UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION I
2100 RENAISSANCE BOULEVARD, SUITE 100
KING OF PRUSSIA, PENNSYLVANIA 19406-2713

August 10, 2012

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 05000272/2012003 AND 05000311/2012003

Dear Mr. Joyce:

On June 30, 2012, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at the Salem Nuclear Generating Station, Units 1 and 2. The enclosed inspection report documents the inspection results, which were discussed on July 12, 2012, with Mr. Fricker, Vice President of Salem Operations, 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 one NRC identified and two self-revealing findings of very low safety significance (Green). These findings were determined to involve violations of NRC requirements. Additionally, a licensee-identified violation, which was determined to be of very low safety significance, is listed in this report. However, because of the very low safety significance, and because they are entered into your corrective action program (CAP), the NRC is treating these findings as non-cited violations (NCVs) consistent with Section 2.3.2 of the NRC Enforcement Policy. If you contest any NCV 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 the Salem Nuclear Generating Station. In addition, if you disagree with the cross-cutting aspect assigned to any finding in this report, you should provide a response within 30 days of the date of this inspection report, with the basis of your disagreement, to the Regional Administrator, Region 1, and the NRC Resident Inspector at Salem Nuclear Generating Station.

In accordance with 10 CFR 2.390 of the NRCs “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 Public Document Room or from the Publicly Available Records (PARS) component of NRC's document 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/

Arthur L. Burritt, Chief
Reactor Projects Branch 3
Division of Reactor Projects

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

Enclosure: Inspection Report 05000272/2012003 and 05000311/2012003
w/Attachment: Supplementary Information

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U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket Nos.:	50-272, 50-311
License Nos.:	DPR-70, DPR-75
Report No.:	05000272/2012003 and 05000311/2012003
Licensee:	PSEG Nuclear LLC (PSEG)
Facility:	Salem Nuclear Generating Station, Unit Nos. 1 and 2
Location:	P.O. Box 236 Hancocks Bridge, NJ 08038
Dates:	April 1, 2012 through June 30, 2012
Inspectors:	D. Schroeder, Senior Resident Inspector P. McKenna, Resident Inspector R. Nimitz, Senior Health Physicist
Approved By:	Arthur L. Burritt, Chief Reactor Projects Branch 3 Division of Reactor Projects

TABLE OF CONTENTS

SUMMARY OF FINDINGS

IR 05000272/2012003, 05000311/2012003; 04/01/2012 - 06/30/2012; Salem Nuclear Generating Station Units 1 and 2; Maintenance Effectiveness and Operability Determinations and Functionality Assessments.

This report covered a three-month period of inspection by resident inspectors and announced inspections performed by regional inspectors. Inspectors identified three findings of very low safety significance (Green), which were NCVs. The significance of most findings is indicated by their color (Green, White, Yellow, or Red) and determined using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" (SDP). The cross cutting aspect of the findings were determined using IMC 0310, "Components Within the Cross-Cutting Areas." Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process", Revision 4, dated December 2006.

Cornerstone: Mitigating Systems

- Green. A self-revealing non-cited violation (NCV) of Technical Specification (TS) 6.8.1.a "Procedures and Programs," was identified because the 13 service water (SW) strainer failed while in-service on March 13, 2012. PSEG failed to perform adequate post-maintenance testing (PMT) on the 13 SW strainer before declaring it operable on January 13, 2012, and therefore did not find inadequate clearance between the strainer drum and body. This issue was entered into PSEG's corrective action program (CAP) as notification 20550115. PSEGs immediate corrective actions were to replace the strainer drum o-ring, adjust the strainer clearances and perform a PMT of the strainer.

  The inspectors determined that the performance deficiency was more than minor because it was associated with the human performance attribute of the Mitigating Systems cornerstone, and it adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the trip of the 13 SW strainer while the 14 SW pump was inoperable for planned maintenance resulted in Salem Unit 1 entering a 72 hour unplanned limiting condition for operation (LCO) for 11.5 hours. The finding was evaluated in accordance with IMC 0609, Attachment 4, "Initial Screening and Characterization of Findings," and was determined to require additional evaluation. The finding was subsequently evaluated in IMC 0609, Phase 3 utilizing the NRC's SAPHIRE 8 risk analysis SDP interface tool using the Salem specific standardized plant analysis review (SPAR) model, and confirmed to be of very low safety significance. This finding has a cross-cutting aspect in the area of human performance, work practices, because PSEG personnel did not follow procedures. Specifically, PSEG personnel failed to comply with procedure "Service Water Auto Strainer Adjustment, Inspection, Repair and Replacement," which required an evaluation of a torque curve generated by a baker box. (H.4(b)) (Section 1R12)

- Green. A self-revealing NCV of 10 Code of Federal Regulation (CFR) Part 50, Appendix B, Criterion XVI, "Corrective Action," was identified because PSEG did not correct a condition adverse to quality. Specifically, repeat failures of solenoid operated valves (SOVs) with

voltage applied greater than design voltage was not been corrected in a timely manner and caused a failure of the 11 control area chiller (CAC).

The performance deficiency was determined to be more than minor because it was associated with the equipment performance attribute of the Mitigating Systems cornerstone and affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Using IMC 0609, Attachment 4, “Initial Screening and Characterization of Findings,” the inspectors determined that a single train of a safety-related system was unavailable for eight hours, less than the TS allowed outage time. Therefore, the issue was of very low safety significance (Green) because it did not result in a loss of system safety function, loss of a single train for greater than TS allowed outage time, or potentially risk-significant due to a fire, flooding, or severe weather initiating event. Immediate corrective actions taken included replacement of the failed SOV, and compensatory measures include periodic temperature monitoring of similar energized SOVs. This finding has a cross-cutting aspect in the area of problem identification and resolution, corrective action program, because PSEG did not take appropriate corrective actions to address a safety issue in a timely manner, commensurate with the safety significance and complexity. Specifically, the premature failure of SOVs, due to a higher than design voltage that created higher than design heat in the coil and insulation, was a known issue that was not corrected in a timely manner. (P.1(d)) (Section 1R12)

- Green. The inspectors identified a NCV of TS 6.8.1.a “Procedures and Programs,” because PSEG failed to properly control and store transient material within seismic class I buildings such that the equipment did not pose a hazard to safe plant operation. Specifically, two large tool gang boxes were stored unrestrained in the vicinity of the sodium hydroxide storage tank and associated containment spray (CS) valves and two full 55 gallon SW maintenance drums were stored unrestrained next to the 11, 12, and 15 containment fan cooler unit (CFCU) SW flow transmitters. This issue was entered into PSEG’s CAP as notification 20559092. PSEGs immediate corrective actions were to restrain the subject material in accordance with the PSEG procedure CC-AA-320-011, “Transient Loads.”

  The performance deficiency was determined to be more than minor because it was associated with the equipment performance attribute of the Mitigating Systems cornerstone and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. The issue was also similar to IMC 0612, Appendix E, “Examples of Minor Issues,” example 4.a which stated the issue was more than minor if the licensee routinely failed to follow their procedure and safety-related equipment was adversely impacted. Specifically, PSEG was not following the requirements of procedure CC-AA-320-011, “Transient Loads,” and equipment had been stowed in close vicinity of safety-related equipment. The finding was evaluated under IMC 0609, Attachment 4, “Initial Screening and Characterization of Findings.” The inspectors determined that the finding is of very low safety significance (Green) because it did not involve loss or degradation of equipment specifically designed to mitigate a seismic event, and did not involve total loss of a safety function that contributes to external event initiated core damage sequences. The finding has a cross-cutting aspect in the area of human performance, work practices, in that PSEG did not define and effectively communicate expectations regarding procedural compliance and personnel did not follow procedures. Specifically, station personnel did not follow procedures for the storage of transient loads in the auxiliary building (H.4(b)) (Section 1R15)

Other Findings

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

REPORT DETAILS

Summary of Plant Status

Salem Nuclear Generating Station Unit 1 (Unit 1) began the period at 100 percent power. On April 24, 2012, plant operators reduced power to 89 percent due to transmission line 5015 maintenance and then to 75 percent for main turbine valve testing. Unit 1 returned to 89 percent power on April 24, 2012 and then to 100 percent power on April 28, 2012. On April 30, 2012, Unit 1 experienced a trip and an inadvertent safety injection signal. Unit 1 was placed in Mode 5 for maintenance and troubleshooting of the reactor protection system (RPS). Unit 1 returned to 100 percent power on May 8, 2012. On June 25, 2012 plant operators reduced power to 91 percent due to a tube leak in the 13B feedwater heater. Unit 1 returned to 100 percent power on June 28, 2012. Unit 1 remained at 100 percent power for the remainder of the period.

Salem Nuclear Generating Station Unit 2 (Unit 2) began the period at 100 percent power. On June 13, 2012, plant operators reduced power to 98 percent due to the 21 moisture separator reheater being removed from service. Operators returned Unit 2 to full power on June 15, 2012. Unit 2 remained at 100 percent power for the remainder of the period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01 – 2 samples)

.1 Readiness for Seasonal Extreme Weather Conditions

a. Inspection Scope

The inspectors performed a review of PSEG's readiness for the onset of seasonal high temperatures. The review focused on SW, component cooling water (CCW), and the emergency diesel generators (EDGs). The inspectors reviewed the Updated Final Safety Analysis Report (UFSAR), TSs, control room logs, and the CAP to determine what temperatures or other seasonal weather could challenge these systems, and to ensure PSEG personnel had adequately prepared for these challenges. The inspectors reviewed station procedures, including PSEG's seasonal weather preparation procedure and applicable operating procedures. The inspectors performed walkdowns of the selected systems to ensure station personnel identified issues that could challenge the operability of the systems during hot weather conditions. Documents reviewed for each section of this inspection report are listed in the Attachment.

b. Findings

No findings were identified.

