August 12, 2003

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

SUBJECT: SALEM NUCLEAR GENERATING STATION - NRC INTEGRATED INSPECTION REPORT 05000272/2003005 and 05000311/2003005

Dear Mr. Anderson:

On June 28, 2003, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Salem Unit 1 and Unit 2. The enclosed integrated inspection report documents the inspection findings, which were discussed on July 14, 2003 with Mr. O'Connor, Mr. Carlin, Mr. Garchow and other members of your staff.

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

The report documents two NRC-identified findings and four self-revealing findings of very low safety significance (Green), all 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 six findings as non-cited violations (NCVs) consistent with Section VI.A of the NRC Enforcement Policy. Additionally, a licensee- identified violation which was determined to be of very low safety significance is listed in this report. If you contest any NCV in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001; with copies to the Regional Administrator, Region I; the Director, Office of Enforcement, and the NRC Resident Inspector at the Salem Nuclear Generating Station.

Since the terrorist attacks on September 11, 2001, NRC has issued five Orders and several threat advisories to licensees of commercial power reactors to strengthen licensee capabilities, improve security force readiness, and enhance controls over access authorization. In addition to applicable baseline inspections, the NRC issued Temporary Instruction (TI) 2515/148, "Inspection of Nuclear Reactor Safeguards Interim Compensatory Measures," and its subsequent revision, to audit and inspect licensee implementation of the interim compensatory measures required by order. Phase 1 of TI 2515/148 was completed at all commercial power nuclear power plants during calendar year 2002 and the remaining inspection activities for Salem Generating Station are scheduled for completion in calendar year 2003. The NRC will continue to monitor overall safeguards and security controls at Salem Generating Station.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

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

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

Enclosure: Inspection Report 050000272/2003005, 050000311/2003005
w/Attachment: Supplemental Information

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REGION I

Docket Nos:	50-272, 50-311
License Nos:	DPR-70, DPR-75
Report No:	05000272/2003005, 05000311/2003005
Licensee:	PSEG Nuclear, LLC
Facility:	Salem Nuclear Generating Station, Unit 1 and Unit 2
Location:	P.O. Box 236 Hancocks Bridge, NJ 08038
Dates:	March 30, 2003 - June 28, 2003
Inspectors:	J. Daniel Orr, Senior Resident Inspector Fred L. Bower, Resident Inspector Gregory C. Smith, Senior Physical Security Inspector Joseph T. Furia, Senior Health Physicist Joe Schoppy, Senior Resident Inspector, Hope Creek Tim O'Hara, Reactor Engineer Scott Barber, Senior Project Engineer Josephine Talieri, Reactor Engineer
Approved By:	Glenn W. Meyer, Chief, Projects Branch 3 Division of Reactor Projects

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SUMMARY OF FINDINGS

IR 05000272/2003005, IR 05000311/2003005, Public Service Electric Gas Nuclear LLC, Salem Unit 1 and Unit 2; 03/30/03 - 06/28/03; Maintenance Implementation, Personnel Performance During Non-routine Plant Evolutions, Post Maintenance Testing, Surveillance Testing, and Other Activities.

The report covered a 13-week period of inspection by resident inspectors, an announced inspection by a regional radiation specialist, and an in-office review by security specialists. Six Green non-cited violations (NCVs) were identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using 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. A self-revealing finding made apparent a non-cited violation of technical specification (TS) 6.8.1 when a surveillance procedure for testing a pressurizer spray valve (2PS3) while at power was not followed. This resulted in the inadvertent initiation of continuous spray to the pressurizer and a resultant reactor pressure transient. Equipment operators misunderstood the task instructions and prematurely unisolated 2PS3. Control room operators were ineffective in receiving communications from the field and did not question actions inconsistent with the pre-job brief.

  This finding is greater than minor, because it had an actual impact on reactor coolant system pressure and operator manual actions were necessary to avert a reactor plant trip. The finding is of very low safety significance because mitigation systems were unaffected by the operator errors. (Section 1R14).

