UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION I
475 ALLENDALE ROAD
KING OF PRUSSIA, PENNSYLVANIA 19406-1415

May 12, 2011

Mr. Thomas P. Joyce
President and Chief Nuclear Officer
PSEG Nuclear LLC - N09
P.O. Box 236
Hancock's Bridge, NJ 08038

SUBJECT: SALEM NUCLEAR GENERATING STATION, UNIT NOS. 1 AND 2 - NRC INTEGRATED INSPECTION REPORT 05000272/2011002 and 05000311/2011002

Dear Mr. Joyce:

On March 31, 2011, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at the Salem Nuclear Generating Station, Unit Nos. 1 and 2. The enclosed integrated inspection report documents the inspection results discussed on April 5, 2011, with Mr. Fricker 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.

The report documents one self-revealing finding of very low significance (Green) and one Severity Level IV violation. The finding was not a violation of NRC requirements. Because of the very low safety significance of the violation and because it was entered into your corrective action program (CAP), the NRC is treating the Severity Level IV violation as a non-cited violation (NCV) consistent with Section 2.3.2 of the NRC Enforcement Policy. If you contest this NCV, 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 I, and the NRC Resident Inspector at Salem Nuclear Generating Station.

In accordance with 10 Code of Federal Regulations (CFR) 2.390 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response (if any) will be available electronically for public inspection in the NRC Public Document Room or from the Publicly

Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

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

Docket Nos: 50-272; 50-311
License Nos: DPR-70; DPR-75

Enclosure: Inspection Report 05000272/2011002 and 05000311/2011002
w/Attachment: Supplemental Information

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/RA/
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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:	05000272/2011002 and 05000311/2011002
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:	January 1, 2011 through March 31, 2011
Inspectors:	D. Schroeder, Senior Resident Inspector P. McKenna, Resident Inspector J. Furia, Senior Health Physicist M. Modes, Senior Reactor Inspector S. Barr, Senior Emergency Preparedness Inspector T. O'Hara, Reactor Engineer C. Crisden, Emergency Preparedness Specialist
Approved By:	Arthur L. Burritt, Chief Projects Branch 3 Division of Reactor Projects

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SUMMARY OF FINDINGS

IR 05000272/2011002, 05000311/2011002; 01/01/2011 - 03/31/2011; Salem Nuclear Generating Station Unit Nos. 1 and 2; Identification and Resolution of Problems, Event Follow-up.

The report covered a three-month period of inspection by resident inspectors, and announced inspections by a regional radiation specialist and reactor engineers. One Green finding and one Severity Level IV NCV were identified. 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 a finding is determined using the guidance in 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: Initiating Events

- Green. A self-revealing finding of very low safety significance was identified for the failure of PSEG to resolve a long standing issue with the reliability of the Unit 1 main generator voltage regulator (VR). A failure in the Unit 1 main generator VR resulted in an automatic reactor trip due to a turbine trip above 50 percent power. Corrective actions include the planned replacement of the VR with a nuclear industry proven design during the October 2011 refueling outage. PSEG entered this issue into their CAP as notification 20481250.

  The performance deficiency was more than minor because it is associated with the equipment performance attribute of the Initiating Events cornerstone and it adversely affected the cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. The finding was evaluated under IMC 0609, Attachment 4, "Phase 1 - Initial Screening and Characterization of Findings." The inspectors determined that the finding is of very low safety significance (Green) because it does not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions will not be available. The inspectors determined that this finding has a cross-cutting aspect in the area of human performance, because PSEG affected long term plant safety by not minimizing long-standing equipment issues. Specifically, considering the increase in the number of Unit 1 main generator VR failures since 2007, PSEG did not resolve the lack of vendor and part support for the Unit 1 main generator VR in a timely manner. (H.2(a)) (Section 4OA3.1)

Cornerstone: Barrier Integrity

- Severity Level IV. The inspectors identified a Severity Level IV NCV of 10 CFR 50.73, "Licensee Event Reporting (LER) System," because PSEG personnel did not provide a written report to the NRC within 60 days after discovery of a condition prohibited by Technical Specification (TS) 3.6.1, "Containment Integrity." This was an NRC-identified violation of reporting requirements and potentially impacted the regulatory process. This type of violation is dispositioned using the traditional enforcement process defined in the NRC Enforcement Policy. In accordance with Section 6.9.d of the Enforcement Policy, this violation is categorized as a Severity Level IV violation.

  PSEG documented the issue in their corrective action program and conducted an evaluation to determine why the assignment to submit an LER was missed. The inspectors determined that this traditional enforcement violation did not involve a Reactor Oversight Process (ROP) finding, therefore, no cross-cutting issue was assigned. (Section 4OA2.2)

REPORT DETAILS

Summary of Plant Status

Salem Nuclear Generating Station Unit 1 (Unit 1) began the period at 100 percent power. On March 24, 2011, plant operators reduced power to 95 percent due to heavy river detritus. Operators returned Unit 1 to full power on March 25, 2011, after river conditions stabilized. On March 27, 2011, operators again reduced power to 90 percent because of heavy river detritus. Operators returned Unit 1 to 100 percent power on March 30, 2011, after river conditions stabilized. 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 March 20, 2011, plant operators reduced power to 85 percent due to heavy river detritus, and increased power to 90 percent on March 21, 2011. On March 24, 2011, plant operators again lowered power to 76 percent due to heavy river detritus, and later that day, raised power to 85 percent after river conditions stabilized. Operators then increased power to 90 percent power on March 31, 2011, and Unit 2 ended the period at 90 percent power.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity, and Emergency Preparedness

1R01 Adverse Weather Protection (71111.01 - 1 sample)

.1 Evaluate Readiness for Impending Adverse Weather Conditions

a. Inspection Scope

The inspectors completed one impending adverse weather protection sample. The inspectors reviewed the actions completed by PSEG to prepare for impending frazzle ice between January 11 and January 13, 2011. The actions were taken based on air temperature, river temperature, and wind speed readings that indicated an increased potential for frazzle ice. The inspectors walked down the service water system during the period of increased potential to confirm that it remained available. The inspectors also reviewed the site's adverse weather procedures to verify that specified actions were completed and that those actions would maintain the plant in a safe condition if impacted by frazzle ice. No significant frazzle ice buildup occurred in the intake during this period. Documents reviewed are listed in the Attachment.

b. Findings

No findings were identified.

1R04 Equipment Alignment (71111.04A - 3 samples; 71111.04S - 1 sample)

.1 Partial Walkdown

a. Inspection Scope

The inspectors completed three partial system walkdown inspection samples. The inspectors walked down the systems listed below to verify the system's operability when redundant or diverse trains and components were inoperable. The inspectors focused their review on potential discrepancies that could impact the function of the system and increase plant risk. The inspectors reviewed applicable operating procedures, walked down control system components, and verified that selected breakers, valves, and support equipment were in the correct position to support system operation. The inspectors also verified that PSEG properly utilized its CAP to identify and resolve equipment alignment problems. Documents reviewed are listed in the Attachment.

- 1A and 1C emergency diesel generators (EDGs) when the 1B EDG and the 1B1 battery charger were out of service (OOS) on January 11
- 11 and 13 control area chillers when 12 control area chiller was OOS on March 11
- Unit 2 SW pumps when 24 SW pump was OOS on March 30

b. Findings

No findings were identified.

.2 Complete Walkdown

a. Inspection Scope

The inspectors conducted one complete walkdown inspection sample of the Unit 1 residual heat removal (RHR) system. The inspectors independently verified the alignment and status of the RHR pump and valve electrical power, labeling, hangers and supports, and associated support systems. The walkdown also included verification of valve positions, evaluation of system piping and equipment to verify pipe hangers were in satisfactory condition, oil reservoir levels were normal, pump rooms were adequately ventilated, system parameters were within established ranges, and equipment deficiencies were appropriately identified. The inspectors interviewed engineering personnel and reviewed corrective action evaluations associated with the system to verify that equipment alignment problems were identified and corrected. Documents reviewed are listed in the Attachment.

b. Findings

No findings were identified.

1R05 Fire Protection (71111.05Q - 5 samples)

.1 Fire Protection - Tours

a. Inspection Scope

The inspectors completed five fire protection quarterly inspection samples. The inspectors walked down the systems listed below to assess the material condition and operational status of fire protection features. The inspectors verified that combustibles and ignition sources were controlled in accordance with PSEG's administrative procedures; fire detection and suppression equipment was available for use; that passive fire barriers were maintained in good material condition; and that compensatory measures for OOS, degraded, or inoperable fire protection equipment were implemented in accordance with PSEG's fire plan. Documents reviewed are listed in the Attachment.

- Unit 1, inner piping penetration area and chiller room, 78' and 100' elevations
- Unit 2, inner piping penetration area and chiller room, 78' and 100' elevations
- Unit 2, mechanical penetration room, 84' and 100' elevations
- Unit 2, fuel handling building, 84', 100', and 116' elevations
- Unit 2, volume control and boric acid tanks, 122' elevation

b. Findings

No findings were identified.