.2 Summer Readiness of Offsite and Alternate Alternating Current (AC) Power Systems

a. Inspection Scope

The inspectors performed a review of plant features and procedures for the operation and continued availability of the offsite and alternate AC power system to evaluate readiness of the systems prior to seasonal high grid loading. The inspectors reviewed PSEG's procedures affecting these areas and the communications protocols between the transmission system operator and PSEG. This review focused on changes to the established program and material condition of the offsite and alternate AC power equipment. The inspectors assessed whether PSEG established and implemented appropriate procedures and protocols to monitor and maintain availability and reliability of both the offsite AC power system and the onsite alternate AC power system. The inspectors evaluated the material condition of the associated equipment by interviewing the responsible system manager, reviewing notifications and open work orders, and walking down portions of the offsite and AC power systems including the 500 kilovolt (KV) switchyard.

b. Findings

No findings were identified.

1R04 Equipment Alignment

Partial System Walkdowns (71111.04Q – 4 samples)

a. Inspection Scope

The inspectors performed partial walkdowns of the following systems:

- Unit 2 EDGs with a single source of offsite power on April 5, 2012
- 1A and 1B EDGs with 1C EDG out of service (OOS) on May 16, 2012
- 21 and 22 auxiliary feedwater (AFW) pumps with 23 AFW pump OOS on May 16, 2012
- 21 CCW pump after return from maintenance on May 31, 2012

The inspectors selected these systems based on their risk significance relative to the reactor cornerstones at the time they were inspected. The inspectors reviewed applicable operating procedures, system diagrams, the UFSAR, 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 for resolution with the appropriate significance characterization.

b. Findings

No findings were identified.

1R05 Fire Protection

.1 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.

- Unit 1, Auxiliary Building, 122' elevation (ventilation)
- Unit 2, Auxiliary Building, 122' elevation (ventilation)
- Unit 1, Auxiliary Building, 122' elevation (Boric Acid Storage Tank area)
- Unit 2, Fuel Handling Building, 130' elevation
- Unit 1, Turbine Generator and Service Buildings, 88' elevation

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 verify that PSEG's flooding mitigation plans and equipment for the Unit 2, 4 kV switchgear room are consistent with the design requirements and the risk analysis assumptions. 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 also focused on Unit 2, 4 kV switchgear room to verify the adequacy of equipment seals located below the flood line, floors and water penetration seals, watertight door seals, common drain lines and sumps, sump pumps, level alarms, control circuits, and temporary or removable flood barriers.

b. Findings

No findings were identified.

1R11 Licensed Operator Requalification Program and Licensed Operator Performance (71111.11Q - 2 samples)

.1 Licensed Operator Requalification Training

a. Inspection Scope

The inspectors observed licensed operator simulator training on June 13, 2012. The scenario included a loss of the AFW storage tank followed by a small break loss of coolant accident. The inspectors evaluated operator performance during the simulated event and verified completion of risk significant operator actions, including the use of abnormal and emergency operating procedures. The inspectors assessed the clarity and effectiveness of communications, implementation of actions in response to alarms and degrading plant conditions, and the oversight and direction provided by the control room supervisor. The inspectors verified the accuracy and timeliness of the emergency classification made by the shift manager and the technical specification action statements (TSASs) 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 licensed operator performance on April 24, 2012, during Unit 1 main turbine valve testing that included an emergent reactor down power from 89 percent to 75 percent reactor power. The inspectors also observed Unit 1 mode change from mode 4 to mode 3 during reactor plant heatup on May 6, 2012. The inspectors assessed the adequacy of communications, the pre-job brief, procedure use, human performance tools, and the oversight and direction provided by the control room supervisor.

b. Findings

No findings were identified.

1R12 Maintenance Effectiveness (71111.12 – 3 samples)

a. Inspection Scope

The inspectors reviewed the samples listed below to assess the effectiveness of maintenance activities on structure, system, or component (SSC) performance and reliability. The inspectors reviewed system health reports, CAP documents, maintenance work orders, and maintenance rule basis documents to ensure that PSEG was identifying and properly evaluating performance problems within the scope of the maintenance rule. For each sample selected, the inspectors verified that the SSC was properly scoped into the maintenance rule 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 maintenance rule system boundaries.

- Unit 1 SW during the week of May 28, 2012
- Unit 1 CCW during the week of June 11, 2012
- Unit 1 control area chillers (CACs) during the week of June 18, 2012

b. Findings

.1 Introduction: A self-revealing Green NCV of TS 6.8.1.a, "Procedures and Programs," was identified because the 13 SW strainer failed while in-service on March 13, 2012. PSEG failed to perform adequate PMT on the 13 SW strainer before declaring it operable on January 13, 2012, and therefore did not find inadequate clearance between the strainer drum and body.

Description: On March 13, 2012, the 13 SW strainer drive motor breaker tripped on thermal overload. PSEG investigated the cause of the tripped breaker and found that there was excessive drag resisting the drum rotation. The strainer was disassembled and a visual inspection of the drum seal o-ring revealed that the seal o-ring was excessively worn. The new strainer drum was installed on January 13, 2012, and the PMT was completed satisfactorily the same day. The 13 SW pump and strainer were not placed back into service until March, 11, 2012, when they ran for 8 hours before they were stopped for a silt inspection. The 13 SW strainer and pump were started again on March 13 and ran for approximately 30 minutes before the strainer tripped on overload. Mission time for the service water pumps is 24 hours.

PSEG conducted an apparent cause evaluation (ACE) and determined that there was inadequate strainer drum o-ring clearance criteria in SC.MD-PM.SW-0003, "Service Water Auto Strainer Adjustment, Inspection, Repair and Replacement," which caused the installed strainer drum o-ring to drag against the strainer body wear ring. PSEG also determined that inadequate PMT allowed the excessive drag between the drum o-ring and the strainer body wear ring to go undetected.

The only PMT accomplished for testing the rotational freedom of the 13 SW strainer drum was rotating the drum with a portable electric drill while measuring drill motor current with a clamp on amp probe, but the procedure listed acceptance criteria for using a Baker box to measure strainer motor amperage. The procedure step that listed the Baker box acceptance criteria for amperage and shape of the torque curve was initialed as complete by the technicians, but the torque curve section, which would have been generated by the Baker box, was marked as not applicable.

A previous root cause evaluation completed by PSEG identified that using clamp on amp probes to measure amperage following strainer maintenance was not as effective in detecting o-ring to body wear ring rubs compared to the Baker box motor testing. In response to this evaluation, PSEG revised SC.MD-PM.SW-0003, "Service Water Auto Strainer Adjustment, Inspection, Repair and Replacement," in December 2011 to add the Baker box torque curve acceptance criteria.

During the ACE investigation for the March 13, 2012 13 SW strainer failure, the technicians stated that they thought the use of the Baker box was optional because there was no procedure step or work order to connect a Baker box to the 13 SW strainer. The procedure step for the torque curve results was marked not applicable by the technicians in the field with no explanation in the comments section. This was not in accordance with PSEG procedure HU-AA-104-101, "Procedure Use and Adherence," and supervisory review of the completed procedure did not identify the issue. As a result, the PMT did not detect the excessive drag between the 13 SW strainer drum o-ring and the strainer body wear ring that caused the strainer to trip on March 13, 2012.

<u>Analysis</u>: The inspectors concluded that the failure of PSEG to complete an adequate PMT on the 13 SW strainer after the replacement of the drum was a performance deficiency. Specifically, due to an inadequate procedure and technician use of "not applicable" in the step of the procedure that evaluated the results of the testing, the instrument needed to monitor the current being used by the 13 strainer rotation motor (Baker box) was not connected to the 13 SW strainer. As such, internal interference was not identified and corrected before the strainer failed on March 13. The inspectors determined that the performance deficiency was more than minor because it was associated with the human performance attribute of the Mitigating Systems cornerstone and it adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences.

The finding was determined to be of very low safety significance in accordance with IMC 0609, Appendix A, "Determining the Significance of Reactor Inspection Findings for At-Power Situations," (IMC 0609A) using SDP Phases 1, 2 and 3. Phase 1 screened the finding to Phase 2 because the inspectors concluded that the finding contributed to both the likelihood of a reactor trip and the likelihood that mitigating systems would not have been available. This conclusion was based upon the increased chance of a loss of service water (LOSW) given one train being unavailable due to strainer maintenance issues and repairs and the loss of redundancy in the service water system to cool mitigating equipment over the assumed 63 day exposure period (January 13 – March 16, 2012, when the 13 strainer was returned to service) The Phase 3 analysis was required because the Salem Pre-solved Risk-Informed Inspection Notebook does not address the loss of one train of SW. An external event evaluation was also conducted, because the internal event increase in core damage frequency (ΔCDF) was in the E-7 range.

The senior reactor analyst conducted Phase 3 evaluation, using the Salem combined internal and external initiating event SPAR model revision 8.20, estimated an internal and external initiating event ΔCDF in the low-E-7 per year range, given the assumption that 13 SW strainer was OOS for the 63-day exposure period and the following changes and assumptions:

The Salem SPAR model was updated to include:

- The human action to cross-tie the Unit 1 and Unit 2 SW systems, through the pump full flow test lines, for non station blackout (SBO) situations. The inspectors reviewed this human action with plant operators finding that the procedure had been properly developed by PSEG following a similar SW strainer

issue in late 2011 and that the actions could be performed in an appropriate timeframe. This recovery was not assumed for Unit 1 SBO events, as the Unit 2 SW system may potentially be unable to support Unit 1 due to offsite or emergency power issues.