Cornerstone: Mitigating Systems

- Green. A self-revealing finding made apparent a non-cited violation of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," for failure to promptly correct a service water valve (12SW380) actuator air leak. The source of the air leak, which was a symptom of the valve failure mechanism, was not fully identified, and the deficient valve failed one month later during a routine plant evolution. The failed valve rendered the 12A component cooling water heat exchanger inoperable.

  This finding is greater than minor, because it had an actual impact on the component cooling system. The finding is of very low safety significance, because it did not reduce the number of operable component cooling water heat exchangers below minimum technical specification requirements for the current river water temperature. (Section 1R12.1)

- Green. A self-revealing finding made apparent a non-cited violation of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," for failure to promptly identify and correct an auxiliary feedwater flow control valve (12AF11) deficient condition. Control air to the valve actuator was throttled from February 28, 2003, to April 9, 2003, and affected the valve stroke time.

  This finding is greater than minor, because it had an actual impact on the auxiliary feedwater system and would have increased the time required to isolate the 12 steam generator for tube rupture mitigation. The finding is of very low safety significance, because remote operation of 12AF11 remained available and the increase in stroke time was not significant, about a twelve second increase. (Section 1R19.1)

- Green. A self-revealing finding made apparent a non-cited violation of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," for failure to prevent recurrence of a service water valve, 12SW17, motor operator failure. Inadequate maintenance practices during an initial repair of 12SW17 introduced deficient torque switch conditions that caused the 12SW17 to fail again, requiring repeat corrective action. 12SW17 is a cross-tie valve, normally open, between independent service water loops.

  This finding is greater than minor because it had an actual impact on the ability to maintain independent service water system trains and reduced service water bay flooding mitigation capabilities. The finding is of very low safety significance, because it did not render either service water loop inoperable. (Section 1R22.1)

- Green. The inspectors identified a non-cited violation of technical specification 6.8.1 for failure to follow maintenance procedures and adequately lubricate a component cooling (CC) system train cross-connect motor-operated valve (1CC17). Maintenance technicians inappropriately used another maintenance procedure not directed in the work order instructions that allowed optional valve stem lubrication. The intended maintenance procedure mandated complete stem cleaning and new lubrication. Eleven months later 1CC17 failed to close during surveillance testing because of aged and hardened valve stem grease.

  This finding is greater than minor, because it had an actual impact on the component cooling system and challenged the ability to establish independent CC system trains. The finding is of very low safety significance because redundant motor operated valves were available to establish independent trains. (Section 4OA2.1)

Cornerstone: Barrier Integrity

- Green. The inspectors identified a non-cited violation of technical specification 4.0.5 for failure to properly implement the American Society of Mechanical Engineers (ASME) inservice testing program for the 15 containment fan coil unit

(CFCU) outlet service water valve, 15SW72. PSEG did not establish appropriate and accurate stroke time reference values for 15SW72. Operability determinations and work management decisions were made based on inaccurate reference values.

This finding is greater than minor, because it affected the availability of the 15 CFCU. The finding is of very low safety significance because the physical integrity of the reactor containment was not affected and other CFCUs were maintained operable consistent with technical specification requirements. (Section 1R19.2)

B. Licensee-Identified Violations

A violation of very low safety significance, which was identified by PSEG has been reviewed by the inspectors. Corrective actions, taken or planned by PSEG have been entered into PSEG's corrective action program. This violation and corrective action tracking number is listed in Section 40A7.

REPORT DETAILS

Summary of Plant Status

Unit 1 began the period at reduced power, 43%, due to severe river grassing and circulating water system maintenance. Power had been reduced on March 24, 2003. Power was restored to 100% on April 2. On April 25 to May 1, 2003, reactor power was reduced to 75% for planned transmission line maintenance. Reactor power was also reduced on May 3, June 14, and June 25 for less than a day each to no lower than 68% for transmission line maintenance.

