May 13, 2003

Mr. Roy A. Anderson
Chief Nuclear Officer and President
PSEG LLC - N09
P. O. Box 236
Hancocks Bridge, NJ 08038

SUBJECT: SALEM NUCLEAR GENERATING STATION - NRC INTEGRATED INSPECTION REPORT 50-272/03-03, 50-311/03-03

Dear Mr. Anderson:

On March 29, 2003, the US Nuclear Regulatory Commission (NRC) completed an inspection at your Salem Units 1 and 2. The enclosed integrated inspection report documents the inspection findings, which were discussed on April 4, 2003, with Mr. Tim O'Connor 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 two NRC-identified findings and two self-revealing findings of very low safety significance (Green); three were determined to involve violations of NRC requirements. However, because of the very low safety significance and because they are entered into your corrective action program, the NRC is treating these three findings as non-cited violations (NCVs) consistent with Section VI.A of the NRC Enforcement Policy. Additionally, a licensee-identified violation which was determined to be of very low safety significance is listed in this report. 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; and the NRC Resident Inspector at the Salem Nuclear Generating Station.

Since the terrorist attacks on September 11, 2001, the NRC has issued five Orders (dated February 25, 2002, January 7, 2003 and three dated April 29, 2003) and several threat advisories to licensees of commercial power reactors to strengthen licensee capabilities, improve security force readiness, and enhance access authorization. The NRC also issued Temporary Instruction (TI) 2515/148 on August 28, 2002, that provided guidance to inspectors to audit and inspect licensee implementation of the interim compensatory measures (ICMs) required by the Order dated February 25, 2002. Phase 1 of TI 2515/148 was completed at all commercial nuclear power plants during calendar year (CY) 2002, and the remaining inspections are scheduled for completion in CY 2003. Additionally, table-top security drills were conducted at several licensee facilities to evaluate the impact of expanded adversary characteristics and the ICMs on licensee protection and mitigative strategies. Information gained and discrepancies identified during the audits and drills were reviewed and dispositioned by the Office of Nuclear Security and Incident Response. For CY 2003, the NRC will continue to monitor overall safeguards and security controls, conduct inspections, and resume force-on-force exercises at selected power plants. Should threat conditions change, the NRC may issue additional Orders, advisories, and temporary instructions to ensure adequate safety is being maintained at all commercial power reactors.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosure 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,

/RA/

Glenn W. Meyer, Chief
Projects Branch 3
Division of Reactor Projects

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

Enclosure: Inspection Report 50-272/03-03, 50-311/03-03
w/Attachment: Supplemental 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:	50-272/2003-03, 50-311/2003-03
Licensee:	PSEG LLC
Facility:	Salem Nuclear Generating Station, Units 1 & 2
Location:	P.O. Box 236 Hancocks Bridge, NJ 08038
Dates:	December 30, 2002 - March 29, 2003
Inspectors:	J. Daniel Orr, Senior Resident Inspector Raymond K. Lorson, Senior Resident Inspector Fred L. Bower, Resident Inspector G. Scott Barber, Senior Project Engineer Joseph T. Furia, Senior Health Physicist F. Jeff Laughlin, Operations Engineer Keith A. Young, Reactor Inspector Robert M. Berryman, Reactor Inspector Daniel L. Schroeder, Reactor Inspector Gregory C. Smith, Senior Physical Security Inspector Jason C. Jang, Senior Health Physicist David P. Beaulieu, Senior Resident Inspector, Calvert Cliffs
Approved By:	Glenn W. Meyer, Chief, Projects Branch 3 Division of Reactor Projects

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SUMMARY OF FINDINGS

IR 05000272/03-03, IR 05000311/03-03; 12/30/02 - 3/29/03; Public Service Electric Gas Nuclear LLC, Salem Units 1 and 2; Adverse Weather Protection, Equipment Alignment, Non-routine Plant Evolutions, Post Maintenance Testing.

The report covered a 13-week period of inspection by resident inspectors, and inspections by a regional radiation specialist, a regional security specialist, and a regional projects inspector. Three Green non-cited violations (NCVs), one Green finding, and one unresolved item (URI) with safety significance to be determined were identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609, “Significance Determination Process” (SDP). 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 3, dated July 2000.

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Initiating Events

- Green. A self-revealing finding occurred when Salem Units 1 and 2 experienced a control air transient. Equipment anomalies during the transient revealed a valve configuration problem, an incomplete control air preventive maintenance item, and inadequate corrective action for a significant air leak.

  This finding was not a violation of NRC requirements, in that the performance deficiencies occurred on non-safety related systems. The finding had an actual impact on plant stability and operator actions were necessary to reseat a reactor coolant system letdown line relief valve. This finding screened to Green in phase 1 of the SDP, because mitigation equipment was not affected by the control air transient. (Section 1R14)

Cornerstone: Mitigating Systems

- Green. The inspectors identified that PSEG did not initiate corrective action to ensure that the emergency diesel generators (EDGs) would remain unaffected by apparent roof leaks.

  This NCV of 10 Code of Federal Regulations (CFR) 50, Appendix B, Criterion XVI, “Corrective Action,” is greater than minor, because it affected the mitigating systems cornerstone of equipment reliability and unavailability. The 1C EDG required corrective action to dry wetted safety-related electrical terminals prior to its operation. This finding was of very low significance, because the 1C EDG condition existed for less than the TS allowed outage time. (Section 1R01)

- Green. A self-revealing finding was identified when the 1B emergency diesel generator (EDG) tripped during post-maintenance testing (PMT). The PMT was for separate test reasons and fortuitously revealed the EDG deficiency. The EDG deficiency involved a known electrical connector problem and inadequate interim corrective actions.

This NCV of 10 CFR 50, Appendix B, Criterion XVI, “Corrective Action,” is greater than minor, because it affected the mitigating systems cornerstone of equipment reliability. This finding was of very low significance, because the inadequate interim corrective actions did not cause any EDG to be inoperable for greater than the TS allowed outage time. (Section 1R19.1)

- Green. The inspectors identified that temporary modifications to the 22 auxiliary feedwater (AFW) pump and the 13 AFW pump skids were not properly evaluated.

  This NCV of 10 CFR 50, Appendix B, Criterion III, “Design Control” was greater than minor, because it affected the mitigating system cornerstone and the reliability of two AFW pumps. This finding was determined to be of very low safety significance, because pump shaft leakoff conditions were such that the unauthorized modifications had not impacted pump operation. (Section 1R04.1)

B. Licensee-Identified Violations

A violation of very low safety significance, which was identified by PSEG has been reviewed by the inspector. Corrective actions, taken or planned by PSEG have been entered into PSEG’s corrective action program. The violation and corrective action tracking number are listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status

Unit 1 began the period at full power. Salem Unit 1 significantly reduced power on January 21, March 3, and March 24, 2003, for river grass conditions. Power was returned to 100% in each instance as the river grass conditions subsided and after the circulating water (CW) system repairs were completed. The details of the January 21 power reduction are described in Section 1R14.2. On February 22 plant operators reduced power to 70% reactor power for switchyard maintenance activities. Power was restored to 100% on February 25.

Unit 2 began the period at 100%. Operators initiated a manual reactor trip on March 29, in response to severe river grass conditions and CW system repairs. The details of the March 29 reactor trip are described in Section 1R14.4. Salem Unit 2 was returned to full power operation on April 2.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection

a. Inspection Scope

The inspectors reviewed PSEG's response to adverse weather conditions during a snow blizzard on February 16 and 17, 2003. The review included control room logs, corrective action notifications and plant walkdowns.

b. Findings

Introduction. The inspectors identified that PSEG did not initiate corrective action to ensure that the EDGs would remain unaffected by existing roof leaks. This finding was determined to be of very low risk significance (Green), because the condition only affected the 1C EDG and existed for less than the allowed out of service time.

Description. On February 16, 2003, the 2A EDG room was inadvertently filled with carbon dioxide from its automatic fire suppression system. Operators and fire protection technicians quickly determined that no fire had caused the actuation. The 2A EDG room was ventilated to habitable conditions within three hours and no other vital plant areas were affected by the carbon dioxide discharge. The 2A EDG remained operable for the duration.

PSEG discovered that a thermal fire protection detector had become wetted by snow entering through ventilation penetrations on the top of the EDG rooms. PSEG entered this problem into its corrective action program as notification 20132342.

On February 20, 2003, the inspectors were present in the 1C EDG room to observe preparations for and the conduct of its monthly surveillance test. The inspectors observed that water was puddling on top of an electrical terminal panel mounted to the 1C EDG generator. Operators present in the room also observed the condition, stopped any further preparations to start the 1C EDG and initiated a request to electrical maintenance. Several terminal connections had become wet through conduit penetrations. The electricians dried the terminal connections. The source of the water was snow melt through roof and ventilation system leaks. The inspector walked down all other Salem Unit 1 and Unit 2 EDG rooms and discovered that 4 of 6 EDG rooms had similar leaks. Only the 1C EDG room leaked onto safety-related electrical equipment.

On February 21, 2003, the inspectors discussed the EDG roof leak conditions with the operations manager. A notification had not yet been initiated for the impact on the 1C EDG. On February 22, 2003, operators initiated a notification for the 1C EDG roof leaks, 20132895.

On March 1, 2003, the inspectors walked down several vital areas of the plant during a rain storm. The inspectors identified other roof leaks in the EDG rooms. In particular the inspectors identified water impinging on all three Salem Unit 1 EDG service water flow control valves, 11, 12, and 13SW39. There was evidence that the leaks had existed over time, because the SW39 valve air operators were stained by the roof leaks. The inspectors were confident the roof leaks were not affecting the controls of the SW39 valves. However, the inspectors believed the roof leaks should have been corrected to assure continued reliable operations of the EDGs.

