviewed the system design to evaluate the adequacy of system monitoring and performance testing. The inspectors reviewed procedures, calculations, and design drawings to verify they were consistent with the design and licensing basis. The inspectors performed walk-downs of the control room panels to verify that the instrumentation that operators relied on for decision making was available and functional. The inspectors reviewed operation of the SW, which encompassed procedures for intake structure operation, abnormal operations, adverse weather conditions, and leak isolation.

To assess the structural integrity of the SW piping and ensure that piping or intake structure degradation was appropriately identified and dispositioned the inspectors performed walkdowns of accessible areas of the intake area (including the SW pumps, strainers, and traveling screens) reviewed station procedures and interviewed engineering personnel. The inspectors reviewed a sample of non-destructive examination records, photographs, including completed or planned CAs to assess the structural integrity condition of the SW piping. The inspectors reviewed pipe inspection records and performed a walkdown of accessible areas containing SW piping to ensure that any leakage or degradation was appropriately identified and dispositioned.

The inspectors reviewed operational and maintenance history, system health reports, and in-service testing results for adverse trends and to verify that the SW functioned as designed. In addition, the inspectors reviewed the monitoring and testing of interface valves between safety-related SW and non-safety-related piping systems to ensure that adequate system flow is available post-accident consistent with design basis assumptions. Surveillance test results were reviewed to verify that the systems and components functioned as designed to verify that the minimum calculated flow rates were properly maintained to essential safety-related components and met the acceptance criteria in the UFSAR and in accordance with American Society of Mechanical Engineers (ASME) Code requirements.

Problem Identification and Resolution

The inspectors verified that PSEG staff entered significant HX/sink performance problems in the CAP. The inspectors verified that PSEG's CAs were appropriate. A list of documents reviewed is provided in the Attachment to this report.

b. Findings

No findings were identified.

1R11 Licensed Operator Requalification Program (71111.11Q – 1 sample)

.1 Quarterly Review of Licensed Operator Requalification Testing and Training

a. Inspection Scope

The inspectors observed licensed operator simulator training on October 25, which included a transmission line fire, SW valve failure, non-vital electrical bus fault, loss of all four RCPs, anticipated transient without scram event, and a reactor coolant system leak. The inspectors evaluated operator performance during the simulated event and verified completion of risk significant operator actions, including the use of abnormal and emergency operating procedures. The inspectors assessed the clarity and effectiveness of communications, implementation of actions in response to alarms and degrading plant conditions, and the oversight and direction provided by the control room supervisor. The inspectors verified the accuracy and timeliness of the emergency classification made by the shift manager and the TS action statements entered by the shift technical advisor. Additionally, the inspectors assessed the ability of the crew and training staff to identify and document crew performance problems.

b. Findings

No findings were identified.

.2 Annual Review (71111.11A – 1 sample)

a. Inspection Scope

On November 7, NRC region-based inspectors conducted an in-office review of results of the licensee-administered comprehensive written examinations and annual operating tests for 2016 for Salem Nuclear Generating Station Unit 1 and 2 operators. The inspection assessed whether Pass/Fail rates were consistent with the guidance of IMC 0609, Appendix I, and “Operator Requalification Human Performance Significance Determination Process (SDP)”. The review verified that the failure rate (individual or crew) did not exceed 20 percent.

- Six out of 74 operators failed at least one section of the Annual Exam. The overall individual failure rate was 8.1 percent.
- None of the 12 crews failed the simulator test. The crew failure rate was 0.0 percent.

b. Findings

No findings were identified.

1R12 Maintenance Effectiveness (71111.12Q – 3 samples)

a. Inspection Scope

The inspectors reviewed the samples listed below to assess the effectiveness of maintenance activities on structure, system, and component (SSC) performance and reliability. The inspectors reviewed system health reports, CAP documents, maintenance WOs, and MR basis documents to ensure that PSEG was identifying and properly evaluating performance problems within the scope of the MR. For each sample selected, the inspectors verified that the SSC was properly scoped into the MR in accordance with Title 10 of the *Code of Federal Regulations* (10 CFR) 50.65 and verified that the (a)(2) performance criteria established by PSEG staff was reasonable. As applicable, for SSCs classified as (a)(1), the inspectors assessed the adequacy of goals and CAs to return these SSCs to (a)(2). Additionally, the inspectors ensured that PSEG staff was identifying and addressing common cause failures that occurred within and across MR system boundaries.

- Unit 1, SGFPs on December 15
- Unit 2, 22 CFCU motor cooler leak on November 9
- Common, Quality control (QC) review of Bailey positioners used in CC HX valves on December 14

b. Findings

Introduction. A self-revealing Green FIN against MA-AA-716-010, "Maintenance Planning Process," was identified for PSEG's inadequate maintenance guidance that resulted in the 11 SGFP experiencing elevated vibrations and ultimately requiring an emergent down power to be taken out of service due to a coupling and shaft failure.

Description. On August 31, 2016, at 2:19 a.m., Salem Unit 1 operators received a vibration alarm for the 11 SGFP. Following a report that turbine bearing vibration of 4.0 mils indicated on its associated panel, maintenance technicians instrumented the SGFP and determined that failure was not imminent. By 7:07 a.m., the turbine outboard bearing vibration level had risen to 4.6 mils. Operators responded to this increase in vibrations by biasing the 11 SGFP turbine speed (reducing relative to the 12 SGFP turbine speed) by 200 rpm in accordance with the overhead alarm response procedure, S1.OP-AR.ZZ-0007, Step 3.5, to reduce 11 SGFP vibrations and transfer load to the 12 SGFP. By this time, 11 SGFP vibrations had been as high as 5.2 mils. Following a 0.2 percent load reduction, vibrations were averaging 5.0 mils. At 8:31 a.m., operators began a series of two percent power reductions and bias adjustments in additional attempts to reduce 11 SGFP vibrations. At 9:10 a.m., operators entered PSEG's abnormal operating procedure (AOP) S1.OP-AB.LOAD-0001, Rapid Load Reduction, in preparations for reducing Salem Unit 1 main turbine load. At 11:20 a.m., with main turbine load at 89.5 percent, maintenance technicians reported that a crack had been observed on the turbine-to-pump shafts' coupling. Sixteen minutes later, at 11:36 a.m., operators commenced a power reduction to 58 percent power in accordance with the rapid load reduction AOP and S1.OP-SO.TRB-0002, Turbine-Generator Shutdown Operations, and removed the 11 SGFP from service at 12:42 p.m. PSEG entered this issue in their CAP as NOTF 20739299, conducted a prompt investigation, troubleshooting, repairs, and a completed a causal evaluation under Order 70189096.