Unit 2 began the period during a plant startup after a manual reactor trip on March 29, 2003, for severe river grassing and circulating water system failures. Power was restored to 100% on April 2, 2003. Power was reduced to 47% on May 10 for turbine valve testing. Full power was nearly restored on May 10, but a moisture separator reheater drain tank lifting relief valve necessitated a down power to 51%. Power was returned to 100% on May 12 after seating the relief valve. Power was reduced on June 26 to 87% for emergent transmission line repairs. Full power was restored the same day.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R04 Equipment Alignment

a. Inspection Scope

Partial System Walkdowns. The inspectors performed partial walkdowns of redundant mitigating systems during equipment maintenance outages to confirm that the redundant systems were available to perform their intended safety functions, in acceptable material condition and protected by administrative controls. The following walkdowns were performed:

- 1B and 1C emergency diesel generators (EDG) during scheduled maintenance on the 1A emergency diesel generator on April 3, 2003.
- Service water intake structure unit 1 bays during scheduled maintenance on the 11 service water pump on April 3, 2003.
- 12 safety injection (SI) pump and 1C EDG during scheduled maintenance on the 11 SI pump on May 29, 2003.
- 11 and 13 auxiliary feedwater (AFW) pumps and room cooler and the 1A EDG during scheduled maintenance on the 12 AFW pump on June 6, 2003.
- 2A and 2B EDGs during scheduled maintenance on the 2C EDG on May 13, 2003.
- Service water intake structure unit 1 bays after service water motor operated valve troubleshooting on May 13, 2003.

Correct system alignments were verified by reviewing the following documents:

- Tagging work control documents 4022076, 4097367, and 4102088
- S1.OP-SO.DG-0002, “1B Diesel Generator Operation”
- S1.OP-SO.DG-0003, “1C Diesel Generator Operation”
- S2.OP-SO.DG-0001, “2A Diesel Generator Operation”
- S2.OP-SO.DG-0002, “2B Diesel Generator Operation”
- S1.OP-SO.SW-0001, “Service Water Pump Operation”
- S1.OP-SO.SJ-0001, “Preparation of the Safety Injection System for Operation”
- S1.OP-SO.AF-0001, “Auxiliary Feedwater System Operation”

Unit 1 Component Cooling Water System Complete Walkdown. The inspectors performed a complete walkdown of the Unit 1 component cooling water system during the weeks of April 21 and April 28, 2003, in order to verify that the system was in proper alignment and consistent with plant drawings. The inspectors reviewed the system health report, engineering evaluations, surveillance procedures and corrective action reports, and interviewed the reliability engineer to determine if there were any issues that could adversely affect the operability of the system. The inspectors also performed a walkdown of the Unit 1 component cooling pumps, heat exchangers, and surge tank areas.

b. Findings

No findings of significance were identified.

1R05 Fire Protection

a. Inspection Scope

On May 21, May 23, and May 28, 2003, the inspectors toured fire areas important to reactor safety to evaluate conditions related to: (1) control of transient combustibles and ignition sources; (2) the material condition, operational status, and operational lineup of fire protection systems, equipment and features; and, (3) the fire barriers used to prevent fire damage or fire propagation. The inspectors referred to administrative procedure NC.NA-AP.ZZ-0025(Q), "Operational Fire Protection Program," during this inspection. The tours included reviews of Pre-Fire Preplans to determine: (1) 10 CFR 50, Appendix R, safe shutdown equipment; (2) construction and fire barrier information; (3) fire detection equipment; (4) fire suppression equipment; and, (5) diagrams of the fire area. The inspectors reviewed the following Pre-Fire Preplans and associated fire areas:

- Unit 1 - FRS-II-432, “Spent Fuel / Component Cooling Heat Exchanger & Pump Area, Elevation: 84'-0"”
- Unit 2 - FRS-II-432, “Spent Fuel / Component Cooling Heat Exchanger & Pump Area, Elevation: 84'-0"”
- 1A EDG - FRS-II-445, “Diesel Generator Area, Elevations: 100' & 122'”
- 1B EDG - FRS-II-445, “Diesel Generator Area, Elevations: 100' & 122'”