- The LOSW initiating event fault tree to determine the frequency. The SW cross-tie was added to allow recovery of SW, not as a method to preclude a loss of SW.

The result was dominated by the loss of offsite power events with: common cause failure of the remaining SW strainers leading an SBO, because of inability to cool the EDGs; reactor coolant pump seal failure and leakage, due to lack of power to the charging and component cooling water systems; and an inability to recover offsite or onsite power within 3 hours. The LOSW events were approximately an order of magnitude lower, due to the credit for the SW cross-tie. Transients and fire events which would result in transients were lower by over an order of magnitude.

The inspectors determined that this finding has a cross-cutting aspect in the area of human performance, work practices, because PSEG personnel did not follow procedures. Specifically, PSEG personnel assigned to perform the procedure SC.MD-PM.SW-0003, “Service Water Auto Strainer Adjustment, Inspection, Repair and Replacement,” did not stop and get the approvals required to mark steps in the procedure as “not applicable.” The inspectors determined that had the technicians taken this action, the appropriate testing was likely to have been performed. (H.4(b))

Enforcement: TS 6.8.1.a requires establishment, implementation, and maintenance of written procedures recommended in Appendix A of Regulatory Guide 1.33, Revision 2, February 1978. Regulatory Guide 1.33, Appendix A, Section 9 requires that maintenance affecting the performance of safety-related equipment be performed per written procedures, documented instructions, or drawings appropriate to the circumstances. Contrary to the above, on January 13, 2012, PSEG technicians did not perform maintenance affecting the performance of the safety-related 13 SW strainer per written procedures, documented instructions, or drawings appropriate to the circumstances. Specifically, due to an inadequate maintenance procedure and technician use of “non-applicable” in the step of the procedure that evaluated the results of the testing, the instrument needed to monitor the current drawn by the 13 strainer motor was not connected. As a result, internal interference between the 13 SW strainer and its housing went undetected and the 13 SW strainer drive motor breaker tripped on thermal overload on March 13, 2012. Because this issue is of very low safety significance (Green) and PSEG entered the issue into the CAP as notification 20550115, this violation is being treated as an NCV consistent with the NRC Enforcement Policy. **(NCV 05000272/2012003-01, 13, Service Water Strainer Unavailability due to Inadequate Post Maintenance Test)**

.2 Introduction. A self-revealing NCV of 10 CFR Part 50, Appendix B, Criterion XVI, “Corrective Action,” was identified because PSEG did not correct a condition adverse to quality promptly. Specifically, repeat failures of SOVs with voltage applied greater than design voltage were not corrected in a timely manner, which caused a failure of the 11 control area chiller (CAC).

<u>Description.</u> A technical evaluation completed by PSEG in December 2008 reviewed safety-related room cooler SOV failures dating back to 2004. This 2008 evaluation identified a design vulnerability, specifically that the normal supply voltage exceeds nominal specified voltage for this type of solenoid valve. This group of SOVs included the six SW outlet valves on the CACs. The corrective action specified was to establish a two-year replacement cycle for the population of 30 normally energized solenoid valves of this type, and to look for replacement SOVs that were designed for a higher input voltage. The two-year replacement cycle did not eliminate the SOV failures.

In January 2011, a long term action to replace this population of SOVs was approved by the Plant Health Committee, but was not placed on the implementation list. In April 2011, an engineering equivalency evaluation determined that the replacement SOV chosen could not be used without an approved design change. The design change was not assigned for completion because the issue was not placed on the Plant Health Committee Implementation List. PSEG has not taken effective action to correct this deficiency since April 2011, and the design change has not been written or approved. Seven failures of these SOVs have been documented since the two-year replacement periodicity was initiated, including a failure of the SOV on the 12 CAC in June 2011, after the SOV had been replaced three months earlier.

Each unit has three safety-related CACs to maintain the control room and relay rooms at temperatures that support the operability and the reliability of electronic equipment. On April 10, 2012, the SW outlet valve for the 11 CAC failed closed due to a failed valve solenoid coil. The chiller did not start on demand and was categorized by PSEG as a critical component failure. As an immediate corrective action, PSEG replaced the SOV and returned the chiller to service following eight hours of unavailability. A compensatory measure that will be completed by PSEG until the modification is completed is to measure the temperature of these susceptible SOVs bi-weekly, and replace them if temperature is above a predetermined limit.

<u>Analysis.</u> PSEG's failure to promptly correct a condition adverse to quality was a performance deficiency. This issue was determined to be more than minor because it was associated with the equipment performance attribute of the Mitigating Systems cornerstone and affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Using IMC 0609, Attachment 4, "Initial Screening and Characterization of Findings," the inspectors determined that a single train of a safety-related system was unavailable for eight hours, less than the TS allowed outage time. Therefore the issue was of very low safety significance (Green) because the finding did not result in a loss of system safety function, loss of a single train for greater than TS allowed outage time, or potentially risk-significant due to a fire, flooding, or severe weather initiating event. This finding has a cross-cutting aspect in the area of problem identification and resolution, corrective action program, because PSEG did not take appropriate corrective actions to address a safety issue in a timely manner, commensurate with the safety significance and complexity. Specifically, the premature failure of SOVs due to higher than design voltage creating higher than design heat in the coil and insulation was a known issue that was not corrected in a timely manner. (P.1(d))

<u>Enforcement.</u> 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Actions," requires, in part, that measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and

equipment, and non-conformances are promptly identified and corrected. Contrary to the above, from January 2011 to April 2012, PSEG identified a condition adverse to quality in that a group of safety-related SOVs was experiencing premature failures while in service at a voltage higher than design voltage, but failed to promptly implement effective corrective actions. Specifically, PSEG proposed a design modification to replace the SOVs that were being operated at greater than design voltage (125 to 132 volts versus a design of 120 volts) in January 2011, but did not take action to initiate the design change in the subsequent sixteen months. Because this issue is of very low safety significance (Green) and PSEG entered the issue into the CAP as notification 20567946, this violation is being treated as an NCV consistent with the NRC Enforcement Policy. **(NCV 05000272/2012003-02, Failure to Correct Repeat Failures in Safety-Related Solenoid Valves in a Timely Manner)**

1R13 Maintenance Risk Assessments and Emergent Work Control (71111.13 – 7 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 applicable station procedures, 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 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.

- Units 1 & 2, single source of offsite power during planned maintenance on electrical bus section 2 on April 2, 2012
- Unit 1, 11 component cooling heat exchanger (CCHX) emergent repair on April 30, 2012
- Unit 1, planned maintenance on 12 CCHX and 12 CCW pump on May 14, 2012
- Unit 2, planned maintenance on 23 AFW pump and 23 CAC on May 16, 2012
- Unit 2, planned maintenance on 23 CCW pump, 23 CAC, 23 Auxiliary Building Ventilation Exhaust fan, and 23 CFCU on May 18, 2012
- Units 1 & 2, single source of offsite power during planned maintenance on 500 KV 2-10 breaker maintenance on May 24, 2012
- Unit 2, planned maintenance on 22 CCW pump and 22 CCHX while 22 station power transformer OOS on June 4, 2012

b. Findings

No findings were identified.

1R15 Operability Determinations and Functionality Assessments (71111.15 – 5 samples)

a. Inspection Scope

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

- Transient loads adjacent to safety related equipment in Unit 1 and 2 auxiliary buildings on April 20, 2012
- Unit 1 train A solid state protection system (SSPS) on May 4, 2012, after an inadvertent safety injection signal on April 30, 2012
- Unit 1 component cooling with 1CC 227 through wall piping leak on April 8, 2012
- Unit 1 stop check valve 11AF23 allowed reverse flow during test on June 20, 2012
- Unit 2 control air header with 2PA3825 PC4, control air pressure transmitter failure on May 17, 2012

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

Introduction: The inspectors identified a Green NCV of TS 6.8.1.a "Procedures and Programs," for failure to properly control and store transient material within seismic Class I buildings such that the equipment did not pose a hazard to safe plant operation. Specifically, two large tool gang boxes were stored unrestrained in the vicinity of the sodium hydroxide storage tank and associated CS valves and two full 55 gallon SW maintenance drums were stored unrestrained next to the 11, 12, and 15 CFCU SW flow transmitters.

Description: PSEG procedure CC-AA-320-011, "Transient Loads", requires in part, that transient equipment that is left unattended and left unsecured in seismic class 1 buildings should be immobilized unless it meets the restraint guidelines exceptions discussed in the procedure.

On April 12, 2012, while performing a walkdown of the Unit 1 Auxiliary building, the inspectors identified two large metal cabinets and two sets of shelves that were not restrained in accordance with PSEG procedures.

On April 17, the inspectors identified several large gang boxes that were not properly restrained, two ladders that were not properly stowed, and several other transient load

stowage issues in Unit 1 and Unit 2. Two of the large gang boxes that were not properly restrained were in the vicinity of the sodium hydroxide storage tank and CS valves that were both safety-related components.

On April 20, the inspectors identified several transient load stowage issues in the mechanical penetration section of the Unit 1 auxiliary building including one full 55 gallon SW maintenance drum stowed unrestrained next to the 11 and 12 CFCU SW flow transmitters and one full 55 gallon SW drum stowed unrestrained next to the 15 CFCU SW flow transmitter. The CFCU flow transmitters are safety-related and seismic class 1.

The inspectors determined that during a seismic event the two unrestrained large gang boxes could damage the sodium hydroxide storage tank or the associated CS valves and that damage to any of these components could challenge containment integrity during a design basis accident. In addition, the SW drums in the mechanical penetration section of the Unit 1 auxiliary building posed a hazard to the CFCU flow transmitters which, if damaged during a seismic event, would challenge SW operability.