Upon further investigation, PSEG determined that the pump shaft coupling hub nut had unthreaded, and separated from the pump shaft. Without the pump coupling hub nut in

place, there were insufficient restraining forces to prevent the pump coupling hub from separating from the tapered pump shaft, resulting in a loss of coupling lubrication and subsequently led to the SGFP coupling failure and cracked pump shaft. PSEG reviewed the Salem Unit 1 SGFP vendor manual for SGFP installation, operation and maintenance vendor technical document (VTD) 125228), and found that the vendor guidance directed the installation of a 'dog-point' set screw beyond the full width of the pump coupling nut to ensure that the coupling nut does not unthread from the pump shaft. Contrary to the vendor guidance, the setscrew that had been installed was not the full length of the coupling nut. PSEG identified that their SGFP maintenance procedure, SC.MD-CM.CN-0001, did not contain the vendor guidance to ensure the installation of a 'dog-point' set screw beyond the full width of the pump coupling nut. This gap in PSEG's SGFP maintenance procedure led to incorrect installation of the set screw the last time the 11 SGFP coupling had been repacked, which was during the spring 2016 refueling outage (WO 30280859).

PSEG's evaluation also determined that since the nut is left-handed, the only manner in which it would loosen given pump rotation was on a significant deceleration. PSEG acknowledged that the 11 SGFP had experienced multiple speed deceleration events between May 26, 2016, and August 3, 2016, due to Advanced Digital Feedwater Control System (ADFWCS) testing and a subsequent feed pump trip when a module failed in the ADFWCS (NOTF 20736802) which corresponded to a deceleration rate of >400 rpm/sec. PSEG found that these significant rate changes impacted the torque on the 11 SGFP coupling locknut, prompting reverse rotation, which was not prevented by the set screw (70188956).

PSEG procedures MA-AA-716-010 (steps 4.2.3, 4.8.8, 4.12.2.3 and 4.21) and MA-AA-716-010-1000 (5.3, 5.14.8, 5.14.11, 5.15.6, and 5.18) used for maintenance planning and the planning process, requires the incorporation of vendor documentation, information and guidance into the work plan, and the performance of the work plan in accordance with approved procedures and vendor technical guidance.

Based on the information above, the inspectors concluded that PSEG not incorporating the vendor manual guidance concerning proper set screw installation into their maintenance procedure was a performance deficiency that was within their ability to foresee and correct, and should have been prevented. PSEG's CAs included: 1) replacing the entire 11 SGFP rotating assembly and installing a new coupling; 2) properly installing a 'dog-point' set screw in accordance with the vendor guidance on all Salem SGFPs; 3) revising the Salem SGFP maintenance procedures to ensure the procedures contain all of the applicable vendor guidance; 4) performing an extent of condition on the other three SGFPs; and 5) assigning actions for Hope Creek to review the issue for applicability to their reactor feed pumps (identical design to the SGFPs).

Analysis. PSEG not incorporating pertinent vendor manual guidance into their SGFP maintenance procedure was a performance deficiency that was within PSEG's ability to foresee and correct. This issue was more than minor since it was associated with the equipment performance attribute of the Mitigating Systems cornerstone and adversely impacted its objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, elevated SGFP vibrations and a damaged coupling resulted in removing the 11 SGFP from service. The inspectors determined that this finding screened to Green in accordance with IMC 0609, Appendix A, because the finding did not represent an actual loss of function of one or more non-TS equipment trains designated as high safety-significant in accordance with PSEG's MR program.

The finding had a cross-cutting aspect in the area of Problem Identification and Resolution, OE, because PSEG did not ensure that the organization systematically and effectively collects, evaluates, and implements relevant internal and external operating experience in a timely manner. Specifically, PSEG did not thoroughly and effectively review external operating experience, OE 307358, from 2013, that involved a reactor feed pump coupling nut of identical design, unthreading due to inadequate set screw engagement. A thorough review of this external OE would have led to a revision to the Salem SGFP maintenance procedure ensuring the vendor guidance on set screw installation was adequate. [P.5]

Enforcement. This finding does not involve enforcement action because no violation of a regulatory requirement was identified. PSEG procedure MA-AA-716-010, "Maintenance Planning Process," step 4.2.3, Revision 18, states, in part, when developing work instructions, determine the repair technique and review vendor technical information input. PSEG's VTD 125228, "Steam Generator Feedwater Pumps – Instructions for Installation, Operation and Maintenance Manual for Feed Pumps Type WGID," Revision 3, directs the installation of a 'dog-point' set screw beyond the full width of the pump coupling nut to ensure that the coupling nut does not unthread from the pump shaft. Contrary to MA-AA-716-010, step 4.2.3, the work instruction contained in the 18-month preventive maintenance activity (WO 30280859) performed during the spring 2016 refueling outage did not contain vendor technical information to ensure installation of a 'dog-point' set screw beyond the full width of the pump coupling nut. Additionally, PSEG's procedure, SC.MD-CM.CN-0001, "Steam Generator Feed Pump Disassembly, Inspection, Repair, and Reassembly," Revision 21, did not contain the detailed vendor instructions for set screw installation. This gap in PSEG's maintenance work process led to incorrect installation of the set screw the last time the 11 SGFP coupling had been removed for maintenance, which ultimately led to the SGFP coupling failure and cracked shaft on August 31, 2016. PSEG's immediate CAs included replacing the entire 11 SGFP rotating assembly and coupling, and revising their SGFP maintenance procedures. PSEG entered this issue into their CAP under NOTF 20740006. Because this finding does not involve a violation and is of very low safety significance, Green, it is identified as a FIN. **(FIN 05000272/2016004-01, Inadequate Maintenance Procedure for Steam Generator Feedwater Pump Coupling Hub Set Screw Installation)**