1R06 Flood Protection Measures (71111.06 - 1 sample)

.1 Internal Flooding

a. Inspection Scope

The inspectors completed one internal flood protection inspection sample. The inspectors evaluated flood protection measures for the Unit 1 RHR pump and heat exchanger (HX) rooms. The inspectors interviewed engineering personnel and walked down the areas to assess the operational readiness of the various features in place that were designed to protect the redundant safety-related components located in these rooms. These features included plant drains, watertight doors, sump pumps, and wall penetration seals. The inspectors also reviewed the penetration seal inspection results, operator logs, and corrective action notifications associated with flood protection measures. The documents reviewed are listed in the Attachment.

b. Findings

No findings were identified.

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

a. Inspection Scope

The inspectors completed one quarterly licensed operator requalification program inspection sample. Specifically, the inspectors observed an unannounced simulator scenario on February 6, 2011. The scenario included a design basis seismic event that caused a steam generator (SG) tube rupture. The plant operators responded to the SG tube rupture by initiating a manual plant trip. The fuel element damage that occurred during the scenario led to a general emergency declaration. The inspectors reviewed operator implementation of the site's abnormal and emergency operating procedures and Emergency Plan, and confirmed that lessons learned items from previous training scenarios and events were incorporated into operator response where applicable. The inspectors also verified that deficiencies identified during the scenario were discussed during scenario debriefs and entered into the CAP, as appropriate. Documents reviewed during this inspection are listed in the Attachment.

b. Findings

No findings were identified.

1R12 Maintenance Effectiveness (71111.12Q - 2 samples)

a. Inspection Scope

The inspectors completed two quarterly maintenance effectiveness inspection samples. The inspectors reviewed performance monitoring and maintenance effectiveness issues for the systems listed below. The inspectors reviewed PSEG's process for monitoring equipment performance and assessing preventive maintenance effectiveness. The inspectors verified that systems and components were monitored in accordance with the maintenance rule program requirements. The inspectors confirmed that the functional failure determinations and unavailability hours for these systems were documented in accordance with the maintenance rule and that PSEG established performance goals for these systems were met. The inspectors also reviewed applicable work orders (WOs), corrective action notifications, and preventive maintenance tasks for these systems. The documents reviewed during the inspection are listed in the Attachment.

- Unit 1 SW pumps and strainers
- Station blackout (SBO) diesel air compressor

b. Findings

No findings were identified.

1R13 Maintenance Risk Assessments and Emergent Work Control (71111.13 - 6 samples)

a. Inspection Scope

The inspectors completed six maintenance risk assessment and emergent work control inspection samples. The inspectors reviewed the maintenance activities listed below to verify that the appropriate risk assessments were performed as specified by 10 CFR 50.65(a)(4) prior to removing equipment for work. The inspectors reviewed the applicable risk evaluations, work schedules, and control room logs for these configurations. PSEG's risk management actions were reviewed during shift turnover meetings, control room tours, and plant walkdowns. The inspectors used PSEG's on-line risk monitor (Equipment OOS workstation) to gain insights into the risk associated with these plant configurations. The inspectors also reviewed corrective action notifications written to document problems associated with risk assessments and emergent work evaluations. Documents reviewed are listed in the Attachment.

- Unit 1, 1B EDG and 1B1 battery charger planned maintenance on January 11
- Unit 2, 2C EDG planned maintenance and 23 containment fan cooler unit emergent maintenance on January 20
- Unit 2, 22 control area air conditioning supply fan planned maintenance and the SBO air compressor and SBO gas turbine generator emergent maintenance on February 7
- Unit 1, 1B 28 Vdc battery missed surveillance test and SBO air compressor and SBO gas turbine generator planned maintenance on February 8
- Unit 1, auxiliary feedwater (AFW) room cooler planned maintenance on February 22
- Unit 1 and Unit 2, 3 Station Power Transformer planned maintenance on March 30

b. Findings

No findings were identified.

1R15 Operability Evaluations (71111.15 - 5 samples)

a. Inspection Scope

The inspectors completed five operability evaluation inspection samples. The inspectors reviewed the operability determinations for degraded or non-conforming conditions associated with:

- Unit 1 and Unit 2, wide range t-hot and t-cold calibration
- Unit 1 and Unit 2, GDC-17 offsite power calculations with revised transformer impedance
- Unit 2, control room emergency air conditioning system expansion joint in leakage into the control room envelope
- Unit 2, 2CS16, containment spray additive tank outlet valve closed indication adjustment
- Unit 2, 2R5 fuel handling building radiation monitor low signal alarm

The inspectors reviewed the technical adequacy of the operability determinations to ensure the conclusions were justified. The inspectors also walked down accessible equipment to corroborate the adequacy of PSEG's operability determinations. Additionally, the inspectors reviewed other PSEG identified safety-related equipment deficiencies during this report period and assessed the adequacy of their operability screenings. Documents reviewed are listed in the Attachment.

b. Findings

No findings were identified.

1R18 Plant Modifications (71111.18 - 1 sample)

.1 Temporary Modification

a. Inspection Scope

The inspectors completed one plant modification inspection sample. The inspectors reviewed temporary plant modification package (1ST-07-005), which removed the input to control room annunciator H21 from the Unit 1 digital VR memory battery low relay. There are several functions alarmed from annunciator H21 and this modification removed the nuisance alarms caused by the memory battery low relay and maintained operator sensitivity to the other alarm inputs to this control room overhead alarm module. The inspectors verified that the design bases, licensing bases, and performance capability of the affected system was not degraded by the modification. The inspectors also reviewed post-modification testing results and the 10 CFR 50.59 evaluation for this temporary modification. The documents reviewed are listed in the Attachment.

b. Findings

No findings were identified.

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

a. Inspection Scope

The inspectors completed five post-maintenance testing (PMT) inspection samples. The inspectors observed portions of and/or reviewed the PMT results for the maintenance activities listed below. The inspectors verified that the effect of testing on the plant was adequately addressed by control room and engineering personnel; testing was adequate for the maintenance performed; acceptance criteria were clear, demonstrated operational readiness, and were consistent with design and licensing basis documentation; test instrumentation calibration was current and the appropriate range and accuracy for the application; tests were performed, as written, with applicable prerequisites satisfied; and equipment was returned to an operational status and ready to perform its safety function. Documents reviewed are listed in the Attachment.

- WO 50135879, 1B EDG planned maintenance on January 12
- WO 60094439, 22 containment spray (CS) pump room cooler planned maintenance on January 18
- WO 60094418, 11 RHR pump room cooler planned maintenance on February 28
- WO 30180804, 12 chiller compressor replaced on March 11
- WO 60094167, SBO diesel air compressor radiator repair on March 25

b. Findings

No findings were identified.

1R22 Surveillance Testing (71111.22 - 7 samples)

a. Inspection Scope

The inspectors completed seven surveillance testing inspection samples. The inspectors observed portions of and/or reviewed results for the surveillance tests listed below to verify, as appropriate, whether the applicable system requirements for operability were adequately incorporated into the procedures and that test acceptance criteria were consistent with procedure requirements, the TS requirements, the Updated Final Safety Analysis Report, and American Society of Mechanical Engineers (ASME) Section XI for pump and valve testing. Documents reviewed are listed in the Attachment.

- S2.OP-ST.CS-0002, 22 CS Pump Inservice Test
- S2.OP-ST.AF-0003, 23 AFW Pump Test
- S2.OP-ST.SJ-0001, 21 Safety Injection Pump Inservice Test
- S2.OP-ST.DG-0013, 2B EDG Endurance Run
- S1.OP-ST.RHR-0001, 11 RHR Pump Inservice Test
- S2.OP-ST.DG-0012, 2A EDG Endurance Run
- S1.OP-ST.RC-0008, Reactor Coolant System Water Inventory Balance

b. Findings

No findings were identified.

1EP2 Alert and Notification System (ANS) Evaluation (71114.02 - 1 sample)

a. Inspection Scope

An onsite review of the Salem and Hope Creek ANS was conducted to assess current maintenance and testing practices. During the inspection, the inspectors reviewed ANS maintenance and testing procedures, maintenance and test records, and the updated Salem and Hope Creek ANS design report to ensure PSEG's compliance with design report commitments for system maintenance and testing. A sample of condition reports (CRs) pertaining to the ANS was reviewed for causes, trends, and corrective actions. The inspectors interviewed the ANS System Manager to discuss system performance and upgrades. The inspection was conducted in accordance with NRC Inspection Procedure 71114, Attachment 2. Planning Standard, 10 CFR 50.47(b)(5), and the related requirements of 10 CFR 50, Appendix E, were used as reference criteria.

b. Findings

No findings were identified.

1EP3 Emergency Response Organization (ERO) Staffing and Augmentation System (71114.03 - 1 sample)

a. Inspection Scope

The inspectors conducted a review of Salem and Hope Creek's ERO augmentation staffing requirements and the process for notifying and augmenting the ERO. The review was performed to ensure the readiness of key PSEG staff to respond to an emergency event and to ensure PSEG's ability to activate their emergency facilities in a timely manner. The inspectors reviewed the Salem and Hope Creek Emergency Plan, duty rosters, and augmentation reports. The inspectors also reviewed a sampling of ERO responders training records to ensure training and qualifications were up to date. The inspection was conducted in accordance with NRC Inspection Procedure 71114, Attachment 3. Planning Standard, 10 CFR 50.47(b)(2), and related requirements of 10 CFR 50, Appendix E were used.

b. Findings

No findings were identified.