<u>Analysis</u>. The deficiency associated with this problem is inadequate problem identification. Four days after a blizzard made apparent EDG roof leaks and caused an inadvertent CO2 actuation, another EDG was impacted. The inspectors could also identify that roof leaks had often wetted some EDG service water cooling valves by the presence of stains. Prior to this finding, these problems were not identified in the corrective action program for resolution. This finding affected the equipment performance attribute of the availability/reliability objective of the mitigating system cornerstone. The finding was more than minor, because corrective action was necessary to dry the 1C EDG electrical terminal panel prior to its operation. This activity also extended its unavailability. The finding screened to green in Phase 1 of the SDP. The performance deficiency existed with the 1C EDG because PSEG did not remain alert to further water intrusion after the 2A EDG CO2 actuation revealed maintenance problems with the EDG roofs. The finding screened to green in Phase 1 of the SDP, because the condition existed for less than the TS allowed outage time.

<u>Enforcement</u>. 10 CFR 50, Appendix B, Criterion XVI, “Corrective Action,” requires that conditions adverse to quality, such as defective equipment, are promptly identified and corrected. Contrary to the above, PSEG failed to identify roof leaks prior to impacting an electrical terminal panel on the 1C EDG. Roof leaks had affected the 2A EDG room by inadvertently actuating CO2 four days prior. The violations were identified on February 20, and March 1, 2003. Because the failure to promptly identify and correct an adverse condition in the EDG rooms was determined to be of very low significance and has been entered into the corrective action program (notification 20132895), this violation is being treated as a non-cited violation consistent with Section VI.A of the NRC Enforcement Policy: NCV 50-272/03-03-01, Failure to Identify EDG Room Roof Leaks.

1R02 Evaluation of Changes, Tests, or Experiments

a. Inspection Scope

The inspectors reviewed samples of safety evaluations for the initiating events, barrier integrity and mitigating systems cornerstones to verify that changes and tests were reviewed and documented in accordance with 10 CFR 50.59 and when required, prior NRC approval was obtained prior to implementation. The samples included safety evaluations for design change package (DCP) changes. The inspectors assessed the adequacy of the safety evaluations through interviews with the cognizant plant staff and review of supporting information, such as calculations, engineering analyses, design change documentation, the Updated Final Safety Analysis Report (UFSAR), technical specifications (TSs) and plant drawings. In addition, the inspectors reviewed the administrative procedures that control the screening, preparation, and issuance of the safety evaluations to ensure that the procedures adequately implemented the requirements of 10 CFR 50.59, "Changes, Tests, and Experiments."

The inspectors also reviewed a sample of changes that PSEG had evaluated (using a screening process) and determined to be outside of the scope of 10 CFR 50.59, therefore not requiring a full safety evaluation. The inspectors performed this review to assess if PSEG conclusions with respect to 10 CFR 50.59 applicability were appropriate. The sample of issues that were screened out included design changes and set point changes.

The inspectors also reviewed issues that had been entered into the corrective action program to determine if PSEG had been effective in identifying problems associated with the 10 CFR 50.59 safety evaluation process. A sample of these issues was selected for further review during which the inspectors assessed the adequacy of the corrective actions which had been implemented for the selected issues.

The safety evaluations and screens were selected based on the safety significance of the affected structures, systems and components (SSC). A listing of the safety evaluations, safety evaluation screens and other documents reviewed is provided in the attachment.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment

.1 Unreviewed AFW Pump Skid Modification

a. Inspection Scope

The inspectors performed a partial system walkdown on March 12 and 13, 2003, during planned maintenance activities for the 22 AFW (AFW) pump train. The inspectors walked down redundant portions of the AFW system and observed that the ongoing maintenance activities did not extend beyond the 22 AFW pump train. The inspectors referenced Salem operating procedure “AFW System Operation,” S2.OP-SO.AF-0001(Q).

b. Findings

Introduction. The inspectors identified that a temporary modification to the 22 AFW pump was not properly evaluated. The temporary modification included tygon hoses attached to all four drain ports on the inboard and outboard pump gland leakoff basins. This finding was determined to be of very low risk significance (Green), because an actual loss of safety function for the 22 AFW pump did not occur.

Description. On February 12, 2003, the inspectors identified tygon hoses attached to all four drain ports on the inboard and outboard pump gland leakoff basins of the 22 AFW pump. The inspectors’ concern was a potential to clog the tygon hoses; the tygon hoses were added only for housekeeping appearances. Clogged tygon hoses would subsequently flood the gland leakoff basin and allow water to penetrate the pump bearing oil seals. The tygon hoses appeared to have been in place for at least several months. The inspectors discussed the tygon hose modification with the main control room supervisors. On February 12, 2003, equipment operators removed the unauthorized modification to the 22 AFW pump.

The inspectors noticed packing leakoff at both ends of the pump shaft. The inspectors estimated the packing leakoff at about one gallon per minute at each end. Packing leakoffs of that magnitude would have flooded the gland leakoff basin within minutes after a tygon hose clogged. The inspectors believed that the tygon hoses attached to route the leakoff directly to a floor drain opening presented a greater potential for clogging compared to the ports alone. The unmodified gland leakoff basin ports would allow water to spill to the equipment base and presented a small opportunity for clogging.

On February 13 during subsequent inspector walkdowns on the Salem Units 1 and 2 AFW systems, the inspectors identified a similar configuration issue with the 13 AFW pump. The 13 AFW pump gland leakoff basins were not identical, but of similar design. The 13 AFW pump gland basins included a threaded bushing at the bottom and another higher elevation overflow port, but below any penetration area to the bearing oil seal. The 13 AFW pump gland basin had been modified with pipe plugs reducing the drain capacity to only one port. The inspectors noticed that the oil seals were not submerged.

Analysis. The deficiency associated with this problem is design control, but it also has an element of problem resolution. PSEG was not thorough in reviewing extent of condition for the specific issue. The inspectors further identified that the 13 AFW pump skid was unnecessarily and inappropriately modified. This finding affected the equipment performance attribute of the reliability objective of the mitigating system cornerstone and the 22 and 13 AFW pumps. This finding is more than minor, because the tygon hoses and pipe plugs reduced the drain capabilities of the gland leakoff basins. A flooded leakoff basin would have contaminated the pump bearing oil. The finding screened to green in Phase 1 of the SDP, because the condition did not cause an actual loss of safety function for any AFW pumps.

Enforcement. 10 CFR 50, Appendix B, Criterion III, "Design Control," requires that measures shall be established for the selection and review of materials and processes that are essential to the safety-related functions of structures, systems, and components. Contrary to the above, PSEG failed to review the addition of drain hoses and pipe plugs to the 22 AFW and 13 AFW pumps gland leakoff basins. The violations were identified on February 12, 2003, and existed for an unknown period of time, but probably greater than several months. Because the failure to assess the impact on AFW pump performance was determined to be of very low significance and has been entered into the corrective action program (notification 20135512), this violation is being treated as a non-cited violation consistent with Section VI.A of the NRC Enforcement Policy: NCV 50-272 and 311/03-03-02, Failure to Properly Evaluate AFW Pump Skid Modifications.

.2 Other Partial System Walkdowns

a. Inspection Scope

The inspectors performed partial system walkdowns on the 12 charging pump on March 3, 2003, and the 1A and 1C emergency diesel generators on March 13. Both partial system walkdowns were performed while planned maintenance occurred on the redundant train. The inspectors verified by walkdowns in the Unit 1 auxiliary building that the redundant trains were operating or aligned in accordance with Salem operating procedures S1.OP-SO-CVC-0002(Q), "Charging Pump Operation" and S1.OP-SO.DG-0001 and 0003(Q), "1A and 1C Diesel Generator Operation."

b. Findings

No findings of significance were identified.

1R05 Fire Protection

a. Inspection Scope

On March 28, 2003, the inspectors walked down all portions of the Salem service water intake structure. The inspectors assessed each area for control of transient combustibles and ignition sources, fire detection and suppression capabilities, and fire barriers. The inspectors referenced Salem fire protection procedure, NC.NA-AP-0025, "Operational Fire Protection Program," and engineering document, DE.PS.ZZ-0001-A2-FHA, "Salem Fire Protection Report - Fire Hazards Analysis," to ascertain PSEG's established fire protection requirements.

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures

a. Inspection Scope

The inspectors reviewed PSEG’s corrective actions to identify and review preventive maintenance practices for safety-related cable vaults susceptible ground water intrusion. The inspectors observed the as-found condition for a vault containing safety-related cables to the Salem Units 1 and 2 service water intake structure. The vault was observed on March 11, 2003, and after significant rain fall. The corrective action notifications included 20127365 and 20105022 and were described in NRC Inspection Report 50-272/02-09, 50-311/02-09, Section 1R06 (URI 50-272 & 50-311/02-09-01).

b. Findings

No findings of significance were identified.

The inspectors observed the only remaining safety-related vault susceptible to ground water intrusion and noted the vault to be dry. There was no evidence of previous flooding. The vaults contained a passive drain system and observed it to be clear of debris. URI 50-272 & 50-311/02-09-01 is closed.

1R11 Licensed Operator Requalification

.1 Biennial Review

a. Inspection Scope

The inspectors reviewed PSEG requalification exam results for the biennial testing cycle. The inspection assessed whether pass rates were consistent with the guidance of NUREG-1021, Revision 8, “Operator Licensing Examination Standards for Power Reactors” and NRC Manual Chapter 0609, Appendix I, “Operator Requalification Human Performance SDP."

