August 11, 2004

Mr. A. Christopher Bakken, III
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 05000272/2004003 and 05000311/2004003

Dear Mr. Bakken:

On June 30, 2004, the US Nuclear Regulatory Commission (NRC) completed an inspection at your Salem 1 & 2 reactor facilities. The enclosed integrated inspection report documents the inspection findings, which were discussed on July 2, 2004, with Mr. Carl Fricker and other members of your staff. An additional exit was also conducted on July 29, 2004, with Mr. Bill Campbell and other members of you staff to present inspection followup details that were not complete on July 2, 2004.

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

This report documents seven self-revealing findings and two NRC-identified findings of very low safety significance (Green), all of which 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 nine findings as non-cited violations (NCVs) consistent with Section VI.A of the NRC Enforcement Policy. Additionally, four licensee-identified violations which were determined to be of very low safety significance are 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.

In accordance with 10 CFR Part 2.390 of the NRC's "Rules of Practice," a copy of this letter and 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,

/RA/

Eugene W. Cobey, Chief
Projects Branch 3
Division of Reactor Projects

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

Enclosure: Inspection Report 05000272/2004003 and 05000311/2004003
w/Attachment: Supplemental Information

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REGION I

Docket Nos:	50-272, 50-311
License Nos:	DPR-70, DPR-75
Report No:	50-272/2004-003, 50-311/2004-003
Licensee:	PSEG LLC
Facility:	Salem Nuclear Generating Station, Units 1 & 2
Location:	P.O. Box 236 Hancocks Bridge, NJ 08038
Dates:	April 1 - June 30, 2004
Inspectors:	J. Daniel Orr, Senior Resident Inspector George J. Malone, Resident Inspector Joseph G. Furia, Senior Health Physicist Michael C. Modes, Senior Reactor Inspector Joseph G. Schoppy Jr., Senior Reactor Inspector Timothy L. O'Hara, Reactor Engineer Steven W. Shaffer, Resident Inspector, Seabrook
Approved By:	Eugene W. Cobey, Chief Projects Branch 3 Division of Reactor Projects

TABLE OF CONTENTS

SUMMARY OF FINDINGS

IR 05000272/2004003, 05000311/2004003; 04/01/2004 - 06/30/2004; Public Service Electric Gas Nuclear LLC, Salem Units 1 and 2; Heat Sink Performance, Maintenance Rule, Post Maintenance Testing, Surveillance Testing, PI&R, and Event Followup.

The report covered a 13-week period of inspection by resident inspectors, and announced inspections by a regional radiation specialist, and materials inspectors. Nine Green non-cited violations (NCVs) were identified. The significance of most findings is indicated by their color (Green, White, Yellow, or 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. Inspector Identified and Self-Revealing Findings

Cornerstone: Initiating Events

- Green. The inspectors identified a non-cited violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," for failure to implement corrective actions and preclude service water flow control valve 21SW102 failure. In December 2003, PSEG developed corrective actions to improve the reliability of the SW102 valves. The corrective actions were not effectively implemented and did not prevent the recurring failure of 21SW102 on May 17, 2004.

  This finding was more than minor because it was associated with the equipment performance attribute, and it affected the initiating event cornerstone objective. In accordance with Inspection Manual Chapter 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," the inspectors conducted a Phase 2 SDP evaluation of the significance of the performance deficiency and determined the finding was of very low safety significance (Green). In this evaluation, the inspectors assumed an exposure period of less than three days, the likelihood of a loss of control room ventilation event was increased by one order of magnitude, all mitigating equipment for a loss of control room ventilation event was unaffected by the finding, and operator recovery actions were feasible. (Section 1R12.2).

Cornerstone: Mitigating Systems

- Green. A self-revealing non-cited violation of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," was made apparent when foreign material, plywood and duct tape, was identified within the 12A and 12B component cooling heat exchanger service water inlet boxes.

  This finding was more than minor because it was associated with the equipment performance attribute, and it affected the mitigating systems cornerstone objective. The inspectors determined that the finding was of very low safety significance (Green) using the Phase 1 SDP because the as-found heat exchanger performance data demonstrated that the heat exchangers were marginally impacted by the foreign material; and thus, the foreign material did not increase the likelihood of a loss of component cooling water event or result in the loss of safety function of the component cooling heat exchangers in any internally or externally initiated core damage accident sequences. (Section 1R07).

- Green. A self-revealing non-cited violation of Technical Specification (TS) 6.8.1.a was made apparent for failure to properly perform maintenance in accordance with written procedures for the 13 turbine-driven auxiliary feedwater pump steam admission valve (1MS132). Maintenance technicians added lubricant, not specified by work instructions, to the valve and actuator stems which prevented the stem block from achieving adequate coupling with the stems.

  This issue was more than minor because it was associated with the equipment performance attribute, and it affected the Mitigating Cornerstone objective. The inspectors determined that the finding was of very low safety significance (Green) using the Phase 1 SDP because the finding was not a design or qualification deficiency; it did not represent an actual loss of safety function of a single train for greater than the TS allowed outage time; and it did not screen as potentially risk significant for externally initiated core damage accident sequences. (Section 1R19.2).

- Green. A self-revealing non-cited violation of 10 CFR Part 50, Appendix B, Criterion III, “Design Control,” was made apparent for failure to incorporate adequate instructions to adjust the open torque switch bypass setting on the 12 nuclear service water header crosstie valve, 12SW17, into the design change package which modified the valve from a limit seated, soft seated butterfly valve to a torque seated, hard seated butterfly valve.

  This issue was more than minor because it was associated with the equipment performance attribute, and it affected the Mitigating Cornerstone objective. The inspectors determined that the finding was of very low safety significance (Green) using the Phase 1 SDP because the finding was a design deficiency that resulted in a loss of function of a single train for less than the TS allowed outage time; and it did not screen as potentially risk significant for externally initiated core damage accident sequences. (Section 1R19.3).

- Green. A self-revealing non-cited violation of Technical Specification 6.8.1.a was made apparent for failure to establish maintenance instructions appropriate to the circumstances for preventive maintenance performed on the 13 turbine-driven auxiliary feedwater pump overspeed trip mechanism. Consequently, PSEG personnel did not identify wear on the overspeed trip device tappet nut which resulted in the 13 turbine-driven auxiliary feedwater pump tripping during surveillance testing on March 30, 2004.

  This issue was more than minor because it was associated with the equipment performance attribute, and it affected the Mitigating Systems Cornerstone objective. The inspectors determined that the finding was of very low safety significance (Green) using the Phase 1 SDP because the finding was not a design or qualification deficiency; it did not represent an actual loss of safety function of a single train for greater than the TS allowed outage time; and it did not screen as potentially risk significant for externally initiated core damage accident sequences. (Section 1R22).

- Green. A self-revealing non-cited violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," was made apparent for failure to identify and correct a condition that rendered the 11 service water traveling water screen (TWS) unavailable.

  This finding was more than minor because it was associated with the equipment performance attribute, and it affected the Initiating Event and Mitigating System Cornerstone objectives. In accordance with IMC 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," the Region I Senior Reactor Analyst (SRA) conducted a Phase 3 SDP analysis of the significance of the performance deficiency and determined the finding was of very low safety significance (Green). In this analysis, the SRA assumed that the 11 TWS was out-of-service for 68 hours and that the loss of service water (LOSW) initiating event frequency increased during this time because of lost redundancy in the service water trains as a result of the performance deficiency. The SRA determined that the increase in core damage frequency due to internally initiated events was in the low E-8 range. (Section 4OA5.7).

- Green. A self-revealing non-cited violation of TS 6.8.1.a was identified for failure to establish maintenance instructions appropriate to the circumstances for preventive maintenance performed on the 25 service water traveling water screen (TWS) which resulted in the subsequent failure of the 25 TWS due to inadequate lubrication of the head shaft bearing.

  This finding was more than minor because it was associated with the equipment performance attribute, and it affected the Initiating Event and Mitigating System Cornerstone objectives. In accordance with IMC 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," the Region I SRA conducted a Phase 3 SDP analysis of the significance of the performance deficiency and determined the finding was of very low safety significance (Green). In this analysis, the SRA assumed that the 25 TWS was out-of-service for 177 hours and that the loss of service water (LOSW) initiating event frequency increased during this time because of lost redundancy in the service water trains as a result of the performance deficiency. The SRA determined that the increase in core damage frequency due to internally initiated events was in the low E-8 range. (Section 4OA5.8).

Cornerstone: Barrier Integrity

- Green. The inspectors identified a non-cited violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," for failure to implement corrective actions and preclude service water flow control valve 25SW223 failure and inoperability of its associated containment fan coil unit (CFCU). In October 2000, PSEG assigned corrective actions to improve the reliability of control air to all Unit 1 and Unit 2 SW223 valves in order to address a know design deficiency. The corrective actions were not implemented on the 25SW223 valve prior to its failure on April 18, 2004, due to the same cause.

This finding was more than minor because it was associated with the structures, systems, or component performance attribute and it affected the barrier integrity cornerstone objective. The inspectors determined that the finding was of very low safety significance using Inspection Manual Chapter 0609, Appendix H, "Containment Integrity Significance Determination Process," because the CFCUs are not important to large early release frequency, in that, the Salem units have large dry containments and the CFCUs only impact late containment failure and source terms. (Section 1R12.1).

- Green. Green self-revealing non-cited violation of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," was made apparent for failure to provide maintenance instructions appropriate to the circumstances for troubleshooting activities on the solid state protection system which led to an invalid safety injection signal actuation and caused the control room emergency air conditioning system to be unable to meet General Design Criteria 19 for approximately 2 hours.

  This finding was greater than minor because it resulted in the Unit 2 control room emergency air conditioning system being aligned such that it did not comply with its design basis for post loss of coolant accident mitigation. The inspectors determined that the finding was of very low safety significance (Green) using the Phase 1 SDP because the finding only represented a degradation of the radiological barrier function provided for the control room. (Section 4OA3.1).

B. Licensee Identified Violations

Violations of very low safety significance, which were identified by PSEG have been reviewed by the inspectors. Corrective actions, taken or planned by PSEG have been entered into PSEG's corrective action program. These violations and corrective action tracking numbers are listed in Section 40A7.

REPORT DETAILS

Summary of Plant Status

Unit 1 began the period in its sixteenth refueling outage. The main generator was placed on-line on June 3 and achieved 100% power on June 11, 2004. A downpower to 45% occurred on June 17 to comply with Technical Specification requirements associated with 12 charging pump discharge check valve back leakage. The charging pump technical issues were resolved the same day and the load reduction was suspended. The main turbine was removed from service on June 19 and June 23 for balance of plant issues. On June 25 the main turbine was restored to 100% power. On June 29 power was reduced to about 85% to support a 500kV line outage.

Unit 2 began the period at 100% power. On April 3, April 14, May 10, and June 29 500kV line outages necessitated Unit 2 operate at reduced power. With the exception of June 29, power was maintained no less than about 85%. On May 21, 2004, operators performed a manual reactor shutdown to cold shutdown conditions in response to a 2B 230V vital bus transformer failure. Unit 2 was restarted on May 31, 2004. 100% power was achieved on June 2, 2004. On June 29, 2004, power was reduced to approximately 65% and restored to 100% on June 30, 2004.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems/Barrier Integrity

1R04 Equipment Alignment (71111.04 - 3 samples)

a. Inspection Scope

Partial System Walkdown. The inspectors performed the following three partial system walkdowns:

- 12 service water (SW) header, 1 and 3 SW bays, and motor control center lineups while the 11 SW header was out-of-service for refueling maintenance activities on April 1 and 2;
- Unit 1 spent fuel pool cooling system during full core off-load on April 6 and 7; and
- 1A emergency diesel generator (EDG) and supporting systems, including fuel oil, service water, starting air, and electrical switch lineups, while the 1B EDG was out of service for planned maintenance on April 13.

