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

November 3, 2014

Mr. Thomas P. Joyce
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 – NRC INTEGRATED INSPECTION REPORT 05000272/2014004 AND 05000311/2014004

Dear Mr. Joyce:

On September 30, 2014, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Salem Nuclear Generating Station, Units 1 and 2. The enclosed inspection report documents the inspection results, which were discussed on October 9, 2014, with Mr. John Perry, Salem Site Vice President, and other members of your staff.

The inspection examined activities conducted under your license as they relate to safety and compliance with the Commission’s rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

This report documents four self-revealing findings of very low safety significance (Green). One of these findings was determined to involve a violation of NRC requirements. However, because of the very low safety significance, and because it is entered into your corrective action program, the NRC is treating this finding as a non-cited violation, consistent with Section 2.3.2.a of the NRC Enforcement Policy. If you contest the non-cited violations in this report, 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, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at Salem Nuclear Generating Station. In addition, if you disagree with the cross-cutting aspect assigned to any finding, 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 Regional Administrator, Region I, and the NRC Resident Inspector at Salem Nuclear Generating Station.

In accordance with Title 10 of the *Code of Federal Regulations* (10 CFR) 2.390 of the NRC’s “Rules of Practice,” a copy of this letter, its enclosure, and your response (if any) will be available electronically for public inspection in the NRC’s Public Document Room or from the Publicly Available Records component of the NRC's Agencywide Documents Access and Management System (ADAMS). ADAMS is accessible from the NRC website at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Glenn T. Dentel, Chief
Reactor Projects Branch 3
Division of Reactor Projects

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

Enclosure: Inspection Report 05000272/2014004 and 05000311/2014004
w/Attachment: Supplementary Information

cc w/encl: Distribution via ListServ

the Publicly Available Records component of the NRC's Agencywide Documents Access and Management System (ADAMS). ADAMS is accessible from the NRC website at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Glenn T. Dentel, Chief
Reactor Projects Branch 3
Division of Reactor Projects

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

Enclosure: Inspection Report 05000272/2014004 and 05000311/2014004
w/Attachment: Supplementary Information

cc w/encl: Distribution via ListServ

Distribution: (via email)
D. Lew, Actg RA
V. Ordaz, Actg DRA
H. Nieh, DRP
M. Scott, DRP
R. Lorson, DRS
J. Trapp, DRS
G. Dentel, DRP
R. Barkley, DRP
M. Draxton, DRP
P. Finney, DRP, SRI
A. Ziedonis, DRP RI
C. Ott, DRP, AA
J. Jandovitz, RI, OEDO
RidsNrrPMSalem Resource
RidsNrrDorlLpl1-2 Resource
ROPreports Resource

DOCUMENT NAME: G:\DRP\BRANCH3\INSPECTION\REPORTS\ISSUED\2014 (ROP 15)\SAL IR 2014004 FINAL .DOCX
ADAMS Accession No. **ML14308A041**

☑ SUNSI Review		☑ Non-Sensitive ☐ Sensitive		☑ Publicly Available ☐ Non-Publicly Available	
OFFICE	RI/DRP	RI/DRP	RI/DRP		
NAME	PFinney/RSB for	RBarkley/RSB	GDentel/GTD		
DATE	11/04/14	10/30/14	11/03/14		

OFFICIAL RECORD COPY

U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket Nos.	50-272, 50-311
License Nos.	DPR-70, DPR-75
Report Nos.	05000272/2014004 and 05000311/2014004
Licensee:	PSEG Nuclear LLC (PSEG)
Facility:	Salem Nuclear Generating Station, Units 1 and 2
Location:	P.O. Box 236 Hancocks Bridge, NJ 08038
Dates:	July 1, 2014 through September 30, 2014
Inspectors:	P. Finney, Senior Resident Inspector A. Patel, Acting Senior Resident Inspector A. Ziedonis, Resident Inspector J. Schoppy, Senior Reactor Inspector R. Barkley, Senior Project Engineer E. Burket, Emergency Preparedness Inspector
Approved By:	Glenn T. Dentel, Chief Reactor Projects Branch 3 Division of Reactor Projects

TABLE OF CONTENTS

SUMMARY 3

REPORT DETAILS 6

1. REACTOR SAFETY 6

1R04 Equipment Alignment 6
1R05 Fire Protection 7
1R06 Flood Protection Measures 7
1R11 Licensed Operator Requalification Program 8
1R12 Maintenance Effectiveness 8
1R13 Maintenance Risk Assessments and Emergent Work Control 9
1R15 Operability Determinations and Functionality Assessments 12
1R19 Post-Maintenance Testing 12
1R20 Refueling and Other Outage Activities 13
1R22 Surveillance Testing 14

4. OTHER ACTIVITIES 14

4OA1 Performance Indicator Verification 14
4OA2 Problem Identification and Resolution 15
4OA3 Follow-Up of Events and Notices of Enforcement Discretion 17
4OA5 Other Activities 24
4OA6 Meetings, Including Exit 26

ATTACHMENT: SUPPLEMENTARY INFORMATION 26

SUPPLEMENTARY INFORMATION A-1

KEY POINTS OF CONTACT A-1

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED A-1

LIST OF DOCUMENTS REVIEWED A-2

LIST OF ACRONYMS A-10

SUMMARY

Inspection Report (IR) 05000272/2014004, 05000311/2014004; 07/01/2014 – 09/30/2014; Salem Nuclear Generating Station Units 1 and 2; Maintenance Risk Assessments and Emergent Work Control; 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. Inspectors identified one non-cited violation (NCV) and three findings (FINs) of very low safety significance (Green). 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 June 2, 2011. Cross-cutting aspects are determined using IMC 0310, "Aspects Within the Cross-Cutting Areas," dated December 19, 2013. All violations of NRC requirements are dispositioned in accordance with the NRC's Enforcement Policy, dated July 9, 2013. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 5, dated February 2014.

Cornerstone: Initiating Events

- Green. A Green, self-revealing FIN was identified against NC.WM-AP.ZZ-0002, "Performance Improvement Process," Revision 6, because PSEG did not adequately correct and prevent recurrence of steam generator feedpump (SGFP) silent coast-down events. Consequently, on April 8, 2014, PSEG operators manually tripped the Unit 1 reactor in response to lowering level in the 13 steam generator that was caused by a coast-down of the 11 SGFP. PSEG created new overhead alarms dedicated to a loss of power to SGFP governor controls, trained licensed operators on a silent SGFP coast-down event, and created a long term corrective action to automate SGFP runbacks on loss of power to the governor controls.

  This issue was more than minor since it was associated with the equipment performance 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. In accordance with IMC 0609, Attachment 4 and Exhibit 1 of Appendix A, the inspectors determined that this finding is of very low safety significance, or Green, because the finding did not cause both a reactor trip and the loss of mitigation equipment relied upon to transition the plant from the onset of the trip to a stable shutdown condition. The inspectors determined there was no cross-cutting aspect associated with this finding since it was not representative of current PSEG performance. Specifically, in accordance IMC 0612, the causal factors associated with this finding occurred outside the nominal three-year period of consideration and were not considered representative of present performance. (Section 4OA3)

- Green. A Green, self-revealing finding against PSEG procedure NC.WM-AP.ZZ-0002, "Performance Improvement Process," Revision 3, was identified for incomplete corrective actions when a Unit 1 main generator phase 'C' differential current lockout relay tripped and resulted in a reactor trip. Specifically, a design change package had not been properly implemented in 2004 in response to a similar 2001 reactor trip. PSEG conducted repairs, visual inspections, and testing, entered this matter in its corrective action program, and completed a root cause analysis.

The issue was more than minor since it was associated with the design control attribute of the initiating events cornerstone and adversely affected its objective to limit the likelihood of events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. In accordance with IMC 0609, Attachment 4 and Exhibit 1 of Appendix A, the inspectors determined that this finding is of very low safety significance, or Green, because the finding did not cause both a reactor trip and the loss of mitigation equipment relied upon to transition the plant from the onset of the trip to a stable shutdown condition. The inspectors determined there was no cross-cutting aspect associated with this finding since it was not representative of current PSEG performance. Specifically, in accordance IMC 0612, the causal factors associated with this finding occurred outside the nominal three-year period of consideration and were not considered representative of present performance. (Section 4OA3)

- Green. A Green, self-revealing finding against PSEG procedure LS-AA-120, “Issue Identification and Screening Process,” Revision 12, was identified for inadequate interim corrective actions when a Unit 1 main generator phase ‘A’ differential current lockout relay tripped and resulted in a reactor trip on May 7, 2014. Specifically, interim corrective actions had not been properly implemented in response to a similar trip on April 13, 2014 for the same failure mechanism. PSEG conducted repairs, entered this matter in its corrective action program, and completed a root cause analysis.

  The issue was more than minor since it was associated with the equipment attribute of the initiating events cornerstone and adversely affected its objective to limit the likelihood of events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Specifically, interim corrective actions did not adequately ensure the near-term reliability of transformer connections following an April 2014 failure, leaving the unit susceptible to a similar failure and a reactor trip in May 2014. In accordance with IMC 0609, Attachment 4 and Exhibit 1 of Appendix A, the inspectors determined that this finding is of very low safety significance, or Green, because the finding did not cause both a reactor trip and the loss of mitigation equipment relied upon to transition the plant from the onset of the trip to a stable shutdown condition. The finding was determined to have a cross-cutting aspect in Human Performance, Conservative Bias, in that individuals use decision-making practices that emphasize prudent choices over those that are simply allowable. That is, proposed actions are determined to be safe in order to proceed rather than unsafe in order to stop. Specifically, PSEG did not take a conservative approach to decisions regarding the scope of repairs given the unusual condition, did not consider the longer-term consequences when determining how to resolve the emergent CT concern, and did not take timely action to address the degraded condition commensurate with its significance, namely vulnerability to a further failure and a consequent reactor trip. [H.14] (Section 4OA3)

Cornerstone: Barrier Integrity

Green. A self-revealing, Green NCV of 10 CFR 50.65(a)(4) was identified when PSEG did not properly assess and manage risk on Salem Unit 1 during an evolution with the potential to cause a reactivity change and overpower event. Specifically, while working on a moisture separator reheater (MSR) drain valve, it failed closed, reduced MSR reheat efficiency, led to turbine control valves opening further, and resulted in an overpower event. Consequently, this resulted in violating the thermal power limit in license condition 2.C.(1). PSEG took actions in accordance with procedures to place the valve in manual and lower power to restore it within the license limit. Additionally, they classified this as a reactivity event, entered it in their corrective action program, and performed an apparent cause evaluation.