The inspectors verified that:

- Crew pass rate was greater than 80%. (Pass rate was 100%)
- Individual pass rate on the dynamic simulator test was greater than or equal to 80%. (Pass rate was 100%)
- Individual pass rate on the comprehensive written exam was greater than 80%. (Pass rate was 100%)
- Individual pass rate on the walk-through (JPMs) was greater than 80%. (Pass rate was 100%)

- More than 75% of the individuals passed all portions of the exam. (100% of the individuals passed all portions of the exam)

b. Findings

No findings of significance were identified.

.2 Quarterly Simulator Observation

a. Inspection Scope

On March 12, 2003, the inspectors observed a licensed operator simulator training scenario to assess the operators' performance and also the evaluators' and participants' critiques. The scenario was considered an as-found evaluation of the operators' performance. It was conducted first in the training schedule after several weeks of off-training activities. The scenario involved a nuclear instrument failure, a main condenser tube failure, a spurious pressurizer spray valve failure, and an anomaly with AFW after the operators initiated a manual reactor trip. The inspectors verified that the operators' actions were consistent with the appropriate operating, alarm response, abnormal and emergency procedures.

b. Findings

No findings of significance were identified.

1R12 Maintenance Rule (MR) Implementation

a. Inspection Scope

The inspectors reviewed recent operating problems, notifications, system health reports, and MR performance criteria to determine whether PSEG had effectively monitored the performance of the Unit 1 and Unit 2 service water systems. The inspectors reviewed PSEG's MR disposition for a service water pump failure on April 28, 2002. The inspectors also reviewed PSEG's intended corrective actions (notification 20098392) for the pump failure.

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessments and Emergent Work Evaluation

a. Inspection Scope

The inspectors reviewed PSEG's planning and risk assessments for the following risk significant activities:

- Emergent 11 residual heat removal (RHR) heat exchanger inoperability resulting from boric acid corrosion and degraded studs on January 8 (Also, see Section 1R15 Operability Evaluations for a more detailed description as it relates to the technical issues.)
- Total station air compressor (SAC) outage during the week of February 19
- 13 AFW pump maintenance during the week of February 27
- 11 Charging pump maintenance on March 3
- 22 AFW pump maintenance on March 13
- 2C EDG planned maintenance on March 19

The inspectors reviewed the risk assessment of these planned maintenance activities with respect to 10 CFR 50.65(a)(4). The inspectors also walked down the protected equipment and maintenance locations to verify that risk was managed in accordance with PSEG's risk evaluation forms.

b. Findings

No findings of significance were identified

1R14 Personnel Performance During Non-routine Plant Evolutions

.1 Loss of the 2B Vital Bus

a. Inspection Scope

The inspectors reviewed PSEG's response to an unexpected loss of the 2B vital bus on January 15, 2003. The event occurred as the result of vibration caused by the discharging of 2B EDG output breaker springs during removal from the 2B bus. The inspectors observed plant process parameters and the operators' response to this event from the control room and reviewed operations procedure, S2.OP-AB.4KV-0002(Q), "Loss of 2B 4KV Vital Bus" to assess whether the response was appropriate and in accordance with TS and procedural requirements. Additionally, the inspectors reviewed the transient assessment response plan (TARP) report and the planned and completed corrective actions to determine whether the operator actions were adequate.

b. Findings

No findings of significance were identified.

.2 Power Reduction Due to a Circulating Water (CW) System Problem

a. Inspection Scope

The inspectors reviewed PSEG's response to an unexpected loss of the 13A CW traveling screen while the 13B CW traveling screen was removed from service for planned maintenance. The loss of the 13A CW traveling screen was caused by the failure of the shear pin after about one week of operation. The inspectors reviewed plant parameters, interviewed operators and reviewed the TARP report to determine whether PSEG responded appropriately to this event.

b. Findings

No findings of significance were identified.

.3 Salem Units 1 and 2 Control Air Transient

a. Inspection Scope

On February 25, 2003, during evolutions to support a total SAC outage, both Salem units experienced lowering control air header pressures. Both units' emergency air compressors auto-started as designed to support the control air systems. Salem Unit 1 was further impacted as a result of the control air transient and a chemical volume control system relief valve lifted. The inspectors interviewed control room operators involved with the control air transient, reviewed emergency classification guidelines, and assessed PSEG's investigation in the matter.

b. Findings

Introduction. Configuration control errors on the station air system and previously identified station air system leaks challenged the backup control air system response. Further equipment anomalies from inadequate preventive maintenance ultimately caused an unexpected reactor coolant system release to the pressurizer relief tank (PRT). This finding was determined to be of very low risk significance (Green), because the reactor coolant system leakage to the PRT was in compliance with TS actions.

Description. Both Salem units are supported by a single station air system. The station air system with three air compressors is further divided into service air and control air portions. The control air system supports safety and non-safety related pneumatically operated instruments and valves. Control air in the auxiliary building is further supported by standby emergency control air compressors (ECACs). The standby ECACs will start on a loss of all three air compressors or a low control air header pressure. The control air system is not needed to prevent or mitigate the consequences of a postulated accident. The service air system supports miscellaneous plant services such as air drops for pneumatic tools.

PSEG intended to secure all three station air compressors (SACs) to facilitate repairs to a common control switch and to replace several SAC service water cooling isolation valves. Five temporary air compressors installed through maintenance header connections were used to maintain the service air and control air headers. The ECACs automatic start on loss of all SACs was disabled to maintain the ECACs in a standby condition.

On February 25 control room operators intended to secure the temporary air compressor operation and support the station air system with the No. 2 SAC. The temporary air compressors proved to be unreliable during trial operation and the original maintenance plans were being abandoned. The No. 2 SAC had not been operated for several weeks but was believed ready for operation.

The No. 2 SAC operated for 26 minutes and then tripped on high oil temperature. Both Unit 1 and Unit 2 ECACs started on low control air header pressures. After the trip of No. 2 SAC, a Unit 1 PRT high pressure alarm was received in the main control room. Operators discovered that a chemical volume and control system letdown isolation valve (1CV7) had closed. The 1CV7 air operated valve isolated the normal reactor coolant system letdown flow path and subjected a 600 psig relief valve (1CV6) to full reactor coolant system pressure, 2235 psig. 1CV6 relieved to the PRT at about 75 gpm for about eight minutes causing the PRT high pressure alarm. Operators reseated 1CV6 by closing the upstream letdown line isolation valves.

PSEG initiated a TARP on February 25 to investigate the control air transient and review the operator and plant responses. The TARP team and other investigations discovered:

1) Existing significant air leaks on the station air system challenged the ability of the ECACs to recover air header pressures on a loss of all station air compressors. For instance, a single leak on a station air line to the service water intake structure accounted for 20% consumption and was discovered on August 28, 2001. The air line repair was canceled with no further evaluation.

2) The No. 2 SAC tripped because a lube oil temperature control valve was manually jacked closed. The configuration control error likely occurred on January 5, 2003, when the No. 2 SAC was returned to service after maintenance activities.

3) The air operated valve, 1CV7, isolating letdown in an abnormal configuration occurred because a redundant air panel failed to swap air supply to the less affected control air header. PSEG discovered that preventive maintenance for the redundant air panel had been incomplete for several years. An oversight in scoping the preventive maintenance for redundant air supply panels neglected the portion of the redundant air panel that could have maintained sufficient air supply to 1CV7.

4) The control room operators and equipment operators adequately responded to the control air transient. PSEG further concluded that the control room operators identified in a reasonable amount of time the lifting letdown relief valve and increasing PRT level. The control operators were prompt to reseat 1CV6 once it had been identified to be open.

The inspectors concluded that PSEG thoroughly investigated the loss of station air header pressure.

<u>Analysis</u>. The performance deficiencies associated with this event included an inadequate resolution of a significant station air system leak, incomplete preventive

maintenance on a control air system component, and human performance for a valve configuration error. This finding was greater than minor, because it had an actual impact on plant stability and operator actions were necessary to reseat a letdown line relief valve. This finding screened to Green in phase 1 of the SDP, because mitigation equipment was not affected by the control air transient.

Enforcement. This finding was not a violation of NRC requirements. Although the reactor coolant system barrier was affected, the performance deficiencies occurred on non-safety related systems. PSEG entered this issue into its corrective action program as notification 20133239.

.4 Salem Unit 2 Manual Reactor Trip Due to CW System Grassing Problems

a. Inspection Scope

On March 29, 2003, at approximately 0400, Salem Unit 2, at 100% power received multiple CW system traveling screen high d/p alarms. Equipment operators at the CW intake structure reported severe grassing conditions. PSEG had established dedicated equipment operators at the CW intake structure to monitor the marsh grass impact during the prior several weeks. (The marsh grass seasonally impacts the Salem units' river water systems as dead reeds and detritus enter the Delaware River during the spring thaws and seasonably high tides.) During the grassing event, the control room operators initiated a downpower and secured three of six CW pumps due to high condenser d/p. After securing the third CW pump, control room operators manually tripped Unit 2 from about 80% power. The inspectors responded to the main control room, interviewed control room operators, walked down all control board indications for abnormalities, walked down the safety-related service water system intake structure, and observed the grassing at the CW intake structure. The inspectors also interviewed management for additional insights on operator and equipment performance. PSEG's program for detritus level monitoring quantified the grass levels during the event as some of the highest in over a decade of monitoring. A significant amount of trash was also present and impacted the CW system performance.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations

.1 Degraded RHR Heat Exchanger Studs

a. Inspection Scope

The inspectors reviewed PSEG's response to a degraded condition identified on January 8, 2003, that involved boric acid corrosion of the 11 RHR heat exchanger lower flange studs. This resulted in a loss of material such that the diameter for several studs was found to be reduced by more than the allowed 5%. PSEG's initial corrective actions were to declare the 11 RHR heat exchanger inoperable, enter TS 3.5.2, which required a 72 hour limiting condition for operation shutdown action. PSEG replaced about thirty studs and exited the TSs action statement. The inspectors reviewed the actions to manage the plant risk, observed selected stud replacement activities, interviewed personnel, and attended maintenance planning meetings to ensure that PSEG implemented appropriate actions to mitigate the plant risk and to restore the 11 RHR heat exchanger to an acceptable condition.