1EP4 Emergency Action Level (EAL) and Emergency Plan Changes (71114.04 - 1 sample)

a. Inspection Scope

Since the last NRC inspection of this program area, PSEG implemented various changes to the Salem and Hope Creek Emergency Plan and implementing procedures. PSEG had determined that, in accordance with 10 CFR 50.54(q), any change made to the Emergency Plan , and its lower-tier implementing procedures, had not resulted in any decrease in effectiveness of the Emergency Plan, and that the revised Emergency Plan continued to meet the standards in 10 CFR 50.47(b) and the requirements of 10 CFR 50, Appendix E. The inspectors reviewed all EAL changes. A sample of emergency plan changes, including the changes to lower-tier emergency plan implementing procedures, were evaluated for any potential decreases in effectiveness of the Salem/Hope Creek Emergency Plan. However, this review by the inspectors was not documented in an NRC Safety Evaluation Report and does not constitute formal NRC approval of the changes. Therefore, these changes remain subject to future NRC inspection in their entirety. The inspection was conducted in accordance with NRC Inspection Procedure 71114, Attachment 4. The requirements in 10 CFR 50.54(q) were used as reference criteria.

b. Findings

No findings were identified.

1EP5 Correction of Emergency Preparedness Weaknesses (71114.05 - 1 sample)

a. Inspection Scope

The inspectors reviewed a sampling of self-assessment procedures and reports to assess PSEG's ability to evaluate their emergency preparedness performance and program. The inspectors reviewed a sampling of CRs from April 2009 through March 2011 initiated by PSEG at Salem and Hope Creek from drills, self-assessments, and audits. The inspectors also reviewed 10 CFR 50.54(t) audit reports and nuclear oversight audits. The inspection was conducted in accordance with NRC Inspection Procedure 71114, Attachment 5. Planning Standard, 10 CFR 50.47(b)(14) and the related requirements of 10 CFR 50, Appendix E , were used as reference materials.

b. Findings

No findings were identified.

1EP6 Drill Evaluation (71114.06 - 1 sample)

a. Inspection Scope

The inspectors completed one drill evaluation inspection sample. On February 3, 2011, the inspectors observed emergency plan response actions at the simulated control room and the technical support center during an emergency preparedness drill. The inspectors evaluated operator performance related to developing event classifications and notifications. The inspectors reviewed the Salem Event Classification Guides. The inspectors referenced Nuclear Energy Institute (NEI) 99-02, "Regulatory Assessment Performance Indicator (PI) Guideline," Revision 5, and verified that PSEG correctly counted the evaluated scenario's contribution to the NRC PI for drill and exercise performance.

b. Findings

No findings were identified.

2. RADIATION SAFETY

Cornerstone: Radiation Safety - Public and Occupational

2RS1 Radiological Hazard Assessment and Exposure Controls (71124.01 - 1 sample)

a. Inspection Scope

Radiological Hazard Assessment
The inspectors determined that, since the last inspection, there have been no changes to plant operations that would result in a significant new radiological hazard for onsite workers or members of the public. The inspectors verified that PSEG assessed the potential impact of previous changes and implemented periodic monitoring, as appropriate, to detect and quantify the radiological hazard.

The inspectors reviewed the last two radiological surveys from selected plant areas. The inspectors verified that the thoroughness and frequency of the surveys were appropriate for the given radiological hazard.

The inspectors conducted walkdowns of the facility, including radioactive waste processing, storage, and handling areas to evaluate material conditions and potential radiological conditions in the radiological controlled area (RCA), protected area, controlled area, contaminated tool storage, and contaminated machine shops.

Instructions to Workers
The inspectors selected containers holding nonexempt licensed radioactive materials that may cause unplanned or inadvertent exposure to workers and verified that they were labeled and controlled in accordance with procedures.

Contamination and Radioactive Material Control
The inspectors observed several 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 verified that the radiation monitoring instrumentation had the appropriate sensitivity for the 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 indicated the presence of licensed radioactive material.

Problem Identification and Resolution
The inspectors verified that problems associated with radiation monitoring and exposure control were identified by PSEG at an appropriate threshold and corrected through the CAP. The inspectors verified the appropriateness of the corrective actions for a selected sample of problems documented in the CAP that involved radiation monitoring and exposure controls and confirmed that PSEG was also assessing the applicability of radiation protection operating experience to their plants.

b. Findings

No findings were identified.

2RS2 Occupational As Low as Reasonably Achievable (ALARA) Planning & Controls (71124.02 - 1 sample)

a. Inspection Scope

Inspection Planning
The inspectors reviewed pertinent information regarding plant collective exposure history, current exposure trends, and ongoing or planned activities to assess current performance and exposure challenges. The inspectors also reviewed the plant's three-year rolling average collective exposure and the site-specific trends in collective exposures and source term measurements.

The inspectors reviewed site-specific procedures associated with maintaining occupational exposures ALARA. This included a review of the processes that PSEG used to estimate and track exposures from specific work activities. The inspectors also reviewed the preliminary exposure estimates for the Spring 2011 refueling outage at Unit 2 and concluded that this estimate, if met, would be a lower exposure than any previous refuel outage for the site.

Source Term Reduction and Control
Using PSEG records, the inspectors determined the historical trends and current status of significant tracked plant source terms known to contribute to elevated facility aggregate exposure. The inspectors determined that PSEG was making allowances or developing contingency plans for expected changes in the source term as the result of changes in plant fuel performance or changes in plant primary chemistry. At Unit 2, the change in source term was primarily due to a significant increase in Cobalt-58 activity as a result of the installation of four new steam generators three years ago.

b. Findings

No findings were identified.

2RS4 Occupational Dose Assessment (71124.04 - 1 sample)

a. Inspection Scope

The inspectors reviewed the results of radiation protection program audits related to internal and external dosimetry.
The inspectors reviewed the most recent National Voluntary Laboratory Accreditation Program (NVLAP) report on PSEG's contractor to confirm the status of the contractor's accreditation.

The inspectors reviewed PSEG procedures associated with dosimetry operations, including issuance/use of external dosimetry, assessment of internal dose, and evaluation and assessment of dose for radiological incidents.

The inspectors verified that PSEG had established procedural requirements for determining when external and internal dosimetry was required.

External Dosimetry: NVLAP Accreditation
The inspectors verified that PSEG's personnel dosimeters that required processing were NVLAP accredited. The inspectors verified the vendor's NVLAP accreditation. The inspectors also ensured that the approved irradiation test categories for each type of personnel dosimeter were consistent with the types and energies of the radiation present and the way that the dosimeter was being used.

External Dosimetry: Passive Dosimeters
The inspectors evaluated the onsite storage of dosimeters before their issuance, during use, and before processing/reading. The inspectors also evaluated the guidance provided to radiation workers with respect to care and storage of dosimeters.

External Dosimetry: Active Dosimeters
The inspectors determined that PSEG uses a "correction factor" to address the response of the electronic dosimeter (ED) for situations when the ED must be used to assign dose. The inspectors verified that the correction factor was based on sound technical principles.

The inspectors selected dosimetry occurrence reports or CAP documents for adverse trends related to EDs, such as interference from electromagnetic frequency, dropping or bumping, failure to hear alarms, etc. The inspectors determined that PSEG had not identified any trends.

Internal Dosimetry: Routine Bioassay
The inspectors reviewed the procedures used to assess dose from internally deposited nuclides using whole body counting equipment. The inspectors verified that the procedures addressed methods for determining if an individual was internally or externally contaminated, the release of contaminated individuals, the determination of entry route, and assignment of dose. The inspectors verified that the frequency of such

measurements was consistent with the biological half-life of the potential nuclides available for intake.

The inspectors evaluated the minimum detectable activity (MDA) of the instrument. The inspectors determined that the MDA was adequate to determine the potential for internally deposited radionuclides sufficient to prompt additional investigation.

The inspectors verified that the system used in each bioassay had sufficient counting time/low background to ensure appropriate sensitivity for the potential radionuclides of interest. The inspectors verified that the appropriate nuclide library was used. The inspectors verified that any anomalous count peaks/nuclides indicated in each output spectra received appropriate disposition.

Special Dosimetric Situations: Declared Pregnant Workers
The inspectors verified that PSEG informed workers, as appropriate, of the risks of radiation exposure to the embryo/fetus, the regulatory aspects of declaring a pregnancy, and the specific process to be used for declaring a pregnancy.

The inspectors selected individuals who had declared their pregnancy during the current assessment period and verified that PSEG's radiological monitoring program for declared pregnant workers was technically adequate to assess the dose to the embryo/fetus. The inspectors reviewed the exposure results and monitoring controls employed by PSEG and with respect to the requirements of 10 CFR Part 20. Three workers declared their pregnancy during 2010.