1R13 Maintenance Risk Assessments and Emergent Work Control (71111.13 – 2 samples)

a. Inspection Scope

The inspectors reviewed station evaluation and management of plant risk for the maintenance and emergent work activities listed below to verify that PSEG performed the appropriate risk assessments prior to removing equipment for work. The inspectors selected these activities based on potential risk significance relative to the reactor safety cornerstones. As applicable for each activity, the inspectors verified that PSEG personnel performed risk assessments as required by 10 CFR 50.65(a)(4) and that the assessments were accurate and complete. When PSEG performed emergent work, the inspectors verified that operations personnel promptly assessed and managed plant risk. The inspectors reviewed the scope of maintenance work and discussed the results of the assessment with the station's probabilistic risk analyst to verify plant conditions were consistent with the risk assessment. The inspectors also reviewed the TS requirements and inspected portions of redundant safety systems, when applicable, to verify risk analysis assumptions were valid and applicable requirements were met.

- Unit 1, Emergent troubleshooting in response to 1R11A elevated counts on October 17
- Unit 2, Emergent troubleshooting in response to 21 auxiliary building ventilation fan trip on November 4

b. Findings

No findings were identified.

1R15 Operability Determinations and Functionality Assessments (71111.15 – 6 samples)

a. Inspection Scope

The inspectors reviewed operability determinations for the following degraded or non-conforming conditions based on the risk significance of the associated components and systems:

- Unit 1, Pinhole leak on 12 CC water room cooler on October 26,
- Unit 2, Centrifugal charging pump minimum flow valve failure to open, operator workaround (OWA) on October 3,
- Unit 2, 2B 125VDC battery low voltage cell on November 4,
- Unit 2, Auxiliary feedwater (AFW) storage tank with low level alarm not coming in at setpoint on November 14,
- Common, Reactor vessel head vent solenoid valve O-ring material non-conformance on October 24, and
- Common, SW with intake bay sump pump unavailable on December 15

The inspectors evaluated the technical adequacy of the operability determinations to assess whether TS operability was properly justified and the subject component or system remained available such that no unrecognized increase in risk occurred. The inspectors compared the operability and design criteria in the appropriate sections of the TSs and UFSAR to PSEG's evaluations to determine whether the components or systems were operable. The inspectors confirmed, where appropriate, compliance with bounding limitations associated with the evaluations. Where compensatory measures were required to maintain operability, such as in the case of OWAs, the inspectors determined whether the measures in place would function as intended and were properly controlled by PSEG. Based on the review of the selected OWA listed above, the inspectors verified that PSEG identified OWAs at an appropriate threshold and addressed them in a manner that effectively managed OWA-related adverse effects on operators and SSCs.

b. Findings

No findings were identified.

1R18 Plant Modifications (71111.18 – 1 sample)

Permanent Modifications

a. Inspection Scope

The inspectors evaluated a modification to the Unit 2 charging system implemented by engineering change package 80102631. The inspectors verified that the design bases,

licensing bases, and performance capability of the affected systems were not degraded by the modification. In addition, the inspectors reviewed modification documents associated with the upgrade and design change. The inspectors also interviewed engineering and operations personnel.

Findings

No findings were identified.

1R19 Post-Maintenance Testing (71111.19 – 3 samples)

a. Inspection Scope

The inspectors reviewed the post-maintenance tests for the maintenance activities listed below to verify that procedures and test activities adequately tested the safety functions that may have been affected by the maintenance activity, that the acceptance criteria in the procedure were consistent with the information in the applicable licensing basis and/or design basis documents, and that the test results were properly reviewed and accepted and problems were appropriately documented. The inspectors also walked down the affected job site, observed the pre-job brief and post-job critique where possible, confirmed work site cleanliness was maintained, and witnessed the test or reviewed test data to verify QC hold point were performed and checked, and that results adequately demonstrated restoration of the affected safety functions.

- Unit 1, 1R11A containment radiation monitor failure on October 7
- Unit 1, 11 SGFP following ADFWCS failure on December 5
- Unit 2, SW to 22 CFCU flow transmitter leak on October 6

b. Findings

No findings were identified.

1R22 Surveillance Testing (71111.22 – 2 samples)

a. Inspection Scope

The inspectors observed performance of surveillance tests and/or reviewed test data of selected risk-significant structures, systems, and components to assess whether test results satisfied TSs, the UFSAR, and PSEG procedure requirements. The inspectors verified that test acceptance criteria were clear, tests demonstrated operational readiness and were consistent with design documentation, test instrumentation had current calibrations and the range and accuracy for the application, tests were performed as written, and applicable test prerequisites were satisfied. Upon test completion, the inspectors considered whether the test results supported that equipment was capable of performing the required safety functions. The inspectors reviewed the following surveillance tests:

- Unit 1, CFCU SW valve stroke timing on November 21 and
- Unit 1, 1A safeguards equipment control sequencer surveillance test on December 2

b. Findings

No findings were identified.

Cornerstone: Emergency Preparedness

1EP4 Emergency Action Level and Emergency Plan Changes (IP 71114.04 – 1 Sample)

a. Inspection Scope

PSEG implemented various changes to the Salem Emergency Action Levels (EALs), Emergency Plan, and Implementing Procedures. PSEG had determined that, in accordance with 10 CFR 50.54(q)(3), any change made to the EALs, Emergency Plan, and its lower-tier implementing procedures, had not resulted in any reduction in effectiveness of the Plan, and that the revised Plan continued to meet the standards in 50.47(b) and the requirements of 10 CFR Part 50 Appendix E.

The inspectors performed an in-office review of all EAL and Emergency Plan changes submitted by PSEG as required by 10 CFR 50.54(q)(5), including the changes to lower-tier emergency plan implementing procedures, to evaluate for any potential reductions in effectiveness of the Emergency Plan. This review by the inspectors was not documented in an NRC Safety Evaluation Report and does not constitute formal NRC approval of the changes. Therefore, these changes remain subject to future NRC inspection in their entirety. The requirements in 10 CFR 50.54(q) were used as reference criteria. The specific documents reviewed during this inspection are listed in the Attachment.

b. Findings

No findings were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

.1 Mitigating Systems Performance Index (6 samples)

a. Inspection Scope

The inspectors reviewed PSEG's submittal of the Mitigating Systems Performance Index for the following systems for the period of October 1, 2015, through September 30, 2016.