- 1C EDG - FRS-II-445, “Diesel Generator Area, Elevations: 100' & 122'”
- 2A EDG - FRS-II-445, “Diesel Generator Area, Elevations: 100' & 122'”
- 2B EDG - FRS-II-445, “Diesel Generator Area, Elevations: 100' & 122'”
- 2C EDG - FRS-II-445, “Diesel Generator Area, Elevations: 100' & 122'”
- Unit 1 - FRS-II-521, “Inner Piping Penetration Area & Chiller Rooms, Elevation: 100'-0"
- Unit 2 - FRS-II-521, “Inner Piping Penetration Area & Chiller Rooms, Elevation: 100'-0"

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures

a. Inspection Scope

The inspectors reviewed the Salem Updated Final Safety Analysis Report (UFSAR), the Individual Plant Examination of External Events and plant procedures to verify that PSEG flood protection measures were consistent with design bases and risk assumptions. The inspector performed a detailed review of the Unit 1 and Unit 2 64' elevation switchgear rooms. Both of these rooms contain 4160 vital switchgear and have significant risk for internal and external flooding events. The inspector toured the areas to determine whether flood vulnerabilities existed and to assess the physical and material condition of flood barriers. A selected sample of the flood seal inspection records was reviewed to verify that the seals were being adequately inspected. A field inspection of some flood penetrations was performed. Recent notifications involving flood protection were reviewed.

The inspectors also interviewed Salem design engineers regarding underground cable splices and the potential to withstand flooding events. Salem design engineering procedure SC.DE-TS.ZZ-2034(Q), "Technical Requirements for Construction of Electrical Installation," was reviewed.

The inspector reviewed Inspection Report S-IR-6A5-0001, Rev. 3 dated August 6, 2002; Results of Annual Inspection of Artificial Island Shoreline.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification

a. Inspection Scope

On June 3, 2003, the inspectors observed a licensed operator simulator training scenario to assess the operators’ performance and the evaluators’ and participants’ critiques. The scenario was considered an as-found evaluation of the operators' performance. It was conducted first in the training schedule after several weeks of off-training activities. The scenario involved a reactor coolant system leak in the pressurizer steam space, control rod anomalies, a loss of offsite power, and a residual heat removal pump relief valve failure. The inspectors verified that the operators' actions were consistent with the appropriate operating, alarm response, abnormal and emergency procedures.

b. Findings

No findings of significance were identified.

1R12 Maintenance Implementation

a. Inspection Scope

Untimely Service Water Valve Corrective Actions. The inspectors reviewed a service water valve (12SW380) failure to confirm that the failure was properly addressed per the maintenance rule and to ensure that appropriate corrective actions were implemented.

b. Findings

Introduction. The inspectors identified a Green NCV for failure to promptly correct a condition that rendered the 12B component cooling (CC) water heat exchanger inoperable.

Description. On January 24, 2003, equipment operators identified an air leak from a service water valve (12SW380) air actuator cap. 12SW380 is the 12A CC heat exchanger service water inlet flow control valve. The source of the air leak was internal to the actuator cover. Operators considered 12SW380 fully operable on January 24, 2003, based on having expected service water flows and differential pressure through the 12A CC heat exchanger. Corrective maintenance (CM) was scheduled for the week of April 20, 2003.

On February 23, 2003, 12SW380 failed to reposition during a routine heat exchanger high flow flush. Control room operators subsequently declared the 12A CC heat exchanger inoperable. The inoperable heat exchanger did not reduce the available CC heat exchangers below minimum technical specification requirements as long as river temperature remained below 67 degrees Fahrenheit.

On March 24, 2003, repairs were initiated to the 12SW380 valve actuator. Maintenance technicians identified a disengaged valve actuator piston rod. The disengaged piston rod was also the source of the air leak through the valve actuator cover. 12SW380 and the 12A CC heat exchanger were restored to an operable condition on April 3, 2003.