The inspectors used the following references during the inspection:

- S1.OP-SO.SW-0002, "11 Nuclear Service Water Header Outage;"
- S1.OP-SO.SF-0002, "Spent Fuel Cooling System Operation;"
- S1.OP-SO.DG-0001, "1A Diesel Generator Operation;" and
- Drawings 205249, 205242, 240670, 205242, and 205233.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05 - 11 samples)

a. Inspection Scope

The inspectors walked down the following twelve risk significant areas to observe the operational condition of fire detection, suppression and barrier systems, and to verify the proper control of transient combustibles. The inspectors referenced Salem pre-fire plans and NC.DE-PS.ZZ-0001-A6-GEN, “Programmatic Standard Salem Fire Protection Report - General.”

- Unit 1 containment all elevations
- Unit 1 and 2 service water intake structure all elevations
- Unit 1 service water tunnel
- Unit 1 and 2 chemical volume control system waste holdup tank area
- Unit 2 volume control and boric acid tank area
- Unit 1 and 2 fuel handling building 84', 100', and 116' elevations
- Unit 1 and 2 fuel handling building 130‘ elevation

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures (71111.06 - 1 sample)

a. Inspection Scope

The inspectors evaluated internal flood protection measures in the Unit 1 78' elevation mechanical penetration room and the Unit 1 service water pipe tunnel. The areas were walked down to assess operational readiness of various features to protect vital electric power systems from internal flooding. Features included drainage systems, water-tight doors and barriers, and electrical and wall penetration seals. The inspectors reviewed the Salem Updated Final Safety Analysis Report (UFSAR) and the Probabilistic Risk Assessment to identify areas susceptible to internal flooding. The inspectors also reviewed engineering evaluation S-C-A900-MEE-0158-0, “Internal Flooding of Power Plant Buildings - INPO-SOER 85-05 Recommendations 1 and 2," and Salem procedures S1.OP-AB.ZZ-0002, “Flooding,” SC.MD-PM.ZZ-0036, “Watertight Door Inspection and Repair,” and SC.FP-SV.FBR-0026, “Flood and Fire Barrier Penetration Seal Inspection.”

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance (71111.07 - 1 sample)

a. Inspection Scope

The inspectors reviewed the 12B component cooling (CC) heat exchanger performance data. The inspectors reviewed performance trending results for the heat exchanger and compared them against acceptance criteria contained in procedure S1.OP-PM.CC-0012, “12 Component Cooling Heat Exchanger High Flow Flush and Alignment.” The inspectors also performed system walkdowns and observations of internal inspections at various times during the Spring 2004 Unit 1 refueling outage. The inspectors interviewed the service water system program manager and discussed the testing methodology for monitoring the thermal-hydraulic performance of the 12B heat exchanger.

b. Findings

Introduction. A Green self-revealing non-cited violation (NCV) was identified for failure to prevent foreign material from entering the 12A and 12B component cooling water heat exchangers.

Description. On April 23, 2004, PSEG personnel conducted a routine internal inspection of the 12A and 12B CC heat exchangers. Personnel discovered pieces of plywood and duct tape in the service water side waterboxes. PSEG personnel concluded that the debris was generated from previous maintenance activities, most likely during the previous refueling outage in Fall 2002. PSEG personnel removed the debris from the heat exchangers. The inspectors noted that PSEG personnel did not identify any foreign material in the 11 CC heat exchanger inspection which had been performed earlier in the refueling outage.

Analysis. The performance deficiency associated with this issue was human performance related and involved a failure to follow station procedure SH.MD-AP.ZZ-0052(Q), “Foreign Material Exclusion,” to prevent foreign material intrusion. Traditional enforcement does not apply because the issue did not have any actual safety consequences or potential for impacting the NRC’s regulatory function, and it was not the result of any willful violation of NRC requirements. This finding was more than minor because it was associated with the equipment performance attribute, and it affected the mitigating systems cornerstone objective. The inspectors determined that the finding was of very low safety significance (Green) using the Phase 1 Significance Determination Process (SDP) because the as-found heat exchanger performance data demonstrated that the heat exchangers were marginally impacted by the foreign material; and thus, the foreign material did not increase the likelihood of a loss of component cooling water event or result in the loss of safety function of the CC heat exchangers in any internally or externally initiated core damage accident sequences.

Enforcement. 10 CFR Part 50 Appendix B, Criterion V, “Instructions, Procedures, and Drawings,” requires that activities affecting quality shall be prescribed by procedures and shall be accomplished in accordance with these procedures. PSEG procedure SH.MD-AP.ZZ-0052(Q), “Foreign Material Exclusion,” Revision 7, contains the instructions and requirements to prevent foreign material intrusion from causing component failures. Contrary to the above, PSEG personnel did not follow SH.MD-AP.ZZ-0052 while performing maintenance on the service water system during the Fall 2002 refueling outage on Salem Unit 1 as evidenced by the foreign material discovered in the 12A and 12B CC heat exchangers on April 23, 2004. Because this failure to follow procedure instructions is of very low safety significance and has been entered into the corrective action program (Notification 20187588), this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: **NCV 05000272/2004003-01, Inadequate FME Fouls 12A and 12B Component Cooling Heat Exchangers**.

1R08 Inservice Inspection (ISI) Activities (71111.08P - 5 samples)

a. Inspection Scope

The inspectors reviewed the reactor vessel top and bottom head inspection activities, including the implementation of ultrasonic, eddy current and visual inspections and the disposition of indications discovered during the volumetric examinations of the reactor vessel head penetration nozzles. The inspectors reviewed the steam generator management program and the eddy current examinations of the steam generator tubes. The inspectors reviewed the component repair and replacement program; however, there were no samples of pressure boundary welding on ASME Class 1 or 2 systems available for review.

The inspectors independently observed 100% of the Unit 1 reactor vessel head visual examinations and subsequently reviewed 100% of the photographic records of the current examination. The inspectors compared the current photographic examination records to the previous visual examination photographic records. The inspectors reviewed the visual examination procedure, interviewed the individuals who performed the visual inspections and reviewed their qualifications to ensure that PSEG's programmatic controls for this activity were appropriate.

The inspectors reviewed the reactor vessel head visual examination results which concluded that there was no evidence of leakage, either from any of the reactor vessel head penetrations or from any of the canopy seals. The inspectors reviewed PSEG's planned and completed corrective actions for the following two anomalies noted during the inspection.

- An indeterminate stain, that appeared to originate from above the canopy seal weld and drive adapter coupling, was observed on a small population of tubes. PSEG planned to evaluate this condition by performing a chemical analysis of the material and by performing a visual examination above the control drive assemblies.
- Developer residue remained on some of the canopy seal welds. The NRC inspectors discussed this issue with the PSEG inspection personnel and concluded that they were capable of differentiating between the developer residue and a canopy seal leak.

The inspectors reviewed the first-time application, at Salem, of ultrasonic and eddy current examinations of the control rod drive assembly penetration nozzles. The examination was performed to comply with the requirements of NRC Order EA-03-009, as revised on February 20, 2004, and included limits as described in relaxation request S1-RR-I3-B21. The inspectors observed the evaluation, by ultrasonic time-of-flight-diffraction, of control drive mechanisms 24 and 74. The inspectors reviewed the calibration used to assure examination adequacy and discussed, with the lead analyst, the calibration's relationship with the test. The inspectors interviewed the Level III responsible for the final acceptance of the test. The inspectors reviewed qualification records and determined that the individuals involved in examining the control drive mechanism tubes were adequately qualified under the auspices of the governing codes and specifications.

The inspectors reviewed the Unit 1 steam generator program, steam generator aging management program, and the steam generator operational assessment. The inspectors observed selected steam generator tube inspection activities to determine whether PSEG's procedures and equipment met the requirements of the plant Technical Specifications, and the Electric Power Research Institute Guidelines.

The inspectors reviewed PSEG's component repair and replacement program to determine whether replacement activities conformed with the requirements of the American Society of Mechanical Engineers (ASME) Code Section XI.

b. Findings

No findings of significance were identified.

1R12 Maintenance Implementation (71111.12 - 2 samples)

a. Inspection Scope

Routine Maintenance Effectiveness Inspection. The inspectors performed two maintenance effectiveness inspections and reviewed notifications documenting past operating problems, system health reports, and maintenance rule performance criteria to determine if PSEG had effectively monitored the performance of two emergent issues. The issues involved a containment fan coil unit flow control valve (25SW223) and a control room ventilation chiller flow control valve (21SW102). The inspectors interviewed system engineers, valve engineers and maintenance rule program coordinators to determine the effectiveness of established and proposed corrective actions. The inspectors also referenced 10 CFR Part 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," and NUMARC 93-01, "Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," to ascertain the acceptability of PSEG's maintenance rule application.

b. Findings

1. 25 Containment Fan Coil Unit Repetitive Failure

Introduction. The inspectors identified a Green NCV for failure to implement corrective actions and preclude repetitive service water flow control valve 25SW223 deficiencies which rendered the associated 25 containment fan coil unit (CFCU) inoperable.

Description. On April 18, 2004, control room operators noticed service water flow oscillations on the 25 CFCU. The operators secured the 25 CFCU in accordance with station procedures and declared it inoperable. Maintenance technicians subsequently discovered a sizable air leak on control air tubing associated with 25SW223 that caused the valve to operate abnormally.

PSEG personnel determined the cause of the failure to be vibration induced fatigue failure at a joint on the air tubing. The inspectors noted that this failure mechanism had been previously identified in evaluation 70009562, which addressed the failure of the same valve in July 2000. The inspectors also noted that one of the corrective actions associated with this evaluation was to replace stiff air tubing with a flexible tubing type. The inspectors observed that some of the stiff tubes had not been replaced on the ten SW223 valves that service five CFCUs in each Salem unit.

Analysis. The performance deficiency associated with this finding has a problem identification and resolution cross cutting aspect. Incomplete corrective action allowed CFCU inoperability to recur from a know control air design deficiency. Traditional enforcement does not apply because the issue did not have any actual safety consequences or potential for impacting the NRC's regulatory function, and it was not the result of any willful violation of NRC requirements. This finding was more than minor because it was associated with the structures, systems, or component performance attribute, and it affected the barrier integrity cornerstone objective. The inspectors determined that the finding was of very low safety significance using Inspection Manual Chapter (IMC) 0609, Appendix H, "Containment Integrity Significance Determination Process," because the CFCUs are not important to large early release frequency, in that, the Salem units have large dry containments and the CFCUs only impact late containment failure and source terms.

Enforcement. 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requires that conditions adverse to quality be promptly identified and corrected. Contrary to the above, PSEG failed to implement corrective actions to correct a known control air deficiency on the 25SW223 valve in a timely manner resulting in the inoperability of 25 CFCU. The corrective actions were developed on October 9, 2000, (order 70009562) and had not been implemented when the valve failed on April 18, 2004. Because this finding is of very low safety significance and the issue has been placed into PSEG's corrective action program (notification 20194799) this violation is being treated as an NCV, consistent with section VI.A of the NRC Enforcement Policy: **NCV 05000311/2004003-02, Repetitive 25 Containment Fan Coil Unit Failure.**

2. 21 Control Room Ventilation Chiller Repetitive Failure

Introduction. The inspectors identified a Green NCV for failure to implement corrective actions and preclude repetitive service water flow control valve 21SW102 deficiencies which rendered the 21 control room ventilation chiller inoperable.