The inspectors informed the control room operators of the uncontrolled transient materials and operators promptly initiated corrective actions to restrain the subject material in accordance with PSEG's transient load procedure. During subsequent plant tours the inspectors identified numerous additional examples of improperly controlled transient material. PSEG promptly corrected the identified individual discrepancies and initiated notification 20559092 to address this additional performance deficiency.

<u>Analysis</u>: The inspectors concluded that the failure of PSEG to properly control and restrain transient material within seismic class 1 buildings was a performance deficiency. Specifically, large tool gang boxes and two full 55 gallon drums were left unsecured and unattended within close proximity to safety related equipment, thereby posing a seismic hazard to the equipment. The finding is more than minor because it is associated with the Mitigating Systems cornerstone attribute of equipment performance and affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e. core damage). The issue is also similar to IMC 0612, Appendix E, Examples of Minor Issues, example 4.a which stated the issue was more than minor if the licensee routinely failed to follow their procedure and safety-related equipment was adversely impacted. Specifically, PSEG was not following the requirements of their procedure, CC-AA-320-011, "Transient Loads," and equipment had been stowed in close vicinity of safety-related equipment.

The finding was evaluated under IMC 0609, Attachment 4, "Initial Screening and Characterization of Findings." The inspectors determined that the finding is of very low safety significance (Green) because it did not involve loss or degradation of equipment specifically designed to mitigate a seismic event, and did not involve total loss of a safety function that contributes to external event initiated core damage sequences. The finding has a cross-cutting aspect in the area of human performance, work practices in that PSEG did not define and effectively communicate expectations regarding procedural compliance and personnel did not follow procedures. Specifically, station personnel did not follow procedures for the storage of transient loads in the auxiliary building (H.4(b))

<u>Enforcement</u>: TS 6.8.1.a requires written procedures to be established, implemented, and maintained covering applicable procedures recommended in Appendix A of NRC

Regulatory Guide 1.33, Revision 2. Appendix A, Section 1 of Regulatory Guide 1.33, requires administrative procedures for equipment control. PSEG procedure CC-AA-320-011, “Transient Loads”, requires in part, that transient equipment that is left unattended and left unsecured should be immobilized unless it meets restraint guidelines exceptions. Contrary to the above, on April 17, 2012 and April 20, 2012, PSEG left transient equipment, which did not meet restraint guideline exceptions, unattended and unsecured, but not immobilized. Specifically on April 17, 2012, two large gang boxes were left unrestrained and unattended in the vicinity of the Unit 1 and Unit 2 safety-related sodium hydroxide storage tank and associated CS valves. Additionally, on April 20, 2012, one full 55 gallon SW maintenance drum was left unrestrained and unattended next to the safety-related 11 and 12 CFCU SW flow transmitters and one full 55 gallon SW drum was left unrestrained and unattended next to the safety-related 15 CFCU SW flow transmitter. Because this issue is of very low safety significance (Green) and PSEG entered the issue into the CAP as notification 20559092, this violation is being treated as an NCV consistent with the NRC Enforcement Policy. **(NCV 05000272, 05000311/ 2012003-03, Deficient Control of Transient Equipment in Seismic Class 1 Auxiliary Building)**

1R18 Plant Modifications (71111.18 – 2 samples)

.1 Permanent Modifications

a. Inspection Scope

The inspectors completed the two permanent modification inspection samples listed below:

- The inspectors evaluated a modification to install upgraded circuit cards in the Solid State Protection System (SSPS), implemented by engineering change package 80096586, “SSPS Circuit Card Upgrade.” PSEG removed the upgraded cards as an interim corrective action following an inadvertent SI signal on Unit 1, which caused a trip and safety injection on April 30, 2012. The inspectors verified that the design bases, licensing bases, and performance capability of the affected systems were not degraded by the modification. In addition, the inspectors reviewed modification documents associated with the design change, including the 10 CFR 50.59 screening document, the configuration control package that allowed use of the upgraded cards, and the decision making documentation that justified temporary removal of the new style cards. The inspectors reviewed revisions to the drawings, interviewed engineering personnel, and procurement personnel to ensure that controls exist so that new cards are not reinstalled into Unit 1 SSPS without approval from PSEG management.

- The inspectors evaluated a modification to change the main turbine electronic overspeed setpoint, implemented by engineering change package 80106209, “Unit 2 Turbine Overspeed Protection Setpoint.” The inspectors verified that the design bases, licensing bases, and performance capability of the affected systems were not degraded by the modification. In addition, the inspectors reviewed modification documents associated with the design change, including the configuration control document, and the operational technical decision making document used to return the Unit 2 main turbine to service. The inspectors also reviewed revisions to the

drawings, interviewed engineering personnel, and reviewed the complex troubleshooting document associated with the Unit 2 turbine trip on March 23, 2012.

b. Findings

No findings were identified.

1R19 Post-Maintenance Testing (71111.19 – 5 samples)

a. Inspection Scope

The inspectors reviewed the 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.

- 16 SW pump motor replacement on April 13, 2012
- Reactor containment ventilation valve (2VC5) unplanned replacement on April 30, 2012
- Component cooling water vent valve (1CC227) unplanned replacement and weld repair on April 30, 2012
- Unit 1, SSPS Train A unplanned card replacement on May 5, 2012
- 23 Charging pump planned maintenance on June 29, 2012

b. Findings

No findings were identified.

1R20 Refueling and Other Outage Activities (71111.20 - 1 sample)

a. Inspection Scope

The inspectors reviewed PSEG's work schedule and outage risk plan for the unplanned outage at Unit 1, which was conducted April 30 through May 8, 2012. The inspectors reviewed PSEG's development and implementation of forced 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 and cooldown 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
- Status and configuration of electrical systems and switchyard activities to ensure that technical specifications were met
- Monitoring of decay heat removal operations
- 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
- Repair activities on shutdown cooling isolation valve IV-38-01
- Startup activities, including reactor plant heatup, containment closeout inspection, and initial criticality
- Fatigue management
- Identification and resolution of problems related to outage activities

b. Findings

No findings were identified.

1R22 Surveillance Testing (71111.22 – 6 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:

- S1.OP-ST.RHR-0002, 12 Residual Heat Removal (RHR) Pump Inservice Test on April 12, 2012
- S1.OP-PT.AF-0003, 13 Turbine-Driven AFW Pump Monthly Surveillance Test on April 24, 2012
- S1.OP-ST.SJ-0022, High Head Emergency Core Cooling System Check Valve Test on April 30, 2012
- S1.OP-ST.SJ-0020, Periodic Leakage Test Reactor Coolant System Pressure Isolation Valves on May 6, 2012
- S2.OP-ST.RHR-0002, 22 RHR Pump Inservice Test on May 10, 2012
- S1.IC-CC.RCP-0066, Containment Pressure Channel IV Calibration on June 18, 2012

b. Findings

No findings were identified.

Cornerstone: Emergency Preparedness

1EP6 Drill Evaluation (71114.06 - 1 sample)

.1 Emergency Preparedness Drill Observation

a. Inspection Scope

The inspectors evaluated the conduct of a scheduled PSEG emergency drill on June 1, 2012, to identify any weaknesses and deficiencies in the classification, notification, and protective action recommendation development activities. The drill scenario included a loss of the AFW storage tank followed by a small break loss of coolant accident. The inspectors observed emergency response operations in the simulator to determine whether the event classification, notifications, and protective action recommendations were performed in accordance with procedures. The inspectors also attended the station drill critique to compare inspector observations with those identified by PSEG staff in order to evaluate PSEG's critique and to verify whether the PSEG staff was properly identifying weaknesses and entering them into their CAP.

b. Findings

No findings were identified.

2. RADIATION SAFETY

Cornerstone: Radiation Safety - Public and Occupational

2RS1 Radiological Hazard Assessment and Exposure Controls (71124.01)

a. Inspection Scope

The inspectors reviewed selected activities and associated documentation in the areas listed below. The evaluation of PSEG's performance was against criteria contained in 10 CFR Part 20, applicable TSs, and applicable station procedures.

Inspection Planning

The inspectors reviewed performance indicators (PIs) for the Occupational Exposure cornerstone. The inspectors also reviewed the results of recent radiation protection program audits and assessments, as available, and any reports of operational occurrences related to occupational radiation safety since the last inspection.

Radiological Hazard Assessment

The inspectors discussed plant operations to identify any significant new radiological hazards for onsite workers or members of the public. The inspectors assessed the potential impact of the changes and monitoring, as appropriate, to detect and quantify the radiological hazards.

The inspectors toured and conducted walkdowns of radiological controlled areas (RCAs) and reviewed radiological surveys from selected plant areas (e.g., Unit 1 and Unit 2 fuel floors and radwaste areas). The inspectors also evaluated material conditions and potential radiological conditions. The inspectors made independent radiation measurements to verify radiological conditions.

Instructions to Workers

The inspectors toured the RCAs and reviewed labeling of containers of radioactive materials to verify labeling and posting was consistent with requirements and was informative to workers.

Contamination and Radioactive Material Control

The inspectors observed locations where PSEG monitors potentially contaminated material leaving the RCA and inspected the methods used for control, survey, and release from these areas. The inspectors observed the performance of personnel surveying and releasing material for unrestricted use to verify that it was performed in accordance with plant procedures and the procedures were sufficient to control the spread of contamination and prevent unintended release of radioactive materials from the site. The inspectors selectively evaluated the radiation monitoring instrumentation sensitivity for the type(s) of radiation present.

The inspectors reviewed PSEG's criteria for the survey and release of potentially contaminated material. The inspectors verified that there was guidance on how to respond to an alarm that indicates the presence of radioactive material.