PSEG's evaluation of the matter also discovered that the 12SW380 valve actuator did not have any associated preventive maintenance activities that could have earlier identified the degrading piston rod engagement.

Analysis. The deficiency associated with this problem is untimely corrective action. Senior reactor operators (SROs) should have questioned the potential source of the air leak internal to the valve actuator. The SROs operability screening was further based on a steady state observation of 12SW380. This finding is more than minor, because it affected the equipment performance attribute of the Mitigating Systems Cornerstone. The availability and reliability of the 12A component cooling water heat exchanger were impacted.

Salem Unit 1 has two CC heat exchangers, 11 and 12. The 12 CC heat exchanger has two sections, 12A and 12B; either section can be operated independently. PSEG has performed an engineering analysis and determined that either 12A or 12B provides sufficient cooling capability for a train of CC, provided river temperature remains below 67 degrees Fahrenheit. The Delaware River remained below 67 degrees Fahrenheit for the duration of this issue.

The inspector screened this finding using phase 1 of the SDP and answered no to each of the mitigating system column questions and no to the seismic, fire, flooding, and severe weather screening criteria. This finding screened to Green, very low safety significance, because it did not result in the actual loss of a safety function of a single train. The 12B CC heat exchanger remained capable of performing its safety function.

Enforcement. 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," requires that measures shall be established that assure deficiencies are promptly identified and corrected. Contrary to the above, PSEG failed to fully identify a valve actuator internal air leak on January 24, 2003, and correct the deficiency before a failure occurred on February 23, 2003. Because the failure to promptly identify and correct the 12SW380 deficiencies was determined to be of very low significance and has been entered into the corrective action program (notifications 20129286 and 20133910), this finding is being treated as a non-cited violation consistent with Section VI.A of the NRC Enforcement Policy: **NCV 50-272/03-05-01**, Untimely Service Water Valve Corrective Actions.

a. Inspection Scope

Emergency Diesel Generator Reviews. The inspectors reviewed recent operating problems, notifications, system health reports, and MR performance criteria to determine whether PSEG had effectively monitored the performance of the Unit 1 and Unit 2 EDGs. The inspectors reviewed corrective actions associated with notifications 20117133, 20121338, and 20144680 involving unavailability hours above performance criteria for the 1A, 1C, and 2A EDGs. The inspectors referenced NUMARC (Nuclear Management and Resources Council) 93-01, Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants and 10 CFR 50.65, Requirements for monitoring the effectiveness of maintenance at nuclear power plants.

b. Findings

No findings of significance were identified.

a. Inspection Scope

13 Auxiliary Feedwater Pump Trip Due to Mechanical Binding of the Steam Inlet Valve. The inspectors assessed PSEG's immediate actions and subsequent evaluation of the 13 AFW pump trip during quarterly inservice testing on May 23, 2003. The details of this event are documented in section 4OA3 of this inspection report. The team reviewed applicable sections of the UFSAR, TS, and engineering evaluations of previous events. The inspectors interviewed engineers, maintenance technicians, operators, and managers to understand the technical and specific details of the 13 AFW pump trip.

The inspectors reviewed applicable PSEG records documenting the 13 AFW pump trip, and subsequent investigations, work orders, and corrective actions. Additionally, the inspectors interviewed the apparent cause analysis team and personnel associated with the testing, troubleshooting and repair activities. Plant management knowledgeable of the decision making processes that transpired during the 13 AFW pump trip event were also interviewed. Documents reviewed during the inspection are listed in the Supplemental Information of this inspection report.

b. Findings

As of June 28, 2003, PSEG had not completed and submitted a Licensee Event Report (LER) for this event. The LER is expected to detail the failures, causes, and corrective actions taken or planned. Pending further review of this event, including the associated LER, this matter is unresolved pending evaluation of potential performance deficiencies and is identified as unresolved item **(URI) 50-272/03-05-02**, Evaluate Causes and Potential Performance Deficiencies Associated with the Trip of the 13 AFW Pump During Surveillance Testing.