Problem Identification and Resolution
The inspectors verified 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. In addition, the inspectors verified the appropriateness of the corrective actions for a selected sample of problems documented by PSEG involving occupational dose assessment.

b. Findings

No findings were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator (PI) Verification (71151 - 9 samples)

a. Inspection Scope

The inspectors reviewed PSEG submittals for the Unit 1 and Unit 2 mitigating systems cornerstone PIs and the Unit 1 and Unit 2 Barrier Integrity cornerstone PIs discussed below. To verify the accuracy of the PI data reported during this period the data was compared to the PI definition and guidance contained in NEI 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 6.

Cornerstone: Mitigating Systems
- Unit 1 and 2 Safety System Functional Failures

Cornerstone: Barrier Integrity

- Unit 1 and 2 Reactor Coolant System (RCS) Leakage; and
- Unit 1 and 2 RCS Specific Activity.

The inspectors verified the accuracy of the data by comparing it to CAP records, control room operators' logs, and plant status reviews required by NRC IMC 2515, Appendix D, "Plant Status." For the Barrier Integrity and Mitigating Systems cornerstones, data reviewed was for all four quarters of calendar year 2010.

Cornerstone: Emergency Preparedness

- Drill and Exercise Performance;
- ERO Drill Participation; and
- ANS Reliability.

To verify the accuracy of the reported data for the PIs listed above, the inspectors reviewed the PI data and supporting documentation that PSEG reported for the Emergency Preparedness cornerstone from the second quarter through the fourth quarter of 2010.

b. Findings

No findings were identified.

4OA2 Identification and Resolution of Problems (71152 - 2 annual samples)

.1 Review of Items Entered into the Corrective Action Program

As required by Inspection Procedure 71152, "Identification and Resolution of Problems," and in order to help identify repetitive equipment failures or specific human performance issues for follow-up, the inspectors performed a daily screening of all items entered into PSEG's CAP. This was accomplished by reviewing the description of each new notification and attending daily management review committee meetings. Documents reviewed are listed in the Attachment.

.2 Annual Sample: Corrosion Causes Valve Stem Failure

a. Inspection Scope

As required by Inspection Procedure 71152, "Identification and Resolution of Problems," Section 02.03, "Annual Follow-up of Selected Issues," the inspectors reviewed notification 20465141, describing the failure of SW valve 21 SW 122, to verify that documentation was complete and accurate and entered in a timely manner. The corrective action was reviewed for the disposition of operability and reportability issues, consideration of extent of condition and cause, generic implications, common cause, and previous occurrences. The corrective action was further reviewed to determine if the classification and prioritization of the problem's resolution was commensurate with the safety significance.

The inspectors reviewed various related documents and interviewed station personnel responsible for the maintenance of 21 SW 122. The inspectors reviewed the root cause evaluation and associated corrective actions. The inspectors compared the root cause of microbiological assisted corrosion, categorized as a significant condition adverse to quality, against the completed corrective actions to confirm that the timeliness and the extent of the corrective action were commensurate with the impact of the adverse condition on the safe operation of the plant. The inspectors verified that the identified degraded condition was reported to appropriate levels of management and reviewed the specified corrective action to determine whether or not the corrective action was appropriately focused to correct the problem.

The inspectors reviewed timeliness of corrective actions. The inspectors confirmed that delays in implementation of corrective actions were justified based on the safety significance of the issue and that, in the case of permanent corrective actions that required significant time to implement, interim or compensatory actions were identified and implemented to minimize the problem or mitigate its effects until the permanent repair was completed.

The inspectors reviewed completed corrective actions to verify that the actions resulted in correction of the identified problem. In this case, because the issue was a significant condition adverse to quality, the inspectors also verified that the completed corrective action would preclude repetition. In addition, the inspectors compared the corrective action against related negative trends associated with human or equipment performance to determine if the corrective action can potentially impact nuclear safety.

The inspectors also reviewed operating experience applicable to this event to verify that the OE was adequately evaluated for applicability and applicable lessons learned were communicated to appropriate organizations and implemented.

b. Observations

During the review, the inspectors noted that the component cooling water temperature from the 21 component cooling heat exchanger (CCHX) began to oscillate on April 3, 2010. On this date, the system's temperature control system was set up so that the 21 CCHX was in lag (higher temperature set point). As a result at the time of the oscillations the 21 SW 122 valve was closed and 21 SW 127 valve was slightly opened.

PSEG concluded, based on the results of the apparent cause evaluation (ACE), that the 21 SW 122 valve stem failed on April 3, which caused the temperature oscillations. From April 3, 2010, to May 17, 2010, while these oscillations continued, PSEG missed an opportunity to identify the failed valve shaft because they did not identify the cause of the temperature oscillations.

When PSEG identified the failed valve shaft, they took timely and comprehensive corrective actions, commensurate with the significance of the condition adverse to quality. PSEG identified the apparent cause, located all valve stems with similar configurations, and implemented a plan to replace all of the susceptible valve stems in a risk informed manner.

c. Findings

Introduction: The inspectors identified a Severity Level IV NCV of 10 CFR 50.73, "Licensee Event Reporting (LER) System," because PSEG personnel did not provide a written report to the NRC within 60 days after discovery of a condition prohibited by TS LCO 3.6.1, "Containment Integrity."

Description: On May 17, 2010, during the performance of a high flow flush on the 21 CCHX, the required SW flow could not be obtained. Troubleshooting to determine the cause of the low flow condition revealed that the stem of the 21 CCHX inlet butterfly valve , 21 SW 122, was completely severed between the valve actuator and disk. Based on the identified condition, PSEG performed a past operability determination for the 21 CC train. PSEG determined that the time of failure was between April 3 and May 17, 2010.

The 21 CCHX inlet isolation valve had safety functions in both the open and closed directions. The safety function in the open direction was to control SW flow to the CCHX; while in the closed direction the valve was required to stroke closed within 30 seconds to mitigate the impact of water hammer and two phase flow on the SW system and in the event of a loss of coolant accident during a station black out.

PSEG determined that, based on the flow rates measured during the 21 CCHX high flow flush completed on May 17, the inlet isolation valve remained capable of controlling adequate HX flow up to a river temperature of 88°F. However, because the stem was completely separated from the disk, PSEG concluded that the valve could not have stroked fully closed in 30 seconds, and on May 17, 2011, they declared 21 SW 122 inoperable.

PSEG procedure S2.OP-ST.SW-0008, "Inservice Testing of Service Water Valves," required operators to enter the action statements for technical specification (TS) limiting condition for operation (LCO) 3.6.1, "Containment Integrity," when 21 SW 122 was declared inoperable. The LCO requires that containment integrity be restored within one hour or be in hot standby in the next six hours. The TS LCO was violated from April 3, 2010, until May 17, 2010, when the containment integrity was restored. On May 17, 2010, PSEG entered the LCO action statement as required by the procedure, but did not recognize the need to provide a written report to the NRC within 60 days in accordance with 10 CFR 50.73(a)(2)(i)(B) that requires licensees to submit an LER for any operation or condition which was prohibited by the plant's TSs within 60 days of discovering the event.

On February 15, 2011, an NRC inspector was conducting an inspection sample for problem identification and resolution regarding the corrective actions for a broken valve stem issue on the 21 SW 122 valve. Based on the inspectors questions, PSEG generated notification 20497369, which states that an LER should have been written for the TS violation based on the evaluated past operability. This was an NRC-identified violation of reporting requirements.

Analysis: The performance deficiency was that PSEG did not provide a written report within 60 days as required by 10 CFR 50.73(a)(2)(i)(B). This violation potentially impacted the regulatory process. In accordance with IMC 0612 Appendix B, this violation is dispositioned using the traditional enforcement process. In accordance with Section 6.9.d of the NRC Enforcement Policy, this violation was categorized as a Severity Level IV violation. Specifically, the 21 SW 122 valve was not operable for the purposes on containment integrity from April 3, 2010 until May 17, 2010, which violated TS 3.6.1.

PSEG's immediate corrective action was to replace the 21 SW 122 valve, which was completed on May 18, 2010. Following discovery that an LER had not been written as required, PSEG's corrective action included conducting an evaluation to determine why an assignment to submit an LER for this TS violation was missed.

The inspectors determined that this traditional enforcement violation did not include an ROP finding, therefore, no cross-cutting issue was assigned.

Enforcement: 10 CFR 50.73, "LER System," requires licensees to submit an LER for any operation or condition which was prohibited by the plant's TSs within 60 days of discovering the event. Contrary to the above, PSEG failed to submit a report within 60 days of May 17, 2010, following the discovery that TS 3.6.1, "Containment Integrity," had been violated. Because this violation was not repetitive or willful, and was entered into PSEG's CAP as notification 20497369, this violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy. **(NCV 05000311/2011002-01; Failure to Submit an LER for a Condition Prohibited by TS Associated with Containment Isolation)**

.3 Annual Sample: Review of Corrective Actions for AFW Pipe Corrosion and Missed ASME Inspections

a. Inspection Scope

Review of Equipment Apparent Cause Evaluation (EQ:ACE) for AFW Piping Corrosion

Between September 20, 2010 and November 17, 2010, and between March 1, 2011 and March 4, 2011, the inspectors reviewed the completed EQ:ACE for the Unit 1 buried AFW piping corrosion and the degradation discovered on the buried control air piping in the fuel transfer tube area (FTTA) identified in April 2010. The inspectors reviewed the cause and associated corrective actions. This condition was originally documented as a licensee identified violation in Section 4OA7 of NRC Inspection Report 05000272; 05000311/2010003.