The issue was more than minor since it was associated with the configuration control attribute of the barrier integrity and adversely affected its objective to provide reasonable assurance that physical design barriers protect the public from radionuclide releases caused by accidents or events. Specifically, the system alignment was impacted during maintenance, resulting in an overpower event. It was also similar to IMC 0612, Appendix E, Example 8.a. The finding was then evaluated using IMC 0609, Attachment 4 and Appendix A, Exhibit 3, where it screened to Green since it was only associated with the fuel cladding barrier. The finding was determined to have a cross-cutting aspect in Human Performance, Avoid Complacency, in that individuals recognize and plan for the possibility of mistakes, latent issues, and inherent risk even while expecting successful outcomes. Individuals are expected to consider potential undesired consequences and implement appropriate error reduction tools. Specifically, PSEG staff relied on past successes and assumed conditions working on this and similar drain valves and did not perform adequate, successive activity reviews when the valve exhibited unexpected responses. [H.12] (Section 1R13)

REPORT DETAILS

Summary of Plant Status

Unit 1 began the inspection period at 100 percent power. The unit remained at or near 100 percent power for the remainder of the inspection period.

Unit 2 began the inspection period shut down for refueling and maintenance outage number 20 (2R20). Operators commenced a reactor startup on July 13 and the unit reached 100 percent power on July 18. The unit remained at or near 100 percent power for the remainder of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R04 Equipment Alignment

Partial System Walkdowns (71111.04Q – 3 samples)

a. Inspection Scope

The inspectors performed partial walkdowns of the following systems:

- Unit 1, the service water (SW) system and electrical support systems during 11 SW pump maintenance on July 24
- Unit 2, the SW system and electrical support systems during 23 SW pump maintenance on August 19 - 22
- Unit 1 and Unit 2, accessible control area ventilation (CAV) dampers and instrumentation, during operation in accident-pressurized mode for maintenance, on August 21

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 Updated Final Safety Analysis Report (UFSAR), technical specifications (TSs), work orders, notifications, and the impact of ongoing work activities on redundant trains of equipment in order to identify conditions that could have impacted system performance of their 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 corrective action program (CAP) for resolution with the appropriate significance characterization.

b. Findings

No findings were identified.

1R05 Fire Protection

Resident Inspector Quarterly Walkdowns (71111.05Q – 5 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 out of service, degraded or inoperable fire protection equipment, as applicable, in accordance with procedures and discussed with station personnel the repair plans for degraded equipment.

- Unit 1, outer penetration area (fire zone 212) on August 14
- Unit 1, relay room (fire zone 91 and 96) on August 14
- Unit 2, inner piping penetration area and chiller rooms (fire zone 122 and 123) on August 14
- Unit 2, 460 V switchgear rooms and corridor (fire zone 119) on August 14
- Common, 4160 V switchgear room (fire zone 218) on August 14

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 assess susceptibilities involving internal flooding. The inspectors also reviewed the CAP to determine if PSEG identified and corrected flooding problems and whether operator actions for coping with flooding were adequate. The inspectors focused on the Unit 1, 4kV (kilovolt) vital switchgear room to verify 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. The inspectors also verified that PSEG's flooding mitigation plans and equipment for the Unit 1, 4kV vital switchgear room were consistent with the design requirements and the risk analysis assumptions.

b. Findings

No findings were identified.

1R11 Licensed Operator Requalification Program (71111.11Q – 2 samples)

.1 Quarterly Review of Licensed Operator Requalification Testing and Training

a. Inspection Scope

The inspectors observed licensed operator simulator training on August 5, which included a requalification examination and a scenario covering the following major events: loss of turbine auxiliary cooling, loss of all feedwater and loss of secondary cooling without auxiliary feed water pump availability. 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, the 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 Quarterly Review of Licensed Operator Performance in the Main Control Room

a. Inspection Scope

The inspectors observed and reviewed low power physics testing in accordance with SC.RE-IO.ZZ-0002, “Low Power Physics Testing and Power Ascension,” Revision 17, on July 13. The inspectors observed infrequently performed test or evolution briefings, pre-shift briefings, and reactivity control briefings to verify that the briefings met the criteria specified in procedure HU-AA-1211, “Pre-job Briefings,” Revision 11. Additionally, the inspectors observed operator performance to verify that procedure use, crew communications, and coordination of activities between work groups similarly met established expectations and standards.

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 work orders, and maintenance rule (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 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 corrective actions 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, 1A emergency diesel generator (EDG) fuel oil leak on July 22
- Unit 1, 12 safety injection (SI) pump breaker failure to close on August 27
- Common, 4kV Switchgear Room structural conditions on August 19-21

b. Findings

No findings were identified.

1R13 Maintenance Risk Assessments and Emergent Work Control (71111.13 – 5 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, 11RD60 moisture separator reheater shell drain valve work on July 1
- Unit 1, 'A' reactor trip breaker failure to close during surveillance on September 11
- Unit 2, 23SJ17, 23 safety injection cold leg check valve, emergent work on July 8
- Common, Yellow risk for CAV in maintenance mode on July 25
- Common, Yellow risk during CAV operation in accident pressurized mode on August 21

b. Findings

Introduction. A self-revealing, Green NCV of 10 CFR 50.65(a)(4) was identified when PSEG did not properly assess and manage risk on Salem Unit 1 during an evolution with the potential to cause a reactivity change and overpower event. Specifically, while working on a moisture separator reheater (MSR) drain valve, it failed closed, reduced MSR reheat efficiency, led to the turbine control valves opening further, and resulted in an overpower event. Consequently, this resulted in violating the thermal power limit in license condition 2.C.(1).

Description. On June 17, a PSEG equipment operator observed 11RD60, the 11 West MSR shell drain and level control valve, cycling every three to five seconds. Moisture separation and reheating of the high-pressure turbine exhaust steam is performed by six combined MSRs. The MSRs and associated drains are not safety-related but are considered Maintenance Rule components. The MSR drain valves position to control condensate level in the MSRs and, therefore, control efficiency of the reheated steam that is supplied to the low pressure main turbines. PSEG entered the cycling valve issue in their CAP (notification 20653895) and recommended an instrument loop tuning. On June 19, at 1:25 a.m., operators received an MSR high level alarm. Equipment operators dispatched to the area identified that the 11RD60 was cycling from 50 to 70 percent. PSEG placed the valve in manual, jacked the valve full open, and entered this in their CAP (20654174). On June 26, at 9:30 a.m., maintenance technicians commenced corrective maintenance on 11RD60, an evolution that had already been completed seven times on similar valves. When the valve was taken from manual to automatic, it resumed cycling while the controller was tuned. The technicians monitored performance over the next several hours. Approximately 75 minutes later, the valve failed closed and operators received an MSR high level alarm. An equipment operator returned 11RD60 to manual and jacked the valve open. Following another control room brief, the technicians returned to the valve to conduct additional tuning. When placed in automatic, the valve did not respond as expected. Specifically, the technicians expected the valve to initially move in the closed direction given MSR level was below the controller setpoint, but also expected the valve to then move in the open direction after the controller received level feedback from the rising level. After four to five minutes, the technicians moved to the controller located on the turbine building roof and discovered the valve had failed closed again. At the same time, the operators received another MSR high level alarm. Due to the reheat steam efficiency loss, steam demand and, consequently reactor power increased. Reactor thermal power exceeded the licensed limit of 3459 MWth for approximately eight minutes and reached a maximum of 3489.9, or 0.89% above the limit. PSEG took actions in accordance with procedures to lower power and restore it within the license limit. Additionally, they classified this as a level-four reactivity event, entered this in the CAP (20655041), and performed an Apparent Cause Evaluation (ACE).

The inspectors reviewed the ACE, interviewed PSEG staff, walked down equipment, and reviewed station procedures and recorded parameters. PSEG determined that the apparent cause was that "operators failed to precisely control the MSR valve tuning evolution due to a knowledge deficiency related to MSR level control valve failure and its resulting impact on steam demand and reactor power level. Risk of the 11RD60 valve failing closed was not recognized by the crew and mitigating actions were not performed to prevent the overpower event." PSEG's investigation also identified that technicians had not been stationed at the controller during the second attempt to tune the valve and that had there been, immediate information would have been provided to the team. Further, the valve had not been adjusted in manual to ensure a "bumpless transfer" when returned to automatic. Finally, monitoring of plant parameters associated with MSR efficiency would have allowed operators additional means to detect MSR level changes.

PSEG procedure WC-AA-105, "Work Activity Risk Management," Revision 2, classifies work activity risk as Low, Medium, High, Production, and Reactivity. During the ACE review, the inspectors identified differences in PSEG staffs' risk assessment of the evolution. Specifically, the Control Room Supervisor and the maintenance supervisor told inspectors that the work activity risk had been determined to be Low-Production and Medium-Production risk, respectively, while the ACE described the risk assessment as Medium-Reactivity. The inspectors determined that the initial evolution had been Medium-Production-Reactivity risk since WC-AA-105, Exhibit 5, lists MSRs as a production risk system and step 4.9.6 states, in part, that "any production risk activity is automatically considered to also be a reactivity risk activity, because it could result in a power change of >20 MWE." WC-AA-105 directs risk management actions based on the assessed risk level. For Medium and High risk activities, form 2 requires identification of the most likely undesirable outcome and designation of contingency and/or compensatory measures and human error prevention techniques to prevent that outcome. The inspectors determined that PSEG's risk assessment and risk management actions associated with the maintenance evolution were inadequate as evidenced by PSEG's post-event evaluation of staff actions in preparation for and during the evolution and overpower event. The issue was determined to be within PSEG's ability to foresee and correct based on both risk procedure guidance, the valve's cycling, and initial response to the closed position before the final failure.