The inspectors reviewed operability determination (OD) 03-001 which concluded that the 11 RHR heat exchanger would be operable (but degraded) provided that at least 14 studs were replaced with new studs and also that the remaining studs (i.e., those left in place) did not exceed a 15% reduction in original diameter. The inspectors observed field measurements for several of the studs removed from the heat exchanger and did not observe any with a diameter reduction of greater than 12%. The inspectors also interviewed plant engineers to assess the adequacy of previous corrective actions for the degraded stud condition.

b. Findings

No findings of significance were identified.

.2 Other Operability Evaluations

a. Inspection Scope

The inspectors reviewed operability screenings or evaluations for the following degraded equipment issues:

- MSSV (21MS15) weepage identified on December 5, 2002
- 1A EDG lube oil strainer degradation identified on January 8, 2003
- 21 Containment fan cooler unit (CFCU) degraded pipe plugs identified on February 15, 2003
- 15 CFCU service water outlet valve (15SW72) failure identified on March 22, 2003

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications

a. Inspection Scope

The inspectors reviewed selected permanent plant modification packages to verify that the design bases, licensing bases, and performance capability of risk significant SSC had not been degraded through plant modifications.

Plant changes were selected for review based on risk insights for the plant and included SSC associated with the initiating events, barrier integrity and mitigating systems cornerstones. The inspection included walkdowns of selected plant systems and components, interviews with plant staff, and the review of applicable documents including procedures, calculations, modification packages, engineering evaluations, drawings, corrective action documents, the UFSAR and TSs.

The inspectors verified that selected attributes were consistent with the design and licensing bases. These attributes included component safety classification, energy requirements supplied by supporting systems, seismic qualification, instrument set-points, uncertainty calculations, electrical coordination, electrical loads analysis, and equipment environmental qualification. Design assumptions were reviewed to verify that they were technically appropriate and consistent with the UFSAR. For each modification the 50.59 screens or evaluations were reviewed as described in section 1R02 of this report. The inspectors verified that procedures, calculations and the UFSAR were properly updated with revised design information and operating guidance. The inspectors also verified that the as-built configuration was accurately reflected in the design documentation and that post-modification testing was adequate to ensure the SSC would function properly.

The inspectors also reviewed issues that had been entered into the corrective action program to determine if PSEG had been effective in identifying problems associated with the plant modification process and activities. A sample of these issues was selected for further review during which the inspectors assessed the adequacy of the corrective actions which had been implemented for the selected issues. A listing of documents reviewed is provided in the attachment.

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing (PMT)

.1 1B EDG Trip During PMT

a. Inspection Scope

The inspectors observed PSEG's response to a 1B EDG electrical trip during PMT on March 14, 2003. The inspectors discussed the matter with technicians in the field and observed PSEG's methodology to discover all potential causes.

b. Findings

Introduction. PSEG had ineffective interim corrective actions for a known deficiency with the Salem EDG potential transformer drawer connectors. This finding was determined to be of very low risk significance (Green), because the inadequate interim corrective actions only affected the 1B EDG for a short duration and only on one subsequent occasion, March 14, 2003.

Description. On March 14, 2003, the 1B EDG output breaker tripped approximately three minutes after achieving full load. The 1B EDG was operating for PMT and had been fast loaded per TS 4.8.1.1.2c. PSEG assembled a TARP team to completely understand the EDG trip.

The TARP concluded that the potential transformer drawer secondary auxiliary coupler, a Jones plug, was not properly connected. The potential transformer drawer and Jones plug were disconnected as part of the ragout for personnel and equipment safety during the maintenance activity. The Jones plug had become misaligned during the return to service. Electrical continuity was lost during the EDG post-maintenance operation and caused the diesel generator output breaker to trip.

EDG trips had occurred for identical reasons on January 6, 2002, and January 9, 2002, for the 1B and 2A EDGs. PSEG had established interim corrective actions after the January 9, 2002, EDG trip to specify electrical continuity checks on the Jones plug after reconnecting.

The technicians for this recent EDG trip performed the continuity checks; however, some anomalies occurred. The technicians initially did not achieve acceptable electrical continuity as verified through resistance checks. Several attempts were made and the drawer bolts were finally tightened to achieve continuity within the acceptable range. The post EDG trip investigation revealed that pins had been dislodged in the Jones connector.

The TARP team concluded that the initial interim corrective actions were inadequate. Additional interim corrective actions were added to visually verify the Jones plug pins mated during PT drawer reinstallation. PSEG also specified additional maintenance instructions to formalize and strengthen the continuity verification process. PSEG intended to complete a permanent design change and eliminate the connector problem for all six Salem EDGs by December 2003.

Analysis. The performance deficiency associated with this problem was inadequate problem identification and resolution. Technicians should have questioned their additional actions to achieve acceptable continuity reading. In January 2002 PSEG should have also more completely defined the interim corrective actions necessary to ensure a proper connection in the degraded Jones plugs. This finding affected the equipment performance attribute of the reliability objective of the mitigating system cornerstone. This finding is more than minor, because the Salem emergency diesel generators were being returned to service without adequate interim corrective actions and verification for a known electrical connector deficiency. The 1B EDG trip on March 14, 2003, was fortuitous in that the conditions were sufficient to reveal the inadequate Jones plug connection during the PMT and not during an actual actuation. The finding screened to green in Phase 1 of the SDP, because the condition did not cause any EDG to be inoperable for greater than its TS allowed outage time.

Enforcement. 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," requires that in the case of significant conditions adverse to quality, measures shall be established that preclude repetition. Contrary to the above, PSEG failed to establish adequate corrective actions to ensure that the Salem EDG PT drawer connectors were reliably connected and verified after maintenance activities. This was a deficient condition that was identified by PSEG on January 9, 2002. Later PSEG established additional corrective action measures on January 14, 2003 after the 1B EDG tripped for the same root cause identified in January 2002. Because the failure to establish adequate measures for deficient EDG PT drawer connectors was determined to be of very low significance and has been entered into the corrective action program (notification 20135488), this violation is being treated as a non-cited violation consistent with Section VI.A of the NRC Enforcement Policy: NCV 50-272 and 311/03-03-03, EDG Deficient Corrective Actions.

.2 22 AFW Pump Packing Performance

a. Inspection Scope

The inspectors observed portions of and reviewed documentation for PMT associated with work activities on the 22 AFW pump train during a planned maintenance outage. The work activities occurred on March 12, 2003, and included redundant air panels 700-2G, 2M, and 2Y preventive maintenance. These redundant air panels affected the operation of AFW flow control valves 21AF21 and 22AF21. The inspectors assessed whether the testing appropriately demonstrated that the 22 AFW pump train was returned to an operationally ready condition. The inspectors were present for an inservice test surveillance on the 22 AFW pump at the conclusion of the maintenance.

b. Findings

The inspectors observed the startup of the 22 AFW pump in the field on March 13. Shortly after startup equipment operators noticed the inboard pump shaft packing gland emitting steam. While a small stream of water is desirable to maintain the packing and pump shaft cool and stable, steam emission is undesirable and could have lead to packing failure and, in the worst case, pump failure.

The operators promptly loosened the packing gland follower and were successful in establishing stable packing gland performance. The 22 AFW pump has had a history of significant packing leakoff. Equipment operators and maintenance technicians were prepared during the pre-job brief and maintenance planning to adjust the 22 AFW pump packing as necessary and on startup.

No recent maintenance activities occurred that should have overtightened the inboard packing gland follower causing steam emission. A senior reactor operator present and overseeing the packing adjustment initiated a corrective action notification (20135513) to review past operability of the 22 AFW pump. This issue will remain unresolved pending PSEG's investigation and review for past operability. (URI 50-311/03-03-04)

.3 13 AFW Pump Maintenance

a. Inspection Scope

The inspectors reviewed post-maintenance test documentation for maintenance activities associated with the 12AF11 and 14AF11 air operated flow control valves. These valves support AFW from the Unit 1 turbine-driven AFW pump to the 12 and 14 steam generators. The inspectors verified that the PMT procedures, activities, and results were adequate to verify operability and functional capability as described in NRC Inspection Procedure 81111.19, "PMT," prior to the affected systems being returned to service. The inspectors also walked down the maintenance locations and verified that maintenance was properly authorized by senior reactor operators and conducted in accordance with procedures.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing

a. Inspection Scope

The inspectors observed portions and reviewed results of the following surveillance tests:

- Unit 2 channel 4 pressurizer pressure calibration on January 28, 2003
- Unit 1 engineered safety features solid state protective system slave relays test for train A on March 5
- 12 component cooling water pump inservice testing on March 13
- 22 EDG fuel oil transfer pump monthly surveillance testing on March 14
- 2B safety-related 4kV bus under voltage relay testing on March 14
- 22 Safety injection pump inservice testing on March 19

The inspectors verified that test results were within procedure requirements, TS requirements, and in-service testing program requirements as applicable.