The inspectors also reviewed the PSEG basis for the 1950 psig design pressure of the AFW system as requested by notification 20462034 and verified changes made to the PSEG buried piping inspection procedure as a result of the corrosion discovered on the Salem Unit 1 AFW buried piping. Documents reviewed are listed in the Attachment.

Review of Root Cause Evaluation (RCE)(20459689/70109827) for Missed ASME Code, Section XI, Paragraph IWA-5244 Inspections

In the same time period as noted above, the inspectors reviewed the completed RCE for the PSEG failure to perform the ASME Code, Section XI, paragraph IWA-5244 inspection/testing of buried AFW piping for Unit 1 and Unit 2. The inspectors reviewed the cause determination, corrective actions to prevent recurrence, the extent of condition, and the extent of cause. This issue was originally documented as an NRC identified violation in Section 1R08 of NRC Inspection Report 05000272; 05000311/2010003. Documents reviewed are listed in the Attachment.

b. Findings and Observations

No findings were identified.

Review of EQ:ACE for AFW Piping Corrosion
PSEG determined that the most probable cause of the corrosion of the buried AFW piping was "the mistaken removal of the originally installed external coating prior to burial of the piping during original plant construction." PSEG determined that the most probable cause for the control air header buried piping through wall leak was "accidental damage to the original Bitumastic 505 tape wrap system from personnel stepping or climbing on the pipe." Corrective actions included the following:

1. PSEG replaced the original AFW buried piping headers, in kind, outside of the containment and outside of the FTTA building, coated this new buried piping with CERAMALLOY CL+ epoxy. Also, PSEG backfilled the replaced piping with a corrosion resistant engineered backfill material.

2. PSEG replaced the other portions of the AFW piping that were originally buried in the FTTA building with piping located above ground.

3. PSEG replaced the leaking control air header piping elbow in the FTTA, in kind, retaped the piping and coated it with Bitumastic 505.

4. PSEG inspected the redundant control air header piping and the two station air headers buried in the same area where the AFW piping was found degraded. The condition of these buried piping runs was satisfactory. Some repair of the pipe coating was required to restore corrosion protection.

5. PSEG is conducting an engineering planning study to review installation of a cathodic protection system at both Salem units.

The inspectors had the following observations on this apparent cause review:

With respect to the buried piping program, PSEG made appropriate changes to the buried piping procedure to improve, formalize, and control the methodology specified by the inspection procedure. The changes included: (a) the procedure now requires engineering to document how a representative inspection sample is selected for each excavation of buried piping, (b) the procedure now specifies that each inspection of buried piping contain a minimum length of piping, (c) the procedure now requires that all discovered non-conforming conditions be entered into the corrective action process for evaluation, tracking and resolution, and (d) PSEG added guidance to the procedure that provides a more specific basis for assigning a risk ranking value for coating and piping material conditions.

Review of RCE (20459689/70109827) for Missed ASME Code, Section XI, Paragraph IWA-5244 Inspections

In response to NRC questions, PSEG notification 20459689 reported the failure to perform the ASME Code, Section XI, paragraph IWA-5244 required pressure tests on the buried AFW piping for Unit 1 and Unit 2. An RCE was performed to identify the causes of the failure to perform these tests. PSEG concluded that the root cause for this event was shortcomings in technical human performance practices that resulted in incomplete initial and subsequent ISI program plans. That coupled with a lack of questioning attitude by ISI inspectors resulted in the failure to perform the required ASME Code Section XI testing. Corrective actions for this issue included:

1. PSEG required a formal pressure test plan including hand-over-hand walk downs, boundary validation, and formal acceptance criteria for buried piping tests during each ten year interval update.

2. PSEG will complete the current ten year update to these requirements; specifically, a number of oversight actions were implemented to ensure the ISI program met current requests including a review of the implementation of other past relief requests.

3. PSEG verified that only approved ISI drawings are used for ISI program planning.

4. PSEG implemented additional training for ISI inspectors.

5. PSEG performed the IWA-5244 required pressure tests for Unit 1 AFW after replacement of the degraded Unit 1 buried piping in May 2010. For Unit 2, PSEG plans to inspect the buried AFW piping and perform the required IWA-5244 testing during the spring 2011 refueling outage. PSEG will also re-route the Unit 2 buried piping in the FTTA to run above ground. Going forward, PSEG will complete ASME Code IWA 5244 pressure testing at the specified frequency on remaining AFW system buried piping at both Unit 1 and 2.

The inspectors made the following observations with respect to the corrective action process, cause determination, corrective actions, extent of condition, and extent of cause:

1. During its extent of conditions review, PSEG identified a missed opportunity to identify and correct degradation on buried safety-related service water system piping. PSEG discovered that between 1988 and 2010 the Unit 1 and Unit 2 safety-related service water buried piping was not pressure tested in accordance with ASME Code, Section XI, paragraph IWA-5244. To address this deficiency going forward, PSEG requested relief from the NRC for the required pressure testing by letter dated October 12, 2010 (LR-N10-0361). The failure to comply with ASME Code requirements per 10 CFR 50.55a for service water constitutes a violation of minor significance not subject to enforcement action in accordance with NRC's Enforcement Policy. The issue was minor because, during that same period, PSEG performed other tests of service water piping as part of commitments made in response with the GL 89-13, "Service Water Integrity Program," that confirmed that piping's integrity.

2. The inspectors observed a weakness in the corrective action process with respect to extent of cause. The inspectors noted that corrective actions for the missed ISI tests were narrowly focused and that some actions should have applied to other departments. For example, PSEG did not create an action or look at a sampling of the other programs for changes that were not properly applied following NRC approval. Examples would include potential inadequate implementation of license amendment changes due to shortcomings in technical human performance practices

coupled with a lack of questioning attitude of other staff personnel. This extent of cause issue was documented by PSEG in notification 20499241.

3. The inspector observed a weakness in the corrective action process due to the use of an undefined term, “legacy issue.” The PSEG EQ:ACE and the RCE review indicated that some of the causes identified were “legacy issues” and indicated that no corrective actions were needed. PSEG staff acknowledged that there was no definition for a “legacy issue” and there was no intention to imply that these issues were exempt from needing corrective actions. The corrective actions assigned appear to be adequate to ensure the ISI program meets requirements. However, if PSEG staff continue to use the term “legacy issue,” then necessary corrective actions could be overlooked for issues that occurred historically. PSEG initiated notification 20498702 to address this weakness.

4OA3 Event Follow-up (71153 - 2 samples)

.1 (Closed) LER 05000272/2010-005-00, Automatic Reactor Trip Due to Actuation of the Generator Protection Relay

a. Inspection Scope

On October 15, 2010, at approximately 1112, the Salem Unit 1 reactor automatically tripped. The automatic reactor trip was caused by a turbine trip. The cause of the turbine trip was actuation of the loss of field relay that provides primary protection for loss of excitation for the main generator. The most likely cause for the actuation of the loss of field relay was a defective automatic digital regulator computer (WDR 2000). The WDR 2000 electronics degraded due to a lack of vendor support and parts availability.

Unit 1 was returned to service with the VR in manual control on October 18, 2010. The Unit 1 VR will be replaced with a nuclear industry proven design during the next scheduled refueling outage. The inspectors completed a review of this LER and identified a finding that was not a violation of regulatory requirements. This LER is closed.

b. Findings

Introduction: A self-revealing finding of very low safety significance was identified for the failure of PSEG to resolve a long standing issue with the reliability of the Unit 1 main generator VR. Because of this, a failure in the Unit 1 main generator VR resulted in an automatic reactor trip due to a turbine trip above 50 percent power.

Description: On October 15, 2010, Unit 1 was operating at 100 percent power when the load dispatcher requested PSEG to lower reactive power output by 50 MVAR. Upon depressing the lower MVAR push button, reactive power rapidly went negative to approximately -100 MVARs and immediately reversed to +270 MVARs and stabilized. Multiple main generator alarms were received in the main control room. As the control room operators implemented the alarm response procedure, a second voltage transient occurred without operator action. Multiple main generator alarms were again received in the main control room and the Unit 1 reactor automatically tripped due to a turbine trip above 50 percent power.

PSEG conducted a reactor trip analysis and determined that the turbine trip was the result of the actuation of the phase C loss of field relay in the main generator protection system. This actuation was caused by a failure in the primary WDR 2000 automatic control loop. PSEG also conducted a root cause investigation after the October 15, 2010, trip and determined the root cause of the Unit 1 main generator and reactor trip was that their long-term asset management process did not resolve the increased failure rate and lack of vendor and part support for the main generator VR.