Regulatory Issue Summary 2007-21, "Adherence to Licensed Power Limits," Revision 1, endorsed the NEI Position Statement for Guidance to Licensees on Complying with the Licensed Power Limit. That guidance describes performance deficiencies that include "failure to take prudent action prior to a pre-planned evolution that could cause a power increase to exceed the licensed power limit." The inspectors determined that the system response during the initial work activity demonstrated the potential to cause a transient increase in reactor power and, therefore, further evaluation of and prudent action based on this performance should have been taken.

<u>Analysis</u>. Improperly assessing and managing risk in accordance with WC-AA-105 was a performance deficiency that was evaluated in accordance with IMC 0612, Appendix B. The issue was determined to be more than minor since it was associated with the configuration control attribute of the barrier integrity cornerstone and adversely affected its objective to provide reasonable assurance that physical design barriers (fuel cladding, reactor coolant system, and containment) protect the public from radionuclide releases caused by accidents or events. Specifically, the system alignment was impacted during maintenance, resulting in an overpower event. It was also similar to IMC 0612, Appendix E, Example 8.a. Specifically, PSEG did not comply with procedural requirements associated with risk that contributed to violating a thermal power limit, a condition prohibited by the operating license. The finding was then evaluated using IMC 0609, Attachment 4 and Appendix A, Exhibit 3, where it screened to Green since it was only associated with the fuel cladding barrier.

The finding was determined to have a cross-cutting aspect in Human Performance, Avoid Complacency, in that individuals recognize and plan for the possibility of mistakes, latent issues, and inherent risk, even while expecting successful outcomes. Individuals are expected to consider potential undesired consequences and implement appropriate error reduction tools. Specifically, PSEG staff relied on past successes and assumed conditions working on this and similar drain valves and did not perform adequate, successive activity reviews when the valve exhibited unexpected responses. [H.12]

<u>Enforcement</u>. 10 CFR 50.65(a)(4) states, in part, that "before performing maintenance activities (including but not limited to surveillance, post-maintenance testing, and corrective and preventive maintenance), the licensee shall assess and manage the

increase in risk that may result from the proposed maintenance activities." Contrary to this, on June 26, 2014, PSEG did not properly assess and manage the risk associated with 11RD60 valve corrective maintenance as implemented by WC-AA-105. Consequently, this resulted in an overpower event that exceeded and, therefore, violated the thermal power limit license condition 2.C.(1). PSEG reduced power below the licensed limit and placed the valve in manual. Because this finding was of very low safety significance, was entered in PSEG's CAP (20655041), and was not repetitive or willful, this finding is being treated as an NCV in accordance with section 2.3.2 of the NRC's Enforcement Policy. **(NCV 05000272/2014-004-01, Improper Risk Assessment and Risk Management Actions for a Reheater Drain Valve)**

1R15 Operability Determinations and Functionality Assessments (71111.15 – 7 samples)

a. Inspection Scope

The inspectors reviewed operability determinations for the following degraded or non-conforming conditions:

- Unit 1, 12 auxiliary feedwater level control valve demand indication failure on June 18
- Unit 1, 12 chiller increased pump-downs in position #3 on August 1
- Unit 1, 14 accumulator back-leakage through 11SJ34 check valve on August 26
- Unit 2, containment differential pressure transmitter erratic indication on July 15
- Unit 2, 22 diesel fuel oil transfer pump flow outside of IST limit on July 28
- Unit 2, 25 and 26 SW pumps low bearing cooling pressure on August 15
- Common, control room envelope boundary open penetration on August 26

The inspectors selected these issues based on the risk significance of the associated components and systems. 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. Where compensatory measures were required to maintain operability, the inspectors determined whether the measures in place would function as intended and were properly controlled by PSEG. The inspectors determined, where appropriate, compliance with bounding limitations associated with the evaluations.

b. Findings

No findings were identified.

1R19 Post-Maintenance Testing (71111.19 – 9 samples)

a. Inspection Scope

The inspectors reviewed the post-maintenance tests (PMTs) for the maintenance activities listed below to verify that procedures and test activities ensured system operability and functional capability. The inspectors reviewed the test procedure to verify that the procedure adequately tested the safety functions that may have been affected by the maintenance activity, that the acceptance criteria in the procedure was consistent with the information in the applicable licensing basis and/or design basis documents, and that the procedure had been properly reviewed and approved. The inspectors also witnessed the test or reviewed test data to verify that the test results adequately demonstrated restoration of the affected safety functions.

- Unit 1, 1A EDG fuel line leak repair on July 1
- Unit 1, 1B 125 VDC and 28 VDC battery charger amp meter sensing line fuse installation on July 10
- Unit 1, 13 chiller low suction pressure trip repair on August 7
- Unit 1, reactor trip bypass breaker 'B' inspection on September 15
- Unit 2, 25SW72, 25 CFCU SW inlet valve repair, on July 10
- Unit 2, reactor vessel level indicating system repair on July 12
- Unit 2, 2C EDG breaker replacement on July 15
- Unit 2, 21SW223, 21 containment fan cooling unit (CFCU) SW outlet valve repair on July 25
- Unit 2, 22 chiller restoration following maintenance, on August 20

b. Findings

No findings were identified.

1R20 Refueling and Other Outage Activities (71111.20)

a. Inspection Scope

The Unit 2 maintenance and refueling outage (2R20), which commenced on April 12, was ongoing at the beginning of the inspection period. The inspectors reviewed PSEG's development and implementation of outage plans and schedules to verify that risk, industry experience, previous site-specific problems, and defense-in-depth were considered. During the outage, the inspectors observed portions of the shutdown, cooldown, and startup processes, and monitored controls associated with the following outage activities:

- Configuration management, including maintenance of defense-in-depth, commensurate with the outage plan for the key safety functions and compliance with the applicable technical specifications when taking equipment out of service
- Implementation of clearance activities and confirmation that tags were properly hung and that equipment was appropriately configured to safely support the associated work or testing
- Installation and configuration of reactor coolant pressure, level, and temperature instruments to provide accurate indication and instrument error accounting
- Status and configuration of electrical systems and switchyard activities to ensure that technical specifications were met
- Monitoring of decay heat removal operations
- Impact of outage work on the ability of the operators to operate the spent fuel pool cooling system
- Reactor water inventory controls, including flow paths, configurations, alternative means for inventory additions, and controls to prevent inventory loss
- Activities that could affect reactivity

- Maintenance of secondary containment as required by technical specifications
- Refueling activities, including fuel handling and fuel receipt inspections
- Fatigue management
- Tracking of startup prerequisites, walkdown of the primary containment to verify that debris had not been left which could block the emergency core cooling system suction strainers, and startup and ascension to full power operation
- Identification and resolution of problems related to refueling outage activities

This inspection effort was counted as an ROP sample during the last report, but since the outage was extended to conduct RCP bolting repairs, outage activities crossed into the first two weeks of this inspection report period.

b. Findings

No findings were identified.

1R22 Surveillance Testing (71111.22 – 4 samples)

a. Inspection Scope

The inspectors observed performance of surveillance tests and/or reviewed test data of selected risk-significant SSCs 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, residual heat removal heat exchanger component cooling flow,
In-service testing (IST) on July 1
Unit 1, Reactor Coolant System (RCS) inventory balance on July 24
Unit 1, end-of-life moderator temperature coefficient measurement on August 14
Unit 2, RCS water inventory balance on July 28

b. Findings

No findings were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

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 July 1, 2013, through June 30, 2014.

- Units 1 and 2, High Pressure Injection System (MS07)
- Units 1 and 2, Heat Removal System (MS08)
- Units 1 and 2, RHR System (MS09)

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

b. Findings

No findings were identified.

4OA2 Problem Identification and Resolution (71152 – 1 sample)

.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 that PSEG entered issues into the CAP at an appropriate threshold, gave adequate attention to timely corrective actions, 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 the CAP and periodically attended condition report screening meetings.

b. Findings

No findings were identified.

.2 Annual Sample: Unit 2 Plant Vent Noble Gas Radiation Monitor Reliability

a. Inspection Scope

The inspectors performed an in-depth review of PSEG's evaluations, the effectiveness of the corrective actions, and the impact to the emergency plan associated with the Unit 2 plant vent noble gas radiation monitor, 2R41. The 2R41 radiation monitor is used in the emergency plan for dose assessment and emergency classification. 2R41 uses four channels; 2R41A is a low range channel for normal operations, 2R41B and 2R41C are the medium and high accident range channels, respectively, and 2R41D provides the gaseous effluent release rate by combining the on-range 2R41A-C with plant vent flow. PSEG submitted a license amendment request in November 2012 to remove a redundant plant vent monitor, 2R45, from its emergency plan. The 2R45 was a backup to the medium and high range channels of 2R41. The safety evaluation report (SER) approving the change was issued in November 2013. From June 2013 to January 2014, the 2R41 radiation monitor was declared inoperable on multiple occasions due to the monitor exhibiting erratic behavior. This inspection was performed to evaluate whether

PSEG was appropriately identifying and evaluating the 2R41 radiation monitor operability issues and taking appropriate corrective actions and compensatory measures to ensure the emergency plan remained capable of being implemented in a timely manner.

The inspectors assessed PSEG's problem identification threshold, evaluations, extent-of-condition reviews, along with the prioritization and timeliness of actions to determine whether the corrective actions were appropriate. Additionally, the inspectors evaluated the impact to the implementation of the emergency plan. The inspectors reviewed the applicable condition reports and associated documents, including work orders, maintenance procedures, as-found test results, and the site emergency plan. The inspectors interviewed personnel from the maintenance, emergency preparedness, and engineering organizations to assess the appropriateness of the maintenance practices and the compensatory measures. Finally, the inspectors walked down the 2R41 radiation monitor skid to assess material condition.

b. Findings and Observations

No findings were identified.