Description. On April 9, 2004, equipment operators identified the 21 chiller condenser service water flow control valve 21SW102 cycling excessively. Operators initiated notification 20185302 to identify the issue and enter it into the corrective action program. Work planners placed the repair activity on hold and rescheduled the maintenance to coincide with a previously planned preventative maintenance (PM) task (order 30102232) the week of May 23, 2004. On April 12, 2004, equipment operators identified a significant packing leak on 21SW102, about 120 drops per minute, and initiated notification 20185551, which was also combined with PM order 30102232. On May 17, the control room operators declared the 21 chiller inoperable when the 21SW102 valve packing failed.

As documented in corrective action evaluation 70035455, which was completed in December 2003 in response to previous SW102 valve failures, PSEG personnel determined that a combination of excessive valve cycling and packing leakage was a sign of imminent failure and corrective maintenance should be expedited. One of the corrective actions associated with this evaluation was to train maintenance superintendents and plant engineers on this symptom and the need for immediate repair. The inspectors noted that corrective maintenance activities had not been expedited to address the degrading condition of 21SW102 between April 9 and May 17, 2004, when the valve failed.

Analysis. The performance deficiency associated with this finding has a problem identification and resolution cross cutting aspect. Corrective actions developed from previous SW102 valve failures were not effectively implemented resulting in additional failures of the 21 chiller. Traditional enforcement does not apply because the issue did not have any actual safety consequences or potential for impacting the NRC's regulatory function, and it was not the result of any willful violation of NRC requirements. This finding was more than minor because it was associated with the equipment performance attribute and it affected the initiating event cornerstone objective. In accordance with IMC 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," the inspectors conducted a Phase 1 SDP screening and determined that a Phase 2 SDP evaluation was required because the finding contributed to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions would not be available.

The inspectors conducted a Phase 2 SDP evaluation of the significance of the performance deficiency and determined the finding was of very low safety significance (Green). In this evaluation, the inspectors assumed an exposure period of less than three days, the likelihood of a loss of control room ventilation event was increased by one order of magnitude, all mitigating equipment for a loss of control room ventilation event was unaffected by the finding, and operator recovery actions were feasible. The dominant accident sequence involved a loss of control room ventilation event with failure of alternate ventilation and failure of operators to shutdown the plant using remote shutdown procedures.

Enforcement. 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requires that conditions adverse to quality be promptly identified and corrected to prevent recurrence. Contrary to the above, corrective actions developed in December 2003 for a known SW102 valve deficiency failed to prevent a similar failure of the 21SW102 valve on May 17, 2004. Because this finding is of very low safety significance and the issue has been placed into PSEG's corrective action program (notification 20194800) this violation is being treated as an NCV, consistent with section VI.A of the NRC Enforcement Policy: **NCV 05000311/2004003-03, 21 Control Room Ventilation Chiller Repetitive Failure.**

1R13 Maintenance Risk Assessments and Emergent Work Evaluation (71111.13 - 7 samples)

a. Inspection Scope

The inspectors reviewed PSEG's planning and risk assessments for seven risk significant activities listed below. The inspectors reviewed control room operating logs and PSEG probabilistic safety assessment risk evaluation forms, walked down protected equipment and maintenance locations, and interviewed involved personnel. These reviews were performed to determine whether PSEG properly assessed and managed plant risk, and performed activities in accordance with applicable Technical Specification and work control requirements. The activities selected were based on plant maintenance schedules and systems that contribute to plant risk. The inspectors also referenced Regulatory Guide 1.182, "Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants," and PSEG procedure SH.OP-AP.ZZ-0027, "On-Line Risk Assessment."

- 1B vital bus outage and No. 3 station power transformer concurrent plant refueling maintenance on April 13, 2004
- Station air compressor emergent repairs on April 17 through 20, 2004
- 5021 500kV line, 1A emergency diesel generator, and 1A inverter concurrent planned refueling maintenance on April 19, 2004
- 5021 500kV line, 3 service water bay, 12 component cooling (CC) heat exchanger, and 11 charging pump concurrent planned refueling maintenance on April 26, 2004
- 2B 230V and 460V vital busses emergent outage and maintenance on May 19, 2004
- Unit 3 gas turbine generator planned maintenance on June 7, 2004
- 12 auxiliary feedwater pump, 12CC water pump and room cooler concurrent planned maintenance on June 28, 2004

b. Findings

No findings of significance were identified.

1R14 Operator Performance During Non-routine Evolutions and Events (71111.14 - 4 samples)

a. Inspection Scope

The inspectors observed control room operators during the performance of four non-routine plant evolutions. The inspectors reviewed operating procedures, attended operator briefings, observed reactor operators manipulate controls during various steps within the operating procedures, and interviewed senior reactor operators regarding contingency plans. Procedures reviewed are listed in the Attachment.

- On March 30 and 31, 2004, the inspectors observed control room operators shut down Unit 1 from power operations to cold shutdown conditions to begin the sixteenth Unit 1 refueling outage.
- On May 21, 2004, the inspectors observed control room operators respond to a trip of the 2B 460V and 230V vital bus. The inspectors further observed operators shut down Unit 1 from power operations to hot standby conditions.

- On May 29, 2004, the inspectors observed operators take Unit 1 critical, perform portions of low power physics testing, and commence turbine testing.
- On May 31, 2004, the inspectors observed operators take Unit 2 critical.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15 - 6 samples)

a. Inspection Scope

The inspectors reviewed six operability determinations (ODs). The reviews assessed technical adequacy, the use and control of compensatory measures, and compliance with the licensing and design basis. The inspectors' review included a verification that the operability determinations were made as specified by PSEG's procedure SH.OP-AP.ZZ-0108, "Operability Assessment and Equipment Control Program." The technical content of the ODs and the follow-up operability assessments were reviewed and compared to applicable Technical Specifications, the Updated Final Safety Analysis Report, and associated design and licensing basis documents. The inspectors also interviewed operations management, design engineers and system engineers. The following operability issues were reviewed:

- 1A emergency diesel generator backfire during mode operations surveillance testing (notification 20184188);
- Unit 2 service water bay 2 ventilation dampers stuck open (notification 20185328 and 20185401);
- Unit 1 containment spray system water-hammer (OD 70038861);
- 12, 21 and 22 RHR mechanical pump seal nonconformance (OD 70038699);
- 13 station power transformer to 1C vital bus infeed breaker failure to close (notification 20185409);and
- 11 and 15 service water pumps failure to start during mode operations surveillance testing (several notifications listed in the Attachment).

b. Findings

No findings of significance were identified. However, the issue involving 11 and 15 service water pumps failing to start was attributed to degraded auxiliary switch contacts in the 12 and 16 service water pump breaker cubicles. This issue is unresolved pending inspector review of failure analysis reports from PSEG contracted laboratories. The inspectors verified that there were no current operability concerns with the replaced auxiliary switches and like switches in other safety applications. This issue is identified as URI 05000272/2004003-04, Failure of 11 and 15 Service Water Pumps Due to Degraded Auxiliary Switch Contacts in Power Supply Breaker.

1R16 Operator Work-Arounds (71111.16 - 2 samples)

a. Inspection Scope

During the week of May 31, 2004, the inspectors performed a review of Unit 1 and Unit 2 PSEG identified operator workarounds and assessed the potential for any cumulative impact for operators to properly respond to a plant transient or accident. The inspectors also walked-down Unit 1 and Unit 2 main control room panels and reviewed all tagged equipment deficiencies for potential unidentified operator workarounds. Control room operator and equipment operator turnover sheets were also reviewed for tracked equipment deficiencies. The inspectors reviewed the Salem Night Order Book to verify that guidance contrary to established written procedures was not being used. The inspectors referenced NRC Inspection Procedure 71111.16, "Operator Workarounds."

b. Findings

No findings of significance were identified.

1R19 Post Maintenance Testing (71111.19 - 8 samples)

a. Inspection Scope

The inspectors observed portions of and reviewed documentation for post maintenance testing (PMT) associated with the following eight work activities:

- Service water turbine header isolation valve (1SW26) replacement;
- 13 auxiliary feedwater pump steam admission valve (1MS132) rebuild;
- Nuclear service water header crosstie valve (12SW17) design change;
- 12 and 16 service water pump cubicle auxiliary switch (52STA) replacements;
- 25 service water pump motor replacement;
- Residual heat removal hot leg injection valve (1RH26) maintenance;
- 13 containment fan cooler unit low speed breaker repair; and
- 1B emergency diesel generator turbocharger replacement.

The inspectors assessed whether: (1) the effect of testing on the plant had been adequately addressed by control room and engineering personnel; (2) testing was adequate for the maintenance performed; (3) acceptance criteria were clear and adequately demonstrated operational readiness, consistent with design and licensing basis documents; (4) test instrumentation had current calibrations, range, and accuracy for the application; (5) tests were performed, as written, with applicable prerequisites satisfied; and (6) equipment was returned to an operable status and ready to perform its safety function.

b. Findings

1. Inoperable Turbine Building Service Water Isolation Valve

On June 02, 2004, PSEG troubleshooting activities identified that turbine building service water (SW) isolation valve 1SW26 was not operating properly. 1SW26 has a safety function to close on a safety injection signal isolating service water to non-safety loads. The troubleshooting was initiated in response to abnormal conditions observed by operators on turbine building service water loads during plant startup activities after the Unit 1 Spring 2004 refuel outage. Technicians discovered that 1SW26 actually became more open with a closed signal. PSEG personnel had refurbished 1SW26 during the refueling outage and it was returned to service on May 07, 2004.

Control room operators immediately declared 1SW26 inoperable for closing and entered Technical Specification 3.6.1.1. for primary containment integrity at 12:30 p.m. on June 02, 2004. Technical specification 3.6.1.1 had applicability to this issue because inadequate isolation by 1SW26 could jeopardize service water lines to containment fan coil units during certain design basis loss of coolant accident scenarios. The limiting condition for operation as specified by Technical Specification 3.6.1.1 was established at 9:41 p.m. on June 02, 2004, when control room operators closed redundant service water isolation valves. The time expended in closing redundant service water isolation valves occurred while operators shut down the reactor from about 18% power to hot standby conditions in response to the issue. PSEG entered the 1SW26 issue into the corrective action program as Notification 20186416.

This issue is unresolved pending completion of PSEG's evaluation and NRC review to determine the existence of a performance deficiency. **URI 05000272/2004003-05, Inoperable Turbine Building Service Water Isolation Valve.**

2. Incorrect Assembly of 1MS132

Introduction. A Green self-revealing NCV of TS 6.8.1.a was identified for failure to perform maintenance on the 13 turbine-driven auxiliary feedwater pump steam admission valve, 1MS132, in accordance with written procedures which rendered the pump unreliable and inoperable.

Description. On May 21, 2004, operators identified 1MS132 stem block failed during performance of S1.OP-ST.AF-0003, "Inservice Testing - 13 Auxiliary Feed Pump." The stem block couples the valve stem to actuator stem. Operators noticed during the test that the 13 turbine-driven auxiliary feedwater pump was running, but 1MS132 did not indicate fully open. Operators were dispatched to the valve where they discovered that the valve was open but the stem was twisted at the stem block. Operators shut 1MS132 and isolated it by closing upstream valves 11MS45 and 13MS45.