The WDR 2000 has a primary and backup drawer for automatic voltage regulation. The Unit 1 startup was delayed after the spring 2007 refueling outage due to problems with the VR that required vendor onsite support. There were three separate issues with load, voltage, and VAR transients during the operating cycle in May 2007, June 2007, and September 2008 before the fall 2008 refueling outage. Additionally, in June 2007, the main generator VR vendor informed PSEG that when the supply of repair parts for the WDR 2000 was depleted the vendor would no longer support the WDR regulator.

In March 2009, the main generator experienced output transients in load, voltage, and VARS. PSEG conducted an ACE that identified the apparent cause as ineffective corrective action. To correct the apparent cause PSEG directed performing a failure investigation and repair on the primary WDR 2000 with the assistance of the vendor. However, actions assigned to track these activities were not specific and comprehensive enough and as a result did not eliminate failures of the primary and backup AVR drawers.

During the March 2010 Unit 1 refueling outage, the primary WDR 2000 drawer was removed and sent to the vendor for troubleshooting and repair. Although the vendor could not identify any failed component, the overall vendor conclusion was that the power system stabilizer board had an intermittent fault. PSEG started up the reactor after the refueling outage and synchronized to the grid with the backup WDR 2000 in service. PSEG did not complete repairs to the primary drawer, but reinstalled it and designated it as "emergency use only." In April 2010, the vendor officially announced that it would no longer troubleshoot or repair the WDR 2000 digital VR drawers.

In July 2010, there were three separate main generator load and VAR oscillations that occurred while the VR backup drawer was in service, and this led PSEG to put the primary VR drawer, that had been designated as "emergency use only," back in service. From that point the primary drawer operated for approximately 2.5 months until the main generator and reactor trip occurred on October 15, 2010. PSEG determined that the turbine trip was a result of a loss of field to the main generator as a result of a failure in the primary WDR 2000 automatic control loop. PSEG conducted a reactor startup and synchronized to the grid with the main generator VR in manual. PSEG entered this event into their CAP as notification 20481250. Corrective actions include the planned replacement of the VR with a nuclear industry proven design during the October 2011 refueling outage.

The inspectors determined that PSEG did not complete the corrective actions directed by the March 2009 ACE, and did not fully address the obsolescence and chronic problems of the WDR 2000 in accordance with step 11 of the Equipment ACE Guide of PSEG LS-AA-124-1003, "Apparent Cause Evaluation Manual," which specifically requires corrective actions for aging, obsolescence, and chronic problem issues.

Analysis: The failure to identify effective corrective actions in the March 2009 ACE for the main generator voltage regulator failures was a performance deficiency. Specifically, PSEG did not fully evaluate the cause or take effective corrective action in accordance with PSEG LS-AA-124-1003, "Apparent Cause Evaluation Manual," after the March 2009 main generator output transients and this did not prevent the October 15, 2010, Unit 1 reactor trip. The inspectors determined that the performance deficiency was more than minor because it is associated with the equipment performance attribute of the Initiating Events cornerstone and it adversely affected the cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical safety functions during shutdown as well as power operations. The finding was evaluated under IMC 0609, Attachment 4, "Phase 1 - Initial Screening and Characterization of Findings." The inspectors determined that the finding is of very low safety significance (Green) because it does not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions will not be available.

The inspectors determined that this finding has a cross-cutting aspect in the area of human performance, because PSEG affected long term plant safety by not minimizing long-standing equipment issues. Specifically, PSEG did not resolve a lack of vendor and part support for the Unit 1 main generator VR considering the increased failure rate of the VR since 2007. (H.2(a))

Enforcement: This finding does not involve enforcement action because no regulatory requirement violation was identified. Because this finding does not involve a violation and has very low safety significance, it is identified as a finding. **(FIN 05000272/2011002-02, Unit 1 Main Generator Voltage Regulator)**

.2 (Closed) LER 05000311/2010-003-00, Automatic Reactor Trip Due to Reactor Coolant Pump Bus Undervoltage

On October 17, 2010, at approximately 0512 hours, Salem Unit 2 automatically tripped due to bus undervoltage for the 21 through 24 reactor coolant pumps (RCPs). The non-safety related group buses that power the RCPs were being fed from the Unit 2 auxiliary power transformer (APT). The APT is directly powered from the Unit 2 main generator. The cause of the automatic reactor trip was an undervoltage condition on the non-safety related group buses that supply power to the RCPs. The undervoltage condition was the result of a loss of Unit 2 main generator excitation during the transfer of the voltage regulator from manual to automatic. Troubleshooting determined that loss of excitation was the result of a degraded 43A transfer relay that failed to transfer excitation control from the manual voltage regulator to the automatic voltage regulator. Corrective actions included replacement of the 43A transfer relay. The inspectors completed a review of this LER and did not identify a violation of regulatory requirements. This LER is closed.

4OA5 Other Activities

Institute of Nuclear Power Operations (INPO) Plant Assessment Report Review

The inspectors reviewed the final report for the INPO plant assessment of the Salem Generating Station, August 2010 evaluation, dated March 2011. No new safety issues were identified

4OA6 Meetings, Including Exit

The inspectors presented the inspection results to Mr. C. Fricker and other members of PSEG management at the conclusion of the inspection on April 5, 2011. The inspectors asked PSEG whether any materials examined during the inspection were proprietary. No proprietary information was identified.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee personnel:
C. Fricker, Site Vice President
E. Eilola, Plant Manager
R. DeSanctis, Maintenance Director
L. Rajkowski, Engineering Director
J. Garecht, Operations Director
R. Gary, Radiation Protection Manager
H. Berrick, Regulatory Assurance
E. Villar, Regulatory Assurance
T. Giles, ISI Program Manager

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Open/Closed		
05000311/2011002-01	NCV	Failure to Submit an LER for a Condition Prohibited by TS Associated with Containment Isolation (Section 4OA2.2)
05000272/2011002-02	FIN	Unit 1 Main Generator Voltage Regulator (Section 4OA3.1)
Closed		
05000272/2010-005-00	LER	Automatic Reactor Trip Due to Actuation of the Generator Protection Relay (Section 4OA3.1)
05000311/2010-003-00	LER	Automatic Reactor Trip Due to Reactor Coolant Pump Bus Undervoltage (Section 4OA3.2)

LIST OF DOCUMENTS REVIEWED

In addition to the documents identified in the body of this report, the inspectors reviewed the following documents and records:

Section 1R01: Adverse Weather Protection

Procedures
SC.OP-PT.ZZ-0002, Station Preparations for Seasonal Conditions, Revision 11

Section 1R04: Equipment Alignment

Procedures
ER-AA-2030, Conduct of Plant Engineering Manual, Revision 8
S1.OP-SO.RHR-0001(Q), Initiating RHR, Revision 29
S1.OP-SO.RHR-0002(Q), Terminating RHR, Revision 16

Drawings

205232	205342

Notifications

20310126	20376371	20379419	20406129	20409415	20494381
20451359	20452617	20458560	20458662	20472916	20474379
20486446	20487750	20491485	20492820	20494381	20495575
20502381					

Orders

60067810	60095085	60095933

Other Documents
SC.DE-BD.RHR-0001(Q), RHR Certification for Design Verification, Revision 0

Section 1R05: Fire Protection

Procedures
FRS-II-454, Salem Unit 1 (Unit 2) Pre-Fire Plan, Volume Control & Boric Acid Tanks Auxiliary Building Elevation: 122'
FRS-II-512, Salem Unit 1 (Unit 2) Pre-Fire Plan, Mechanical Piping Penetration Area Elevations: 78' & 100'
FRS-II-521, Salem Unit 1 (Unit 2) Pre-Fire Plan, Inner Piping Penetration Area & Chiller Rooms Elevation: 100'
FRS-II-711, Salem Unit 1 (Unit 2) Pre-Fire Plan, Fuel Handling Building Elevations: 84', 100' & 116'

Section 1R06: Flood Protection Measures

Procedures
S1.OP-AB.ZZ-0002(Q), Flooding, Revision 2

Drawings

205232	206963	605818

Notifications

20310126	20376371	204526217

Other Documents
ND.DE-PS.ZZ-0010(Q), Internal Hazards Program, Revision 1
S-1-ZZ-MDC-0484, Amount of Water Required to Flood to the Level in Gallons, Revision 0
S-C-A900-MEE-0158-0, Internal Flooding of Power Plant Buildings, Revision 0
S-C-ZZ-MDC-0572, Design Pressure Criteria for Salem Generating Station Barriers, Revision 8

S-C-ZZ-SDC-1203, Moderate Energy Break Analysis, Revision 3
SC.FP-SV.FBR-0026(Q), Flood and Fire Barrier Penetration Seal Inspection, Revision 4