1R13 Maintenance Risk Assessments and Emergent Work Evaluation

a. Inspection Scope

The inspectors selected the maintenance activities listed below for review through direct observation, document review (risk assessment reviews, operating logs, industry operating experience and notifications), and personnel interviews. This review was performed to determine whether PSEG properly assessed and managed plant risk, and performed activities in accordance with applicable TS and work control requirements. The inspectors also walked down the protected equipment and maintenance locations to verify that risk was managed in accordance with risk evaluation forms.

- Planned maintenance on the 11 service water pump concurrent with emergent maintenance for the 12AF11, auxiliary feedwater flow control valve to the 12 steam generator on April 8, 2003

- Inspection of the 2A EDG turbocharger on April 30, 2003
- Planned maintenance on the 2C EDG and 23 containment fan coil unit concurrent with emergent maintenance on the 23 component cooling pump on May 13, 2003
- Planned maintenance on the 21 component cooling pump and the 23 charging pump on May 27, 2003

b. Findings

No findings of significance were identified

1R14 Personnel Performance During Non-routine Plant Evolutions

a. Inspection Scope

The inspectors reviewed the Salem Unit 2 control room operators' response to a lowering reactor coolant system pressure on April 17, 2003. The event occurred during a pressurizer spray valve, 2PS3, retest for packing adjustment. During the course of full stroke opening, a manual isolation valve for 2PS3 was prematurely opened by equipment operators. The inspector review was completed through interviews, procedure verification, the transient assessment response plan report, and corrective action notifications.

b. Findings

Introduction. A Green self-revealing NCV was identified for failure to follow surveillance procedures. This failure caused an inadvertent pressurizer continuous spray down and resultant reactor pressure transient.

Description. On April 17, 2003, PSEG completed a packing adjustment on 2PS3. The packing gland follower was tightened to reduce an existing packing leak that was identified during the Salem Unit 2 forced outage on March 29, 2003. PSEG had monitored the packing leakage and had on other occasions performed the activity without error. The packing leak was about one drop per second.

2PS3 was manually isolated by a downstream valve, 2PS29, during the course of the maintenance and was intended to remain isolated during the retest. With 2PS29 closed, pressurizer spray would not occur through 2PS3 and reactor coolant system pressure would remain unaffected. The retest involved remotely stroking 2PS3 from the main control room. The retest was directed by surveillance procedure S2.OP-ST.PZR-0003, "Inservice Testing Pressurizer PORV and Spray and Reactor Head Vent Valves."

In the course of stroke testing 2PS3, human error caused 2PS29 to be prematurely opened causing RCS to depressurize from 2235 psig to 2144 psig. An equipment operator believed that the retest had already occurred and believed that 2PS3 was in a configuration to support opening 2PS29.

Control room operators responded to the lowering RCS pressure and manually restored pressure consistent with abnormal operating procedure S2.OP-AB.PZR-0001, “Pressurizer Pressure Malfunction.” An automatic reactor trip would have occurred at 2000 psig and operators were prepared to manually trip the reactor at 2050 psig, consistent with their training.

The inspectors did not identify any issues with the operators’ response to recover RCS pressure. PSEG’s investigation determined that inadequate communications, and command and control were likely causes of the human error. Communications between the field and the control room occurred prior to opening 2PS29 but were not effective. Senior reactor operators did not question containment entry alarms and communications inconsistent with the sequence discussed during the prejob brief.

Analysis. The performance deficiency associated with this problem is a failure to follow surveillance procedures. This finding is more than minor, because it affected the human performance attribute of the Initiating Events Cornerstone. A human performance error upset plant stability, and manual recovery actions were necessary to avert a reactor plant trip.

The inspector screened this finding using phase 1 of the SDP and answered no to each of the initiating event column questions. The finding screened to Green, very low safety significance, because it only contributed to the likelihood of a reactor trip with no complications.