The inspectors reviewed and discussed sealed source inventory records and reconciliation reports. The inspectors selectively verified sources were accounted for and have been verified to be intact (i.e., they are not leaking their radioactive content). The inspectors reviewed six-month source leak test data.

The inspectors selectively reviewed reconciliation report transactions for nationally tracked sources.

Radiological Hazards Control and Work Coverage

The inspectors toured the facility and evaluated ambient radiological conditions (e.g., radiation levels or potential radiation levels). The inspectors verified the existing conditions were consistent with posted surveys, radiation work permits, and worker briefings.

The inspectors conducted selective inspection of posting and physical controls for high radiation areas (HRAs) and very high radiation areas (VHRAs) to verify conformance with the Occupational PI.

Risk-Significant HRA and VHRA Controls

The inspectors selectively discussed with the Radiation Protection Manager, supervisors, and technicians the controls and procedures for high-risk HRAs and VHRAs and any procedural changes since the last inspection. The inspectors discussed

methods employed by PSEG to provide control of VHRA access including potential reduction in the effectiveness and level of worker protection.

Radiation Worker Performance

The inspectors selectively reviewed radiological problem reports since the last inspection to identify human performance errors and determine if there were any observable patterns. The inspectors discussed corrective actions for identified concerns with PSEG personnel.

Radiation Protection Technician Proficiency

The inspectors selectively reviewed outage radiological problem reports to identify those that indicated the cause of the events due to radiation protection technician error and to evaluate the corrective action approach taken by PSEG to resolve the reported problems.

Problem Identification and Resolution

The inspectors determined if problems associated with radiation monitoring and exposure control were being identified by PSEG at an appropriate threshold and were properly addressed for resolution in their CAP. The inspectors discussed corrective actions for identified concerns.

b. Findings

No findings were identified.

2RS2 Occupational As Low As Reasonably Achievable (ALARA) Planning & Controls (71124.02)

a. Inspection Scope

Inspection Planning

The inspectors reviewed pertinent information regarding plant collective exposure history, current exposure trends, and ongoing or planned activities in order to assess current performance and exposure challenges. The inspectors reviewed the plant's three-year rolling average collective exposure.

The inspectors evaluated and determined the site-specific trends in collective exposures using various methods such as plant historical data, including outage work activity dose, evaluation of as low as reasonably achievable (ALARA) data, and source term data.

Radiological Work Planning

The inspectors selectively compared accrued results achieved (dose rate reductions, person-rem used), with the intended dose established in PSEG's ALARA planning for selected work activities including person-hour estimates. The inspectors determined the reasons for inconsistencies between intended and actual work activity doses, as necessary. The inspectors selectively evaluated reasons for increased doses for work

as compared to original estimates. As part of this review, the inspectors reviewed work-in-progress reviews.

Source Term Reduction and Control

The inspectors used PSEG records to determine the historical trends and current status of significant tracked plant source term known to contribute to elevated facility aggregate exposure. The inspectors discussed source term reduction efforts.

Problem Identification and Resolution

The inspectors determined if problems associated with ALARA planning and controls were being identified by PSEG at an appropriate threshold and were properly addressed for resolution in their CAP. The inspectors discussed corrective actions for identified ALARA concerns with the health physics staff.

b. Findings

No findings were identified.

2RS3 In-Plant Airborne Radioactivity Control and Mitigation (71124.03)

a. Inspection Scope

Inspection Planning

The inspectors selectively reviewed the plant UFSAR to identify areas of the plant designed as potential airborne radiation areas and any associated ventilation systems or airborne monitoring instrumentation. The inspectors also reviewed the UFSAR for overview of the respiratory protection program and a description of the types of devices used.

The inspectors reviewed the reported PIs to identify any related to unintended dose resulting from personnel intakes of radioactive materials.

Engineering Controls

The inspectors selected various portable systems to monitor and warn of changing airborne concentrations in the plant. The inspectors evaluated the alarms and setpoints to prompt PSEG/worker action to ensure that doses are maintained within the limits of 10 CFR Part 20 and ALARA.

The inspectors evaluated PSEG's use and decision criteria for evaluating levels of hard-to-detect airborne radionuclides.

Problem Identification and Resolution

The inspectors reviewed and discussed problems associated with the control and mitigation of in-plant airborne radioactivity to evaluate PSEG's identification and resolution in their CAP.

b. Findings

No findings were identified.

2RS4 Occupational Dose Assessment (71124.04)

a. Inspection Scope

Inspection Planning

The inspectors reviewed available radiation protection program audits related to internal and external dosimetry or corrective action documents to gain insights into overall PSEG performance in the area of dose assessment.

The inspectors reviewed the most recent National Voluntary Laboratory Accreditation Program (NVLAP) accreditation report for PSEG's dosimetry.

The inspectors reviewed PSEG procedures associated with dosimetry operations and evaluation of dose assessments. The inspectors evaluated procedure guidance for personnel monitoring.

External Dosimetry

The inspectors evaluated the use of personnel dosimeters that require processing to verify NVLAP accreditation. The inspectors determined if PSEG uses a "correction factor" to address the response of the electronic dosimeter as compared to its NVLAP accredited dosimeter for situations when the electronic dosimeter must be used to assign dose.

Internal Dosimetry

The inspectors reviewed routine bioassay (in vivo) procedures used to assess dose from internally deposited nuclides using whole body counting equipment.

The inspectors evaluated the minimum detectable activity of PSEG's instrumentation used for passive whole body counting to determine if the minimum detectable activity was adequate to determine the potential for internally deposited radionuclides sufficient to prompt additional investigation.

Problem Identification and Resolution

The inspectors selectively reviewed corrective action documents to verify that problems associated with occupational dose assessment were being identified by PSEG at an appropriate threshold and were properly addressed for resolution in their CAP.

b. Findings

No findings were identified.

2RS5 Radiation Monitoring Instrumentation (71124.05)

a. Inspection Scope

Inspection Planning

The inspectors reviewed the plant UFSAR to identify radiation instruments associated with monitoring area radiological conditions including airborne radioactivity, process streams, effluents, materials/articles, and workers.

Walkdowns and Observations

The inspectors selected various portable survey instruments in use for risk-significant radiological work or available for issuance and checked calibration and source check stickers for currency, and to assess instrument material condition and operability.

The inspectors selected personnel contamination monitors, portal monitors, and small article monitors and verified that the periodic source checks were performed.

Calibration and Testing Program

The inspectors selectively reviewed alarm setpoint data for various personnel and equipment monitors at RCA exits to verify that the alarm setpoint values were reasonable under the circumstances to ensure that licensed material was not released from the site.

Problem Identification and Resolution

The inspectors selectively reviewed corrective action documents associated with radiation monitoring instrumentation to determine if PSEG identified issues at an appropriate threshold and placed the issues in their CAP for resolution. In addition, the inspectors evaluated the appropriateness of the corrective actions for a selected sample of problems documented by PSEG that involved radiation monitoring instrumentation.

b. Findings

No findings were identified.

2RS6 Radioactive Gaseous and Liquid Effluent Treatment (71124.06)

a. Inspection Scope

The inspectors selectively reviewed aspects of PSEG's gaseous and liquid effluent control program in the below listed areas.

Inspection Planning and In-Office Inspection

The inspectors reviewed the Radiological Effluent Release Report issued since the last inspection to determine if the reports were submitted as required by the Offsite Dose

Calculation Manual (ODCM) and TSs. The inspectors reviewed the reports for any anomalous results, unexpected trends, or abnormal releases identified by PSEG for further inspection.

The inspectors reviewed the reports to identify radioactive effluent monitor operability issues reported by PSEG as provided in effluent release reports.

The inspectors also reviewed groundwater remediation reports.

ODCM and UFSAR Reviews

The inspectors reviewed the UFSAR descriptions of the radioactive effluent monitoring systems, treatment systems, and effluent flow paths to verify during inspection walkdowns.

b. Findings

No findings were identified.

2RS7 Radiological Environmental Monitoring Program (REMP) (71124.07)

a. Inspection Scope

Inspection Planning

The inspectors reviewed the annual radiological environmental operating reports, since the last inspection, to verify that the REMP was implemented in accordance with the TS and ODCM. The inspectors reviewed the report for changes to the ODCM with respect to environmental monitoring, commitments in terms of sampling locations, monitoring, and measurement frequencies, land use census, inter-laboratory comparison program, and analysis of data.

The inspectors reviewed the ODCM and the UFSAR to identify locations of environmental monitoring stations and to review for information regarding the environmental monitoring program and meteorological monitoring instrumentation.

b. Findings

No findings were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151 - 6 samples)

Initiating Events Performance Index

a. Inspection Scope

The inspectors reviewed PSEG submittals for the following initiating events PIs:

- Unit 1 and Unit 2 unplanned scrams;
- Unit 1 and Unit 2 unplanned scrams with complications; and
- Unit 1 and Unit 2 unplanned power changes.

To determine the accuracy of the PI data reported during those periods, the inspectors used definitions and guidance contained in Nuclear Energy Institute Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6. The inspectors also reviewed PSEG CAP records, control room operators' logs, the site operating history database, and key PI records to validate the accuracy of the submittals.

b. Findings

No findings were identified.

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

.1 Routine Review of Problem Identification and Resolution Activities

a. Inspection Scope

As required by Inspection Procedure 71152, "Problem Identification and Resolution," the inspectors routinely reviewed issues during baseline inspection activities and plant status reviews to verify 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: Review of SW Grassing Events

a. Inspection Scope

The inspectors reviewed the corrective actions taken based on a 2011 root cause evaluation (RCE) for SW grassing events. The inspectors reviewed the progress made on corrective actions assigned and the effectiveness of these corrective actions.