The inspectors determined that PSEG appropriately captured the 2R41 erratic behavior and operability issues in their CAP. PSEG performed troubleshooting in accordance with station procedures and took compensatory measures, as appropriate, when the 2R41 radiation monitor was declared inoperable.

In accordance with procedure SC.CH-AB.ZZ-1102, "Response to Inoperable Technical Specification Effluent Monitors and Equipment," PSEG implemented compensatory measures for the inoperable 2R41 radiation monitor that included more frequent plant vent samples being taken and analyzed for noble gases. The results were then compared to the values in the emergency action level (EAL) tables to verify that a threshold was not exceeded which would require an event declaration.

Following the issuance of the SER on November 27, 2013, the 2R41 exhibited erratic behavior on December 8, 2013, and troubleshooting efforts identified soldering flux residue on a preamplifier extension cable pin. The pin was examined and cleaned, and the radiation monitor was restored to service. On January 2, 2014, 2R41 exhibited similar behavior, and troubleshooting efforts were performed with the input/output board being replaced. On both occasions, there was no repetition of the erratic behavior during the monitoring period prior to returning to service. In accordance with procedure MA-AA-716-004, "Conduct of Troubleshooting," if after performing troubleshooting activities, the issue is corrected, or the fault is localized, checks to verify operability can be performed and the maintenance activity closed. After previous troubleshooting methods were unsuccessful in preventing recurrence of the erratic behavior, PSEG escalated troubleshooting efforts when on January 15, 2014, the 2R41 radiation monitor again exhibited erratic behavior. The troubleshooting activities included a failure mode and casual table process and on-site assistance from the vendor. During this troubleshooting process, PSEG determined that the cadmium-tellurium detector was the source of the erratic behavior, and the detector was replaced. Following a monitoring period, the radiation monitor was declared operable.

PSEG performed a common cause evaluation in March 2014 to address the operational burden and maintenance resource challenges associated with the radiation monitoring system (RMS) as a whole. The inspectors noted an action item (ACIT #6) was developed to improve the use of equipment autopsies for failure analysis of RMS equipment to prevent repeat failures.

Based on the documents reviewed and discussions with engineering, maintenance, and emergency preparedness personnel, the inspectors determined that PSEG's response to the issue was commensurate with its safety significance and that the actions taken were reasonable to address the issues identified. Additionally, the inspectors found PSEG's actions did not impact the timely implementation of the emergency plan.

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

.1 (Closed) LER 05000272/2014-002-00: Manual Reactor Trip Due to Loss of 11 Steam Generator Feedwater Pump

a. Inspection Scope

On April 8, 2014, Unit 1 experienced a loss of power to the 11 steam generator feedpump (SGFP) governor control circuit, and manually tripped the reactor in response to lowering level in the 13 steam generator. The cause of the loss of power to the 11 SGFP governor control circuit was determined to be a ground fault on a limit switch test cable associated with the SGFP turbine main steam stop valve. The inspectors reviewed the LER, the associated root cause analysis and corrective actions, interviewed PSEG staff, and walked down associated components. This LER is closed.

b. Findings

Introduction. A Green, self-revealing FIN was identified against NC.WM-AP.ZZ-0002, "Performance Improvement Process," Revision 6, because PSEG did not adequately correct and prevent recurrence of steam generator feedpump (SGFP) silent coast-down events. Consequently, on April 8, 2014, PSEG operators manually tripped the Unit 1 reactor in response to lowering water level in the 13 steam generator that was caused by a coast-down of the 11 SGFP.

Description. On April 8, 2014, at 9:12 p.m., Salem Unit 1 was operating at approximately 100% power when operators received an alarm indicating failure of the 12 Essential Controls Inverter (ECI), followed by several other alarms. At 9:13 p.m., operators observed failed indications associated with 11 SGFP, as well as lowering steam generator water level, and took manual action to trip 11 SGFP in accordance with the alarm response procedure. As expected, this initiated a main turbine automatic runback to approximately 66 percent turbine loading. At 9:14 p.m., operators manually tripped the reactor due to 13 steam generator water level approaching its setpoint for an automatic reactor trip. PSEG's post-event investigation determined that a ground fault on a limit switch test cable associated with the 11 SGFP turbine main steam stop valve caused a momentary power transfer of 12 ECI, and opened the 12 Miscellaneous AC breaker 8. Once breaker 8 opened to clear the fault, 12 ECI transferred back to the normal power source. The opening of breaker 8 removed power to the 11 SGFP speed probes. As part of the governor control circuit, loss of power to the probes resulted in a governor controller shutdown and SGFP coast-down, thereby constituting a "silent coast-down." The SGFP governor controls were not designed to generate a SGFP trip signal following a governor controller shutdown.

PSEG entered this issue in their CAP (20646085) and performed a root cause analysis (RCA). PSEG determined the root cause "was a result of an accumulation of missed opportunities by Salem Station to use the corrective action system effectively." PSEG also stated that "a known deficiency in the SGFP governor circuit design increased the likelihood of a SGFP shutdown and a reactor trip." The RCA documented several opportunities to address SGFP turbine coast-down events, which were historically unalarmed and referred to as "silent" SGFP coast-downs. Specifically, silent SGFP coast-downs occurred in 1999, 2001, and twice in 2002. Three of these silent coast-down events involved successful main turbine runbacks that were manually initiated prior to, and successfully averted, automatic reactor trips on low steam generator water level. On November 12, 2002, Unit 1 experienced a silent coast-down of the 11 SGFP and manual reactor trip on lowering steam generator water level. PSEG had performed an RCA for that event, and determined the root cause for the "unrecoverable steam generator level" and manual reactor trip was "the unannounced 11 SGFP runback at 180 rpm/min" (i.e., coast-down). The 2002 RCA established a corrective action to "annunciate and eliminate" silent SGFP coast-downs, and designated this as a corrective action to prevent recurrence (CATPR). In response to this action, PSEG created a speed deviation alarm for the SGFPs, and an alarm procedure with a designated action to manually trip the affected SGFP to initiate a main turbine runback. Although not explicitly stated in the RCA, the inspectors determined that the intent of the CATPR was to prevent recurrence of the "unrecoverable steam generator level" as a result of SGFP coast-down events, because the alarm procedure achieves this action through initiation of a main turbine runback. The inspectors determined that the speed deviation alarm installed as a result of the 2002 event did not provide adequate annunciation capability for operators to successfully diagnose a SGFP coast-down prior to the onset of "unrecoverable steam generator level" on April 8, 2014. Finally, the 2002 RCA also established a separate design change action to provide uninterruptible power supplies (UPS) for the SGFP governor controls, but inadvertently omitted the speed probes from the scope during design change development.

After the April 8, 2014 trip, PSEG used simulations to determine that operators would have between 30 and 45 seconds to properly diagnose a SGFP turbine coast-down event and take action to initiate a turbine runback prior to an automatic rector trip on low steam generator water level. PSEG's interim corrective actions following the 2014 event included creating new overhead alarms dedicated to a loss of power to SGFP governor controls, and training licensed operators on a silent SGFP coast-down event. Additionally, PSEG performed a design change on Unit 2 to power the SGFP speed probes from an UPS and incorporated the same design change into the fall 2014 Unit 1 refueling outage scope of work. Long term corrective actions included development of advanced digital feedwater control system design changes that will automate turbine runbacks in the event of SGFP governor control power losses.

NC.WM-AP.ZZ-0002 was the CAP procedure effective at the time of the November 2002 event. Step 5.3.2 required that root cause analyses include "actions to correct the condition and prevent recurrence." NC.CA-TN.ZZ-0003, "Root Cause Manual," Revision 0, defined CATPRs as "Fundamental measures taken to correct the deficiency and prevent recurrence." The inspectors determined that the CATPR designated and completed as a result of the 2002 RCA did not adequately correct and prevent recurrence of silent SGFP coast-downs that result in "unrecoverable steam generator level." Specifically, the speed deviation alarm installed as a result of the 2002 event did not provide adequate annunciation capability for operators to successfully diagnose a SGFP coast-down prior to the onset of "unrecoverable steam generator level" on April 8, 2014.

Analysis. PSEG's inadequate corrective action to prevent recurrence of silent SGFP coast-down events in accordance with NC.WM-AP.ZZ-0002 was a performance deficiency. This issue was more than minor since it was associated with the equipment performance 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, the inadequate corrective action did not prevent recurrence of a silent SGFP coast-down that also resulted in a reactor trip. In accordance with IMC 0609, Attachment 4 and Exhibit 1 of Appendix A, the inspectors determined that this finding is of very low safety significance, or Green, because the finding did not cause both a reactor trip and the loss of mitigation equipment relied upon to transition the plant from the onset of the trip to a stable shutdown condition.

The inspectors determined there was no cross-cutting aspect associated with this finding since it was not representative of current PSEG performance. Specifically, in accordance IMC 0612, the causal factors associated with this finding occurred outside the nominal three-year period of consideration and were considered not representative of present performance.