PSEG personnel evaluated the condition and found that technicians had erroneously applied a lubricant to the threaded valve stem and threaded valve stem coupling block during valve reassembly on May 18, 2004, following over-speed testing on the 13 auxiliary feed pump turbine. The lubricant prevented the block from achieving adequate coupling with the valve stem. The poor coupling allowed the valve stem to twist inside the coupling block which allowed the valve to open but did not allow the open limit switch to be actuated. Maintenance procedure, SH.IC-GP.ZZ-0002, "Disassembly, Inspection, Reassembly and Testing of Masoneilan Model 37/38 Air Operated Actuators," which was the appropriate procedure for performing maintenance, did not prescribe lubricating the stem or stem block.

Analysis. The performance deficiency associated with this event has human performance and problem identification and resolution cross cutting aspects. Specifically, work procedures did not instruct lubrication to be applied to the stem block, however, maintenance technicians erroneously added lubricant. Problem identification and resolution aspects were evident because this valve failed in May 2003 from similar maintenance deficiencies associated with the stem block reassembly. Reference NRC Inspection Report 05000272/2003007 and 05000311/2003007, Section 1R12.

Traditional enforcement does not apply because the issue did not have any actual safety consequences or potential for impacting the NRC's regulatory function, and it was not the result of any willful violation of NRC requirements. This issue was more than minor because it was associated with the equipment performance attribute, and it affected the Mitigating Systems Cornerstone objective. The inspectors determined that the finding was of very low safety significance (Green) using the Phase 1 SDP because the finding was not a design or qualification deficiency; it did not represent an actual loss of safety function of a single train for greater than the TS allowed outage time; and it did not screen as potentially risk significant for externally initiated core damage accident sequences.

Enforcement. Salem Unit 1 Technical Specification 6.8.1.a. requires that written procedures shall be established covering the activities in Appendix A of Regulatory Guide 1.33, Revision 2, February 1978, which specifies that maintenance that can affect the performance of safety-related equipment should be properly performed in accordance with written procedures, documented instructions, or drawings appropriate to the circumstances. Contrary to the above, on May 18, 2004, 1MS132 was not reassembled in accordance with maintenance procedure SH.IC-GP.ZZ-0002, "Disassembly, Inspection, Reassembly and Testing of Masoneilan Model 37/38 Air Operated Actuators," in that, maintenance technicians performed an action not specified by procedure when lubricant was added to the valve and actuator stems at the stem block coupling. The lubricant caused 1MS132 to operate unreliably. Because the failure to properly perform maintenance on 1MS132 is of very low safety significance and has been entered into PSEG's corrective action program (20190856), this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: **NCV 05000272/2004003-06, Incorrect Assembly of 1MS132.**

3. Design Modification Resulting in Failure of 12SW17 to Open

Introduction. A Green self-revealing NCV of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," was identified during the 16 service water pump surveillance testing on June 6, 2004, when the 12 nuclear service water header crosstie valve, 12SW17, failed to stroke open. The 12SW17 had been modified, but valve engineers did not identify the need to change torque switch bypass characteristics.

Description. At 1:34p.m. on June 6, 2004, 12SW17 failed to stroke open during performance of S1.OP-ST.SW-0006, "Inservice Testing - 16 Service Water Pump." Subsequent troubleshooting efforts by maintenance technicians revealed a problem with a torque switch bypass that prevented the valve from opening. The bypass was adjusted and the valve was opened at 5:57p.m. later that day.

PSEG personnel changed the design of the 12SW17 valve during refueling outage 1R16 from a limit seated, soft seated butterfly valve to a torque seated, hard seated butterfly valve design. The valve opening torque characteristics are significantly different for a soft seated valve and a hard seated valve of this type. Opening torque for a hard seated butterfly valve must be bypassed for a significantly longer duration or the torque switch will trip the valve when opened. The valve's design change package

(DCP) did not revise the open torque switch bypass control, as was necessary. Maintenance procedure, SH.MD-EU.ZZ-0011, “Valve Operation Test and Evaluation System (VOTES) Data Acquisition for Motor Operated Valves,” and Attachment 10, “Limit Switch Settings,” identified the open torque switch bypass be nominally set at 25% to 50% of stem travel for a hard seated butterfly valve. However, the actual setting of this switch prior to the failure was 3.3% of stem travel.

Analysis. The performance deficiency has a human performance cross cutting aspect. Valve engineers did not ensure that instructions provided by maintenance procedure, SH.MD-EU.ZZ-0011, “Valve Operation Test and Evaluation System (VOTES) Data Acquisition for Motor Operated Valves,“ were incorporated into the DCP. Traditional enforcement does not apply because the issue did not have any actual safety consequences or potential for impacting the NRC’s regulatory function, and it was not the result of any willful violation of NRC requirements. This issue was more than minor because it was associated with the equipment performance attribute, and it affected the Mitigating Systems Cornerstone objective. The inspectors determined that the finding was of very low safety significance (Green) using the Phase 1 SDP because the finding was a design deficiency that resulted in a loss of function of a single train for less than the TS allowed outage time; and it did not screen as potentially risk significant for externally initiated core damage accident sequences.

Enforcement. 10 CFR 50, Appendix B, Criterion III, “Design Control,” states, in part, that measures shall be established to assure that applicable regulatory requirements and the design basis for those structures, systems, and components to which this appendix applies are correctly translated into specifications, drawings, procedures and instructions. Contrary to the above, the 12SW17 design package, order 80060251, implemented on April 29, 2004, did not contain adequate instructions to adjust the open torque switch bypass setting on 12SW17 to be appropriate for a hard seated butterfly valve design. Consequently, 12SW17 failed to open after being closed on June 6, 2004. Because the failure of 12SW17 to operate correctly is of very low safety significance and has been entered into PSEG’s corrective action program (20192409), this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: **NCV 05000272/2004003-07, Design Modification Resulting in Failure of 12SW17 to Open.**

1R20 Refueling and Other Outage Activities (71111.20 - 2 samples)

1. Unit 1 Refueling Outage 16 Activities

a. Inspection Scope

The inspectors reviewed the Salem 1R16 Schedule Review and Risk Assessment Report for the Unit 1 refueling outage (March 30 - June 3, 2004) to confirm that PSEG had appropriately considered risk, industry experience, and previous site-specific problems in developing and implementing a plan that assured maintenance of defense-in-depth. During the refueling outage, the inspectors observed portions of the shutdown and cooldown processes and monitored PSEG controls over the outage activities listed below. Documents reviewed during the inspection are listed in the Attachment.

- Outage risk management
- Confirmation that tagged equipment was properly hung and equipment configured to safely support work or testing and redundant equipment remained available
- Reactor coolant pressure, level, and temperature instrument availability
- Electrical system and switchyard configurations and controls
- Decay heat removal operability and operation
- Spent fuel pool cooling capabilities and operation
- Reactor water inventory controls and contingency plans
- Reactivity controls
- Primary containment status and controls
- Fuel off-load and core re-load observed from the containment refueling bridge, the spent fuel pool, and the main control room
- Startup and ascension to full power operation, tracking of mode change and startup prerequisites, walkdown of the primary containment to verify that debris had not been left which could block the emergency core cooling system suction strainer
- Problem identification and resolution related to refueling outage activities

b. Findings

No findings of significance were identified.

2. Unit 2 Forced Outage Activities

a. Inspection Scope

In preparation for Unit 2 plant restart following the 2B 230V vital bus transformer failure and repair, the inspectors performed the activities listed below.

- The inspectors interviewed system engineers, senior plant managers, maintenance technicians and supervisors and observed the as-found condition of the 2B 230V vital bus transformer to ascertain extent of condition concerns for like transformers in other safety applications. The inspectors also discussed preliminary results that PSEG was receiving from its contracted laboratory for failure analysis of the 2B 230V vital bus transformer.

- On May 30 and 31, 2004, the inspectors reviewed the Technical Specification Action Statement Log and the estimated critical position calculation, and performed plant equipment walkdowns.
- On May 31, 2004, the inspectors observed the reactor startup and portions of the power ascension activities.

Various documents associated with shutdown and restart activities are listed in the attachment.

b. Findings

No findings of significance were identified. However, the issue involving the 2B 230V vital bus transformer failure is unresolved pending inspector review of failure analysis reports from PSEG contracted laboratories. The inspectors verified that there were no operability concerns with like transformers in other plant safety applications. This issue is identified as URI 05000311/2004003-08.

1R22 Surveillance Testing (71111.22 - 8 samples)

a. Inspection Scope

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

- S1.OP-ST.SSP-0007, “Engineered Safety Features Containment Isolation - Phase A,” on April 1, 2004;
- SC.MD-FT.SEC-0003, “2C SEC Functional Test,” on April 16, 2004;
- S1.RA-IS.ZZ-0001, “Type B & C Leak Rate Test,” (12CS48 and 11CS48) on April 09, 2004;
- S1.OP-ST.SW-0004, “Inservice Testing - 14 Service Water Pump,” on June 29, 2004; and
- S1.OP-ST.SSP-0001, “Manual Safety Injection - SSPS,” on April 01, 2004.

Additionally, the inspectors reviewed the following surveillance testing problems:

- 13 Auxiliary feedwater pump trip during S1.OP-ST.AF-0007, “Inservice Testing Auxiliary Feedwater Valves Mode 3," on March 30, 2004;
- Inoperable 21 and 22 reactor protection over-temperature delta-temperature instruments during S2.IC-CC.RCP-0005, “2TE-421A-B #22 RX [Reactor] Coolant Delta T-Tavg Protection Channel II,” on March 16 and 17, 2004; and
- Containment spray water hammer during S1.OP-ST.CS-0005, ”Inservice Testing Containment Spray Pump Full Flow Test and Containment Spray Check Valves,” on April 21, 2004.

The inspectors verified that the apparent or root cause of equipment failures were adequately explored, corrective actions developed, and the basis for returning to an operable status was acceptable.

b. Findings

Introduction. A Green self-revealing NCV of TS 6.8.1.a was identified for failure to establish maintenance instructions appropriate to the circumstances for preventive maintenance performed on the 13 turbine-driven auxiliary feedwater pump overspeed trip mechanism. Consequently, PSEG personnel did not identify wear on the overspeed trip device tappet nut which resulted in the 13 turbine-driven auxiliary feedwater pump tripping during surveillance testing on March 30, 2004.

Description. On March 30, 2004, at 8:34 p.m., during the performance of surveillance test S1.OP-ST.AF-0007, “Inservice Testing Auxiliary Feedwater Valves Mode 3," the 13 turbine-driven auxiliary feedwater pump tripped on initial startup. Vibration monitoring equipment had been installed on the equipment prior to startup and the highest observed turbine speed was 1900 rpm, well below the expected overspeed trip setpoint (4800 - 5200 rpm).

Equipment operators did not identify any other problems with the pump, reset the turbine trip throttle valve (1MS52), and successfully restarted the pump. PSEG personnel initiated a technical issues process evaluation while the pump remained inoperable. Unit 1 entered mode 4 reactor plant conditions on March 30, 2004, at 11:38p.m., at which time the 13 turbine-driven auxiliary feedwater pump was no longer required to be maintained operable. The inspectors noted that the 13 turbine-driven auxiliary feedwater pump had been successfully operated during surveillance testing about 45 hours prior to the pump trip.