- Common, Emergency AC Power System (MS06)
- Common, High Pressure Injection System (MS07)
- Common, Cooling Water System (MS10)

To determine the accuracy of the performance indicator (PI) data reported during those periods, the inspectors used definitions and guidance contained in Nuclear Energy Institute (NEI) Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 7. The inspectors also reviewed PSEG's operator narrative logs, notifications, mitigating systems performance index derivation reports, event reports, and NRC integrated IRs to validate the accuracy of the submittals.

b. Findings

No findings were identified.

4OA2 Problem Identification and Resolution (71152 – 2 samples)

.1 Routine Review of Problem Identification and Resolution Activities

a. Inspection Scope

As required by Inspection Procedure 71152, "Problem Identification and Resolution," the inspectors routinely reviewed issues during baseline inspection activities and plant status reviews to verify PSEG entered issues into their CAP at an appropriate threshold, gave adequate attention to timely CAs, and identified and addressed adverse trends. In order to assist with the identification of repetitive equipment failures and specific human performance issues for follow-up, the inspectors performed a daily screening of items entered into their CAP and periodically attended condition report screening meetings. The inspectors also confirmed, on a sampling basis, that, as applicable, for identified defects and non-conformances, PSEG performed an evaluation in accordance with 10 CFR Part 21.

b. Findings

No findings were identified.

.2 Semi-Annual Trend Review

a. Inspection Scope

The inspectors performed a semi-annual review of site issues to identify trends that might indicate the existence of more significant safety concerns. As part of this review, the inspectors included repetitive or closely-related issues documented by PSEG included repetitive or closely-related issues that may have been documented by PSEG outside of the CAP, such as trend reports, PIs, major equipment problem lists, system health reports, MR assessments, and maintenance or CAP backlogs. The inspectors also reviewed PSEG CAP database for all quarters of 2016 to assess notifications written in various subject areas (equipment problems, human performance issues, etc.), as well as individual issues identified during the inspectors' daily condition report review (Section 4OA2.1). The inspectors reviewed the PSEG CAP trending data, conducted under LS-AA-125, to verify that PSEG personnel were appropriately evaluating and trending adverse conditions in accordance with applicable procedures.

b. Findings and Observations

No findings were identified.

PSEG documented a number of trends during the year to include water intrusion (20743735, 70189257), leaks at threaded connections (20746255), MRC-rejected evaluations (20746159), and radiation monitor performance (20738481).

With respect to radiation monitors, the inspectors noted a rise in the number of radiation monitor failures that were not resolved in a timely manner. From July 25 through December 2, there were six failures (20737200, 20736489, 20746453, 20747233, 20750062, and 20751649) that required NRC special reports, driven by either TSs or the Offsite Dose Calculation Manual. PSEG had identified a trend in radiation monitor failures on August 18 under the NOTF cited above, completed a

common cause evaluation, and generated actions to address both CA timeliness and vendor quality issues. The inspectors assessed that the individual issues were minor.

As part of PSEG's GL 89-13 Program, a Basis Document states that the site will trend the EDG SW Inlet and Outlet Temperatures. Inspectors identified that this is not done, although the data is collected and could be trended. While trending of the temperature change across a HX alone does not necessarily provide enough information to detect degradation of the heat transfer surfaces, it would show that the HX is capable of transferring heat. However, the inspectors noted that this method does not fully meet the industry Electric Power Research Institute (EPRI) guidelines as a method to monitor performance. Salem's GL 89-13 Program commitment method of ensuring EDG HX functionality is periodic inspection and cleaning. As documented in Section 1R07 of this report, the inspectors determined that PSEG was in compliance with station GL 89-13 commitments. PSEG documented this issue in NOTF 20749932.

Additionally, in response to several inspector and third party observations on the timeliness of documenting deficiencies, PSEG documented a trend in the staff's threshold for NOTF initiation (20738075, 20751437, and 20751821).

.3 Annual Sample: Plant Barrier Impairment Issues

a. Inspection Scope

Since late 2013, a number of issues related to plant barrier impairments (PBI) have been identified. Green NCVs were identified in IR 05000272;311/2013-004, 2015-001, and 2015-004. The inspectors completed an inspection of PSEG's evaluation, prioritization, and CAs for these and related issues. The inspectors conducted interviews, walked down plant equipment, and reviewed causal evaluations and CAs.

b. Findings and Observations

No findings were identified.

Following the first 2015 NCV, PSEG's apparent cause evaluation determined that a contributing cause was that PBI training had not been provided to Operations and Maintenance departments because the task was not analyzed and the need for additional training was not recognized to close a knowledge gap (70176616). To address this, one long term corrective action (LTCA) from this evaluation was to include this training in Plant Access Training to station staff as approved by the Senior Training Counsel. Inspectors observed that in completing the LTCA, PSEG determined that "although not in Plant Access Training as the action directs, NEIT (nuclear in-processing training) is required training for all personnel." This was contrary to LS-AA-125, "Corrective Action Program," Revision 21, step 4.5.3 that "if the intent of a 'corrective action' cannot be performed as assigned," then the change requires department head approval and that change of intent requests are reviewed and approved by the Management Review Committee. PSEG documented this in NOTF 20753322. Inspectors determined that this issue was minor in accordance with IMC 0612 Appendix B.

4OA3 Follow-Up of Events and Notices of Enforcement Discretion (71153 – 4 samples)

.1 Plant Events

a. Inspection Scope

For the plant events listed below, the inspectors reviewed and/or observed plant parameters, reviewed personnel performance, and evaluated performance of mitigating systems. The inspectors communicated the plant events to appropriate regional personnel, and compared the event details with criteria contained in IMC 0309, "Reactive Inspection Decision Basis for Reactors," for consideration of potential reactive inspection activities. As applicable, the inspectors verified that PSEG made appropriate emergency classification assessments and properly reported the event in accordance with 10 CFR 50.72 and 50.73. The inspectors reviewed PSEG's follow-up actions related to the events to assure that PSEG implemented appropriate corrective actions commensurate with their safety significance.