Enforcement. NC.WM-AP.ZZ-0002, "Performance Improvement Process," Revision 6, step 5.3.2, requires that root cause evaluations include "actions to correct the condition and prevent recurrence." Contrary to NC.WM-AP.ZZ-0002, PSEG designated and implemented a CATPR in 2002 that did not adequately correct and prevent recurrence of silent SGFP coast-down events. Because this finding does not involve a violation and is of very low safety significance, Green, it is identified as a FIN. **(FIN 05000272/2014-004-02, Inadequate Corrective Action to Prevent Recurrence of Silent Steam Generator Feed Pump Coast-Downs)**

.2 (Closed) LER 05000272/2014-003-00: Reactor Trip due to Actuation of Generator Protection

a. Inspection Scope

On April 13, 2014, Unit 1 experienced an automatic reactor trip. The direct cause was a main generator lockout resulting from a main generator transformer overall differential relay trip. The relay tripped due to a failed wiring termination on the 'C' phase neutral generator current transformer. The inspectors reviewed the LER, the associated root cause analysis and corrective actions, interviewed PSEG staff, and walked down associated components. This LER is closed.

b. Findings

Introduction. A Green, self-revealing finding against PSEG procedure NC.WM-AP.ZZ-0002, "Performance Improvement Process", Revision 3, was identified for incomplete corrective actions when a Unit 1 main generator phase 'C' differential current lockout relay tripped and resulted in a reactor trip. Specifically, a design change package (DCP) had not been properly implemented in 2004 in response to a similar 2001 reactor trip.

<u>Description</u>. The Salem Unit 1 main turbine generator uses current transformers (CTs) to reduce its large currents to usable values to facilitate functions such as metering, voltage regulation, control, and protection. There are eighteen CTs installed on the Unit 1 Main Generator. If a protective circuit CT fails, a plant trip will occur due to protective relay actuation.

In May 2001, Unit 1 tripped from full power due to a main generator 'A' phase neutral CT degraded termination. Investigation into the open circuit led to discovery of a heat-damaged field wiring termination in a junction box. In addition to replacing the field wiring with a higher temperature-rated design, PSEG completed a root cause analysis (RCA) (70017189) from which a corrective action to prevent recurrence was created to evaluate a more suitable product for the CT field wiring application. This corrective action was implemented on Unit 1 in 2004 as DCP 80036354. The inspectors noted that the RCA effectiveness review was completed two years earlier, in January 2002. Notably, the corrective action review board at that time acknowledged that this review was "more of an extent of condition review" and commented that "the effectiveness review was limited" and "could not do a true effectiveness review" at that time.

On April 13, 2014, Unit 1 tripped from full power on a main generator phase 'C' differential current lockout relay. Troubleshooting identified the cause as an open circuit on the differential neutral bushing CT. PSEG conducted repairs to include replacement of the connection for the failed CT, two other CTs, and a degraded secondary CT identified in January 2014. Additionally, PSEG completed visual inspections and testing and entered this in their CAP (20646670). An RCA was completed and PSEG determined that the approved design from the 2001 trip had not been properly implemented. Specifically, while the CT field wiring had been upgraded with a higher temperature wiring in accordance with the DCP, the terminations had not been installed to the approved, environmentally robust design.

At the time of the 2001 DCP, NC.WM-AP.ZZ-0002 was the station CAP procedure. In steps 7.3 and 7.9, it respectively defined a corrective action as an "action that shall be completed to correct or preclude a quality condition" with a quality condition including a "deficiency in non-safety related equipment." NC.CA-TM.ZZ-0003, Root Cause Manual, Revision 0, was in effect at the time of the 2001 trip. Chapter 3 of this procedure states, in part, that "corrective actions should correct and prevent recurrence of the issues" and that corrective actions to prevent recurrence are "long-term fundamental corrective actions." Finally, in Chapter 6, it states that an effectiveness review is intended to be a "verification of corrective actions being completed as intended." The inspectors determined that the inadequate implementation of the DCP following the 2001 event was an inadequately implemented corrective action that was within PSEG's ability to foresee and correct.

<u>Analysis</u>. Inadequate implementation of a corrective action associated with the 2001 CT failure and reactor trip as required by NC.WM-AP.ZZ-0002 was a performance deficiency. The performance deficiency was determined to be more than minor since it was associated with the design control attribute of the initiating events cornerstone and adversely affected its objective to limit the likelihood of events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Specifically, a plant modification was not implemented, leaving the unit susceptible to a similar failure that resulted in a reactor trip in April 2014. In accordance with IMC 0609, Attachment 4 and Exhibit 1 of Appendix A, the inspectors determined that this finding is

of very low safety significance, or Green, because the finding did not cause both a reactor trip and the loss of mitigation equipment relied upon to transition the plant from the onset of the trip to a stable shutdown condition.

The inspectors determined there was no cross-cutting aspect associated with this finding since it was not representative of current PSEG performance. Specifically, in accordance IMC 0612, the causal factors associated with this finding occurred outside the nominal three-year period of consideration and were considered not representative of present performance.

Enforcement: NC.WM-AP.ZZ-0002, step 7.3 requires, in part, that a corrective action is an "action that shall be completed to correct or preclude a quality condition." Contrary to this, PSEG staff improperly implemented a corrective action associated with a design change to prevent recurrence of main generator CT failures that could result in a reactor trip. Consequently, a reactor trip occurred on April 13, 2014, as a result of a main generator CT failure. PSEG conducted repairs and captured this finding in their CAP (20646670). Since the generator CT field wire is not a safety-related component, there was no violation of regulatory requirements. Because this finding does not involve a violation and is of very low safety significance, Green, it is identified as a FIN. **(FIN 05000272/2014-003-00, Incomplete Corrective Action on Current Transformers Results in Reactor Trip)**

.3 (Closed) LER 05000272/2014-04-00: Reactor Trip due to Actuation of Generator Protection

a. Inspection Scope

On May 7, 2014, Unit 1 experienced an automatic reactor trip. The direct cause was a main generator lockout resulting from a main generator differential relay trip. The relay tripped due to a failed wiring termination on the 'A' phase neutral generator current transformer. The inspectors reviewed the LER, the associated root cause analysis and corrective actions, interviewed PSEG staff, and walked down associated components. This LER is closed.

b. Findings

Introduction. A Green, self-revealing finding against PSEG procedure LS-AA-120, "Issue Identification and Screening Process," Revision 12, was identified for inadequate interim corrective actions when a Unit 1 main generator phase 'A' differential current lockout relay tripped and resulted in a reactor trip. Specifically, interim corrective actions had not been properly implemented in response to a similar trip on April 13, 2014 for the same failure mechanism.

Description. The Salem Unit 1 main turbine generator uses CTs to reduce its large currents to usable values to facilitate functions such as metering, voltage regulation, control, and protection. There are eighteen CTs installed on the Unit 1 Main Generator. If a protective circuit CT fails, a plant trip will occur due to protective relay actuation.

On April 13, 2014, Unit 1 tripped from full power on a main generator phase 'C' differential current lockout relay. Troubleshooting identified the cause as an open circuit on the differential neutral bushing CT. PSEG conducted repairs to include replacement of the connection for the failed CT, two other CTs identified during inspections, and a degraded secondary CT identified in January 2014. PSEG also completed CT testing and initiated a root cause analysis via their CAP (20646670).

On May 7, 2014, Unit 1 tripped from full power on a main generator phase ‘A’ differential current lockout relay. Troubleshooting identified the cause as an open circuit on the wiring from the protective relay to the CT neutral bushing. PSEG’s response included replacing the CT field wires and terminations on all 18 CTs, testing the CTs, establishing periodic maintenance, and entering this in their CAP (20649969). Failure analysis determined that the CT connection insulating tape failed due to chronic thermal fatigue, permitting moisture intrusion due to inadequate environmental controls.

PSEG completed an analysis of the April and May 2014 CT connection failures/reactor trips and determined that the root cause was improper termination of CT lead wires to field wire connections. Specifically, the terminations had not been installed to the approved, environmentally robust design. A contributing cause was that the extent-of-condition visual examination and testing to identify potential common mode failures was not adequately challenged by the station. Specifically, from January through April 2014, there were three degraded CT secondary circuits and one CT secondary failure. One of the degraded circuits was on the ‘A’ phase and was captured in a notification (2063560) as indicative of a high impedance connection. Additionally, PSEG’s rationale for not performing a more intrusive inspection or additional repairs following the April 2014 trip was that testing had shown the CT connections were acceptable. In this case, however, PSEG subsequently determined, via a test data comparison for the two trips, that the testing performed would identify degraded CTs but not degraded connections.

LS-AA-120, step 2.7, defines interim corrective actions as “action(s) taken to temporarily prevent the effects of a condition or make an event less likely to recur during the period when the condition is being evaluated and until final corrective actions… are completed.” Step 4.4.3 requires PSEG to “ensure any immediate actions and interim corrective actions were initiated, completed, and/or documented.” The inspectors determined that the interim corrective actions following the April 2014 CT failure and reactor trip were inadequate in that they did not prevent the effects of the CT connection condition nor did they make an associated failure and consequent reactor trip less likely to recur during the period of the root cause analysis. The inspectors concluded that this was within PSEG’s ability to foresee and correct. The performance deficiency associated with terminations not installed in accordance with the approved, environmentally robust design was dispositioned in Section 4OA3.2 of this report.

Analysis. Inadequate interim corrective actions following the April 2014 CT failure and reactor trip was a performance deficiency against LS-AA-120. The performance deficiency was determined to be more than minor since it was associated with the equipment attribute of the initiating events cornerstone and adversely affected its objective to limit the likelihood of events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. Specifically, interim corrective actions did not adequately ensure the near-term reliability of CT connections following an April 2014 failure, leaving the unit susceptible to a similar failure that resulted in a reactor trip in May 2014. In accordance with IMC 0609, Attachment 4 and Exhibit 1 of Appendix A, the inspectors determined that this finding is of very low safety significance, or Green, because the finding did not cause both a reactor trip and the loss of mitigation equipment relied upon to transition the plant from the onset of the trip to a stable shutdown condition.