PSEG’s technical issues process evaluation and root cause evaluation later determined that the overspeed trip device tripped, not due to overspeed, but because of inadequate latching. Less than adequate contact between the tappet nut and the overspeed head lever were a direct cause of the pump trip. Excessive wear existed on the tappet nut. PSEG personnel further determined that the root cause of the issue involved inadequate maintenance processes that failed to detect and correct the tappet nut wear. Root cause evaluators reviewed an annual overspeed trip device preventative maintenance instruction (PM plans 200801and 254043) and noted that inspection guidance or clear expectations were not provided. The last annual overspeed trip device inspection was completed on January 26, 2004. The evaluators believed that the preventative maintenance activity was being performed inconsistently because a 1999 overspeed trip device inspection identified a valid linkage pin deficiency, yet all subsequent annual inspections did not carry forward the deficiency or note its existence even though it was not yet corrected.

Analysis. PSEG’s failure to provide adequate preventative maintenance instructions was a performance deficiency. This issue also had cross-cutting aspects of problem identification and resolutions weaknesses, in that, PSEG investigated an inadvertent trip of the 13 turbine-driven auxiliary feedwater pump in May 2003, but did not identify these issues. Also, a corrective action from the May 2003 pump trip had not been completed to revise all procedures for resetting the turbine trip throttle with an added step providing more assurance of proper resetting. Traditional enforcement does not apply because the issue did not have any actual safety consequences or potential for impacting the NRC’s regulatory function, and it was not the result of any willful violation of NRC requirements. This issue was more than minor because it was associated with the equipment performance attribute, and it affected the Mitigating Systems Cornerstone objective. The inspectors determined that the finding was of very low safety significance (Green) using the Phase 1 SDP because the finding was not a design or qualification deficiency; it did not represent an actual loss of safety function of a single train for greater than the TS allowed outage time; and it did not screen as potentially risk significant for externally initiated core damage accident sequences.

Enforcement. Salem Unit 1 Technical Specification 6.8.1.a. requires that written procedures shall be established covering the activities in Appendix A of Regulatory Guide 1.33, Revision 2, February 1978, which specifies that maintenance that can affect the performance of safety-related equipment should be properly performed in accordance with written procedures, documented instructions, or drawings appropriate to the circumstances. Contrary to the above, on January 26, 2004, PSEG personnel performed preventive maintenance on the 13 turbine-driven auxiliary feedwater pump overspeed trip device using instructions that were not appropriate to the circumstances which resulted in their failure to identify wear on the overspeed trip device tappet nut. As a result, the 13 turbine-driven auxiliary feedwater pump tripped during surveillance testing on March 30, 2004. Because the failure to properly perform maintenance on the 13 turbine-driven auxiliary feedwater pump is of very low safety significance and has been entered into PSEG's corrective action program (notification 20184229), this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: **NCV 05000272/2004003-09, Inadequate 13 Auxiliary Feedwater Pump Inspection Instructions.**

1R23 Temporary Plant Modifications (71111.23 - 1 sample)

a. Inspection Scope

The inspectors reviewed Temporary Modification No. 04-013, "Station Air Compressor Alternate Service Water Discharge Path," on April 20, 2004. The temporary modification involved blind flanges and fire hoses to provide an alternate discharge path for service water cooling from the station air compressors. The station air compressors are the normal source of control air for both Salem Unit 1 and 2. The inspectors assessed whether PSEG followed its administrative process for implementing the modification NC.DE-AP.ZZ-0030, "Control of Temporary Modifications," and verified that the alternate discharge path did not impact structures, systems, or components important to safety.

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness [EP]

1EP6 Drill Evaluation (71114.06 - 1 sample)

a. Inspection Scope

The inspectors observed one emergency preparedness (EP) drill from the control room simulator and the emergency operations facility on June 30, 2004. The inspectors evaluated the conduct of the drill, performance related to developing classifications, and notifications. The inspectors reviewed the Salem/Hope Creek Emergency Plan and the Salem Event Classification Guide. The inspectors referenced Nuclear Energy Institute 99-02, "Regulatory Assessment Performance Indicator (PI) Guidelines" and verified that PSEG had correctly counted this drill's contribution to the NRC PI for Drill and Exercise Performance.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2OS1 Access Control to Radiologically Significant Areas (71121.01 - 5 samples)

a. Inspection Scope

The inspector identified two exposure significant work areas within radiation areas, high radiation areas (<1 R/hr), or airborne radioactivity areas in the plant and reviewed associated PSEG controls and surveys of these areas to determine if the controls (e.g., surveys, postings, barricades) were acceptable. The areas reviewed were inside the Unit 1 bioshield and on the Unit 1 refueling floor.

The inspector walked down these areas and their perimeters to determine: whether prescribed radiation work permit (RWP), procedure, and engineering controls were in place; whether PSEG surveys and postings were complete and accurate; and whether air samplers were properly located. The controls implemented were compared to those required by plant Technical Specifications 6.12 and 10 CFR Part 20, Subpart G, for control of access to high and locked high radiation areas.

The inspector reviewed RWPs used to access these and other high radiation areas and identify what work control instructions or control barriers have been specified. The inspector reviewed electronic personal dosimeter (EPD) alarm set points (both integrated dose and dose rate) for conformity with survey indications and plant policy.

The inspector reviewed RWPs for airborne radioactivity areas with the potential for individual worker internal exposures of >50 mrem CEDE (20 DAC-hrs). The inspector verified barrier integrity and engineering controls performance (e.g., HEPA ventilation system operation).

During job performance observations, the inspector observed radiation worker performance with respect to stated radiation protection work requirements. The inspector determined that they were aware of the significant radiological conditions in their workplace, and the RWP controls/limits in place, and that their performance took into consideration the level of radiological hazards present.

b. Findings

No findings of significance were identified.

2OS2 ALARA Planning and Controls (71121.02 - 5 samples)

a. Inspection Scope

The inspector obtained from PSEG a list of work activities ranked by actual/estimated exposure that were in progress during the Unit 1 refueling outage, and selected two of the work activities of highest exposure significance (reactor maintenance and reactor vessel head inspection).

The inspector reviewed the ALARA work activity evaluations, exposure estimates, and exposure mitigation requirements. The inspector determined that PSEG has established procedures, engineering and work controls, based on sound radiation protection principles, to achieve occupational exposures that are ALARA.

The inspector compared the results achieved (dose rate reductions, person-rem used) with the intended dose established in PSEG's ALARA planning for these work activities.

Based on scheduled work activities and associated exposure estimates, the inspector selected two work activities, listed above, in radiation areas, airborne radioactivity areas, or high radiation areas for observation. The inspector evaluated PSEG's use of ALARA controls for these work activities by evaluating PSEG's use of engineering controls to achieve dose reductions; evaluating procedures and controls for consistency with PSEG's ALARA reviews; determined if sufficient shielding of radiation sources was provided for; and, determined if dose expended to install/remove the shielding exceeded the dose reduction benefits afforded by the shielding.

The inspector observed radiation worker and radiation protection technician performance during work activities being performed in radiation areas, airborne radioactivity areas, or high radiation areas. The inspector determined that workers demonstrated the ALARA philosophy in practice. The inspector also observed radiation worker performance to determine whether the training/skill level was sufficient with respect to the radiological hazards and the work involved.

The inspector reviewed the 2004 Unit 1 refueling outage (1R16) exposure goals. PSEG established an outage goal of 117 person-rem, which included exposure goals of: 24.35 person-rem for reactor maintenance; 22.2 person-rem for primary side steam generator work; 16.15 person-rem for in-service inspections; 5.3 person-rem for secondary side steam generator work; and, 4.5 person-rem for the regenerative heat exchanger work.

b. Findings

No findings of significance were identified.

2OS3 Radiation Monitoring Instrumentation (71121.03 - 2 samples)

a. Inspection Scope

The inspector identified the types of portable radiation detection instrumentation used for job coverage of high radiation area work, other temporary area radiation monitors currently used in the plant, and continuous air monitors associated with jobs with the potential for workers to receive 50 mrem CEDE.

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

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES [OA]

4OA1 Performance Indicator Verification (71151 - 6 samples)

a. Inspection Scope

The inspectors sampled PSEG submittals for the Salem Units 1 and 2 performance indicators (PIs) listed below for the period from April 2003 through March 2004. The inspectors used the PI definitions and guidance contained in NEI 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 2, to verify the accuracy of the PI data reported during the period.

Mitigating Systems Cornerstone

- Safety System Functional Failures

Barrier Integrity Cornerstone

- Reactor Coolant System Activity
- Reactor Coolant System Leakage

The inspectors reviewed all licensee event reports for the safety system functional failure PI, spreadsheet data for daily reactor coolant system dose equivalent iodine results for the Reactor Coolant System (RCS) Activity PI, and spreadsheet data for all daily RCS leakage results for the RCS Leakage PI.

b. Findings

No findings of significance were identified.

4OA2 Problem Identification and Resolution (71152)

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 items entered into PSEG's corrective action program. This review was accomplished by often attending daily screening meetings and accessing PSEG's computerized database.

1. Annual Sample Review (1 sample)

a. Inspection Scope

The inspectors selected five notifications (20153240, 20157706, 20160523, 20182794, and 20182795) for detailed review. The issues identified in these notifications were associated with auxiliary building ventilation charcoal system testing and were generic to Salem Units 1 and 2. Specifically, the tests involved Technical Specification Surveillance Requirement 4.7.7.1.b.5 to sample the charcoal adsorber to ASTM D3803-1989 requirements and verify that the efficiency of the charcoal tested was greater than 85%.

b. Findings and Observations

There were no findings identified associated with the reviewed notifications. However, the inspectors identified the following observations related to problem identification and resolution: the problems reported in several of these notifications were not well defined; the root cause of the failed charcoal filter unit was not identified in a timely manner; and the charcoal analysis data was not trended. The inspectors verified that an adequate root cause analysis was performed and corrective actions were appropriate and executed in a timely manner relative to the identified problem. Therefore, the inspectors concluded that no findings or violations of regulatory requirements occurred.

2. Semi-Annual Assessment of Trends (1 sample)

a. Inspection Scope

The inspectors evaluated problem identification and resolution (PI&R) trending for air-operated valve and motor-operated valve issues and performance monitoring. The inspectors reviewed component health reports, interviewed component engineers, and verified that all recent valve issues identified through plant status were entered into the corrective action program with actions for root or apparent cause evaluation. The inspectors also discussed valve maintenance performance during the recent Unit 1 Spring 2004 outage with maintenance managers and the valve engineering group manager.

b. Findings and Observations

No findings or observations of significance were identified.

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

Section 1R12.1 describes corrective actions to resolve a design deficiency on ten identical service water flow control valves in October 2000 yet several valves had not been modified and an additional failure occurred. The finding refers to an April 18, 2004, 25SW223 valve failure and associated inoperability of the 25 containment fan coil unit.

Section 1R12.2 describes corrective actions to expedite corrective maintenance on control room ventilation chiller service water flow control valves, SW102, when specific degraded conditions were observed. PSEG has not resolved the reliability concerns with the SW102 valves and the corrective actions to expedite maintenance were overlooked in April 2004 and another SW102 valve failed emergently.