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications

a. Inspection Scope

The inspectors reviewed Temporary Modification No. 03-001, "Salem Unit 1 No.14 Steam Generator Level Transmitter Level Column Vent Valve Seat Leakage." The temporary modification involved the installation of an additional isolation valve on the vent line downstream of the leaking vent valve. The inspector assessed: (1) the adequacy of the 10 CFR 50.59 evaluation; (2) the seismic qualification evaluation that assessed the weight of the additional valve on the instrument tubing; and (3) the adequacy of the post-installation testing.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2OS1 Access Control to Radiologically Significant Areas

a. Inspection Scope

During the period February 24-28, 2003, the inspector reviewed exposure significant work areas (i.e., High Radiation Areas, and Airborne Radioactivity Areas) in the plant and associated controls and surveys of these areas to determine if the controls (e.g., surveys, postings, barricades) were acceptable. For these areas, the inspector reviewed radiological job requirements and attended job briefings to determine if radiological conditions in the work area were adequately communicated to workers through briefings and postings.

The inspector also verified radiological controls, radiological job coverage, and contamination controls to ensure the accuracy of surveys and applicable posting and barricade requirements. The inspector obtained this information via interviews with PSEG personnel, walkdown of systems, structures, and components, and examination of records, procedures, or other pertinent documents.

The inspector determined if prescribed radiation work permits (RWPs), procedures and engineering controls were in place, whether PSEG surveys and postings were complete and accurate, and if air samplers were properly located. The inspector reviewed RWPs used to access exposure significant work areas to identify the acceptability of work control instructions or control barriers specified.

The inspector reviewed electronic pocket dosimeter alarm set points (both integrated dose and dose rate) for conformity with survey indications and plant policy. RWP #105, Task #0810002, which allowed access to High Radiation Areas in the low level radwaste storage facility and five posted high or locked high radiation areas located in the spent fuel and auxiliary buildings, were reviewed as part of this inspection. The controls implemented by PSEG were compared to those required under plant TS 6.12 and 10 CFR 20, Subpart G, for control of access to high and locked high radiation areas.

b. Findings

No findings of significance were identified.

2OS2 ALARA Planning and Controls

a. Inspection Scope

The inspector reviewed ALARA job evaluations, exposure estimates, and exposure mitigation requirements and compared ALARA plans with the results achieved. A review was conducted of: the integration of ALARA requirements into work procedures and RWP documents; the accuracy of person-hour estimates and person-hour tracking; and generated shielding requests and their effectiveness in dose rate reduction. The inspector obtained this information via interviews with PSEG personnel, walkdown of systems, structures, and components, and examination of records, procedures, or other pertinent documents.

A review of actual exposure results versus initial exposure estimates for work performed during 2002 was conducted including: comparison of estimated and actual dose rates and person-hours expended; determination of the accuracy of estimations to actual results; and determination of the level of exposure tracking detail, exposure report timeliness and exposure report distribution to support control of collective exposures to determine conformance with the requirements contained in 10 CFR 20.1101(b). The actual 2002 exposure was 154.49 person-rem for Unit 1 and 131.428 person-rem for Unit 2. The inspector also reviewed the exposure goal established for 2003 (9.75 person-rem for Unit 1 and 115.25 person-rem for Unit 2), which included an exposure goal of 110 person-rem for the Unit 2 spring refueling outage (2RF13).

b. Findings

No findings of significance were identified.

2OS3 Radiation Monitoring Instrumentation

a. Inspection Scope

The inspector reviewed field radiological controls instrumentation utilized by radiation protection (RP) technicians and plant workers to measure radioactivity, including portable field survey instruments, friskers and portal monitors. The inspector reviewed five selected RP instruments observed in the radiologically controlled area (RCA). Items reviewed was verification of proper function and certification of appropriate source checks and calibration for these instruments used to ensure that occupational exposures are maintained in accordance with 10 CFR 20.1201.

The evaluation of PSEG performance was based on interviews with PSEG personnel, walkdown of systems, structures, and components, and examination of records, procedures, or other pertinent documents.

b. Findings

No findings of significance were identified.

Cornerstone: Public Radiation Safety

2PS3 Radiological Environmental Monitoring Program (REMP)

.1 REMP

a. Inspection

The inspector reviewed the following documents to evaluate the effectiveness of PSEG's REMP at the PSEG Maplewood Testing Services Laboratory, Maplewood, NJ, and at the Salem/Hope Creek site. The requirements of the REMP are specified in the Technical Specifications/Offsite Dose Calculation Manual (TS/ODCM).

Maplewood Testing Services Laboratory

- 2001 Annual REMP Report and the 2002 Draft Report;
- Analytical results for 2003 REMP samples;
- Most recent calibration results for all TS/ODCM air samplers;
- Calibration results for gamma, alpha/beta, and tritium measurement instruments;
- Review of Maplewood Testing Services Laboratory Quality Assurance (QA) Manual;
- Implementation of the quality control program;
- Review of the 2002 gamma, alpha/beta, and tritium quality control charts;
- Implementation of the interlaboratory and intralaboratory comparisons;
- Implementation of the environmental thermoluminescent dosimeters (TLDs) program;
- Land Use Census procedure and the 2001/2002 results;
- Associated sampling and analytical REMP procedures.

Salem/Hope Creek Site

- Salem ODCM (Revision 15, July 11, 2002), Hope Creek ODCM (Revision 20, April 5, 2002), and technical justifications for ODCM changes, including sampling media and locations;
- Most recent calibration results of the newly installed Primary Tower (work order 60023443) and Back-up Tower (work order 6002344) meteorological monitoring instruments for wind direction, wind speed, and temperature;
- Review of the 2002 meteorological monitoring data recovery statistics;
- Meteorological monitoring program self-assessment report;
- QA Assessment Reports (Report Nos. 2002-0218, REMP/ODCM Procedures, Training, Performance Indicators, and Event Followup) for the REMP/ODCM implementations.

The inspector toured and observed the following activities to evaluate the effectiveness of PSEG's REMP:

- Observation for the operability of meteorological monitoring instruments at the tower and the control room;
- Observation of PSEG's analytical laboratory activities, PSEG Maplewood Testing Services Laboratory;
- Observation for air iodine/particulate sampling techniques;
- Walkdown for determining whether air samplers and TLDs were located as described in the ODCM (including control and indicator stations) and for determining the equipment material condition.

The inspector also reviewed the potential onsite and offsite radiological dose consequences associated with PSEG's discovery of a leak in the Unit 1 spent fuel pool and the subsequent identification of tritium contamination in four onsite test well locations (K, L M, N) located adjacent to the onsite Salem facility. The specific discussion associated with this matter are contained in Section 4OA3 of this report and NRC Inspection Report 50-272; 50-311/2002-009 Section 4OA2.3.

b. Findings

No findings of significance were identified.

.2 Radioactive Material Control Program

a. Inspection Scope

The inspector reviewed the following documents and made observations to ensure that PSEG met the requirements specified in its program for the unrestricted release of material from the RCA:

- Most recent calibration results for the radiation monitoring instrumentation (small articles monitor, SAM-9), including the (a) alarm setting, (b) response to the alarm, and (c) the sensitivity;
- PSEG's criteria for the survey and release of potentially contaminated material using a gamma spectroscopy (calibrations efficiency for bulk sample analyses);
- Methods used for control, survey, and release from the RCA;
- Use of SAM-9 at RCA access points;
- Associated procedures and records to verify for the lower limits of detection for bulk sample analyses.

The review was against criteria contained in 10CFR20, NRC Circular 81-07, NRC Information Notice 85-92, NUREG/CR-5569, Health Position Data Base (Positions 221 and 250), and PSEG's procedures.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA2 Problem Identification and Resolution

.1 CW System Frequent Failures

a. Inspection Scope

The inspectors also reviewed the identified root cause(s) and planned corrective actions for the loss of the 13A CW traveling screen event discussed in Section 14.2. The root causes for this event included improper alignment of the shear pin hub caused by inadequate maintenance procedural guidance. The inspectors also reviewed corrective action program documents to determine whether other previous shear pin failures had occurred due to improper alignment during maintenance.

b. Findings

No findings of significance were identified; however, the inspectors identified that the corrective actions for previous similar events that involved the breaking of the shear pins had not been effective. This was not considered a violation of NRC requirements since the CW system was not a safety-related mitigating system.

.2 REMP Corrective Action Review

a. Inspection Scope

The inspector reviewed the selected following documents to evaluate the effectiveness of PSEG's problem identification and resolution processes in the areas of REMP:

- Condition Reports (CRs) for the REMP:
  1003-4916; 1006-6506; 1006-9421; 1006-9422; 1007-2124; 1007-5340; 1007-6168; 1007-5391; 1007-6519; 1007-6891; 1007-9940 and 1009-9983
- CRs for the Meteorological Monitoring Programs:
  2009-5181; 2010-0037; 2010-3814; 2010-8528; 2012-3864; 2011-4695; 2012-5321; 2012-6346; 2012-7542; 2012-8819; 2013-0388; 2013-0744; 2013-0854; and 2013-0854;
- Special Report: Hope Creek-Plant Event #39561- Loss of Meteorological Data at Salem and Hope Creek Stations, February 4, 2003,
- Action Plan for Improving Meteorological Monitoring System Reliability;
- Self-Assessment Report Number 80043789 Activity 040, Meteorological System, June 21, 2002.

b. Findings

No findings of significance were identified.

.3 10 CFR 50.59 and Plant Modification Corrective Action Review

a. Inspection Scope

The inspectors reviewed corrective action documents associated with 10 CFR 50.59 issues and plant modification issues to ensure that PSEG was identifying, evaluating, and correcting problems associated with these areas and that the corrective actions for the issues were appropriate. The inspectors also reviewed several QA audit and self-assessments related to 10 CFR 50.59 and plant modification activities at the Salem Generating Station.

b. Findings

No findings of significance were identified.

.4 Occupational Radiation Safety Corrective Action Review

a. Inspection Scope

The inspector reviewed QA audits and surveillance, and RP department self-assessments performed during the period from July 2002 - February 2003, related to occupational radiation safety, and determined if identified problems were entered into the corrective action system for resolution. Attachment 1 contains a listing of the documents reviewed. The inspector also reviewed the tracking, evaluation and resolution of these identified issues.

b. Findings

No findings of significance were identified.