Enforcement. Salem Unit 2 technical specifications, Section 6.8.1 requires that written procedures be implemented for surveillance and test activities of safety-related equipment. Contrary to the above, on April 17, 2003, operators failed to follow surveillance procedure S2.OP-ST.PZR-0003, “Inservice Testing Pressurizer PORV and Spray and Reactor Head Vent Valves” and did not establish the necessary test conditions for cycling 2PS3, resulting in an RCS pressure transient. Because this failure to follow surveillance procedures was of very low safety significance and has been entered into the corrective action program (Notification 20140179), this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: **NCV 50-311/03-05-03**, Failure to Follow Surveillance Instruction to Prevent a Continuous Pressurizer Spray Event.

1R15 Operability Evaluations

a. Inspection Scope

Other Operability Evaluations. The inspectors reviewed several operability determinations (ODs) or other equipment deficiencies with potential operability issues. The review 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 (CRFAs) were reviewed and compared to applicable TS, the UFSAR, and associated design and licensing basis documents. The following operability issues were reviewed:

- OD 03-004 (Order 70031370), 12 AFW Pump Run-out Protection Circuit Calibration Not Within Tolerance Band.
- OD 03-006 (Order 70031962), Following Tracer Gas Testing the Common Control Room Envelope In-Leakage is Operable but Degraded Pending License Change Request to Use Alternate Source Term
- OD 03-005 (Order 70031624), SW65 Stops Not Reset After Maintenance (23SW65)
- Notifications 20137701 and 20137702 for reactor coolant system leaks on sample system valves 21SS661 and 23SS661
- Notification 20137782 for an inadequate design change to all Unit 1 and Unit 2 component cooling pump bearing oilers
- Notification 20143144 for a Unit 1 service water header cross-connect valve (12SW17) failure

The inspectors also reviewed the following documents:

- S-C-CAV-MEE-1761, Control Room Toxic Gas In-Leakage Evaluation for the CR-TGT CROD
- S-C-ZZ-MEE-1762, Post-LOCA Doses Using TID Source Term for Operability Determination
- Notification 20122928, 22 CFCU Flow Oscillations - 14SW65 Minimum Stops Not Reset After Replacement

b. Findings

No findings of significance were identified.

1R16 Operator Work-Arounds

a. Inspection Scope

During the week of June 9, 2003, 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 referenced NRC Inspection Procedure 71111.16, Operator Workarounds.

b. Findings

No findings of significance were identified.

1R19 Post Maintenance Testing

a. Inspection Scope

Auxiliary Feedwater System Flow Control Valve Inadequate Corrective Actions. The inspectors reviewed an AFW flow control valve (12AF11) anomaly identified during inservice testing. The anomaly was previously identified during a post maintenance test but was not thoroughly investigated by PSEG valve engineers. The inspectors reviewed the maintenance activities that contributed to the valve anomaly, notifications to investigate the root cause of the valve anomaly, and interviewed valve engineers.

b. Findings

Introduction. A self-revealing Green NCV was identified for failure to promptly correct a condition that degraded the AFW flow control valve to the 12 steam generator from the turbine AFW pump (13 AFW pump).

Description. On February 28, 2003, PSEG completed maintenance on the air controls to 12AF11. Post maintenance testing included an inservice stroke time test. The initial stroke time test was slow compared to the baseline stroke time, about 30 seconds compared to 18 seconds. The identification and resolution of the problem was not entered into the corrective action program. Maintenance technicians lubricated the valve stem and slightly adjusted a control air pressure regulator. Subsequent stroke times were acceptable and consistent with the baseline stroke time for 12AF11.

On April 8, 2003, a routine inservice stroke time inservice test was performed for 12AF11. The results were very similar to the post maintenance testing performed on February 28, 2003. PSEG further investigated the matter recognizing that previous corrective actions did not address the root cause.