Section 1R11: Licensed Operator Requalification Program

Procedures
2-EOP-LOSC-1, Loss of Secondary Coolant, Revision 23
2-EOP-SGTR-1, Steam Generator Tube Rupture, Revision 27
2-EOP-SGTR-3, Steam Generator Tube Rupture with LOCA – Subcooled Recovery, Revision 24
2-EOP-TRIP-1, Reactor Trip or Safety Injection, Revision 27
NF-AA-400, Fuel Reliability, Revision 5
OP-AA-101-111-1003, Use of Procedures, Revision 3
SC.OP-AB.ZZ-0004, Earthquake, Revision 0
S2.OP-AB.RC-0002, High Activity in Reactor Coolant System, Revision 8

Section 1R12: Maintenance Effectiveness

Procedures
SC.OP-PT.CA-0001, SBO Diesel Control Air Compressor Test, Revision 13

Drawings
604495, No. 2 Unit Yard Control Air – Station Blackout

Notifications

20382186	20452972	20500592	20500737	20485873	20487251
20456882	20456942	20461380	20497429	20494024	20495493
20496252	20448722	20448549	20490756		

Orders

30155494	30174779	30188675	30203337	60089127	60094167
70106660	70108962	70109144	70109572	70110453	70115234
70116982	70118531	80103010			

Other Documents
316472, Vendor Manual, Operator and Maintenance Manual D0825 Portable Compressor, Revision 3
PCM Template, Small Diesel Engine, 7/26/2004
Salem Maintenance Rule 2009 (a)(3) Periodic Assessment
S1 Service Water Pump Train Reliability (Cumulative) Chart, from 3/1/2008 to 3/1/2011
S1 Service Water Single Load Reliability (Cumulative) Chart, from 3/1/2008 to 3/1/2011
S1 SWIS Bay 3 Sump Reliability (Cumulative) Chart, from 3/1/2008 to 3/1/2011
System Health Report, Control Air, Quarter 4, 2010

Section 1R13: Maintenance Risk Assessments and Emergent Work Control

Other Documents
Salem Unit 1 Operator's Risk Report, Dated 1/11/2011, 2/22/2011, 3/29/2011
Salem Unit 2 Operator's Risk Report, Dated 1/20/2011, 2/7/2011

Section 1R15: Operability Evaluations

Procedures
S1.IC-CC.RC-0054, Reactor Coolant Wide Range Temperature (Hot Leg), Revision 17
S1.IC-CC.RC-0055, Reactor Coolant Wide Range Temperature (Cold Leg), Revision 17
S2.IC-CC.RM-0006, 2R5 Fuel Handling Building Area Radiation Monitor, Revision 10
S2.OP-ST.CS-0003, Inservice Testing Containment Spray Valves, Revision 7
S2.OP-ST.SSP-0009, Engineered Safety Features SSPS Slave Relays Test – Train "A," Revison 31
SC.RA-AP.ZZ-0051, Leakage Monitoring and Reduction Program, Revision 2

Drawings
205248
205335
205348
ELE-1: 500 KV→4 KV Overview, Revision 2, dated 9/1/2005

Notifications

20402949	20404287	20404287	20491607	20496285	20496387
20496388	20493119	20494082	20494513	20495611	20491607
20498212	20499930				

Orders

50136538	60094525	70094890	70102904	70115159	70117917
70119516	70118887	70120139	70120394	70119080	

Other Documents
315734, Salem Unit 2 Radiation Monitoring System Manual, Revision 16
901555, Radiation Monitoring System, Revision 2
OP-AA-108-115, Operability Determinations, Revision 3
SA-SURV-003, Risk Assessment of Missed Surveillance - 1B 28 VDC Battery, Revision 0
Prompt Investigation Report: 1B 28VDC Battery

Section 1R19: Post-Maintenance Testing

Procedures
S2.OP-ST.CS-0002, Inservice Testing – 22 Containment Spray Pump, Revision 21
S2.OP-ST.SW-0014, Inservice Testing Room Cooler Valves Modes 1-6, Revision 9
SC.OP-PT.CA-0001, SBO Diesel Control Air Compressor Test, Revision 13
SC.OP-ST.CH-0004, Chilled Water System - Chillers, Revision 11
SH.IC-GP.ZZ-0002, Disassembly, Inspection, Reassembly and Testing of Masoneilan Model 37/38 Air Operated Actuators, Revision 10
S1.OP-ST.SW-0014, Inservice Testing Room Cooler Valves Modes 1 - 6, Revision 5
S1.RA-ST.SW-0014, Inservice Testing Room Cooler Valves Modes 1 - 6 Acceptance Criteria, Revision 24

Notifications

20452972	20500592

Orders

30155494	30174779	30180804	30188675	30203337	50135528
60089127	60094167	60094439			

Other Documents
316472, Vendor Manual, Operator and Maintenance Manual D0825 Portable Compressor, Revision 3

Section 1R22: Surveillance Testing

Procedures
S2.OP-ST.CS-0002, Inservice Testing – 22 Containment Spray Pump, Revision 21
S1.OP-ST.RC-0008, Reactor Coolant System Water Inventory Balance, Revision 23
S2.OP-ST.DG-0001, 2A Diesel Generator Surveillance Test, Revision 46
S2.OP-ST.DG-0002, 2B Diesel Generator Surveillance Test, Revision 45
S2.OP-ST.DG-0012, 2A Diesel Generator Endurance Run, Revision 25`
S2.OP-ST.DG-0013, 2B Diesel Generator Endurance Run, Revision 25
S2.OP-ST.DG-0019, 2A Diesel Generator Hot Restart Test, Revision 12
S2.OP-ST.DG-0020, 2B Diesel Generator Hot Restart Test, Revision 12
S2.OP-ST.SJ-0001, Inservice Testing - 21 Safety Injection Pump, Revision 19
S2.OP-PT.AF-0003, 23 Auxiliary Feedwater Pump Periodic Run, Revision 1
S1.OP-ST.RHR-0001, Inservice Testing - 11 Residual Heat Removal Pump, Revision 18

Orders
50135528

Other Documents
OP-SH-111-101-1001, Salem 2 Narrative Log, dated 2/9/2011

Section 1EP2: Alert and Notification System (ANS) Evaluation
Procedures
EP-AA-121-1002, PSEG Alert Notification System (ANS) Program, Revision 0
EP-AA-121-1004, PSEG ANS Corrective Maintenance, Revision 0
EP-AA-121-1005, PSEG ANS Preventive Maintenance Program, Revision 1
EP-AA-121-1006, PSEG ANS Siren Monitoring, Troubleshooting, and Testing, Revision 0

Other Documents
Final REP-10 Design Review Report, PSEG Salem and Hope Creek
Contract No. 2008-PSEG-001, ANS Services, LLC, Alert Notification System Monitoring and Maintenance for PSEG Nuclear, LLC, dated 2/1/2008
Monthly Siren System Status Reports, January 2010 - February 2011

Section 1EP3: ERO Staffing & Augmentation System

Procedures
EP-AA-120-1007, Maintenance of Emergency Response Organization (ERO), Revision 2
EP-AA-120-1010, Emergency Preparedness Training Administration, Revision 0

Other Documents
PSEG Nuclear Emergency Plan, Revision 67

Emergency Preparedness Unannounced Drill Critique Report (H09-U1), 11-16-09
Emergency Preparedness Unannounced Drill Critique Report (S10-U1), 11-29-10
Monthly Pager Tests, dated 1/25/2010, 2/18/2010, 3/22/2010, 4/27/2010, 5/12/2010, 6/15/2010, 7/20/2010, 8/10/2010, 9/20/2010, 1/11/2010, 11/22/2010, and 12/14/2010

Section 1EP4: Emergency Action Level (EAL) and Emergency Plan Changes

Procedures
EP-AA-120-1001, 10 CFR 50.54(q) Change Evaluation, Revision 1
LS-AA-104, 50.59 Review Process, Revision 6

Screenings/Evaluations

2010-03	2010-05	2010-06	2010-07	2010-08	2010-09
2010-10	2010-11	2010-12	2010-13	2010-14	2010-15
2010-17	2010-22	2010-23	2010-24	2010-25	2010-26
2010-28	2010-29	2010-30	2010-31	2010-32	2010-33
2010-34	2010-35	2010-36	2010-37	2010-38	2010-39
2010-40	2010-41	2010-42	2010-43	2010-44	2010-45

Section 1EP5: Correction of Emergency Preparedness Weaknesses

Other Documents
Emergency Preparedness Training Drill Critique Reports: S09-01, S10-01, H10-02, S10-04, and S11-01
Emergency Preparedness Exercise Critique Report H09-03
Emergency Preparedness Unannounced Drill Critique Reports H09-U1 and S10-U1
Emergency Preparedness Focused Area Drill Critique Report H10-01
Emergency Preparedness Practice Exercise Critique Report S10-02
Emergency Preparedness Graded Exercise Critique Report S10-03
Emergency Preparedness Notifications, January 2010 - February 2011
Emergency Preparedness Audit Report, Audit NOSPA-HPC-10-02 (10 CFR 50.54 (t) Report)

Focused Self-Assessment Reports
SAP Order 70106832, NRC Inspection Preparedness, dated 3/10/2010
SAP Order 70105785, Salem 2010 Graded Exercise Offsite Readiness, dated 6/28/2010
SAP Order 70106113, Non-accredited Training Programs/EP, dated 5/7/2010
SAP Order 70100792, Regulatory Affairs Knowledge Transfer and Retention Determination, dated 9/29/2010
SAP Order 70111235, Emergency Preparedness Rulemaking Readiness, dated 9/29/2010
SAP Order 70117239, NRC Emergency Preparedness Program Inspection, dated 12/14/2010