Section 1R19.2 describes a repeat failure of the 13 turbine driven auxiliary feedwater pump due to incorrect maintenance on the steam admission valve. A previous failure due to inadequate maintenance on the same valve was described in NRC Inspection Report 05000272/2003007 and 05000311/2003007 Section 1R12. The maintenance errors were not identical, but the issues illustrate corrective action weaknesses in improving the quality of maintenance on the 13 turbine driven auxiliary feedwater pump steam admission valve.

Section 1R22 describes a failure to identify a degraded condition on the 13 turbine driven auxiliary feedwater pump overspeed trip mechanism. Corrective actions from an earlier failure were also not complete.

Section 4OA5.7 describes a failure by equipment operators to early identify an icing condition on the 11 service water traveling water screen. The icing occurred due to a leaky spray wash valve.

4OA3 Event Followup (71153 - 3 samples)

1. (Closed) Licensee Event Report (LER) 05000311/2004003-00, Salem Unit 2 Control Room Emergency Air Conditioning System Unable to Mitigate the Consequences of an Accident

a. Inspection Scope

Inspectors reviewed the LER and the associated corrective action evaluation (notification 20170863) to verify the cause of the April 12, 2004, control room air conditioning event was identified and that the corrective actions were appropriate. The control room emergency air conditioning system (CREACS) alignment problem was caused by an invalid safety injection (SI) signal generated during solid state protection system (SSPS) testing on Unit 1. The inspectors verified that timely notifications were made in accordance with 10 CFR Part 50.72, PSEG staff implemented the appropriate plant procedures, and that plant equipment performed as required.

b. Findings

Introduction. A Green self-revealing NCV of 10 CFR Part 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings,” was identified for failure to provide maintenance instructions appropriate to the circumstances for troubleshooting activities on the solid state protection system.

Description. Salem Units 1 and 2 have a common control room supported by Unit 1 and Unit 2 CREACS trains. On April 12, 2004, the control room ventilation was aligned for refueling maintenance activities on Unit 1. With the established ventilation lineup, Salem Unit 2 must be able to align its make up air supply to pressurize the control room envelope from the Unit 1 intake to meet the requirements of General Design Criteria 19 (for control room habitability and radiation protection). During the inadvertent SI signal generated during troubleshooting on Unit 1, make up air supply was aligned to Unit 2 and defeated to the Unit 1 air intake. Salem Unit 2 was unable to meet GDC 19 criteria for the duration of the signal, about two hours.

PSEG personnel identified that the cause of the SI signal was due to the use of a defective universal circuit card during a troubleshooting activity on the SSPS. During a circuit card replacement evolution that changed existing SSPS circuit cards with refurbished cards, PSEG personnel exhausted the supply of refurbished cards troubleshooting an indication problem. Troubleshooting continued with non-refurbished cards that were just pulled from the system. Existing procedures did not preclude the practice of swapping previously used circuit cards or define the amount of extra refurbished cards needed to perform anticipated troubleshooting. A SI signal was generated when a non-refurbished card that had a defective circuit was placed into the low pressurizer pressure safety injection portion of the SSPS. The failed part of the card was not used in its prior position nor was it tested prior to troubleshooting. This resulted in the failed card not being detected prior to reuse.

Analysis. PSEG's failure to provide appropriate maintenance instructions for troubleshooting activities on the solid state protection system was a performance deficiency. Traditional enforcement does not apply because the issue did not have any actual safety consequences or potential for impacting the NRC's regulatory function, and it was not the result of any willful violation of NRC requirements. This finding was greater than minor because it resulted in the Unit 2 CREAC being aligned such that it did not comply with its design basis for post loss of coolant accident mitigation. The inspectors determined that the finding was of very low safety significance (Green) using the Phase 1 SDP because the finding only represented a degradation of the radiological barrier function provided for the control room.

Enforcement. 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," states, in part, that activities affecting quality shall be prescribed by written instructions, procedures, or drawings of a type appropriate to the circumstances. Contrary to the above, on April 12, 2004, PSEG failed to provide maintenance instructions appropriate to the circumstances for troubleshooting activities on the solid state protection system which led to an invalid safety injection signal actuation and caused the control room emergency air conditioning system to be unable to meet General Design Criteria 19 for approximately 2 hours. Because this failure to maintain adequate maintenance procedures is of very low safety significance and has been entered into PSEG's corrective action program (order 70038387), this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: **NCV**

05000311/2004003-10, Inadequate Troubleshooting Procedures Cause an Inadvertent SI Signal. This LER is closed.

2. (Closed) LER 05000311/2004002-00, Failure to Comply with Technical Specifications During Reactor Protection Instrument Calibration

On March 17, 2004, PSEG personnel discovered that the reactor coolant loop 21 over-temperature delta-temperature (OTDT) protection instrument was inoperable while the 22 OTDT protection instrument was inoperable during calibration. The concurrent inoperability was prohibited by Technical Specification 3.3.1.1 and existed from 9:26 a.m. on March 16 to 6:16 p.m. on March 17, 2004. The 21 OTDT protection instrument was incorrectly declared operable on March 16 when temperature instrument calibrations were complete but the associated pressurizer pressure instrument calibrations were not yet done. Corrective actions involved restoring the 21 OTDT instrument to operable. Long term actions were intended to modify OTDT calibration procedures and processes such that the pressurizer pressure and temperature inputs be calibrated in succession prior to declaring operability.

This finding was more than minor because it was associated with the configuration control attribute, and it affected the fuel cladding barrier of the Barrier Integrity Cornerstone objective. The inspectors determined that the finding was of very low safety significance (Green) using the Phase 1 SDP because the finding was associated with the fuel barrier. This licensee-identified finding involved a violation of TS 3.3.1, Reactor Trip System Instrumentation. The enforcement aspects of the violation are discussed in Section 4OA7. This LER is closed.

3. (Closed) LER 05000272/2004002-00, Non-conservative Technical Specifications - Containment Fan Coil Units

On February 24, 2004, PSEG identified a discrepancy between Salem Units 1 and 2 Technical Specifications 3.6.2.3 and the current licensing basis analyses assumptions. Specifically, PSEG had reviewed Westinghouse analysis NSAL 00-010, “Containment Safeguards Heat Removal Capability,” issued on June 15, 2000, and had revised its Updated Final Safety Analysis Reports (in April 2002) for containment heat removal requirements, but had not identified a deficient Technical Specification action statement based on the original plant licensing basis. The Updated Final Safety Analysis Report and the Westinghouse analysis stated that the only analyzed acceptable combination of containment spray (CS) trains and containment fan coil units (CFCUs) to meet containment heat removal requirements is three CFCUs and one CS train. Technical Specification 3.6.2.3.b allowed two operable CFCUs and no containment spray trains operable for 72 hours. PSEG identified at least one past occurrence of less than three operable CFCUs on each unit. The identified occurrences were a matter of hours, and two of the three inoperable CFCUs had been declared inoperable for associated emergency diesel generator inoperability. Corrective actions involved notifying control room operators of the non-conservative CFCU Technical Specifications through an administrative letter and submitting a Technical Specification change request to the NRC on April 15, 2004.

The finding was more than minor because it was associated with the structures, systems, or components performance attribute, and it affected the Barrier Integrity Cornerstone objective. The inspectors determined that the finding was of very low safety significance using IMC 0609, Appendix H, “Containment Integrity Significance Determination Process,” because the CFCUs are not important to large early release frequency, in that, the Salem units have large dry containments and the CFCUs only impact late containment failure and source terms. This licensee-identified finding involved a violation of 10 CFR Part 50, Appendix B, Criterion XVI, “Corrective Action.” The enforcement aspects of the violation are discussed in Section 4OA7. This LER is closed.

4OA4 Cross Cutting Aspects of Findings

Section 1R07 describes a human performance error and inadequate foreign material exclusion maintenance practices that allowed plywood and tape to foul the 12A and 12B component cooling water heat exchangers.

Section 1R19.2 describes a human performance error involving maintenance technicians performing an action not authorized by procedure and adding lubricant to the valve and actuator stems at the stem block coupling which caused the 13 turbine-driven auxiliary feedwater pump to be inoperable.

Section 1R19.3 describes a human performance error involving valve engineers failing to incorporate instructions to adjust the open torque switch bypass setting on the 12 nuclear service water header crosstie valve, 12SW17, into the design change package which modified the valve from a limit seated, soft seated butterfly valve to a torque seated, hard seated butterfly valve.

4OA5 Other (Optional 4-point format)

1. Temporary Instruction 2515/150, Revision 2, Reactor Pressure Vessel Head and Vessel Head Penetration Nozzles (NRC Order EA-03-009)

a. Ultrasonic, eddy current, and visual examinations were performed by qualified and knowledgeable personnel. In addition to classroom training that met the requirements specified by the American Society for Non-Destructive Test Personnel qualification standard (SNT-TC-1A), the individuals had years of job related experience. In the case of the ultrasonic testing, the individuals had specific classroom training on the IntraSpec system. The individuals performing the eddy current testing were qualified data analysts.

b. The reactor head was free of debris, insulation, dirt, or boron deposits. Except for the normal interference caused by the density of the control drive tubes, there were no interferences to visually examining the head penetrations. The technicians used mirrors and illumination to view the entire penetration periphery of each control drive tube.

c. Small boron deposits, as described in NRC Bulletin 2001-01, could be identified and characterized.

d. No material deficiencies were identified that required repair.

e. The only impediment to the examination was the limited control drive accessibility of some penetrations located on the underside of the reactor vessel head. This impediment was discussed in relaxation request S1-RR-13-B21 which was reviewed and approved by NRR.

f. The basis used for the temperatures used in the susceptibility ranking calculation were plant specific measurements.

g. The disposition of indications revealed during non-visual examinations was consistent with Appendix D of the Temporary Instruction.

h. Procedures existed to identify boric acid indications for pressure retaining components above the RPV head.

i. PSEG was planning to perform follow-on examinations to determine the source of an indeterminate stain that appeared to originate from above the canopy seal weld. The inspector reviewed the planned actions to investigate this anomaly and did not identify any findings.

b.	<u>Findings</u>

No findings of significance were identified.

2.	<u>Temporary Instruction 2515/152, Reactor Pressure Vessel Lower Head Penetration Nozzles (NRC BULLETIN 2003-02)</u>

a.1 The examination was performed by qualified and knowledgeable personnel with certification to the American Society of Mechanical Engineers (ASME), Section XI, Level II and Level III for visual examiners. The qualification and training requirements are described in ASME Section XI.

a.2 The examination was performed in accordance with procedures.

a.3 The visual examination was adequate to identify, resolve, and dispose of deficiencies.

a.4 The examination performed was capable of identifying pressure boundary leakage and/or lower head corrosion described in the Bulletin.

b. The reactor vessel lower head was free of dirt, debris and insulation, or other foreign material that could adversely affect viewing of the penetrations. No boric acid deposits were identified at the interface between the vessel and the penetrations.

c. The inspection was conducted by direct visual inspection with ability to identify small boric acid deposits as described in Bulletin 2003-02.

d. If present, small boric acid deposits representing reactor coolant leakage, as described in Bulletin 2003-02, could be identified and characterized.

e. No impediments to the inspection were identified.

f. Because no boric acid was identified at the junction between the vessel and the penetration further examinations were unnecessary.

b.	<u>Findings</u>

No findings of significance were identified.