- Unit 1, loss of 1C 4kV bus during breaker maintenance on December 14

b. Findings

No findings were identified.

.2 (Closed) Licensee Event Report (LER) 05000311/2016-004-00: Auxiliary Feedwater Pump Auto Start

a. Inspection Scope

On February 16, 2016, during a Unit 2 reactor startup following a unit trip, the 22 SGFP tripped while operators were transferring the steam supply to the pump from heating steam to main steam. The 22 SGFP trip initiated emergency safeguard feature actuation for start of the 21 and 22 AFW pumps. PSEG made reports under 10 CFR 50.72 and 50.73 for an event or condition that resulted in automatic actuation of the AFW system. Through RCE 70184454, PSEG determined that the specification agreed upon by PSEG and the vendor did not identify an additional feature, an acceleration rate trip, and that the procedure for swapping from low to high pressure steam did not include a conservative method for implementing a change in steam supply source. Inspectors reviewed the root cause analysis and associated documents, interviewed PSEG staff, and walked down associated equipment.

b. Findings

Inspectors documented a self-revealing Green finding (FIN) in Section 1R15 of IR 05000272;311/2016-001. No further issues were identified. This LER is closed.

.3 (Closed) LER 05000311/2016-006-00: Automatic Reactor Trip Due to Trip of the 21 Reactor Coolant Pump

a. Inspection Scope

On August 31, 2016, the 21 RCPs tripped on instantaneous overcurrent due to a fault, which resulted in an automatic reactor trip on low flow in one reactor coolant loop above the P-8 permissive setpoint (36 percent reactor power). The trip of the RCP was caused

by a SW leak that developed on the 22 CFCU. The 21, 22 and 23 AFW pumps started, as designed, on low steam generator level following the unit trip. PSEG made reports under 10 CFR 50.72 and 50.73 for an event or condition that resulted in automatic actuation of the reactor protection system and the AFW system. Through RCE 70189117, PSEG determined that the root cause for the reactor trip was inadequate procedure guidance for restoration of 22 CFCU that resulted in a void collapse (water hammer) in the SW discharge piping of 22 CFCU. Inspectors reviewed the RCE and associated documents, interviewed PSEG staff, and walked down associated equipment.

b. Findings

This LER is closed.

Introduction. The inspectors determined there was a self-revealing Green NCV of TS 6.8.1.c, "Surveillance and test activities of safety-related equipment," when PSEG did not establish adequate procedures for restoring SW to a drained section of discharge piping from the CFCUs following surveillance test activities. Consequently, during restoration of SW to 22 CFCU following testing on August 31, 2016, refilling the voided SW piping created a pressure pulse sufficient to extrude the motor cooler cover plate spacer gasket inside primary containment, resulting in leakage that caused a 21 RCP cable fault and subsequent reactor trip.

Description. On August 31, 2016, Salem Unit 2 experienced an automatic reactor trip due to loss of flow in 21 reactor coolant loop above the P-8 permissive setpoint (36 percent reactor power). The 21 RCP breaker tripped open on overcurrent protection following a fault in the inner enclosure assembly of the electrical cable penetration 2-31. The fault was later determined to be most likely the result of a wetted insulator board used in the power cable terminal connection, caused by an estimated 50 gallon per minute SW leak from the 22 CFCU motor cooler cover plate and spacer gasket. Further inspection of the 22 CFCU motor cooler revealed several areas of the spacer-to-tubesheet gasket being extruded and torn. PSEG reported the unplanned reactor trip and automatic actuation of the AFW system under Event Notification (EN) 52213.

Through RCE 70189117, PSEG determined that the root cause for the 22 CFCU motor cooler leak was inadequate procedure guidance for restoration of 22 CFCU that resulted in a void collapse (water hammer) in the SW discharge piping of 22 CFCU. Immediately prior to the trip, SW supply piping to the 21 and 22 CFCUs was being restored following isolation for stroke time testing of the SW accumulator discharge valves. The SW accumulators are designed with fast-acting discharge valves, that fail open during loss of power, to ensure the SW piping supply to, and discharge from, the CFCU motor coolers remains water solid during a loss of off-site power that momentarily stops and re-starts the running SW pumps. The SW supply piping to the CFCUs penetrates containment at a low elevation and travels up to the CFCUs at a higher elevation inside containment. The discharge piping returns back down to a low elevation to exit the containment.

As part of PSEG's RCE, a third party engineering firm performed a thermal-hydraulic computer model to evaluate the SW piping conditions during the stroke time testing configuration, calculate the resultant pressure transient at the motor cooler cover plate and spacer gaskets during system restoration, and determine the maximum pressure that the motor cooler gasket configuration can withstand. Based on the results of the third part engineering modeling and calculations, PSEG concluded that because the rate of opening the SW inlet valve was not prescribed during system restoration, the potential

existed for the valve to be opened rapidly enough to result in a significant pressure perturbation that exceeded the maximum allowable pressure of the gasket configuration. Additionally, PSEG determined that the non-safety-related inner enclosure assembly for faulted electrical cable penetration 2-31 was subjected to conditions outside of its design requirements when it was wetted with leakage from the extruded CFCU gasket.

PSEG identified two contributing causes to this event. The first was that the CFCU motor and main cooler gaskets have low operating margin, making them more susceptible for failure during pressure perturbations. The second contributing cause was that previous evaluations did not eliminate SW leaks from the CFCU cooler gaskets due to limited scope of the evaluations. Specifically, previous CAP evaluations in 2016, 2014, 2008, and 2005 identified system pressure perturbations and filling and venting methods as potential causes of previous motor cooler gasket leaks, but corrective actions from the previous evaluations did not address filling and venting methods.

The inspectors reviewed PSEG's RCE, and determined that the assigned corrective actions were reasonable and commensurate with the root and contributing causes. Assigned corrective actions from the RCE included: revise applicable procedures for restoring SW to the CFCUs following SW discharge valve testing, and for filling and venting activities; develop a design change configuration for the CFCU gasket connections; and revise the CAP procedure governing Management Review Committee to assist in determining the scope and level of evaluations recommended by the Station Oversight Committee, to ensure that appropriate attention if given to station issues.