.5 Security Program Implementation

a. Inspection Scope

The inspectors reviewed the findings of an independent team that had been contracted by PSEG to review security program implementation. The audit team concluded that there were potential violations of security plan and regulatory requirements regarding response team staffing and compensatory measures. PSEG did not consider the findings to be violations of the security plan or regulatory requirements; however, they did forward the audit team findings to the NRC for review.

The inspectors' review disclosed that the response team manning issue involved the use of some response team members on compensatory posts. The inspectors' review of this issue determined that this practice did not degrade the total overall defensive strategy and was not a violation of the security plan or regulatory requirements. Additional information on this issue would contain Safeguards Information and is, therefore, not documented here.

The inspectors' review of the potential violation regarding compensatory measures disclosed that the compensatory measures initially implemented for some degraded assessment aids met security plan and regulatory requirements. However, upon further PSEG management review, it was determined that the compensatory measures could be strengthened by the addition of an officer posted in the area. The posted officer exceeded the compensatory requirements identified in the security plan. Additional information on this issue would contain Safeguards Information and is, therefore, not documented here.

b. Findings

No findings of significance were identified.

.6 Cross-References to PI&R Findings Documented Elsewhere

Section 1R01 describes a degraded condition, a roof leak, in the 2A EDG room that caused a CO2 fire suppression system actuation. A few days afterwards PSEG had not addressed additional EDG room roof leaks that allowed water to enter a safety related electrical panel on the 1C EDG. The inspectors also identified that other roof leaks were impinging safety-related EDG equipment as evidenced by water stains; yet no corrective actions existed to address the degraded roof conditions.

Section 1R04.1 describes an unauthorized modification identified by NRC inspectors on the 22 AFW pump. The inspectors further identified that PSEG did not perform an adequate extent of condition review and the 13 AFW pump was similarly impacted.

Section 1R14.3 describes a control air transient that was negatively impacted by equipment deficiencies, air leaks, in the station air control system. One air leak in particular was a significant load on the control air system performance. The air leak had been previously identified by PSEG, but repairs were canceled with no further action intended. Although the control air system is outside the regulatory scope of a required corrective action program, this finding demonstrated weaknesses in correcting equipment deficiencies that impacted a reactor safety cornerstone.

Section 1R19.1 describes a finding for inadequate interim corrective actions associated with EDG reliability. The event further includes a detail for lack of resolution when expected results were not initially received.

4OA3 Event Followup

.1 Salem Unit 1 Spent Fuel Pool Water Leak

a. Inspection Scope

As described in NRC Inspection Report No. 50-272/02-09; 50-311/02-09, PSEG identified the presence of a leak of contaminated water into the Unit 1 Auxiliary Building associated with the Unit 1 spent fuel pool. The inspector reviewed PSEG's ongoing investigation, the action plan to resolve this issue, and its collection of samples from existing and supplemental test well locations to determine if the leak had potentially impacted the onsite and offsite environment. During this inspection, the inspector reviewed the latest sample results, ongoing sampling, and sample analyses as discussed below. The inspector also reviewed the current status of the implementation of PSEG's action plan to investigate, mitigate, and repair the leak. PSEG's plan included a testing and repair plan, development and implementation of a site sampling plan, engineering support and analysis plan, leak identification plan, cleaning of telltale drains and remote visual inspection of telltales, robotic and submersible inspections of the spent fuel pool, diving support as necessary, local leak rate testing, and root cause analysis. The inspector also reviewed PSEG's extent of condition review efforts. The potential dose consequences on the Hope Creek site were also reviewed.

On February 3-4, 2003, the inspector and New Jersey State representatives toured the Fuel Handling and Auxiliary Buildings to examine locations where Unit 1 spent fuel pool water was leaking or believed to be leaking into adjacent areas (e.g., Unit 1 78-foot Mechanical Penetration Room, Unit 1 64-foot Switch Gear Room). The inspector also toured the areas where PSEG dug supplemental test wells for purposes of detecting and evaluating potential tritium migration and locating the source of the leak.

On February 6, 2003, PSEG identified that two onsite wells (N and O) located next to the Unit 1 spent fuel building exhibited tritium contamination above the state reporting level. PSEG promptly informed New Jersey and the NRC. The inspector reviewed the sample results.

On February 11, 2003, the inspector reviewed the performance of PSEG's Maplewood Testing Services Laboratory, Maplewood, New Jersey. This laboratory analyzes REMP samples collected around the Salem/Hope Creek site as required by the TS and the ODCM. This laboratory also analyzes samples collected of on-site well waters and soil samples. The inspector reviewed: (1) analytical methodologies; (2) measurement techniques for tritium, gamma, and gross alpha/beta; (3) implementation of the quality control program; (4) review of the 2002 gamma, alpha/beta, and tritium quality control charts; (5) implementation of the inter-laboratory and intra-laboratory comparisons; and (6) calibration results for gamma, alpha/beta, and tritium measurement instruments.

On February 19, 2003, PSEG informed the NRC that two additional wells (M, K) were found to contain tritium. One test location was next to the Unit 1 spent fuel storage building while the other was located adjacent to the Unit 2 containment building. PSEG had informed New Jersey. The inspector reviewed those sample results.

The inspector reviewed onsite sample results of wells to determine the presence of tritium contamination for wells termed production wells, which provide potable water for the Salem and Hope Creek site. The inspector also reviewed analytical results of tritium and gamma isotopes for water samples collected at monitoring wells at 20-ft, 40-ft, 60-ft, and 80 ft. depths, as applicable. The inspector also reviewed New Jersey analyses for tritium. The inspector reviewed the analytical results of gamma isotopes, which indicated that there was no evidence of plant related gamma contaminations in the wells. The comparisons of tritium results between PSEG and New Jersey were reviewed to evaluate level of agreement. The inspector also reviewed the analytical sample results for wells that were located on the outer periphery of the Salem facility to ascertain potential migration of contamination beyond the four wells (K, M, N, and O) identified to contain tritium contamination.

As discussed above, PSEG identified, as of February 26, 2003, that four onsite test well locations (K, M, N, and O) exhibited varying levels of detectable tritium contamination. Three of the test wells were adjacent to the Unit 1 Fuel Handling Building. The fourth sample location was adjacent to the Unit 2 containment area. The inspector performed independent dose calculations, using the methodology specified in NRC Regulatory Guide 1.109, to independently assess the potential offsite doses attributable to tritium contained in onsite test well locations. These calculations conservatively assumed the consumption of water with highest measured tritium concentrations and the presence of a viable drinking water pathway.

b. Findings

No findings of significance were identified.

The inspector did not identify any immediate impact of the Unit 1 spent fuel pool leak and associated test well tritium contamination on the health and safety of onsite workers or members of the public. PSEG was continuing to implement its leak identification, repair, and mitigation plan including the ongoing sampling and analysis aspects of the plan. PSEG was cleaning out telltale drains for the Unit 1 spent fuel pool to aid in location of apparent leaks. Liquid from telltale drains was being collected and processed via the liquid radwaste processing system.

.2 (Closed) LER 50-272/02-004-00, Manual Reactor Trip and Automatic AFW Actuation on Low Steam Generator Level due to Feedwater Pump Runback

On November 12, 2002, Salem Unit 1 was manually tripped due to a steam generator feedwater pump runback resulting from an accidental control circuit short during maintenance troubleshooting. Plant response to the manual reactor trip was normal. This event was also described in NRC Inspection Report 50-272/02-09, 50-311/02-09, Section 1R14 Personnel Performance During Non-Routine Plant Evolutions. This LER was reviewed by the inspector, and no findings of significance or violations of NRC requirements were identified. PSEG entered the reactor trip and maintenance issue into its corrective action program as notification 20122632. This LER is closed.

.3 (Closed) LER 50-272/02-006-00, As Found Values for MSSV and Pressurizer Safety Valve (PSV) Lift Setpoints Exceed TS Allowance

This LER described out of specification results for as found lift setpoints on a PSV and a MSSV. The valves were removed during the 1R15 Salem Unit 1 outage in October 2002 for testing in accordance with TS 4.0.5, Surveillance Requirements for inservice inspection and testing of ASME Code Class 1, 2 and 3 components. A PSV tested at

-3.50% and below the 3% lift setting tolerance in TS 3.4.2.2. A MSSV tested at +4.71% and above the 3% lift setting tolerance in TS 4.7.1.1. The inspectors reviewed the LER and interviewed valve engineers involved with the test program. PSEG concluded that the PSV may have lifted low because it was a manufacturer original assembly valve and internal parts may not have been lapped. PSEG also determined that the MSSV probably lifted high due to misalignment from rough handling at the Salem site prior to shipment. The MSSVs are tested at an offsite facility. PSEG had previously determined that rough handling of safety valves can impact the lift setpoint. PSEG's failure to establish controls that impacted the performance of a PSV and a MSSV is a minor violation.

The LER described an actual benefit for the lower PSV setting in regards to overpressure protection of the reactor coolant system boundary. An inadvertent safety injection analysis was also considered and the lower set PSV did not affect the calculated results since safety injection would not have caused the PSV to lift at even the lower setpoint. The lower set PSV did not impact the barrier integrity cornerstone.

Although PSEG believed the MSSV setpoint drift occurred post-removal for testing, the LER considered the impact of an installed higher set MSSV. The MSSV in question was the highest set MSSV, four other MSSVs relieve at lower required TS setpoints. For all applicable final safety analysis report events, the highest set MSSV did not open and thus absent another failure, there was no impact on the calculated results for the limiting transients or the barrier integrity cornerstone. This finding constitutes a violation of minor significance that is not subject to enforcement action in accordance with Section IV of the NRC's Enforcement Policy. PSEG documented the setpoint drift problems in notifications 20116805 and 20116997. This LER is closed.