3. <u>(Closed) URI 05000272 & 311/2003009-10: Temporary Instruction 2515/153 - Reactor Containment Sump Blockage (NRC BULLETIN 2003-01)</u>

a. <u>Inspection Scope</u>

The inspectors completed a review of PSEG's response to Bulletin 2003-01, "Potential Impact of Debris Blockage on Emergency Sump Recirculation at Pressurized-Water Reactors," as required by TI 2515/153. Unit 2 containment and sump activities were inspected during the Fall 2003 Unit 2 refueling outage. Unresolved item 05000272 and 311/2003009-10 was opened to inspect Unit 1 containment and sump activities and to verify completion of licensed operator training and emergency plan procedure changes and training as committed in PSEG's Bulletin 2003-01 response. For Salem Unit 1, the inspectors interviewed material engineers, observed containment trough boroscope inspections video tapes, observed the as found condition of the sump internals through photographs and in-field observations, observed external screen meshing and other external sump features, performed independent containment walkdowns for potential loose debris, and reviewed the results of PSEG's containment walkdowns and containment sump inspections. The inspectors verified that PSEG revised emergency plan procedure NC.EP-EP.ZZ-0201, "TSC - Integrated Engineering Response," and provided adequate notice and training to emergency response organization personnel. The inspectors also interviewed control room operators to verify that they had knowledge of containment sump blockage indications and had received training as committed in PSEG's Bulletin 2003-01 response.

b. <u>Findings</u>

No findings of significance were identified.

The following input addresses the specific reporting requirements of TI 2515/153:

a. Unit 1 entered a refueling outage on March 30, 2004, and returned to power on June 3, 2004. A containment walkdown to quantify potential debris sources was conducted by PSEG during the refueling.

b. Not applicable.

c. Not applicable.

d. The PSEG Unit 2 containment walkdown checked for gaps in the sump's screened flowpath and for major obstructions in containment upstream of the sump. PSEG did not identify any gaps or major obstructions.

e. PSEG did not and has not expedited the performance of any sump-related modifications that may be found necessary after performing sump evaluations.

Unresolved item 05000272 & 311/2003009-10 is closed.

4. <u>Temporary Instruction 2515/156 - Offsite Power System Operational Readiness</u>

a. <u>Inspection Scope</u>

The inspectors performed Temporary Instruction 2515/156, “Offsite Power System Operational Readiness.” The inspectors collected and reviewed information pertaining to the offsite power system specifically relating to the areas of the maintenance rule (10 CFR Part 50.65), the station blackout rule (10 CFR Part 50.63), offsite power operability, and corrective actions. The inspector reviewed this data against the requirements of 10 CFR Part 50 Appendix A General Design Criterion 17, “Electric Power Systems,” and Salem Unit 1 and 2 Technical Specifications. This information was forwarded to the NRC Division of Nuclear Reactor Regulation (NRR) for further review.

b. <u>Findings</u>

No findings of significance were identified.

5. <u>NRC Review of PSEG’s Spill Records</u>

a. <u>Inspection Scope</u>

On May 19, 2004, the inspectors and a representative from the New Jersey Bureau of Nuclear Engineering, met with a PSEG representative to review records of spills or other unusual occurrences involving the potential spread of contamination around the facility, equipment, or site. At the time of this review, PSEG was conducting on-going evaluations of the records for completeness. PSEG personnel had identified eleven historical spills or occurrences, entered them into table format, and developed background information (e.g., remediation efforts) on each. PSEG personnel identified three spills as appropriate for documentation in 10 CFR Part 50.75(g) records. PSEG was also maintaining records of the other spills or occurrences which were also reviewed by the inspectors.

b. <u>Findings</u>

No findings of significance were identified.

6. <u>(Closed) URI 05000272 & 311/2003009-01:</u> Degraded Internal Flooding Mitigation Equipment for Vital Switchgear Rooms

The inspectors reviewed the risk analysis associated with the removal of flood mitigation curbs in the unit 1 & unit 2 vital switchgear rooms on elevation 84' of the auxiliary building and the misconfiguration of floor drains in the corridor between the two rooms. The corrective action notification directing the risk analysis is 20167048 and was described in NRC inspection report 50-272/03-09, 50-311/03-09, Section 1R06 (URI 05000272,311/2003009-01).

The evaluation performed by PSEG showed that there was no increase in plant risk due to the absence of curbing and floor drains. The evaluation showed that the performance deficiency does not impact any of the reactor safety cornerstones. PSEG installed curbing at the correct locations and returned the floor drains to the proper configuration. The inspectors found the analysis and corrective actions to be adequate. The URI 05000272,311/2003009-01 is closed.

7. <u>(Closed) URI 05-272/04-02-01, Failure of 11 Traveling Water Screen due to Ice Buildup</u>

Introduction. A Green self-revealing NCV of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," was identified for failure to identify and correct a condition that rendered the 11 service water traveling water screen (TWS) unavailable.

Description. During the first quarter integrated inspection period (NRC Inspection Report 05000272 and 311/2004002 dated May 13, 2004), the inspectors reviewed an 11 TWS failure that occurred on January 31, 2004 due to ice buildup. The issue was unresolved to understand the existence of a performance deficiency.

The 11 TWS and associated 11 service water pump were inoperable from January 31, 2004, to February 3, 2004. The out-of-service time was delayed due to difficulties in thawing the 11 TWS and to repair a leaking spray wash valve which had caused the icing.

The inspectors reviewed PSEG's corrective action evaluation (notification 20180280) of the issue and determined that equipment operators failed to identify the icing on the 11 TWS prior to its failure because the operators were not sensitive to the potential impact of the ice buildup on the screens even though an inspector had expressed concern about the existence of ice on the screens several days prior. Earlier identification would have allowed the operators to implement contingency actions to prevent the excessive icing while maintaining the 11 TWS operable. Actions could also have been developed to repair the leaking spray wash valve.

Analysis. The performance deficiency involved the failure to identify and correct an icing condition on the 11 TWS, which resulted in its failure and an increase in the unavailability of the 11 service water train. Traditional enforcement does not apply because the issue did not have any actual safety consequences or potential for impacting the NRC's regulatory function, and it was not the result of any willful violation of NRC requirements. This issue was more than minor because it was associated with the equipment performance attribute, and it affected the Initiating Event and Mitigating System Cornerstone objectives. The performance deficiency also had problem identification and resolution cross-cutting aspects, specifically as related to equipment monitoring.

In accordance with IMC 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," the inspectors conducted Phase 1 SDP screening and determined that a Phase 2 evaluation was required because the performance deficiency degraded both the Initiating Event and Mitigating Systems Cornerstones. However, the inspectors were unable to evaluate the finding using Phase 2, because the Risk-Informed Inspection Notebook for Salem Generating Station did not evaluate loss of service water initiating events. As a result, the Region I Senior Reactor Analyst (SRA) conducted a Phase 3 analysis.

The SRA determined that the finding was of very low safety significance (Green). The SRA conducted the analysis using the NRC's Standardized Plant Analysis Risk (SPAR) model, Revision 3.04, for the Salem facility which was modified to update the service water system fault trees by adding: the traveling water screens; electrical dependencies; new common cause failure data for traveling water screen and strainers; and operator actions to isolate the turbine building loads and provided reactor coolant pump (RCP) seal cooling in the event of a loss of service water or station blackout initiating event.

The SRA also modified the charging pump and motor-driven auxiliary feedwater pump fault trees to update the room cooling dependencies, based on recent licensee analysis of the ability of auxiliary building ventilation to supply necessary cooling. In addition, the SRA updated the loss of offsite power initiating event frequency data and non-recovery probabilities using the values in NUREG/CR-5496, “Evaluation of Loss of Offsite Power Events at Nuclear Power Plants: 1980 - 1996."

In the analysis, the SRA assumed that the 11 TWS was out-of-service for 68 hours and that the loss of service water (LOSW) initiating event frequency increased during this time because of lost redundancy in the SW trains as a result of the performance deficiency. The SRA determined that the increase in core damage frequency due to internally initiated events was in the low E-8 range. The dominant accident sequence involved a LOSW followed by operator failure to recover service water, resulting in a reactor coolant pump seal failure due to loss of cooling.

Enforcement. 10 CFR Part 50, Appendix B, Criterion XVI, “Corrective Action,” requires, in part, that conditions adverse to quality be promptly identified and corrected. Contrary to the above, on January 31, 2004, equipment operators did not identify a degrading condition, icing, on the 11 TWS, and did not take action to correct. Because this finding is of very low safety significance and the issue has been placed into PSEG’s corrective action program (notification 20180280) this violation is being treated as a NCV, consistent with section VI.A of the NRC Enforcement Policy: **NCV 05000272/2004003-11, Failure of 11 Traveling Water Screen due to Ice Buildup.**

8. (Closed) URI 05-311/04-02-03, Failure of 25 Traveling Water Screen due to Inadequate Lubrication

Introduction. A Green self-revealing NCV of TS 6.8.1.a was identified for failure to establish maintenance instructions appropriate to the circumstances for preventive maintenance performed on the 25 service water traveling water screen.

Description. During the first quarter integrated inspection period (NRC Inspection Report 05000272 and 311/2004002 dated May 13, 2004), the inspectors reviewed a 25 TWS failure that occurred on February 1, 2004, due to inadequate lubrication. The 25 TWS and associated 25 service water pump train were inoperable from February 1, to February 8, 2004. The issue was unresolved to understand the existence of a performance deficiency.

The inspectors reviewed PSEG’s apparent cause evaluation (notification 20181900) and determined that TWS preventive maintenance was not properly preplanned and performed in accordance with maintenance instructions which were appropriate to the circumstances. Specifically, the maintenance instructions did not provide adequate guidance to ensure that the head shaft bearing was adequately greased.

Analysis. The performance deficiency involved the failure to establish maintenance instructions appropriate to the circumstances for preventive maintenance performed on the 25 service water traveling water screen which resulted in its failure and an increase in the unavailability of the 25 service water train. Traditional enforcement does not apply because the issue did not have any actual safety consequences or potential for impacting the NRC’s regulatory function, and it was not the result of any willful violation of NRC requirements. This issue was more than minor because it was associated with the equipment performance attribute, and it affected the Initiating Event and Mitigating System Cornerstone objectives.

In accordance with IMC 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," the inspectors conducted Phase 1 SDP screening and determined that a Phase 2 evaluation was required because the performance deficiency degraded both the Initiating Event and Mitigating Systems Cornerstones. However, the inspectors were unable to evaluate the finding using Phase 2, because the Risk-Informed Inspection Notebook for Salem Generating Station did not evaluate loss of service water initiating events. As a result, the Region I Senior Reactor Analyst (SRA) conducted a Phase 3 analysis.

The SRA determined that the finding was of very low safety significance (Green). The SRA conducted the analysis using the NRC's Standardized Plant Analysis Risk (SPAR) model, Revision 3.04, for the Salem facility which was modified to update the service water system fault trees by adding: the traveling water screens; electrical dependencies; new common cause failure data for traveling water screen and strainers; and operator actions to isolate the turbine building loads and provided reactor coolant pump (RCP) seal cooling in the event of a loss of service water or station blackout initiating event. The SRA also modified the charging pump and motor-driven auxiliary feedwater pump fault trees to update the room cooling dependencies, based on recent licensee analysis of the ability of auxiliary building ventilation to supply necessary cooling. In addition, the SRA updated the loss of offsite power initiating event frequency data and non-recovery probabilities using the values in NUREG/CR-5496, "Evaluation of Loss of Offsite Power Events at Nuclear Power Plants: 1980 - 1996."