The finding was determined to have a cross-cutting aspect in Human Performance, Conservative Bias, in that individuals use decision-making practices that emphasize prudent choices over those that are simply allowable. That is, proposed actions are determined to be safe in order to proceed rather than unsafe in order to stop. Specifically, PSEG did not take a conservative approach to decisions regarding the scope of repairs given the unusual condition, did not consider the longer-term consequences when determining how to resolve the emergent CT concern, and did not take timely action to address the degraded condition commensurate with its significance, namely vulnerability to a further failure and a consequent reactor trip. [H.14]

Enforcement: LS-AA-120, step 2.7 defines an interim corrective action as an "action taken to temporarily prevent the effects of a condition or make an event less likely to recur during the period when the condition is being evaluated and until final corrective actions… are completed" and step 4.4.3 requires that they be completed. Contrary to this, PSEG staff did not implement adequate interim corrective actions following on April 13, 2014, CT failure and reactor trip. Consequently, a reactor trip occurred on May 7, 2014, as a result of another main generator CT failure. PSEG conducted repairs and captured this finding in their CAP (20649969). Since the generator CT field wire is not a safety-related component, there was no violation of regulatory requirements. Because this finding does not involve a violation and is of very low safety significance, Green, it is identified as a FIN. **(FIN 05000272/2014-004-00, Inadequate Interim Corrective Actions on Current Transformers Result in Reactor Trip)**

.4 (Closed) LER 05000311/2014-003-00: Enforcement Discretion Received for Exceeding Allowable Outage Time for Inoperable Offsite Power Source

a. Inspection Scope

On February 13, 2014, the 24 Station Power Transformer (SPT) was declared inoperable due to elevated transformer combustible gas levels indicative an active internal thermal fault. PSEG requested enforcement discretion for TS 3.8.1.1, Action a.3, which required restoration of the transformer to operable status within 72 hours and the estimate time for replace the transformer was estimated to exceed that timeframe. The NRC verbally granted the Notice of Enforcement Discretion (NOED) and documented these details in inspection report (IR) 05000272; 311/2014-002, section 4OA3. PSEG subsequently submitted an LER for this NOED since the TS allowable outage time had been exceeded. The inspectors reviewed this LER, the associated causal analysis, interviewed PSEG staff, and walked down related equipment. Additionally, the inspectors reviewed this issue as an unresolved item (URI) as required by IMC 0410, "Notices of Enforcement Discretion," and documented the results under section 4OA5 of this report. This LER is closed.

b. Findings

No findings were identified.

4OA5 Other Activities

.1 (Closed) Unresolved Item (URI) 05000272/2013005-02: Performance Monitoring of Reactor Trip Breakers

a. Inspection Scope

In IR 05000272; 311/2013-005, inspectors identified a URI concerning Maintenance Rule Functional Failure (MRFF) determinations of Unit 1 reactor trip breakers. Specifically, the 1B normal and 1A bypass reactor trip breakers did not meet as-found acceptance criteria during semi-annual maintenance. Additionally, there were delays in the MRFF evaluations. Following inspector questioning, PSEG's re-evaluation determined that the 1B normal reactor trip breaker was an MRFF and engineering staff were in the process of further evaluating to determine if it was a Maintenance-Preventable Functional Failure (MPFF). PSEG had also re-evaluated the 1A bypass breaker and determined it was still not an MRFF. The inspectors had also identified performance criterion (PC) issues in that there was a high threshold of 6 MPFFs in 36 months and no condition-monitoring PC despite requirements. The inspectors reviewed PSEG's determinations of the MRFF and MPFF aspects of these breakers as well as revisions to the monitoring of these components, interviewed PSEG staff, observed reactor trip breaker operations, and reviewed associated corrective actions to determine if performance was being effectively controlled and monitored.

b. Findings

No findings were identified.

Performance Criteria

On February 26, 2014, PSEG completed a maintenance rule scoping change that consisted of both broadening the list of procedures with acceptance criteria to those that apply to the bypass breakers and adding condition-based monitoring criteria in accordance with station guidance. PSEG also completed a Maintenance Rule Performance Criteria (PC) change that consisted of reducing the allowable number of MPFFs to 0 per 18 month rolling average and creating a criterion of 7 condition-based monitoring events per 18 month rolling average. The latter PC is based on 48 individual tests expected over that timeframe. These actions were captured under evaluation 70161919.

MRFFs/MPFFs

PSEG determined that the 1B normal reactor trip breaker MRFF (notification 20587013) was also an MPFF. However, under the revised system PCs, the issues counted as two separate condition monitoring events instead of an MPFF. PSEG also re-evaluated the 1A reactor trip bypass breaker undervoltage trip attachment force degradation value (20615370) and determined that it was not an MRFF as it is not within the maintenance rule scope. The degradation value is calculated from force measurement values that are both within the scope and used for condition-based monitoring. PSEG also re-evaluated an additional 1B normal reactor trip breaker undervoltage time response (20617155) and determined it to be an MRFF. This MRFF could not be evaluated for a potential MPFF as the breaker had been overhauled, thereby preventing determination of any maintenance-related causes. The inspectors identified that PSEG had not captured this aspect in their CAP and also challenged PSEG on the non-conservative approach to its consideration under the maintenance rule. PSEG captured this in their CAP (20658902) and ultimately agreed with the inspectors. In response, PSEG appropriately included this breaker's as-found performance as a condition monitoring event. Overall, under the revised program, neither Unit 1 nor Unit 2 reactor trip breakers currently exceed the established PCs.

In accordance with the NRC Enforcement Manual, a failure to establish appropriate (a)(2) performance criteria, move an (a)(2) system to (a)(1) solely because its performance criteria are not met, or to correctly characterize a failure as an FF or MPFF are not violations of 10 CFR 50.65(a)(2). Therefore, PSEG's incorrect and untimely characterizations of reactor trip breaker performance were not violations and were not more than minor. The inspectors also determined that PSEG actions reasonably assured that the reactor trip breakers were capable of performing their intended function and that appropriate preventive maintenance was being performed. Therefore, this URI is closed.

.2 (Closed) Unresolved Item (URI) 05000311/2014002-08: NOED for Replacement of 24 Station Power Transformer

a. Inspection Scope

In IR 05000272; 311/2014-002, inspectors identified a URI, as required by IMC 0410, when a NOED from TS was granted in response to 24 SPT elevated gassing on February 13, 2014, removal of 24 SPT from service, and replacement activities with an onsite available spare. Specifically, TS 3.8.1.1, Action a.3, requires restoration of the 24 SPT to operable status within 72 hours, and the total time to replace the transformer with an onsite available spare was estimated to take up to 216 hours. In response to the URI, the inspectors performed inspection activity to determine if there was a performance deficiency associated with 24 SPT elevated gassing.

b. Findings

No findings were identified.

PSEG performed Equipment Apparent Cause Evaluation (EQACE) 70163632, in order to determine the cause of the elevated combustible gas that was detected in the transformer oil content. PSEG concluded that a manufacturing defect resulted in the high gassing levels that caused the SPT to be removed from service in February. Specifically, one of six core clamping bolts had a missing insulating washer, which created an unintentional core ground and excessive gassing.

The inspectors reviewed the EQACE, interviewed PSEG staff, and reviewed associated corrective actions to determine if there was a performance deficiency associated with 24 SPT elevated gassing. The inspectors also noted that PSEG deferred electrical testing of 24 SPT during the fall 2012 refueling outage (2R19). PSEG examined the test deferral in the EQACE, and determined that since the gassing did not occur until September 2013, almost 1 year after the 2012 testing was scheduled; it is unlikely that the electrical testing would have revealed indications of a problem. The inspectors reviewed preventive maintenance (PM) history on the 24 SPT, compared the PM basis against industry standards and recommendations for large power transformers, and reviewed 24 SPT electrical testing data dating back to 2006. The inspectors determined that the 24 SPT elevated gassing was not attributed to any performance deficiencies by PSEG. Based on the overall review and inspection of the URI, the inspectors concluded that there was no performance deficiency by PSEG.

This URI is closed.

4OA6 Meetings, Including Exit

On October 9, 2014, the inspectors presented the inspection results to Mr. John Perry, Salem Site 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.

ATTACHMENT: SUPPLEMENTARY INFORMATION

SUPPLEMENTARY INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel
J. Perry, Site Vice President
L. Wagner, Plant Manager, Salem
M. Adair, Senior Fire Protection Engineer
C. Banner, Manager, Emergency Preparedness
J. Bergeron, Superintendent, Instrumentation and Control (I&C)
C. Beeson, System Engineer
T. Brennan, Maintenance Supervisor
D. Boyle, Engineering Programs
T. Cachaza, Regulatory Assurance
K. Chambliss, Regulatory Assurance Manager
R. DeNight Jr., Operations Director
J. Giunta, System Engineer, Radiation Monitoring System
S. Goss, Nuclear Engineer
A. Johnson, Design Engineering Manager
B. Ketterer, System Manager
D. LaFleur, Regulatory Assurance
B. Leghorn, Chief Technician – Controls
C. Lynch, Senior Reactor Operator
J. Owad, PE, Structural Design Engineer
J. Stavely, Salem NOS Manager
S. Swenson, Plant Engineering Manager

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Open/Closed

05000272/2014004-01	NCV	Improper Risk Assessment and Risk Management Actions for a Reheater Drain Valve (Section 1R13)
05000272/2014004-02	FIN	Inadequate Corrective Action to Prevent Recurrence of Silent Steam Generator Feed Pump Coast-Downs (Section 4OA3)
05000272/2014004-03	FIN	Incomplete Corrective Action on Current Transformers Results in Reactor Trip (Section 4OA3)
05000272/2014004-04	FIN	Inadequate Interim Corrective Actions on Current Transformers Result in Reactor Trip (Section 4OA3)

Closed

05000272/2014002-00	LER	Reactor Trip due to Loss of the 11 Steam Generator Feedwater Pump (Section 4OA3)
05000272/2014003-00	LER	Reactor Trip due to Actuation of Generator Protection (Section 4OA3)
05000272/2014004-00	LER	Reactor Trip due to Actuation of Generator Protection (Section 4OA3)
05000311/2014003-00	LER	Enforcement Discretion Received for Exceeding Allowable Outage Time for Inoperable Offsite Power Source (Section 4OA3)
05000272/2013005-02	URI	Performance Monitoring of Reactor Trip Breakers (Section 4OA5)
05000272/2014002-08	URI	NOED for Replacement of 24 Station Power Transformer (Section 4OA5)