.4 <u>(Closed) LER 50-272/02-009-00</u>, Failure to Perform Required Action of TS 3.1.3.2.1

0n December 12, 2002, control rod 1C3 individual rod position indication was declared inoperable on Salem Unit 1. The associated TS action statement 3.1.3.2.1.a required that either the position of the non-indicating rod be determined by use of the power distribution monitoring system (PDMS) or the incore movable detectors once every 8 hours or reduce thermal power to less than 50% of rated. Reactor engineers performed the rod position verification by the PDMS twice at six hour intervals on Unit 2 instead of Unit 1. Reactor engineers later reviewing the results of the PDMS surveillance determined that the verification was performed on the wrong Salem unit. The PDMS verification was performed correctly on Unit 1 seven hours late. The surveillance validated that rod 1C3 on Unit 1 was within its required position. PSEG entered this human performance issue into its corrective action program as notification 20124652 . This finding is more than minor, because it impacted a fuel cladding attribute for the barrier integrity cornerstone. This finding was also considered to have a very low safety significance (Green) by the Phase 1 SDP because it only involved the fuel barrier. This licensee-identified finding was a violation of TS 3.1.3.2.1, Rod Position Indication Systems. Because this finding was determined to be of very low significance and has been entered into the corrective action program (notification 20124652), this violation is being treated as a non-cited violation consistent with Section VI.A of the NRC Enforcement Policy. This LER is closed.

.5 Salem Unit 2 Manual Reactor Trip on March 29, 2003

Control room operators manually tripped Salem Unit 2 in response to CW system challenge precipitated by severe marsh grass at the intake structure. The inspectors responded to the site and main control room verifying that the trip response was normal and that stable hot shutdown conditions were verified. Other aspects of the inspectors activities are described in Section 1R14.1.

4OA5 Other

.1 (Open) URI 50-272/02-09-06: Determine if PSEG met all ODCM and 10 CFR 20 effluent release requirements associated with the Unit 1 spent fuel pool leak.

a. Inspection Scope

As discussed in Section 4OA2 of this report, the inspector reviewed current onsite radiological sample results for near field and far field wells surrounding the Salem facility. The inspector also conducted a baseline radiological environmental monitoring inspection for the Salem and Hope Creek site to evaluate offsite dose impact associated with site operations.

b. Findings

At the completion of this inspection, PSEG was continuing with its onsite sampling program to identify the distribution of tritium in onsite groundwater. Four onsite test wells were identified to contain detectable levels of tritium. PSEG was evaluating development of additional sampling plans to evaluate, in part, tritium migration. This URI remains open pending inspector review of additional sample plans and PSEG sample results.

4OA6 Meetings, including Exit

On April 4, 2003, the resident inspectors presented the inspection results to Mr. Tim O'Connor and other members of this staff who acknowledged the findings. The inspectors confirmed that proprietary information was not provided or examined during the inspection.

4OA7 Licensee-Identified Violations

Section 4OA3.4 of this inspection report describes a violation of very low safety significance (Green) which was identified by PSEG and is a violation of NRC requirements which meets the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as a non-cited violation.

ATTACHMENT: SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee personnel

J. Carlin, Vice President of Engineering
T. Cellmer, Radiation Protection Manager
D. Garchow, Vice President of Licensing/Projects
K. Augustine, CVCS System Engineer
J. Balcita, Lead Engineer (Appendix R)
C. Berger, 50.59 Technical Response Lead
J. Bisti, DCP HC Technical Response Lead
K. Buddebohn, Licensing
K. Fleischer, Supervisor of Design Engineering
V. Fregonese, Engineering Manager
M. Hassler, Radiation Protection Operations Superintendent - Salem
J. Hilditch, Tech. Support Supervisor
F. Hummel, RHR System Engineer
G. Jones, Tech. Support Business Analyst
C. Kapes, Reliability Engineer
T. McCool, DCP Salem Technical Response Lead
M. Moiser, Licensing
R. Montgomery, Senior Engineer, Flow Accelerated Corrosion Program
N. Nag, Electrical Engineer
J. Nagle, Licensing Supervisor
T. Neufang, ALARA Supervisor - Salem
J. O,Connor, Engineering, Plant Chief
M. Pat, QA Engineer
B. Rodgers, Design Engineer/Sargent & Lundy
G. Salamon, NSL Manager
B. Sebastian, ALARA and Support Superintendent
E. Springer, DMG Business Analyst
M. Tadjalli, Engineering Supervisor
J. Volence, Staff Engineer
L. Wazdinger, Ops Director

NRC personnel

R. Lorson, Senior Resident Inspector, Salem
F. Bower, Resident Inspector, Salem

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-311/03-03-04	URI	22 AFW pump packing performance. (Section 1R19.2)

Opened and Closed

50-272/03-03-01	NCV	Failure to identify EDG room roof leaks. (Section 1R01)
50-272&311/03-03-02	NCV	Failure to properly evaluate AFW pump skid. (Section 1RO4.1)
50-272&311/03-03-03	NCV	EDG deficient corrective actions. (Section 1R19.1)

Closed

50-272&311/02-09-01	URI	Submerged safety-related electrical cables appropriate corrective actions. (Section 1R06)

Discussed

50-272/02-09-06	URI	Salem Unit 1 Spent Fuel Pool Water Leak. (Section 4OA5)

LIST OF DOCUMENTS REVIEWED

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

Sections 1R02 and 1R17

Permanent Plant Modifications

DCP 80008148,	Salem Unit 2 Steam Generator Nozzle Transition Forging, Rev. 0
DCP 80008505,	4KV/125VDC Control Circuit Modification, Rev. 2
DCP 80008741,	Modification of PORV control circuits, Rev. 1
DCP 80017352,	Modify Control Wiring Configuration and Gearing for 21SJ54, Rev. 0
DCP 80029004,	Appendix R Cable Reroutes - Unit 2, Rev.1
DCP 80030171,	Hot Shutdown Panel Cross Tie - Unit 2, Rev.1
DCP 80033503,	Installing Vents on RHR to Safety Injection/Charging Pump Cross Connection Piping for Salem 2, Rev. 2

10 CFR 50.59 Safety Evaluations

S00-019,	Removal of PDP Charging Pump from Service, Rev. 0
S00-027,	2PR1 and 2PR2 Control Circuit Modification, Rev. 0
S01-004,	Increase Setpoint of BF-82 and BF-90 PSVs from 1350 psig to 1620 psig, Rev. 4
S01-008,	Unit 1 RMS Upgrade, Rev. 0
S01-013,	15/25 Feed Water Heater Pressure Equalizing Line Orifice Resizing, Rev. 1
S01-017,	Hot Shutdown Panel Cross Tie - Unit 1, Rev. 1
S02-001,	Analysis of CVCS Cross-Tie, Rev. 0
S02-006,	Salem Unit 1 Steam Generator Snubber Elimination, Rev. 0
S02-007,	Evaluation of MSIVs as Containment Isolation Valves, Rev. 0

10 CFR 50.59 Safety Evaluation Screens

DCP 80005242,	Salem Unit Containment Particulate, Iodine, and Gas RMS Upgrade, Rev. 1
DCP 80006746,	Overhead Annunciator DAC Firmware Upgrade
DCP 80015124,	Wiring Change for MOVs 2CV68 and 2CV69
DCP 80017352,	Modify Control Wiring Configuration and Gearing for 21SJ54, Rev. 0
DCP 80020460,	Modification of Fan 2VHE45, ABV Exhaust Fan Number 21
DCP 80022667,	230 VAC Circuit Breaker Instantaneous Trip Settings: I-2110 MCC
DCP 80026404,	ABV Exhaust Fan (Number 23 - 2VHE47) Bearing Replacement
DCP 80027983,	Change in Tap Location for Discharge Pressure of 21 Component Cooling Pump
DCP 80029004,	Appendix R Cable Reroutes/Hot Short Re-mediation, Rev. 1
DCP 80033503,	Installing Vents to RHR to Safety Injection/Charging Pump Cross Connect Piping for Salem 2, Rev. 2
DCP 80030171,	Hot Shutdown Panel Cross Tie - Unit 2, Rev. 0
DCP 80034979,	Steam Generator Scrubber Elimination, Rev. 0
DCP 80037132,	2SJ12/13 Leakage Resolution
DCP 80041307,	Change S/G Low-Low Level Setpoint To Account For OE 13281, Rev. 1

Design References and Calculations

ES-4.003(Q),	125 Volt DC Short Circuit and System Voltage Drop Calculation, Rev. 2
ES-13.006(Q),	Breaker and Relay Coordination Calculation for safety-related AC Systems, Rev. 2
ES-15.005(Q),	230 Vital Bus Voltage Drop Calculations for Control Circuits, Rev. 1
ES-15.009(Q),	Essential Controls Inverter Load Study For PSEG SNGS Units 1 and 2, Rev. 5
S-C-BF-MDC-1153,	Resolution of Balance of Plant Design Pressure, Rev. 2
S-C-BF-MDC-1876,	Feedwater Heater High Level Trip During Plant Load Transients, Rev. 0
S-C-CN-MEE-1073,	Condensate System Design Pressure Reconciliation, Rev. 1

S-C-G-240-MDC-0239, MSR & FW Heater Drain Tank Equalizing Line Orifice Sizing, Rev. 0