In the analysis, the SRA assumed that the 25 TWS was out-of-service for 177 hours and that the loss of service water (LOSW) initiating event frequency increased during this time because of lost redundancy in the SW trains as a result of the performance deficiency. The SRA determined that the increase in core damage frequency due to internally initiated events was in the low E-8 range. The dominant accident sequence involved a LOSW followed by operator failure to recover service water, resulting in a reactor coolant pump seal failure due to loss of cooling.

Enforcement. Salem Unit 2 Technical Specification 6.8.1.a requires that written procedures shall be established covering the activities in Appendix A of Regulatory Guide 1.33, Revision 2, February 1978, which specifies that maintenance that can affect the performance of safety-related equipment should be properly performed in accordance with written procedures, document instructions, or drawings appropriate to the circumstances. Contrary to the above, on November 26, 2003, PSEG personnel performed maintenance on the 25 TWS using instructions that were not appropriate to the circumstances which resulted in the failure of the 25 TWS on February 1, 2004, due to inadequate lubrication of the head shaft bearing. Because this finding is of very low safety significance and the issue has been placed into PSEG's corrective action program (notification 20181900) this violation is being treated as a NCV, consistent with section VI.A of the NRC Enforcement Policy: **NCV 05000311/2004003-12, Failure of 25 Traveling Water Screen due to Inadequate Lubrication.**

4OA6 Meetings, Including Exit

NRC/PSEG Management Meeting - Reactor Oversight Process Annual Assessment & PSEG's Assessment Work Environment at Salem/Hope Creek

The NRC conducted a meeting with PSEG on June 16 to discuss (1) NRC's annual assessment of safety performance at Salem and Hope Creek for calender year 2003, (2) the results of recently completed assessments of the work environment by PSEG, and (3) the action plan currently being developed by PSEG to address the results of their work environment assessments. The meeting occurred at the Holiday Inn Select Bridgeport, New Jersey and was open for public observation. A copy of slide presentations can be found in ADAMS under accession numbers ML041690528 and ML041690564.

Exit Meeting

On July 2, 2004, the resident inspectors presented the inspection results to Mr. Carl Fricker and other members of his staff who acknowledged the findings. On July 29, 2004, the resident inspectors conducted an additional exit meeting with Mr. Bill Campbell to update the significance determination process results for issues related to the 11 and 25 service water traveling water screen failures.

4OA7 Licensee-Identified Violations

The following violations of very low significance (Green) were identified by PSEG and are violations of NRC requirements which meet the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as NCVs.

- 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requires, in part, that conditions adverse to quality, such as deficiencies, be promptly identified and corrected. Contrary to this, on June 15, 2000, PSEG did not identify and correct a deficient technical specification (TS) action statement, 3.6.2.3.b, identified through a Westinghouse analysis NSAL 00-010 "Containment Safeguards Heat Removal Capability." On at least two occasions the Salem Units 1 and 2 operated in this condition, with insufficient operable containment fan cooling units (CFCUs). The conditions existed for about 18.5 hours on September 3, 2002, for Unit 1 and for about 4 hours on July 2, 2003, for Unit 2. This issue was identified in PSEG's corrective action program (CAP) as notification 20178888 and in LER 05000272, 311/2004002-00. The inspectors determined that the finding was of very low safety significance using Inspection Manual Chapter 0609, Appendix H, "Containment Integrity Significance Determination Process," because the CFCUs are not important to large early release frequency, in that, the Salem units have large dry containments and the CFCUs only impact late containment failure and source terms.

- Salem Unit 2 Technical Specification 3.3.1.1 requires minimum operable reactor trip system instrumentation channels be operable consistent with table 3.3-1. Contrary to this, on March 16, 2004, PSEG did not maintain at least three over-temperature delta-temperature (OTDT) instruments operable on Unit 2 for about 33 hours. This issue was identified in PSEG's CAP as notification 20181988 and in LER 05000311/2004002-00. The inspectors determined that the finding was of very low safety significance (Green) using the Phase 1 SDP because the finding was associated with the fuel barrier.

- Salem Unit 1 Technical Specification 6.12.2 requires high radiation areas with dose rates greater than 1.0 rem/hour at 30 centimeters be conspicuously posted and locked. Contrary to this, on May 29, 2004, radiation protection technicians in preparation for a reactor startup and during a containment walkdown discovered an unlocked gate to the reactor cavity area. A review of logs indicated that the gate had been unlocked for about a day and current radiation levels actually did not require locking. However, this issue was more than minor because the pending plant startup would have elevated radiation levels above 1 rem/hour. This finding is of very low safety significance because unauthorized personnel exposures did not occur. This issue was identified in PSEG's CAP as notification 20191467.
- Salem Unit 2 Technical Specification 3.3.2.1 requires engineered safety feature actuation system (ESFAS) instrumentation channels be operable consistent with table 3.3-3. Contrary to this, on May 27, 2004, control room operators did not reinstate the automatic safety injection (SI) actuation logic prior to mode 4 reactor plant conditions. The automatic SI logic was reinstated about 5 hours later. This finding is of very low safety significance because it did not affect shutdown risk as evaluated by Appendix G, "Shutdown Operations Significance Determination Process," of Inspection Manual Chapter 0609. This issue was identified in PSEG's CAP as notification 20191254.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee personnel:

C. Conner, NDE Engineer
P. Fabian, Steam Generator Engineer
R. Gary, Radiation Protection Manager
J. Nagle, Supervisor Licensing
W. Treston, Supervisor ISI
S. Zeigler, ALARA Specialist

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000272/2004003-04	URI	Failure of 11 and 15 Service Water Pumps Due to Degraded Auxiliary Switch Contacts in Power Supply Breaker (Section 1R15)
05000272/2004003-05	URI	Inoperable Turbine Building Service Water Isolation Valve (Section 1R19.1)
05000311/2004003-08	URI	Failure of the 2B 230V Vital Bus Transformer (Section 1R20)

Opened and Closed

05000311/2004003-00	LER	Salem Unit 2 Control Room Emergency Air Conditioning System Unable to Mitigate the Consequences of An Accident. (Section 4OA3.1)
05000311/2004002-00	LER	Failure to Comply With Technical Specifications During Reactor Protection Instrument Calibration (Section 4OA3.2)
05000272/2004002-00	LER	Non-Conservative Technical Specifications Containment Fan Coil Units (Section 4OA3.3)
05000272/2004003-01	NCV	Inadequate FME Fouls 12A and 12B Component Cooling Heat Exchangers (Section 1R07)
05000311/2004003-02	NCV	Repetitive 25 Containment Fan Coil Unit Failure (Section 1R12.1)
05000311/2004003-03	NCV	21 Control Room Ventilation Chiller Repetitive Failure (Section 1R12.2)

05000272/2004003-06	NCV	Incorrect Assembly of 1MS132 (Section 1R19.2)
05000272/2004003-07	NCV	Design Modification Resulting in Failure of 12SW17 to Open (1R19.3)
05000272/2004003-09	NCV	Inadequate 13 Auxiliary Feedwater Pump Inspection Instructions (Section 1R22.1)
05000311/2004003-10	NCV	Inadequate Troubleshooting Procedures Cause an Inadvertent SI Signal (Section 4OA3.1)
05000311/2004003-11	NCV	Failure of 11 Traveling Water Screen due to Ice Buildup (Section 4OA5.7)
05000272/2004003-12	NCV	Failure of 25 Traveling Water Screen due to Inadequate Lubrication (Section 4OA5.8)

Closed

05000272,311/2003009-10	URI	Temporary Instruction 2515/153 - Reactor Containment Sump Blockage (NRC Bulletin 2003-01) (Section 4OA5.3)
05000272,311/2003009-01	URI	Degraded Internal Flooding Mitigation Equipment for Vital Switchgear Rooms (Section 4OA5.6)
05000272/2004002-01	URI	Failure of 11 Traveling Water Screen due to Ice Buildup (Section 4OA5.7)
05000311/2004002-03	URI	Failure of 25 Traveling Water Screen due to Inadequate Lubrication (Section 4OA5.8)

Discussed

NONE

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 1R8 documents reviewed:

SC.SG-AP.ZZ-0001(Q) - Rev. 6; Steam Generator Management Program
Steam Generator Degradation Assessment, Salem Unit 1 Refueling Outage 16 (1R16), April 2004; Engineering Evaluation No. S-1-RC-MEE-1824, Rev. o, 3/31/04
NEI Deviation 80061541 Update For Revision 6 Of EPRI Guidelines - Deviation Process Control Requirements, 9/8/03.
NEI Deviation 80062418 Update For Revision 6 Of EPRI Guidelines - Deviation Analyst Performance Monitoring, 9/8/03.
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IPTE Briefing - S1C17 Startup and LPPT
Turbine Startup - Solenoid Functional Test (S1.OP-PT.TRB-0002)
Turbine - Generator Startup Operations (S1.OP-SO.TRB-0001)

Estimated Critical Conditions (SC.RE-RA.ZZ-0001)
Inverse Count Rate Ratio During Reactor Startup (SC.RE-RA.ZZ-0002)
SC.RE-IO.ZZ-0002, Low Power Physics Testing and Power Ascension
S1.OP-IO.ZZ-0003, Hot Standby to Minimum Load
S1.OP-IO.ZZ-0004, Power Operations
S1.OP-IO.ZZ-0005, Minimum Load to Hot Standby
S1.OP-IO.ZZ-0006, Hot Standby to Cold Shutdown
S1.OP-IO.ZZ-0009, Defueled to Mode 6
S1.OP-IO.ZZ-0010, Spent Fuel Pool Manipulations
S1.OP-SO.RC-0001, Reactor Coolant Pump Operation
1-EOP-TRIP-1, Reactor Trip of Safety Injection
S2.OP-AB.460-0002, Loss of 2B 460/230V Vital Bus
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Core Operating Limits Report for Salem Unit 2, Cycle 14 (NFS-0231), Rev. 1
Hot Standby to Minimum Load (S2.OP-IO.ZZ-0003), Rev. 19
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Inverse Count Rate Ratio During Reactor Startup (SC.RE-RA.ZZ-0002), Rev. 2

LIST OF ACRONYMS

ABV	Auxiliary Building Ventilation
AFWP	Auxiliary Feedwater Pump
ALARA	As Low As Is Reasonably Achievable
ASME	American Society of Mechanical Engineers
CAP	Corrective Action Program
CC	Component Cooling
CFCUs	Containment Fan Coil Units
CFR	Code of Federal Regulations
CREACS	Control Room Emergency Air Conditioning System
CS	Containment Spray
DCP	Design Change Package
EDG	Emergency Diesel Generator
EP	Emergency Preparedness
EPD	Electronic Personal Dosimeter
ESFAS	Engineered Safety Feature Actuation System
I&C	Instrument and Calibration
IMC	Inspection Manual Chapter
ISI	Inservice Inspection
LCAV	Loss of Control Room Ventilation
LPPT	Low Power Physics Testing
NCV	Non-cited Violation
NRC	Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation
NUMARC	Nuclear Management and Resources Council, Inc.
OD	Operability Determination
OTDT	Over-temperature Delta-temperature
PARS	Publicly Available Records
PI&R	Problem Identification and Resolution
PIs	Performance Indicators
PMT	Post Maintenance Testing
PSEG	Public Service Electric Gas
RCA	Radiologically Controlled Area
RP	Radiation Protection
RWP	Radiation Work Permit
SDP	Significance Determination Process
SI	Safety Injection
SSPS	Solid State Protection System
SW	Service Water
TS	Technical Specifications
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
VOTES	Valve Operation Test and Evaluation System