Analysis. The inspectors determined there was a performance deficiency that was within PSEG's ability to foresee and correct because PSEG procedures did not provide adequate instruction for filling SW to a drained section of piping to the CFCUs. This issue was more than minor since it was associated with the procedure quality attribute of the Initiating Events cornerstone and adversely impacted its objective to limit the likelihood of events that upset plant stability and challenge critical safety functions. Specifically, a drained section of SW piping was rapidly re-filled, resulting in a pressure transient that extruded 22 CFCU motor cooler gasket, wetted the 4kV cable connection associated with 21 RCP, and tripped 21 RCP which subsequently resulted in a reactor trip. Additionally, the containment pressure control function provided by the 22CFCU was challenged by the SW leak. Using IMC 0609, Attachment 4 and Appendix A, Exhibit 1, the inspectors determined that this finding was of very low safety significance, or Green, since mitigating equipment relied upon to transition the plant to stable shutdown remained available.

The finding had a cross-cutting aspect in the area of Problem Identification and Resolution, Evaluation, in that the organization thoroughly evaluates issues to ensure that resolutions address causes and extent of conditions commensurate with their safety significance. Specifically, previous PSEG causal evaluations in 2016 and 2014 identified system pressure perturbations and filling and venting methods as potential causes of previous motor cooler gasket leaks, but did not thoroughly evaluate those issues such that the resolution addressed the cause. [P.2]

Enforcement. TS 6.8.1.c, "Surveillance and test activities of safety-related equipment," states, in part, that written procedures shall be established covering surveillance and test activities of safety-related equipment. Contrary to the above, prior to September 19, 2016, PSEG procedure S2.OP-ST.SW-0016, "Inservice Testing Service Water Accumulator Discharge Valves," Revision 5, steps 5.1.17 and 5.2.17, were not established to provide adequate instructions for filling and venting SW to a drained

section of piping to the associated CFCU following surveillance and test activities of safety-related valves. Consequently, during restoration of SW to 22 CFCU following testing on August 31, 2016, a drained section of SW piping was re-filled rapidly enough to create a pressure transient that extruded the 22 CFCU motor cooler cover plate gasket inside primary containment, wetted the 4kV cable connection associated with 21 RCP, and tripped 21 RCP which subsequently resulted in a reactor trip. PSEG entered this issue in the CAP under NOTF 20740014, and completed RCE 70189117. Corrective actions to revise the applicable sections of S2.OP-ST.SW-0016 were completed on September 19, 2016, with further enhancement on November 10, 2016. Because this violation was of very low safety significance (Green), and was entered into PSEG's CAP, this issue is being treated as an NCV consistent with Section 2.3.2 of the Enforcement Policy. **(NCV 05000311/2016004-02, Inadequate Surveillance Test Procedure Results in Water Hammer and Reactor Trip)**

.4 (Closed) LER 05000272/2015-006-00: Pressurized Power Operated Relief Valves and Block Valves Do Not Meet the Requirements of 10 CFR Part 50 Appendix R

a. Inspection Scope

On August 26, 2015, PSEG identified a fire scenario that could cause spurious operation of the Pressurizer Power Operated Relief Valves (PORVs) and also prevent the ability to manually close the associated PORV Block valves given a loss of offsite power. This scenario invalidated assumptions in Salem's Safe Shutdown Analysis with respect to reactor coolant system inventory and pressure control. PSEG completed a causal analysis and determined that the issue was due to the absence of validating actions taken in 1999 to correct the issue to ensure compliance with 10 CFR Part 50, Appendix R. PSEG also implemented interim compensatory measures and completed plant modifications to restore compliance. Inspectors reviewed the LER, causal analysis, and interim and final corrective actions, conducted walkdowns of associated equipment, and interviewed PSEG staff.

b. Findings

A PSEG-identified NCV is documented in Section 4OA7 of this report. This LER is closed.

4OA6 Meetings, Including Exit

On January 18, 2017, the inspectors presented the inspection results to Mr. Charles McFeaters, Salem Vice President, and other members of the PSEG staff. The inspectors verified that no proprietary information was retained by the inspectors or documented in this report. PSEG management acknowledged and did not dispute the findings.

4OA7 Licensee-Identified Violations

The following PSEG-identified violation of NRC requirements was determined to be of very low safety significance (Green) and meet the NRC Enforcement Policy criteria for being dispositioned as an NCV.

As a result of a Salem Post-Fire Safe Shutdown Analysis update, PSEG submitted LER 272/1999-009-00 when they identified that cables for pressurizer PORVs and associated block valves were routed in the same containment cable trays, a fire-induced spurious

operation concern, that could result in a pathway for a loss of reactor coolant inventory and pressure control. A similar condition was also identified for a fire in the control or relay rooms that could affect alternate shutdown capability. The NRC dispositioned this issue in IR 05000272;311/1999-010. On August 26, 2015, PSEG identified that they had not adequately completed corrective actions associated with the relay rooms. Specifically, a fire scenario involving cables within cabinets existed that could result in spurious PORV operation while preventing the ability to manually close block valves. At the time of this discovery, the safe shutdown analysis did not include the evaluations required to credit closure of both PORVs and block valves in the main control room prior to evacuation. Local, manual closure of the block valves had been incorporated into procedures but could be delayed up to 40 minutes in the scenario while EDGs were restored. The loss of reactor coolant inventory and pressure control had not been accounted for during this timeframe.

The issue was determined to be more than minor since it was associated with the protection against external factors (Fire) attribute of the Mitigating Systems cornerstone and adversely affected its objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. The finding was evaluated in accordance with IMC 0609, Appendix A, Attachment 4, and Appendix F. The IMC 0609, Appendix F, Attachment 1, Step 1.6, permits screening of the issue with PSEG fire PRA results provided there is an approved fire PRA for the plant. PSEG provided a fire PRA evaluation for the degraded condition but since the PRA results were not from a finalized, approved fire PRA, additional evaluation was required. The Senior Reactor Analyst (SRA) conducted a detailed assessment of the issue using the External Initiator Risk Informed Inspection Notebook for Salem Generating Station (Revision 1). Fires of concern were determined to be those confined to the Unit 1 and Unit 2 Relay Rooms. This is modeled in table 3.3.13 of the notebook as Fire Group M. For evaluation, it was assumed that “Spurious PORV Due to Hot Short” had a probability of 1.0. For this model, this would indicate a condition in which a PORV and its associated block valve were open. Given the exposure period of greater than 30 days, this would result in a change in core damage frequency of approximately 1E-8, Green, for Unit 1 and Unit 2. The notebook was conservative since the evaluation assumed the failure of the PORV to close as opposed to the more realistic probability that fire would cause a spurious failure of a PORV and hot short resulting in failure of the block valve. The dominant sequences included:

1) Fire in the relay room with a failure of the PORV to close and a failure of high pressure injection and
2) Fire in the relay room with a failure of the PORV to close and a failure of high pressure recirculation.