PSEG documented a SW system cumulative operability evaluation, and the inspectors reviewed this evaluation to ensure that a consistent approach was taken to resolve the SW system issue with system challenges during periods of heavy river detritus. In addition, inspectors reviewed the finding documented during the 2011 Problem Identification and Resolution team inspection, titled "Untimely Completion of Corrective Actions Results in Number 11 Service Water Strainer Trip Due to Grassing."

b. Findings and Observations

No findings were identified.

The inspectors observed that 53 of 74 actions assigned from the RCE have been completed. A key corrective action was to eliminate the ring grooves that were associated with the strainer trip during heavy grass noted in the problem identification and resolution team inspection finding. The inspectors verified that the five SW strainers that did not have a wear resistant monel ring installed in the strainer body were either replaced with a new style body that included the monel ring or were plasma sprayed to eliminate the existing ring grooves.

The inspectors noted that there was a maintenance related trip of the 13 SW strainer, documented in this report under Section 1R12. A procedure change that specified the use of a Baker box to get a current trace during the PMT of SW strainers was marked as not applicable following the repair of the 13 SW strainer. PSEG determined that the use of the Baker box during the PMT of the 13 strainer could have prevented the subsequent failure of this strainer by detecting the strainer rub during Baker box testing. The inspectors determined that the corrective action implemented from the 2011 RCE to perform Baker box testing after strainer maintenance was not fully effective. Subsequent to the 13 SW strainer event PSEG revised the procedure to provide the steps necessary to ensure that technicians would use the Baker box testing during PMT following applicable maintenance on a strainer.

Some corrective actions, including a corrective action to prevent recurrence to correct design deficiencies with the SW screens and the SW strainers have not met assigned due dates. Specifically, the SW design study for these improvements has not been completed, and thus the recommended design has not been presented to the Plant Health Committee for approval. Consequently, the time frame to implement these design changes to improve the reliability of the SW system has been delayed. PSEG design engineers stated that the design change study was waiting for finalization of the site water permit and subsequently acknowledged that the strainer design changes are independent of the water permit approval process. PSEG could be more proactive in the study, approval, and implementation of these SW strainer design changes. The proposed design change to the service water strainers is to eliminate the rubber o-ring that has resulted in strainer trips due to rubbing, as well as creating grooves in the strainer body, which can cause strainer trips during grassing season. This design change was due to be implemented in July 2012. The inspectors determined that the design changes are necessary for the long term reliability of the strainers, but the delay in making the change was not considered more than minor because it has not yet caused an issue, as the strainer grooves were recently repaired using a plasma spray.

.3 Semi-Annual Trend Review

a. Inspection Scope

The inspectors performed a semi-annual review of site issues, as required by Inspection Procedure 71152, "Problem Identification and Resolution," to identify trends that might indicate the existence of more significant safety issues. In this review, the inspectors included repetitive or closely-related issues that may have been documented by PSEG outside of the CAP, such as trend reports, PIs, major equipment problem lists, system health reports, maintenance rule assessments, and maintenance of CAP backlogs.

The inspectors also reviewed PSEG's CAP database for the six-month period of December 1, 2011, through May 31, 2012, to assess condition reports written on equipment problems and human performance issues, as well as individual issues identified during the NRCs daily condition report review (Section 4OA2.1). The inspectors reviewed the PSEG nuclear oversight report for the first quarter of 2012 to verify that PSEG personnel were appropriately evaluating and trending adverse conditions in accordance with applicable procedures.

b. Findings and Observations

No findings were identified.

The inspectors noted an adverse trend in the reliability of specific safety-related equipment. The CACs experienced several failures during the six-month time period reviewed. The CACs are a Maintenance Rule (a)(1) system, and improvements to this system have been sporadic, with the unavailability and number of failures above the goal for the system. There have been multiple failures of limit switches, most notably the 1CC 215, which has failed to indicate open during periodic testing. This is a chronic issue that has not been resolved similar to the 11 chiller solenoid valve failure documented as a finding in this report under Section 1R12. There were two unit trips during the period reviewed, one on Unit 1 and one on Unit 2. Each of these trips involved an equipment failure, but neither of these failures was caused by inadequate maintenance. Design change rigor may have had a role in each of the trips. Both the electrohydraulic control (EHC) system and the SSPS had digital upgrades to the systems that subsequently resulted in plant trips. PSEG personnel are aware of these adverse trends and are taking corrective actions to mitigate or eliminate these issues.

4OA3 Follow-Up of Events and Notices of Enforcement Discretion (71153 – 2 samples)

.1 (Closed) Licensee Event Report (LER) 05000311/2012-001-0, Automatic Reactor Trip Due to Turbine Trip

On March 23, 2012, at approximately 2:28 PM, Salem Unit 2 experienced an automatic reactor trip with a loss of two reactor coolant pumps. The cause of the reactor trip was a turbine trip and the cause of the turbine trip was the spurious, simultaneous spiking of all three 103 percent overspeed inputs to the turbine digital electro hydraulic controller. PSEG performed a root cause evaluation that determined that the spiking may have been caused by inadequate grounding of the generator shaft, but a definitive cause could not be determined. As a corrective action, PSEG raised the electronic overspeed

trip setpoint from 103 percent to 108 percent. PSEG determined that the 108 percent setpoint provides adequate overspeed protection, and the channel spiking would not have tripped the turbine with the revised setpoint.

PSEG determined that the reactor coolant pump trips occurred due an abnormal electrical system lineup. At the time of the reactor trip, the 22 station power transformer was tagged OOS for maintenance. After the turbine trip and non-vital bus transfer from the auxiliary to the station power transformers, power to the F and G group buses was lost due to unavailability of the 22 station power transformer. Subsequently, as expected, the 23 and 24 reactor coolant pumps tripped due to the maintenance alignment. PSEG documented the issues associated with this event in notification 20552317. The inspectors completed a review of this LER and did not identify a violation of regulatory requirements. This LER is closed.

.2 (Closed) LER 05000272/2012-001-0, Single Train Actuation of Safety Injection Due to Failure of Solid State Protection System

On April 30, 2012, at 10:03 AM, Salem Unit 1 experienced an invalid Train A safety injection, reactor trip, main steam line isolation, EDG start, Phase A isolation, and start of the AFW pumps. TS 3.0.3 was entered due to both trains of safety injection actuation logic being blocked after actuation per system design. The plant exited TS 3.0.3 at 2:28 PM when Train B of the SSPS was reset. The operating crew however, failed to recognize all TSASs associated with inoperability of a single train of the SSPS and did not meet the requirement for entry into Mode 4. On May 1, 2012, at 8:02 AM, operators identified the applicable TSAS and commenced a plant cooldown. The plant entered Mode 4 at 5:39 PM and entered Mode 5 at 9:29 PM. The safety injection was caused by invalid actuation of Train A of the SSPS. The apparent cause of the failure to recognize entry into TSASs was a lack of procedural adherence. The enforcement aspects of this violation are discussed in Section 4OA7. PSEG documented the issues associated with this event in notification 20557859. The inspectors did not identify any new issues during the review of the LER. This LER is closed.

4OA6 Meetings, Including Exit

On July 12, 2012, the inspectors presented the inspection results to Mr. Fricker, Vice President of Salem Operations, and other members of PSEG management. The inspectors verified that no proprietary information was retained by the inspectors or documented in this report.

4OA7 Licensee-Identified Violations

The following violation of very low safety significance (Green) was identified by PSEG and is a violation of NRC requirements which meets the criteria of the NRC Enforcement Policy for being dispositioned as a NCV.

- TS 3.3.2.1, “Engineered Safety Feature Actuation System Instrumentation,” requires the channels and interlocks shown in Table 3.3-3 to be operable with their trip setpoints set consistent with the values shown in the trip setpoint column of Table 3.3-4. Specifically, automatic actuation logic for the main steam line isolation and auxiliary feedwater is required to have two operable channels, but only had one operable channel following the inadvertent train A safety injection signal on April 30,

2012. Contrary to TS 3.3.2.1, Table 3.3-3, Action Statement 20, Mode 4 was not entered in the required time by 2:28 AM on May 1, 2012. PSEG determined that action statement 20 was applicable at 8:02 AM on May 1, subsequently entered the action statement, commenced cooldown, and entered Mode 4 at 5:39 PM.

PSEG entered this issue into the CAP as notification 20557859. The inspectors determined that the finding was of very low safety significance (Green) in accordance with NRC IMC 0609, Attachment 4, “Initial Screening and Characterization of Findings,” Mitigation Systems, because the finding was not a design or qualification deficiency, did not result in an actual loss of safety function, and was not potentially risk significant for external events.