LIST OF DOCUMENTS REVIEWED

* Indicates NRC-identified

Section 1R01: Adverse Weather Protection

Procedures
OP-AA-108-111-1001, Severe Weather and Natural Disaster Guidelines, Revision 10
SC.OP-AB.ZZ-0001, Adverse Environmental Conditions, Revision 16
SC.FP-SV.FBR-0026, Flood and Fire Penetration Seal Inspection, Revision 5

Notifications
20662087 20662385 20662401 20663147* 20663197* 20662995*
20663095*

Evaluations
70127952

Maintenance Orders/Work Orders
30127686 30216247 30192805 30171251 30150761

Other Documents
VTD 327743, Penetration Seal Inspection List
FSAR 2.4, 3.4
NCV 05000325/2014003-01

Section 1R04: Equipment Alignment

Procedures
S1.OP-SO.CAV-0001, Control Area Ventilation Operation, Revision 37
S2.OP-SO.CAV-0001, Control Area Ventilation Operation, Revision 39
S2.OP-SO.SW-0001, Service Water Pump Operation, Revision 27
S2.OP-SO.SW-0005, Service Water System Operation, Revision 41
S1.OP-SO.SW-0005, Service Water System Operation, Revision 39
S2.OP-ST.SW-0013, Service Water Valve Verification, Revision 1

Notifications

20468593	20597073	20647752	20659756	20659757	20659790
20659886	20659953	20659970	20659987	20660062	20660073
20660074					

Drawings
205248 Sheets 1, 2, No. 1 Aux Bldg. Control Area Air Conditioning & Ventilation, Revisions 37 & 49
205342 Sheets 1, 2, 3, & 6, No. 2 Unit Service Water Nuclear Area, Revisions 79, 75, 76, & 70
205348 Sheets 1, 2, No. 2 Aux Bldg. Control Area Air Conditioning & Ventilation, Revisions 29 & 39

Maintenance Orders/Work Orders
30154158 30160851

Other Documents

4079476	4079477	4281703	4329348	4356470	4359444

Section 1R05: Fire Protection

Procedures
FRS-II-914, Unit 1, (Unit 2) – Pre-Fire Plan, Outer Penetration Area, Revision 2
FRS-II-441, Unit 1, (Unit 2) – Pre-Fire Plan, Relay and Battery Rooms, and Corridor, Revision 7
FRS-II-521, Unit 1, (Unit 2) – Pre-Fire Plan, Inner Piping Penetration Area & Chiller Rooms, Revision 3
FRS-II-431, Unit 1, (Unit 2) – Pre-Fire Plan, 460V Switchgear Rooms and Corridor, Revision 8
FRS-II-421, Unit 1, (Unit 2) – Pre-Fire Plan, 4160V Switchgear Rooms and Corridor, Revision 6
S2.FP-ST.FS-0116, Switchgear Rooms and Electrical Penetration Area Dry Sprinkler System Functional Test and Inspection, Revision 2
S1.FP-ST.FD-0029, Functional Test of Class 1 Smoke and Thermal Detectors, Revision 16
S2.FP-ST.FD-0029, Functional Test of Class 1 Smoke and Thermal Detectors, Revision 13

Notification
20649852 20658404 20658699

Other Documents
FP-015-F3, Hourly Firewatch Inspection Log, 8-13-14, 8-12-14

Section 1R06: Flood Protection Measures

Procedures
S1.OP-AB.ZZ-0002, Flooding, Revision 3
SC.FP-SV.FBR-0026, Flood and Fire Barrier Penetration Seal Inspection, Revision 2
SC.OP-SO.BD-0001, Station Sumps, Revision 7

Notifications
20325499 20659741 20659923 20659963 20660080

Drawings
205223 Sheets 1, 2, 3, No. 1 Building & Equipment Drains - Conventional, Revisions 34, 38, 46
233620, No. 1 Unit Sump and Flood Pumps - Conventional, Revision 12
602105, Unit 1 & 2 Penetration Seal Locations EL 84' Room Numbering Floor Plan, Revision 1
602141, Unit 1 Penetration Seal Locations Room 15401 EL 84' North-South Corridor Unit 1 & 2 Common - East Wall, Revision 2
SN-3, SE-Foam with Cable Thru Fire and/or Pressure Barrier, Revision 4
SN-37, Biscoseal with Cables in Sleeve Thru High Pressure Barrier, Revision 1

Maintenance Orders/Work Orders
30072938 30260275

Other Documents
ND.DE-PS.ZZ-0010-A5, Internal Hazards Program Appendix A5 – Flooding Analysis Methodology, Revision 1
NLR-N93109, Generic Letter 88-20: Individual Plant Examination (IPE) Report for Salem Generating Station Unit Nos. 1 and 2, dated 7/30/93
SA-PRA-012, Salem Generating Station Probabilistic Risk Assessment – Internal Flood Evaluation Summary Notebook, Revision 1
S-C-ZZ-SDC-1203, Moderate Energy Break Analysis (Reconstitution), Revision 3
VTD 327742, Penetration Seal E-15401-062 Inspection, performed January 20, 2004

Section 1R12: Maintenance Effectiveness

Procedures
SC.RE-IO.ZZ-0002, Low Power Physics Testing and Power Ascension, Revision 17
SC.RE-ST.ZZ-0001, Initial Criticality and Testing Advanced Digital Reactivity Computer, Revision 20
S2.OP-IO.ZZ-0003, Hot Standby to Minimum Load, Revision 39
A-O-ZZ-SEE-1160, Establishment of Requirements for Monitoring the Condition of Structures, Revision 1
ER-AA-310-1009, Condition Monitoring of Structures, Revision 2
S-C-ZZ-SEE-1035, Evaluation of Deteriorated Concrete Areas in Plant Structures – Salem Generating Station, Revision 0
S-IR-6S0-0023, Falcon Power Inc. Groundwater Intrusion Report, Revision 0
S1.OP-SO.DG-0001, Attachment 17, Individual High Pressure Fuel Injection Pump Lockout, Revision 36
ER-AA-1200, Critical Component Failure Clock, Revision 6
S1.OP-ST.DG-0001, 1A Diesel Generator Surveillance Test, Revision 45

Notifications

20143874	20255384	20497755	20561196
20656591	20659952*	20659954*	30112809
20143874	20255384	20497755	20561196
20656591	20659952*	20659954*	30112809
20652270	20659337	20664925*	

Evaluations
70167623-0010

Other Documents
PSEG License Amendment Request NLR-N94099 / LCR 94-15, EDG Fuel Oil Storage, dated 06/29/2014
NRC Safety Evaluation associated with EDG Fuel Oil Storage, dated 06/20/1995
S-C-DF-MDC-1316, Salem 1 and 2 EDG Fuel Oil Storage Basis, Revision 2

Section 1R13: Maintenance Risk Assessments and Emergent Work Control

Procedures
ER-AA-600, Risk Management, Revision 7
OP-AA-101-112-1002, On-Line Risk Assessment, Revision 8
OP-AA-108-116, Protected Equipment Program, Revision 9
WC-AA-101, On-Line Work Management Process, Revision 22
WC-AA-105, Work Activity Risk Management, Revision 2
S1.IC-ST.SSP-0010, SSPS Train A – Reactor Trip Breaker UV Coil and Automatic Shunt Trip, Revision 37
MA-AA-716-004, Conduct of Troubleshooting, Revision 12
ORAM Contingency Plan, RCS at Mid-Loop Post-Refueling (23SJ17), dated 07/08/2014
S2.OP-SO.RC-0006, Draining the Reactor Coolant System <101 Foot Elevation with Fuel in the Vessel, Revision 37

Notifications

20663166*	20663162*	20659582	20661817
20662028	20662087	20662035	20661807
20662179*	20655041	20655735	20655409

Evaluations
70167490-0060

Maintenance Orders/Work Orders
50167637
60118068

Other Documents
NDE Surface Examination Test Report Records, 23SJ17 Liquid Penetrant Examination, 07/05/12014, 07/08/2014
Salem Generating Station Unit 1 Risk Assessment (Work Week 434), Revision 0
Salem Generating Station Unit 2 Risk Assessment (Work Week 434), Revision 0

Section 1R15: Operability Determinations and Functionality Assessments

Procedures
S1.OP-ST.SJ-0002, Inservice Testing – 12 Safety Injection Pump, Revision 19
ER-AA-321-1005, Condition Monitoring for Inservice Testing of Check Valves, Revision 5
SC.IC-LC.CBV-0001, Containment Ventilation Differential Pressure Loop Calibration, Revision 5
S2.OP-AR.ZZ-0002, 24-26 SW Pump Bearing Water Pressure Low, Revision 35

Notifications

20659705	20659987*	20660073	20663001
20627770	20654143	20654669	20635278
20635531	20635564	20656624	20656399
20655947	20659705	20658953	20659065
20657694	20657614		

Drawings
205234, Safety Injection, Sheets 1(2, 4), Revisions 56(47, 45)
611433, AFW 11 Steam Generator Inlet Valve Controller, 11AF21-AO, Revision 1
624716, Unit 2 Containment Ventilation Differential Pressure Loop Diagram, Revision 0

Evaluations
70168577 70167136 70167816 60118624

Maintenance Orders/Work Orders
60113983 60118149 60080771 60080050 80064143

Other Documents
S-C-AF-MDC-0445, Auxiliary Feedwater Hydraulic Analysis, Revision 3
SC-CBV006-01, Containment Building Differential Pressure Indication Loop Uncertainty, Revision 0