PSEG’s results were consistent with the SRA’s analysis.

Title 10 CFR Part 50, Appendix B, Criterion XVI, requires, in part, that conditions adverse to quality are promptly identified and corrected. Salem Unit 1 and 2 license conditions 2.(C).5 and 2.(C).10 respectively require, in part, that PSEG shall implement and maintain all provisions of the fire protection program. PSEG's Quality Assurance Topical Report states that the Quality Assurance Program is applied to the Fire Protection Program consistent with Branch Technical Position APCSB 9.5-1 Appendix A, Section C requirements that include, under Corrective Action, that conditions adverse to fire protection are promptly identified, reported, and corrected. Contrary to this, from about 1999 to August 2015, actions from a previous, related fire-induced circuit failure scenario did not completely correct the condition resulting in the inability to credit manual closure of PORV and PORV block valves in an associated fire scenario. PSEG entered this in their CAP as NOTFs 20700943 and 20750010.

ATTACHMENT: SUPPLEMENTARY INFORMATION

SUPPLEMENTARY INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel
C. McFeaters, Site Vice President
K. Grover, Plant Manager, Salem
S. Boesch, Service Water System Engineer
D. Burgin, Emergency Preparedness Manager
F. Hummel, Nuclear Staff Engineer
K. King, Design Engineer
R. Montgomery, Principal Nuclear Engineer
W. Muffley, Operations Training Manager
G. Pahwa, Senior Engineer

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Open and Closed		
05000272/2016004-01	FIN	Inadequate Maintenance Procedure for Steam Generator Feedwater Pump Coupling Hub Set Screw Installation (Section 1R12)
05000311/2016004-02	NCV	Inadequate Surveillance Test Procedure Results in Water Hammer and Reactor Trip (Section 4OA3.3)
Closed		
05000311/2016-004-00	LER	Auxiliary Feedwater Pump Start (Section 4OA3.2)
05000311/2016-006-00	LER	Automatic Reactor Trip Due to Trip of the 21 Reactor Coolant Pump (Section 4OA3.3)
05000272/2015-006-00	LER	Pressurized Power Operated Relief Valves and Block Valves Do Not Meet the Requirements of 10 CFR Part 50 Appendix R (Section 4OA3.4)

LIST OF DOCUMENTS REVIEWED

* Indicates NRC-identified

Section 1R01: Adverse Weather Protection

Procedures
SC.OP-PT.ZZ-0002, Station Preparations for Seasonal Conditions, Revision 14
SC.MD-GP.ZZ-0001, Station Preparations for Winter – Mechanical, Revision 7
SC.MD-GP.ZZ-0178, Station Preparations for Winter – Electrical, Revision 21
WC-AA-107, Seasonal Readiness, Revision 14

Notifications
20679656 20715837 20715838 20743363 20746608 20750691
20751521 20752036

Maintenance Orders/Work Orders
30275386 30288775 30289364 30295107 60125396

Section 1R04: Equipment Alignment

Procedures
S1.OP-PT.TRB-0003, Main Turbine Valve Stroke Testing, Revision 20
S1.OP-SO.CN-0002, Steam Generator Feed Pump Operation, Revision 32

Notifications
20723716 20737762 20741032 20743169 20743169 20744118*
20744119* 20744316* 20747490* 20747492* 20747743 20748065
20748074 20748075 20748229 20748701* 20748703 20749023
20749285 20749290 20749301 20749426 20749431 20749432
20749450 20749453 20749494 20749544

Drawings
205242, Unit 1 Service Water Nuclear Area, Sheet 6, Revision 94
205342, Unit 2 Service Water Nuclear Area, Sheet 6, Revision 71

Other Documents
Adverse Condition Monitoring Plan 16-018, S1MS-11MS29 Position, Revision 0

Section 1R05: Fire Protection

Procedures
FP-SA-2562, Unit 2 Auxiliary Building Ventilation Units, Revision 0
FP-SA-2563, Unit 2 Auxiliary Building Volume Control and Boric Acid Tanks, Revision 0
FP-SA-1547, Unit 1 Mechanical Penetration Area, Revision 0
FP-SA-1851, Circulating Water Building Complex, Revision 0
S2.FP-ST.FBR-0028, Class 1 Fire Damper Operability Test, Revision 5

Notifications
20744867* 20749624 20749624 20749647* 20749648*
20749916

Drawings
205348, Unit 2 Auxiliary Building Control Area Air Conditioning and Ventilation, Sheet 2, Revision 40

Maintenance Orders/Work Orders
30191788

Other Documents
Drill Scenario 54159621

Section 1R06: Flood Protection Measures

Notifications
20747551* 20747554* 20750223*

Drawings
203066, Sheet 4, 4160 Vital Bus Service Water Pump Breaker Cubicles, Revision 1
205447, Sheet 1, Service Water Intake Yard, Duct Runs, & Pipe Tunnel, Revision 37