Procedures

NC.CC.AP.ZZ-0015(Q),	Development and Maintenance Bill of Materials and Equipment Masters, Rev. 0
NC.CC-AP.ZZ-0080(Q),	Engineering Change Process, Rev. 4
NC.CC-AP.ZZ-0081(Q),	Engineering Change Implementation & Test Process, Rev. 4
NC.CC-AP.ZZ-0082(Q),	Implementation Plans, Rev. 1
NC.CC-AP.ZZ-0083(Q),	Test Plans, Rev. 1
NC.CC-AP.ZZ-0084(Q),	Conduct of Test, Rev. 0
NC.DE-AP.ZZ-0008(Q),	Control of Design & Configuration Change, Tests, and Experiments For Workbook Style Change Packages, Rev. 2
NC.DE-WB.ZZ-0001(Q),	Standard Design Change Workbook One, Rev.15
NC.DE-WB.ZZ-0002(Q),	Generic Equivalent Replacement, Rev. 5
NC.DE-WB.ZZ-0003(Q),	Engineering Workbook For Equivalent Replacement, Rev. 9
NC.DE-WB.ZZ-0004(Q),	Engineering Workbook For Document Only And Part Change Sponsor Organization, Rev. 8
NC.DE-WB.ZZ-0005(Q),	Engineering Workbook For As-Built Document, Rev. 8
NC.DE-WB.ZZ-0006(Q),	Engineering Change Authorization, Rev. 14
NC.NA-AP.ZZ-0008(Q),	Configuration Control Program, Rev. 18
NC.NA-AP.ZZ-0059(Q),	Regulatory Change Determination & 10CFR50.59 Review Process, Rev. 9
NC.NA-AS.ZZ-0059(Q),	10CFR50.59 Program Guidance, Rev. 5
NC.WM-AP.ZZ-0002(Q),	Performance Improvement Process, Rev. 6
SC.MD-PM.ZZ-0005(Q),	Molded Case Circuit Breaker Maintenance, Rev. 3
SC-MD-PM.ZZ-0005(Q),	Molded Case Circuit Breaker Maintenance, Rev. 2, Completed November 9, 2001
S1.OP-AB.CR-0002(Q),	Control Room Evacuation Due To Fire In Control Room, Relay Room Or Ceiling Of The 460/230V Switchgear Room, Rev. 12
S2.OP-AB.CR-0002(Q),	Control Room Evacuation Due To Fire In Control Room, Relay Room Or Ceiling Of The 460/230V Switchgear Room, Rev. 15
S1.OP-SO.CVC-0023(Q),	CVCS Cross-Connect Alignment To Unit 2, Rev. 0
S1-OP-SO.115-0002(Q),	Alternate Shutdown System UPS System Operation, Rev. 5
S2-OP-SO.115-0002(Q),	Alternate Shutdown System UPS System Operation, Rev. 7
S1.RA-ST.CVC-0023(Q),	Inservice Testing 13 Charging Pump Acceptance Criteria, Rev. 4

CRs, Notifications and Work Orders

CRs

70017302	70019043	70022332	70023141	70023469
70023621	70023988	70024420	70024911	70027683
70028176	70028654	70028713		

Notifications

20087950	20088412	20095350	20097818	20097861
20099102	20108633	20111616	20118250	20120389

20124328	20128225	20128353

Work Orders

30027562	30027563	30034414	30034580	50000262
60006815	60006816	60006817	60015019	60015020

Drawings

Piping and Instrument Diagrams

205202 A 8760, Sh. 1-3	Steam Generator Feed & Condensate
205205 A 8762, Sh. 1-6	Unit 1 Bleed Steam & Heater Drains
205228-A-8761, Sh. 2	Number 1 Unit Chemical And Volume Control Operation, Rev. 76
205305 A 8762, Sh. 1-6	Unit 2 Bleed Steam And Heater Drains
205324-A-8761,	Number 1 Unit Safety Injection, Rev. 51
244083-A-9679,	Number 1 Unit Pressurizer PORV And Stop Valves And Overpressure Protection System, Rev. 18
244084-A-9679,	Number 2 Unit Pressurizer PORV And Stop Valves And Overpressure Protection System, Rev. 9

Single Line Diagrams

203002-A-8789,	Number 1 Unit 4160 Vital Buses One-Line, Rev. 34
203007-A-8789,	Number 1 Unit 125VDC One-Line, Rev. 28
203061-A-8789,	Number 2 Unit 4160 Vital Buses One-Line, Rev. 32
207910-A-1776,	1A West Valves And Misc. 230V Vital Controller Center One-Line, Rev. 37
211349-B-9511,	Number 1 Unit Control Area 1ADE 28VDC Distribution Cabinet, Rev. 11
222485-A-1779,	Number 2 Unit Auxiliary Building 2C West Valves And Misc. 230V Vital Contr. Ctr. One-Line, Rev. 47
223720-A-1404,	Number 2 Unit 125VDC One-Line, Rev. 31

Schematic Diagrams

110454,	Assembly Drawing Safety Injection Pumps, Rev. 2

Self-Assessments and QA Audits

Focused Self-Assessment Report,	1R14 Outage DCP Quality Self-Assessment, Configuration Control, June 27, 2001
Focused Self-Assessment Report,	80048378, Focused Self-Assessment To Ensure That The Outstanding Changes Identified On Affected Documents Associated With Change Packages Are Incorporated On

	Permanent Design Document Accurately And Efficiently, Design Engineering, August 28, 2002
Focused Self-Assessment Report,	80055021, Assessment of 10 CFR 50.59 Program Implementation, Nuclear Safety and Licensing, December 27, 2002
Focused Self-Assessment Report,	80043343, Internal Bench Marking Of The Implementation of Design Change Process In The PSEG Nuclear Organizations, Technical Support Organization, July 31, 2002
Focused Self-Assessment Report,	80053554, 1R15 Modification Effectiveness, Technical Support Organization/Implementation and Test Group, December 21, 2002
QA Assessment Report 2002-0071,	2R12 Outage Activities - Tech. Support/Nuclear Reliability, June 4, 2002
QA Assessment Report 2002-0162,	Sargent & Lundy Change Package Quality, July 3, 2002
QA Assessment Report 2002-0197,	Salem 1R15 Engineering Outage Preparations, August 12, 2002
QA Assessment Report 2002-0279,	1R15 Outage Engineering Oversight, December 10, 2002

Miscellaneous Documents

ANSI B 31.1, 1967, Part 102-Design Criteria
ND.DE-TS.ZZ-2012(Q), Low Voltage Circuit Breakers and Combination Starters - Salem 240V and 480V Control Circuits, Rev. 1
SIC-00-023R Structural Integrity Report, Steam Generator Feedwater Nozzle Transition Replacement Process
Site Organization Chart, Engineering Organization
TS, Salem Generating Station
Updated Final Safety Analysis Report, Salem Generating Station
VTD 301137, Dresser Industries Installation, Operating and Maintenance Manual for Centrifugal Charging and SI Pumps, Rev. 25
VTD 316490-01, CCP Pump Performance Curve

Section 4OA2: RP Program Assessments

QA Assessments and Observations

QAAR 2003-0005	RF-11 Pre-Outage Assessment
QAAR 2002-0147	Portable Instrument repair and Calibration
QAAR 2002-0222	Radiation Monitoring System
QAAR 2002-0293	1R15 Refueling Outage Activities
QAAMF 2002-0318	Salem 1R15 Temporary Shielding Installation
QAAMF 2002-0322	Salem 1R15 RP Area Setups and Work Practices
QAAMF 2002-0341	Salem 1R15 Management Oversight
QAAMF 2002-0350	Normal Operating Pressure/Normal Operating Temperature Containment Walkdown
QAAMF 2002-0356	NRC Performance Indicators

Departmental Self-Assessments

80047782/0020	RP Corrective Action Evaluations
80047782/0050	Decontamination
80047782/030	Personnel Contamination Events
RP3Q-02-001	RP Performance for Filter Replacement Activities
80047782/070	Remote Alarming Radiation Monitors Evaluation
80038318/0120	Self-Monitor Program
80038318/070	Work Practices of RP
80051804/0020	RP Assessment of Corrective Actions
80051804/0060	Management/Supervisor/Tech Oversight
80051804/0030	OE Program Effectiveness
80047782/0060	Respiratory Protection
RP4Q-02-001	Impact of Security Personnel Loading on Whole Body Contamination Monitors
80051804/070	Surveys and Monitoring
RP1Q-03-001	2002 RP Self-Assessment Schedule Performance
RP1Q-03-003	PWR/ALARA Committee Meeting
RP1Q-03-002	2002 RP CRE

LIST OF ACRONYMS

AFW	Auxiliary Feedwater
ALARA	As Low As Is Reasonably Achievable
CFCU	Containment Fan Cooler Unit
CFR	Code Of Federal Regulations
CR	Condition Report
CW	Circulating Water
CY	Calendar Year
DCP	Design Change Package
ECACs	Emergency Control Air Compressors
EDG	Emergency Diesel Generator
ICMs	Interim Compensatory Measures
MR	Maintenance Rule
MSSV	Main Steam Safety Valve
NCVs	Non-Cited Violations
NRC	Nuclear Regulatory Commission
ODCM	Offsite Dose Calculation Manual
PARS	Publicly Available Records
PDMS	Power Distribution Monitoring System
PMT	Post-Maintenance Testing
PRT	Pressurizer Relief Tank
PSEG	Public Service Electric Gas
PSV	Pressurizer Safety Valve
QA	Quality Assurance
RCA	Radiologically Controlled Area

REMP	Radiological Environmental Monitoring Program
RHR	Residual Heat Removal
RP	Radiation Protection
RWP	Radiation Work Permit
SAC	Station Air Compressor
SDP	Significance Determination Process
SSC	Structures, Systems and Components
TARP	Transient Assessment Response Plan
TLDs	Thermoluminescent Dosimeters
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item