ATTACHMENT: SUPPLEMENTARY INFORMATION

SUPPLEMENTARY INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel
C. Fricker, Site Vice President
L. Wagner, Plant Manager
J. Kandasamy, Regulatory Affairs Manager
R. Wegner, Maintenance Director
G. Sosson, Engineering Manager
J. Garecht, Operations Director
S. Taylor, Radiation Protection Manager
J. Stavely, Nuclear Oversight Manager
T. Neufang, Radiation Protection Superintendent
L. Curran, Manager Plant Engineering
S. Markos, Design Engineering

LIST OF ITEMS OPENED, CLOSED, DISCUSSED, AND UPDATED

Open/Closed

05000272/2012003-01	NCV	13 Service Water Strainer Unavailability due to Inadequate Post Maintenance Test (Section 1R12)
05000272/2012003-02	NCV	Failure to Correct Repeat Failures in Safety-Related Solenoid Valves in a Timely Manner (Section 1R12)
05000272; 311/2012003-03	NCV	Deficient Control of Transient Equipment in Seismic Class Auxiliary Building (Section 1R15)

Closed

05000311/2012-001-0	LER	Automatic Reactor Trip due to Turbine Trip (Section 4OA3.1)
05000272/2012-001-0	LER	Single Train Actuation of Safety Injection Due to Failure of Solid State Protection System (Section 4OA3.2)

LIST OF DOCUMENTS REVIEWED

Section 1R01: Adverse Weather Protection

Procedures
OP-AA-108-107-1001, Electric System Emergency Operations and Electric Systems Operator Interface, Revision 3
OP-AA-108-111-1001, Severe Weather and Natural Disaster Guidelines, Revision 7
SC.OP-AB.ZZ-0001, Adverse Environmental Conditions, Revision 14
SC.OP-PT.ZZ-0002, Station Preparations for Seasonal Conditions, Revision 11
S1.OP-AB.GRID-0001, Abnormal Grid, Rev. 20
WC-AA-107, Seasonal Readiness, Revision 12

Notifications

20554383	20554735	20559021	20559962	20560082	20560631
20560811	20561957	20562325	20562472	20563132	20564402
20564666					

Orders

60098737	60099567	60100038	60102528

Other Documents
2012 Salem Seasonal Readiness Affirmation, 04/30/2012

Section 1R04: Equipment Alignment

Other Documents
Salem 2 Narrative Log, dated 5/31/2012

Section 1R05: Fire Protection

Procedures
FRS-II-211, Salem Unit 1 (Unit 2) Pre-Fire Plan, Turbine Generator Area Elevation: 88', Revision 5
FRS-II-453, Salem Unit 1 (Unit 2) Pre-Fire Plan, Auxiliary Building Ventilation Units Elevation: 122', Revision 2
FRS-II-453, Salem Unit 1 (Unit 2) Pre-Fire Plan, Volume Control Tank and Boric Acid Storage Tanks Elevation: 122', Revision 2
FRS-II-453, Salem Unit 1 (Unit 2) Pre-Fire Plan, Fuel Handling Building Elevation: 130', Revision 2
FP-AA-011, Control of Transient Combustible Material, Revision 2

Section 1R11: Licensed Operator Requalification Program

Procedures
S1.OP-AB.LOAD-0001, Rapid Load Reduction, Revision 13
S1.OP-AB.RCP-0001, Reactor Coolant Pump Abnormality, Revision 15
S1.OP-PT-TRB-0003, Main Turbine Valve Stroke Testing, Revision 19

Notifications

20480400	20556416	20556502	20556508	20556829

Orders

30217248	600944419	70109169	70113486

Other Documents
PSEG Nuclear, LLC, Salem - Onsite Training Drill (S12-02) Scenario Synopsis, dated 6/13/2012
EP-AA-125-1002-F01, DEP Observation Checklist, dated 6/13/2012

Section 1R12: Maintenance Effectiveness

Procedures
HU-AA-104-101, Procedure Use and Adherence, Revision 5
SC.MD-PM.SW-0003, Service Water Auto Strainer Adjustment, Inspection, Repair and Replacement, Revision 33
ER-AA-310-1005, Maintenance Rule - Dispositioning Between (a)(1) and (a)(2), Revision 7

Notifications

20327612	20359162	20500324	20508596	20510870	20516276
20516527	20549815	20550115	20564070	20563517	20557259
20540274	20541697	20503779	20521806	20524405	20535209
20483436	20560870	20559725	20505134	20555441	

Orders

30173090	30211698	70094668	70097757	70100093	70120968
70136190	70127716	70138827	70125115	70122783	70096972

Other Documents
DE_CB.SW-0047, Configuration Baseline Documentation for Service Water System, Revision 7
Salem 1, SW Header Reliability (Cumulative) Chart, 6/2009 - 6/2012
Salem 1, SW Pump Train Reliability (Cumulative) Chart, 6/2009 - 6/2012
Salem 1, 11-16 SW Pump Unavailability (Cumulative) Chart, 6/2009 - 6/2012
Salem 1, 11-12 SW Nuclear Header Unavailability (Cumulative) Chart, 6/2009 - 6/2012
Salem 1, SW System Health Report, Q1-2012
Salem 1, SW Maintenance Rule Checkbook, May 2012
(a)(1) Determination Issue Report Number: 70127716-0010
Salem Nuclear Generating Station, System Function Level Maintenance Rule Scoping, Component Cooling Water
Salem 1 Narrative Log, CC215, 6/4/2010 - 6/4/2012
Salem 1 Narrative Log, dated 4/19/2012
Salem MRC Review Report, dated 4/23/2012

Section 1R13: Maintenance Risk Assessments and Emergent Work Control

Procedures
OP-AA-101-112-1002, On-Line Risk Management, Revision 6
OP-AA-108-116, Protected Equipment Program, Revision 6
WC-AA-101, On-Line Work Management Process, Revision 19

Notifications

20559949	20559942

Other Documents
SGS Unit 1 PRA Risk Assessment for Work Week 221 (5/20 to 5/26), Revision 1
SGS Unit 2 PRA Risk Assessment for Work Week 221 (5/20 to 5/26), Revision 1
SGS Unit 1 PRA Risk Assessment for Work Week 223 (6/3 to 6/9), Revision 0
SGS Unit 2 PRA Risk Assessment for Work Week 223 (6/3 to 6/9), Revision 0
SGS Unit 1 PRA Risk Assessment for Work Week 214 (4/1 to 4/7), Revision 0
SGS Unit 2 PRA Risk Assessment for Work Week 214 (4/1 to 4/7), Revision 0
Operators Risk Report, dated 5/14/2012, 5/16/2012, and 5/18/2012
Salem 1 Narrative Log, dated 5/14/2012
12 CCHX Risk Assessment Email from H. Balian, dated 5/14/2012

Section 1R15: Operability Evaluations

Procedures
CC-AA-320-011, Transient Loads, Revision 0
CC-AA-11, Nonconforming Materials, Parts, or Components, Revision 3

Notifications

20555233	20554281	20555801	20559092	20559391	20560244
20564596	20565357	20565476	20565235	20520193	20557259
20557256					

Orders

70138617	70138770	70140127	70127128	70115963	70132047
70138792					

Other Documents
Salem U1 - S1AF - 11AF23 Failed Inservice Test Prompt Investigation
PSEG VTD No. 316527-03 04, Forged Steel Univalve Globe Stop-Check Valve Fig. w/Tag Sheet and Buttweld End Detail
Technical Evaluation 70138737-0050, Evaluation of Leakage Upstream of 11CC227
Operators Risk Report, dated 5/2/2012
Salem 1 Narrative Log, dated 4/28/2012

Section 1R18: Plant Modifications

Other Documents
DCP 80106209, Revise Unit 2 Turbine Overspeed Protection Setpoint, Revision 0
DCP 80096586, SSPS Circuit Card Upgrade, Revision 1
Unit 2 Narrative Log dated April 24, 2012

Section 1R19: Post-Maintenance Testing

Procedures
S1.IC-ST.SSP-0004, Train A Reactor Trip and Reactor Bypass Breaker P-4 Permissive Test, Revision 18
S1.IC-ST.SSP-0008, Solid State Protection System Train A Functional Test, Revision 38
S1.IC-ST.SSP-0010, Solid State Protection System Train A – Reactor Trip Breaker UV Coil and Auto Shunt Trip, Revision 25
S1.OP-ST.SW-0006, Inservice Testing – 16 Service Water Pump, Revision 32
S1.OP-ST.CC-0001, Inservice Testing - 11 Component Cooling Pump, Revision 22

S2.OP-ST.CBV-0001, Inservice Testing Containment Ventilation Valves Modes 1-6, Revision 8
S2.OP-ST.CVC-0005, Inservice Testing – 23 Charging Pump, Revision 20
S2.OP-ST.RPI-0004, IST – Remote Position Verification – Penetration Area, Revision 8
S2.OP-LR.VC-0003, Type C Leak Rate Test 2VC5 and 2VC6, Revision 2
S2.RA-ST.CVC-0005, Inservice Testing 23 Charging Pump Acceptance Criteria, Revision 13

Notifications
20557259

Orders

30146266	30191619	30218297	30224790	50148415	60102533
60102811	60102788				

Other Documents
Salem 1 Narrative Log, dated 4/28/2012, 4/29/2012, and 4/30/2012

Section 1R20: Refueling and Other Activities

Procedures
1-EOP-TRIP-1, Reactor Trip or Safety Injection, Revision 27
1-EOP-Trip-3, Safety Injection Termination, Revision 22
CC-AA-5001, Post Transient or Scram Walkdown, Revision 4
MA-AA-716-004, Conduct of Troubleshooting, Revision 11
OP-AA-106-101-1006, Operational Control and Technical Decision Making Process, Revision 6
S1.IC-FT.RCP-0098, Steam Generator Steam Flow and Turbine Steam Line Inlet Pressure Protection Channel 1, Revision 24
MA-AA-716-012, Post Maintenance Testing, Revision 8
OP-SA-108-114-1001, Post-Trip Data Collection Guidelines - Salem, Revision 2
OP-AA-108-108, Unit Restart Review, Revision 11

Notifications

20557403	20557410	20557413	20557470	20557471	20557472
20557491	20557494	20557515	20557516	20557555	20557561
20557562	20557594	20557627	20557693	20557701	20557836
20557837	20557859	20557922	20557941	20558188	20558208
20558361	20559611	20557113	20557485	20557628	20557415
20557495	20557583	20557922	20557487	20559093	20557119
20557120	20557393	20557622	20557623	20557626	20557482
20557484	20557631	20557635	20557417	20557407	20557398
20557399	20557400	20557405	20557411	20557486	20557588
20557740	20557834	20557829	20557833	20557832	