Section 1R19: Post-Maintenance Testing

Procedures
OP-ST.DG-0001(Q), 1A Diesel Generator Surveillance Test, Revision 45
S2.OP-ST.DG-003, 2C Diesel Generator Surveillance Test, Revision 51
S1.OP-SO.28-002, 1B 28VDC Battery Charger Operation, Revision 8
S1.OP-SO.125-002, 1B 125VDC Battery Charger Operation, Revision 8
S2.OP-ST.SW-0010, Inservice Testing Containment Fan Cooler Unit Service Water Valves, Revision 20
S2.OP-ST.CH-0004(Q), Chilled Water System – Chillers, Revision 18
S1.OP-ST.CH-0004, Chilled Water System – Chillers, Revision 12, Performed 08/06/2014
SC.IC-PT.RVL-0001, RVLIS Level Output Scaling Adjustments and Heat-up Data Collection, Revision 14
SC.IC-SC.RVL-0020, Reactor Vessel Level Instrumentation System Transmitter Calibration, Revision 16
S2.OP-SO.RVL-0001, Reactor Vessel Level Instrumentation System, Revision 18
S2.IC-DC.RVL-0001, Reactor Vessel Level Instrumentation System Local Transmitter Data Collection and Calibration, Revision 1

Notifications

20573304	20652270	20656261	20656271
20641498	20615839	20650325	20659055
20660415	20661667	20659146	20659890
20662110	20641498	20615839	20650325
20659055	20659146	20659890	20656452
20658384	20658579	20658645	20660657
20661301	20657350	20655397	20655628
20656341	20656114		

Drawings
211343 A 8859-15, Unit 1 – Auxiliary Building Control Area No. 1B – 125V DC Bus

Maintenance Orders/Work Orders

50168146	60114386	60114393	60117953	60118619	60119046
30267425	60118520	30243230			

Evaluations
70136073 70168067 70167720

Other Documents
FMCT 20657350 – Troubleshoot and Repair Cause of 21SW223 not Opening
NRC Information Notice 97-25: Dynamic Range Uncertainties in the Reactor Vessel Level Instrumentation

Section 1R20: Refueling and Other Outage Activities

Procedures
S1.OP-IO.ZZ-0003, Hot Standby to Minimum Load, Revision 7
S2.OP-ST.CAN-0007, Refueling Operations – Containment Closure, Revision 27
S2.OP-SO.SF-0009, Refueling Operations, Revision 18
S2.OP-SO.SF-0003, Filling the Refueling Cavity, Revision 31
S2.OP-SO.RC-0002, Vacuum Fill of the RCS, Revision 31
S2.OP-SO.RC-0005, Draining the RCS to ≥ 101 Foot Elevation, Revision 42
S2.OP-SO.RC-0006, Draining the RCS < 101 Feet Elevation with Fuel in the Vessel, Revision 37
SC.OP-DL.ZZ-0011, RCS Heat-up and Cooldown, Revision 11
SC.RE-FR.ZZ-0001, Fuel Handling, Revision 50
SC.MD-FR.CAN-0001, Outage Equipment Hatch Installation, Removal Seal Replacement and Door Manipulation for Containment Closure, Revision 17
Cold Shutdown to Hot Standby, S2.OP-IO.ZZ-0002(Q), Revision 59
Pressurizer Heatup/Cooldown Log, SC.OP-DL.ZZ-0012(Q), Revision 5
Reactor Coolant Pump Operation, S2.OP-SO.RC-0001(Q), Revision 30

Section 1R22: Surveillance Testing

Procedures
SC.RE-ST.ZZ-0007, Moderator Temperature Coefficient Measurement, Revision 16
S-013, Westinghouse Electric Corporation Electro-Mechanical Division, No. 2 and No. 3 Seal Operating Criteria, Revision 1

S1.OP-ST.RC-0008, RCS Water Inventory Balance, Revision 26
S1.OP-SO.RC-0004, Containment Sump, Revision 14
S2.OP-ST.RC-0008, RCS Water Inventory Balance, Revision 37
S2.OP-SO.RC-0004, Containment Sump, Revision 15
S1.OP-ST.CC-0003, Inservice Testing – 13 Component Cooling Pump, Revision 24, performed 03/18/2014 and 06/11/2014

Notifications
20656104 20656319 20657025 20657023 20655629 20643459

Evaluations
70164743

Other Documents
OP-AA-106-101-1006-F1, Plant Issue Resolution Documentation Form, OTDM: S-14-006, Revision 0
Salem Common Standing Order: 23 RCP #2 Seal Increased Leakage

Section 4OA1: Performance Indicator Verification

Procedures
LS-AA-2001, Collecting and Reporting of NRC Performance Indicator Data, Revision 11
LS-AA-2200, MSPI Data Acquisition and Reporting, Revision 4
ER-AA-600-1047, MSPI Basis Document, Revision 4
SC-MSPI-001, MSPI Basis Document, Revision 8

Notifications
20625687 20640464 20661196* 20661296*

Miscellaneous
NEI 99-02, Regulatory Assessment Performance Indicator Guideline, Revision 7
MSPI Derivation Reports, Unavailability and Unreliability Indices for Units 1 and 2, MS07, MS08, and MS09 for June 2013 and June 2014

Section 4OA2: Problem Identification and Resolution

Procedures
EP-AA-121-1003, Equipment Important to Emergency Response – Work Prioritization, Revision 0
MA-AA-716-004, Conduct of Troubleshooting, Revision 12
NC.EP-EP.ZZ-0309(Q), Dose Assessment (MIDAS) Instructions, Revision 11
SC.CH-AB.ZZ-1102(Q), Response to Inoperable Technical Specification Effluent Monitors and Equipment, Revision 25
SC.CH-SA.WD-0244(Q), Plant Vent Sampling, Revision 31
EP-SA-111-203, SGS ECG – EAL Technical Basis, Revision 01
FP-AA-0005, Fire Protection Key Control Program, Revision 2
SY-AA-101-120, Control of Security Locks, Keys, Cores, and Combination Locks, Revision 11
S1.OP-AB.FIRE-0001, Control Room Fire Response, Revision 6

Notifications

20656217*	20656206*	20656508*	20658955*
20636722	20633215	20658026*	20655065
20642891	20639536	20625364	20654140
20625363	20662439*	20662775*	

Work Orders
60113950, NUCM 2R41B Elevated after Source Check, dated 11/13/13
60114227, NUCM 2R41B Reading High/Erratic, dated 11/15/13
60114423, NUCM 2R41B Failed, Normal Light is out in CR, dated 12/11/13
60114841, NUCM 2R41B Reading High, dated 1/6/14
60115097, NUCM 2R41B Failed High, 2/5/14

Miscellaneous
Common Cause Evaluation 70162556, Radiation Monitoring System (RMS), Failures dated April 15, 2014

Section 4OA3: Follow-up of Events and Notices of Enforcement Discretion

Procedures
ER-AA-2004, System Vulnerability Review Process, Revision 6
LS-AA-125, Corrective Action Program, Revisions 11 through 18
LS-AA-125-1001, Root Cause Evaluation Manual, Revision 9
NC.CA-TM.ZZ-0003, Root Cause Manual, Revision 0
NC.CA-TM.ZZ-0003, Root Cause Evaluation Guideline, Revisions 1 and 2
NC.WM-AP.ZZ-0002, Performance Improvement Process, Revisions 5 and 5

S1.OP-AR.ZZ-0002, Overhead Annunciators Window B, Alarm B-43, 12 Essential Controls Inverter Failure, Revision 28
S1.OP-AR.ZZ-0007, Overhead Annunciators Window G, Alarm G-6, 11 SGFP Trouble, Revision 37
S1.OP-AR.ZZ-0007, Overhead Annunciators Window G, Alarm G-23, 11/12 SGFP Speed Deviation, Revision 37
S1.OP-AR.ZZ-0007, Overhead Annunciators Window G, Alarm G-31, 11 SGFP Governor Shutdown, Revision 37

Notifications
20663142* 20664732* 20646085

Evaluations
70165169 70106673 70154960 70154960

Evaluations
80054219

Other Documents
Licensed Operator Training, Condensate and Feedwater System, dated 09/06/2013
System Vulnerability Review Report for Salem Feedwater System, November 2010

<u>Section 4OA5: Other Activities</u>

<u>Notifications</u>
20658646 20658640 20653482

<u>Evaluations</u>
70147637 70156892 70163632 70033503 80100802

<u>Other Documents</u>
24 SPT Electrical Testing Data, 03/25/2014, 10/26/2009, and 10/18/2006
Doble Transformer Leakage Reactance Training slides, dated April 9, 2013
EPRI 106857-V38, EPRI Preventive Maintenance Basis: Volume 38 – Transformers, November 1998

LIST OF ACRONYMS

10 CFR	Title 10 of the *Code of Federal Regulations*
ACE	apparent cause evaluation
ACIT	action item
ADAMS	Agencywide Documents Access and Management System
ALARA	As Low As Reasonably Achievable
CAP	corrective action program
CATPR	corrective action to prevent recurrence
CAV	control area ventilation
CFR	Code of Federal Regulations
CRE	control room envelope
CT	current transformer
DCP	design change package
EAL	emergency action level
ECI	essential controls inverter
EDG	emergency diesel generator
EQACE	equipment apparent cause evaluation
EPD	Electronic Personnel Dosimeter
FIN	finding
IMC	inspection manual chapter
IST	in-service testing
kV	kilovolt
LER	licensee event report
MAC	miscellaneous AC
MPFF	maintenance preventable functional failure
MR	maintenance rule
MRFF	maintenance rule functional failure
MSR	moisture separator reheater
NCV	non-cited violation
NOED	notice of enforcement discretion
NRC	Nuclear Regulatory Commission
OE	operating experience

OHA	overhead alarm
PC	performance criterion
PI	performance indicator
PMT	post-maintenance test
PSEG	Public Service Enterprise Group Nuclear LLC
RCA	root cause analysis
RCE	root cause evaluation
RCP	reactor coolant pump
RCS	reactor coolant system
RMS	radiation monitoring system
SDP	significance determination process
SER	safety evaluation report
SGFP	steam generator feedpump
SPT	station power transformer
SSC	structure, system, and component
SW	service water
TLD	Thermo-luminescent Dosimeter
TS	Technical Specifications
UFSAR	Updated Final Safety Analysis Report
URI	unresolved item