Section 1R07: Heat Sink Performance

Procedures
ER-AA-340-1002, Service Water Heat Exchanger and Component Inspection Guide, Revision 6
S1.OP-PT.SW-0006, Service Water Fouling Monitoring Diesel Generators, Revision 10
S1.OP-PT.SW-0006, Service Water Fouling Monitoring Diesel Generators, Revision 11
SC.MD-PM.DG-0017, Diesel Generator Lube Oil and Jacket Water Cooler Internal Inspection, Revision 4
SC.MD-PM.DG-0017, Diesel Generator Lube Oil and Jacket Water Cooler Internal Inspection, Revision 6
ER-AA-340, GL 89-13 Program Implementing Procedure, Revision 6
SC.MD-PM.CC-0002, Component Cooling Heat Exchangers #11, 21 and 22 Internal Inspection, Revision 15
S2.OP-PT.SW-0027, 22 Component Cooling Heat Exchanger Heat Transfer Performance Data Collection, Revision 17
S1.OP-ST.DG-0001, 1A Diesel Generator Surveillance Test, Revision 47
ER-AA-5400-1002, Underground Piping Examination Guide, Revision 3
S2.OP-PM.CC-0022, 22 Component Cooling Heat Exchanger High Flow Flush and Alignment, Revision 19
OP-AA-108-111-1001, Severe Weather and Natural Disaster Guidelines, Revision 14
S2.OP-AB.ZZ-0002, Flooding, Revision 4
S2.OP-AR.ZZ-0002, Overhead Annunciators Window B, Revision 36
S2.OP-AB.SW-0003, Service Water Bay Leak, Revision 7
S2.OP-SO.SW-0001, Service Water Pump Operation, Revision 27
SC.CH-SO.CL-0831, Chlorination System Operation and Surveillance, Revision 23
SC.CH-SO.CL-0830, Chlorination System Startup and Shutdown, Revision 23
S2.OP-AB.ZZ-0003, Component Fouling, Revision 16
S2.OP-SO.ZZ-0003, Component Biofouling, Revision 10
SC.MD-GP.SW-0001, Service Water Silt Survey, Revision 16
S2.OP-PT.SW-0007, Service Water Fouling Monitoring Containment Fan Coil Units, Revision 20
S2.OP-PT.SW-0004, Service Water Fouling Monitoring Safety Injection and Charging Pumps, Revision 11
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S2.OP-PT.SW-0027, 22 Component Cooling Heat Exchanger Heat Transfer Performance Data Collection, dated October 11, 2006
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S2.OP-ST.SW-0011, Inservice Testing Service Water 2SW26 Valve, Modes 5-6, dated November 10, 2016

S2.OP-ST.SW-0007, Inservice Testing Service Water Valves, Modes 1-4, dated February 26, 2016
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S2.OP-PM.CC-0022, 22 Component Cooling Heat Exchanger High Flow Flush and Alignment, dated July 29, 2016
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S2.OP-PT.SW-0002, Flush of Emergency SW Supply and Return for the Emergency Air Compressor, dated September 12, 2016
S2.OP-ST.SW-0001, Inservice Testing – 21 Service Water Pump, dated September 20, 2016
S2.OP-ST.SW-0002, Inservice Testing – 22 Service Water Pump, dated August 26, 2016
S2.OP-ST.SW-0003, Inservice Testing – 23 Service Water Pump, dated August 26, 2016
S2.OP-ST.SW-0004, Inservice Testing – 24 Service Water Pump, dated September 14, 2016
S2.OP-ST.SW-0005, Inservice Testing – 25 Service Water Pump, dated September 14, 2016
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Focused Area Self-Assessment (FASA), Salem & Hope Creek Generic Letter 89-13 Programs, dated August 28, 2006
Engineering Programs Assessment: SW Reliability Generic Letter (89-13) 80061063, dated December 17, 2003
30131587 OP 0050, 89-13 Inspection Report – 1A EDG JW & LO Coolers, dated April 9, 2010
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S1.OP-AR.ZZ-0002, Overhead Alarm B-29, 11013 SW Pump Sump Area Level Hi, Revision 29
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20739961	20739961	20741455	20742479	20746164	20747486
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S1.OP-AB.CN-0001, Main Feedwater/Condensate System Abnormality, Revision 21

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NC.EP-EP.ZZ-0404, Protective Action Recommendations (PARS) Upgrades, Revision 7

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ER-AA-600-1047, Mitigating System Performance Index Basis Document, Revision 4

LS-AA-2001, Collecting and Reporting of NRC Performance Indicator Data

LS-AA-2003, Use of the INPO Consolidated Data Entry Database for NRC and WANA Data Entry, Revision 6

LS-AA-2080, Monthly Data Elements for NRC Safety System Functional Failures, Revision 5

LS-AA-2190, Monthly Data Elements for NRC/INPO Consolidated Data Entry – Monthly Operating Report (MOR), Revision 4

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20623371	20633614	20677643	20745340*	20746510*	20749520*
20749989*	20751458*	20751459*	20751665*	20751815*	20751844*
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60130540	70161591	70162241	70162562	70162744	70164126
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Section 4OA3: Follow-up of Events and Notices of Enforcement Discretion

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20751662	20751669	20751669	20753354	20753432	20753433

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LIST OF ACRONYMS

10 CFR	Title 10 of the *Code of Federal Regulations*
ADAMS	Agencywide Documents Access and Management System
ADFWCS	Advanced Digital Feedwater Control System
AFW	auxiliary feedwater
AOP	abnormal operating procedure
ASME	American Society of Mechanical Engineers
CA	corrective action
CAP	corrective action program
CC	component cooling
CFCU	containment fan cooling unit
EAL	Emergency Action Level
EDG	emergency diesel generator
EN	event notification
EPRI	Electric Power Research Institute
FIN	finding
GL	generic letter
HX	heat exchanger
IMC	inspection manual chapter
IR	inspection report
kV	kilovolt
LER	licensee event report
LTCA	long term corrective action
MR	maintenance rule
NCV	non-cited violation
NEI	Nuclear Energy Institute
NEIT	nuclear in-processing training
NOTF	notification

NRC	Nuclear Regulatory Commission
OE	operating experience
OOS	out of service
OWA	operator workarounds
PBI	plant barrier impairment
PI	performance indicator
PMT	post-maintenance test(ing)
PORV	power operated relief valve
PSEG	Public Service Enterprise Group Nuclear LLC
QC	quality control
RCE	root cause evaluation
RCP	reactor coolant pump
RTP	rated thermal power
SDP	significance determination process
SGFP	steam generator feedwater pump
SRA	senior reactor analyst
SSC	structure, system, and component
SW	service water
TS	technical specification
UFSAR	Updated Final Safety Analysis Report
UHS	ultimate heat sink
VTD	vendor technical document
WO	work order