Orders

60082706	70137905	70138039	70138321	70138388

Other Documents
Troubleshooting Work Sheet and Complex Troubleshooting Failure Mode Cause Table (FMCT), 05/01/2012
Issue Resolution Documentation Form, 05/04/2012
Operational Control and Technical Decision Making Process, 04/30/2012
Unit 1 Trip Report, 4/30/2012

Salem Unit 1 Reactor Containment, FRS-II-611, Fire Zone Code: 1-4-5, pgs. 2 and 3 of 3
Diagram of Air Operated Systems
MA-AA-716-012, Attachment 1, Fire Protection Equipment Test Matrix, Revision 18
Salem 1 Forced Outage 4/30/2012 Rx Trip & SI Logic Sketch
Operability Evaluation 12-004, Revision 0
MA-AA-716-004, Attachment 2, Troubleshooting Worksheet, Determine the Cause of Unit 1 Rx Trip and Safety Injection, dated 4/30/2012

Section 1R22: Surveillance Testing

Procedures
S1.OP-PT.AF-0003, 13 Auxiliary Feedwater Pump Periodic Run, Revision 2
S1.OP-ST.RHR-0002, Inservice Testing – 12 RHR Pump, Revision 18
S1.OP-ST.SJ-0022, High Head ECCS Check Valve Testing in Modes 1-3, Revision 1
S1.RA-ST.RHR-0002, 12 RHR Pump Acceptance Criteria, Revision 8
S1.OP-ST.SJ-0020, Periodic Leakage Test, RCS Pressure Isolation Valves, Revision 20
S1.OP-PT.SW-0004, Service Water Fouling Monitoring, Safety Injection and Charging Pumps, Revision 9
S1.IC-CC.RCP-0066, 1PT-948A Containment Pressure Protection Channel IV, Revision 10
S2.OP-ST.RHR-0002, Inservice Testing - 22 Residual Heat Removal Pump, Revision 31

Notifications

20492820	20556206	20556208	20556372	20557418	20558389
20558388	20558387				

Orders

30225017	50148233	50137372

Other Documents
S-C-RHR-MDC-1463, RHR Pump TDH Calculation, Revision 1
Salem 1 Narrative Log, dated 5/6/2012

Section 1EP6: Drill Evaluation

Other Documents
PSEG Nuclear, LLC, Salem - Onsite Training Drill (S12-02) Scenario Synopsis, dated 6/13/2012
EP-AA-125-1002-F01, DEP Observation Checklist, dated 6/13/2012

Section 2RS1: Access Control to Radiologically Significant Areas

Procedures
RP-AA-302, Determination of ALPHA Monitoring Levels, Revision 3
RP-AA-376, Radiological Posting, Labeling and Marking, Revision 6
RP-AA-350, Response to Potentially Contaminated Personnel, Revision 10
RP-AA-401-1001, Special Instructions for Highly Radioactive Incore Components, Revision 0
RP-AA-403, Administration of the Radiation Work Permit Program, Revision 3
RP-AA-460, Control for High and Very High Radiation Areas, Revision 15
NC.RP-TI.ZZ-0206, Dose Assessment for Airborne Radioactive Material Exposure

Other Documents
Technical Report No. 2000-01, Evaluation of Portal and Personnel Monitor Sensitivity to Internal

Gamma Emitting Radionuclides at PSEG
Occupational Radiation Safety Assessments – 70133618, 70108066, 70109036, 70106827, 70183260
Audit NOS-12-2001
Audit NOSA-SLM-11-07
Oversight Assessment Report NOSPA-SA-11-3C
(Corrective Action Documents (20553623, 20553532, 20553448, 20553447
NRB Minutes - 12-06, 07, 08, 09, 010
Source Inventory
Dosimeter - NVLAP certification data
Contamination Control – Personnel Contamination Data
Source transaction (reconciliation) and leak test data

Section 2RS2: Occupational ALARA Planning and Controls

Procedures
RP-AA-400, ALARA program, Revision 6
RP-AA-401, Operational ALARA Planning and Control, Revision 12
RP-AA-403, Administration of the Radiation Work Permit Program, Revision 3

Other Documents
SAC Meeting Minutes – Station Goals
Salem 1 R21 Outage Dose Report
Salem 1 21 RFO Performance Report
Salem 2 18 RFO Performance Report
Salem 2011-2015 Exposure Reduction Plan
Post-Job ALARA Reviews

Section 2RS3: In-Plant Airborne Radioactivity Control and Mitigation

Other Documents
Occupational Dose Summary
Radiological Source Term Data
Airborne Radioactivity Intake Assessments
Corrective Action Documents (various)

Section 2RS4: Occupational Dose Assessment

Procedures
RP-AA-211, Personnel Dosimetry Performance Verification, Revision 7
RP-AA-220, Bioassay Program, Revision 7
RP-AA-250, External Dose Assessment from Contamination, Revision 6
RP-AA-302, Determination of ALPHA Monitoring Levels, Revision 3
RP-AA-350, Response to Potentially Contaminated Personnel, Revision 10
NC.RP-TI.ZZ-0206, Dose Assessment for Airborne Radioactive Material Exposure

Other Documents
Luminant – Dosimetry Evaluation
NVLAP Testing Certification In-light
RP-AA-220, Annual Bioassay Program Review - 2011
Exposure Control and Dose Records

General Source Term Data
Personnel Contamination Event Logs
Personnel Intake Investigations
Corrective Action Documents (various)

Section 2RS5: Radiation Monitoring Instrumentation

Procedures
RP-AA-302, Determination of ALPHA Monitoring Levels, Revision 3
RP-AA-350, Response to Potentially Contaminated Personnel, Revision 10
RP-AA-401-1001, Special Instructions for Highly Radioactive Incore Components, Revision 0
NC.RP-TI.ZZ-0206, Dose Assessment for Airborne Radioactive Material Exposure
RP-AA-503, Unconditional Release Survey Method, Revision 7

Other Documents
General Source Term Data
General Instrumentation Calibration and Source Check Data
Technical Report No. 2000-01, Evaluation of Portal and Personnel Monitor Sensitivity to Internal Gamma Emitting Radionuclides at PSEG

Section 2RS6: Radioactive Gaseous and Liquid Effluent Treatment

Other Documents
Annual Effluent Release and Environmental Reports 2011
Offsite Dose Calculation Manual (Rev. 26) and changes
Reports (various) - Routine Groundwater
General Source Term Data

Section 2RS7: Radiological Environmental Monitoring Program (REMP)

Other Documents
Annual Effluent Release and Environmental Reports 2011
Offsite Dose Calculation Manual (Rev. 26) and changes

Section 4OA1: Performance Indicator Verification

Other Documents
PSEG Nuclear Performance Summary: Salem P.2: Power History Curve, dated 4/13/2012
1Q/2012 Performance Indicators - Salem 1 and 2 - Unplanned Scrams per 7000 Critical Hours, dated 5/11/2012
1Q/2012 Performance Indicators - Salem 1 and 2 - Unplanned Power Changes per 7000 Critical Hours, dated 5/11/2012
1Q/2012 Performance Indicators - Salem 1 and 2 - Unplanned Scrams with Complications, dated 5/11/2012

Section 4OA2: Problem Identification and Resolution

Procedures
S1.OP-ST.CH-0004, Chilled Water System - Chillers, Revision 11
SC.MD-PM.CH-0001, Acme Chiller Compressor Inspection and Repair, Revision 18

Notifications

20550768	20550758	20551613	20551615	20550379	20550691
20549313	20549866				

Orders

60101901	70135613	70106293

Other Documents

Apparent Cause Evaluation: 13 Chiller Excessive Cycling
Root Cause Evaluation: Multiple Failures of the 12 and 13 Chillers
MA-AA-716-004, Attachment 2, Troubleshooting Work Sheet, Return 13 Chiller to a Fully Operable Status, dated 3/5/2012
LER 05000272/2009-001-01, Chillers Inoperability Exceeds TS Allowed Outage Time
NCV 05000272/2010002-01, Chillers Inoperability Exceeds TS Allowed Outage Time
Information Notice No. 94-82, Concerns Regarding Essential Chiller Reliability During Periods of Low Cooling Water Temperature, dated 12/5/1994

LIST OF ACRONYMS

AC	Alternating Current
ACE	Apparent Cause Evaluation
ADAMS	Agencywide Documents Access and Management System
AFW	Auxiliary Feedwater
ALARA	As Low As Reasonably Achievable
CAC	Control Area Chiller
CAP	Corrective Action Program
CCHX	Component Cooling Heat Exchanger
CCW	Component Cooling Water
CFCU	Containment Fan Cooler Unit
CFR	Code of Federal Regulations
CS	Containment Spray
EDG	Emergency Diesel Generator
HRA	High Radiation Area
IMC	Inspection Manual Chapter
KV	Kilovolt
LCO	Limiting Condition for Operation
LER	Licensee Event Report
LOSW	Loss of Service Water
NCV	Non-Cited Violation
NRC	Nuclear Regulatory Commission
NVLAP	National Voluntary Laboratory Accreditation Program
ODCM	Offsite Dose Calculation Manual
OOS	Out of Service
PARS	Publicly Available Records
PI	Performance Indicator
PMT	Post-Maintenance Test/Testing
PSEG	Public Service Enterprise Group Nuclear LLC
RCA	Radiological Controlled Area
REMP	Radiological Environmental Monitoring Program
RHR	Residual Heat Removal
RPS	Reactor Protection System
SBO	Station Blackout
SDP	Significance Determination Process
SOV	Solenoid Operated Valve
SPAR	Standardized Plant Analysis Review
SSC	Structure, System, or Component
SSPS	Solid State Protection System
SW	Service Water
TS	Technical Specification
TSAS	Technical Specification Action Statement
UFSAR	Updated Final Safety Analysis Report
VHRA	Very High Radiation Area