Nuclear Oversight Performance Assessment Reports
NOSPA-HC-09-2C NOSPA-HC-09-3C NOSPA-HC-10-1C NOSPA-HC-10-2C
NOSPA-HC-10-3C

Section 2RS4: Occupational Dose Assessment

Other Documents
NVLAP 2011 Certificate of Accreditation for Landauer, Inc. (Glenwood, IL) #100518-0
Comanche Peak NPP Self-Assessment SA-2009-028, On-Site Assessment of Landauer

Personnel Dosimetry Performance Testing Conducted for NVLAP at Pacific Northwest National Laboratory for Landauer, Inc, dated 4/28/2008
NVLAP On-Site Assessment Report for Landauer, Inc, dated 5/25/2010-5/28/2010
FASTSCAN Whole Body Counter System Calibration, 2/20/2009 and 3/1/2010

Section 4OA1: Performance Indicator Verification

Procedures
EP-AA-125-1001, Emergency Preparedness Performance Indicator Guidance, Revision 0
EP-AA-125-1002, ERO Performance - Performance Indicators Guidance, Revision 2
EP-AA-125-1003, ERO Readiness - Performance Indicator Guidance, Revision 0

Other Documents
4Q/2010 Performance Indicators - Salem 1 and Salem 2, Reactor Coolant System Activity
4Q/2010 Performance Indicators - Salem 1 and Salem 2, Reactor Coolant System Leakage
4Q/2010 Performance Indicators - Salem 1 and Salem 2, Safety System Functional Failures (PWR)

Section 4OA2: Identification and Resolution of Problems

Procedures
S2.OP-ST.SW-0008, Inservice Testing Service Water Valves, Revision 14
LS-AA-125, Corrective Action Program (CAP) Procedure, Revision 13
LS-AA-120, Issue Identification and Screening Process, Revision 10
LS-AA-125-1002, Common Cause Analysis Manual, Revision 6
LS-AA-125-1003, Apparent Cause Evaluation Manual, Revision 10
WC-AA-111, Predefine Process, Revision 6

Notifications (*NRC Identified)

20465141	20495169	20485301	20462034	20459689	20457262
20461283	20498702	20458568	20460078	20456999	20499241*
20499463*	20499161*				

Orders

70110650	30085750

Drawings
205236 - SIMP - 0, Salem Nuclear Generating Station, No. 1 Unit, AFW System Simplified P&ID, dated 6/16/1999
205236 A 8761-54, Salem Nuclear Generating Station, No. 1 Unit, AFW System Simplified P&ID, dated 6/6/1984
207483, Unit 1 AFW System, YARD Piping

Technical Evaluations and Orders

70110267	70108698	70108698	70108698
70108698	80101381	70109108	

Cause Evaluations
Root Cause Evaluation, Salem ASME Code, Section XI Inservice Inspection (ISI) Implementation, Order 70109827

Apparent Cause Evaluation, Auxiliary Feedwater (AFW)/Control Air (CA) Buried Piping Degradation, CR20458568/70109108

Technical Standards
NC.NE-TS.ZZ-6605, PSEG Nuclear LLC, Technical Standard, Coating System and Color Schemes, dated 4/3/2006

Specifications
S-C-MPOO-MGS-0001, Piping Schedule SPS28
S-C-MPOO-MGS-0001, Piping Schedule SPS54

Other Documents
Maintenance Plans: S1203496, S2203429, and S2203430
OpEval 10-005: 20460078 (70109482 Operation 0010)
NIS2A Form, S1-AF Piping (Common), Plan 60089561, dated 9/21/2010
NIS2A Form, S1-AF Piping, DCP 80101382, dated 10/30/2010
PSEG Letter, LR-N10-0361, Subject: Request for Relief from ASME Code Pressure Test for Service Water Supply Buried Piping, dated 10/12/2010
PSEG Letter, LR-N10-0372, Subject: Response to NRC Request for Additional Information, dates October 12, 2010, related to the Buried Piping Inspection Program associated with the Salem Nuclear Generating Station, Units 1 and 2 License Renewal Application

Section 4OA3: Event Follow-up

Procedures
S2.MD-DC.GEN-0003, Calibration of Unit 2 Main Generator Voltage Regulator, Revision 4
S2.MD-DC.GEN-0004, Online Replacement of Automatic Voltage Regulator Card, Revision 0

Notifications

20455515	20460491	20465015	20469362	20469644	20471233
20478349	20478465	20481092	20481093	20481094	20481190
20481191	20481250	20481252	20481254	20481310	20481313
20481379	20481381	20481384	20481430	20481557	20481560
20481642	20481904	20481913	20440208	20440267	20440278
20476611	20485896	20497369	20463639		

Orders

60092828	80102604	30124500	30144783	70112033	70069318
70110650					

Other Documents
OTDM S-10-016, Salem Unit 1 Main Generator Voltage Regulator, Revision 6
OTDM S-10-017, Salem Unit 2 Main Generator Voltage Regulator, Revision 6
Unit 1 Adverse Condition Monitoring and Contingency Plan, dated 10/18/2010
OP-AA-106-101-1006, Attachment A, Issue Resolution Documentation Form, Revision 6
OP-SA-108-114-1001, Attachment 1 (Trip Report), Attachment 2 (Post Reactor Trip/ECCS Actuation Review), Form 1 (Pre-Trip Conditions), Form 2 (Sequence of Events Checklist), Form 3 (Post-Trip Conditions), and Form 4 (Post-Trip Data Collection), Revision 1 (Identifying Numbers 20481381 and 20481250)
OP-AA-108-108, Unit Restart Review, Revision 10

OP-AA-108-111, Attachment 1, Adverse Condition Monitoring and Contingency Plan, Salem Unit 1 Voltage Regulator Performance
Prompt Investigation Report, Salem Unit 2 Reactor Trip upon Swapping Voltage Reg. to Auto
Prompt Investigation Report, Notification 20481250, Salem Unit 1 Reactor Trip
Complex Troubleshooting (Troubleshooting Data Sheet), IR No: 20481381, Salem Unit 2 Turbine/Reactor Trip indicated by 4 kV Group Bus UV after changing the Voltage Regulator from manual to automatic
Complex Troubleshooting (Troubleshooting Data Sheet), IR No: 20481250, Salem Unit 1 Turbine/Reactor Trip indicated by generator diff and loss of field
Root Cause Evaluation, Unit 2 Tripped When Placing the Main Generator Voltage Regulator to Automatic Operation (Order 70115228)
MA-AA-716-210-1001, GE - Main Exciter, dated 1/19/2011
MA-AA-716-210-1001, Westinghouse - Exciter, dated 1/19/2011
MA-AA-716-210-1001, Circuit Cards - GE Main Generator and Main Turbine Systems, dated 1/19/2011
MA-AA-716-210-1001, Relays - Control/Timing, dated 2/25/2011
MA-AA-716-210-1001, GE - Main Exciter, dated 2/24/2011
MA-AA-716-210-1001, Westinghouse - Exciter, dated 2/24/2011
OP-SH-11-101-1001, Salem 2 Narrative Log, dated 10/17/2010

LIST OF ACRONYMS

ACE	Apparent Cause Evaluation
ADAMS	Agency-wide Documents Access and Management System
AFW	Auxiliary Feedwater
ALARA	As Low As Reasonably Achievable
ANS	Alert and Notification System
APT	Auxiliary Power Transformer
ASME	American Society of Mechanical Engineers
CAP	Corrective Action Program
CCHX	Component Cooling Heat Exchanger
CFR	Code of Federal Regulation
CR	Condition Report
CS	Containment Spray
EAL	Emergency Action Level
ED	Electronic Dosimeter
EDG	Emergency Diesel Generator
EP	Emergency Preparedness
ERO	Emergency Response Organization
FEMA	Federal Emergency Management Agency
FTTA	Fuel Transfer Tube Area
HX	Heat Exchanger
IMC	Inspection Manual Chapter
ISI	Inservice Inspection
LER	Licensee Event Report
MDA	Minimum Detectable Activity
MVAR	Mega-volts Amperes Reactive
NCV	Non-cited Violation
NEI	Nuclear Energy Institute
NRC	Nuclear Regulatory Commission
NVLAP	National Voluntary Laboratory Accreditation Program
OOS	Out-of-Service
PARS	Publicly Available Records
PI	Performance Indicator
PMT	Post-Maintenance Test
PSEG	Public Service Enterprise Group Nuclear LLC
RCA	Radiological Controlled Area
RCE	Root Cause Evaluation
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RHR	Residual Heat Removal
ROP	Reactor Oversight Process
SBO	Station Blackout
SDP	Significance Determination Process
SG	Steam Generator
SW	Service Water
TS	Technical Specifications
URI	Unresolved Item
VR	Voltage Regulator
WO	Work Order