PSEG discovered that a control air valve to 12AF11 had been severely throttled, affecting the performance of 12AF11. The control air valve was likely not properly returned to full open after maintenance was completed on February 28, 2003. Valve engineers determined that the initial slow time occurred because an insufficient air volume was not available to pressurize control air lines and also adequately operate the valve air actuator. Subsequent valve strokes performed shortly after an initial stoke would be faster, because control air delivered would transfer directly to the air actuator as control air lines were already pressurized.

Analysis. The performance deficiency associated with this problem was untimely corrective actions. Maintenance technicians and valve engineers should have entered the initial valve stroke time anomaly into the corrective action program. The valve stem lubrication and the control air pressure regulator adjustment did not appropriately address the very slow stroke time initially observed.

12AF11 is a normally open valve and the issue involved valve closing. 12AF11 does not receive any automatic isolation signals and would only be closed to isolate auxiliary feedwater to the 12 steam generator. AFW isolation only occurs via operator manual action and is assumed not to occur until ten minutes from an initiating event. The inspectors determined that remote operation of 12AF11 remained available and the increase in stroke time was not significant, about a 12-second increase. The finding is more than minor, because it affected the equipment performance attribute of the Mitigating Systems Cornerstone.

The inspectors screened this finding using Phase 1 of the SDP and answered no to each of the mitigating system column questions and no to the seismic, fire, flooding, and severe weather screening criteria. The finding screened to Green, very low safety significance, because it did not result in the actual loss of a safety function for 12AF11.

Enforcement. 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," requires that measures shall be established that assure deficiencies are promptly identified and corrected. Contrary to the above, PSEG failed to enter into the corrective action program an AFW flow control valve anomaly on February 28, 2003 and did not correct the deficiency leading to the degraded condition. The deficient condition was corrected on April 9, 2003. Because the failure to promptly identify and correct the 12AF11 deficiency was determined to be of very low significance and has been entered into the corrective action program (notifications 20138903 and 20138938), this finding is being treated as a non-cited violation consistent with Section VI.A of the Enforcement Policy: **NCV 50-272/03-05-04**, Untimely Auxiliary Feedwater Valve Corrective Actions.

a. Inspection Scope

15 CFCU outlet isolation valve (15SW72) Inoperability Due to Slow Stroke Time. The inspectors reviewed several post-maintenance testing activities to assess 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:

- S1.OP-ST.SW-0010(Q), "Inservice Testing - Containment Fan Cooler Unit (CFCU) Service Water Valves" on March 20, 2003
- S1.OP-ST.SW-0010(Q), "Inservice Testing - Containment Fan Cooler Unit (CFCU) Service Water Valves" on March 21, 2003, following maintenance on 15SW72 in accordance with Order 60035586
- S1.OP-ST.SW-0010(Q), "Inservice Testing - Containment Fan Cooler Unit (CFCU) Service Water Valves" on March 22, 2003
- S1.OP-ST.SW-0010(Q), "Inservice Testing - Containment Fan Cooler Unit (CFCU) Service Water Valves" on March 23, 2003
- S1.OP-ST.SW-0010(Q), "Inservice Testing - Containment Fan Cooler Unit (CFCU) Service Water Valves" on June 12, 2003, following maintenance on 15SW72 in accordance with Order 60031890

A list of other documents reviewed is included in the Supplemental Information of this report.

b. Findings

Introduction. The inspectors identified a Green non-cited violation for the inadequate implementation of the inservice testing (IST) program as applied to the 15 CFCU outlet isolation valve (15SW72).

Description. During an IST surveillance on December 26, 2002, 15SW72 stroked closed in 13.09 seconds. This valve exceeded the IST action and TS-required acceptance criteria. The valve was retested several times and the closing stroke time continued to improve. The final accepted stroke time was 3.6 seconds. Engineering personnel determined (Order 70028828) that a build-up of silt in the bushing area of the valve caused the failure. Repeated stroking of the valve appeared to clear the condition. Notification 20126100 documented a task to retest 15SW72 every 45 days as a condition to maintain and assure operability. On February 14, 2003, the stroke time test did not occur as intended and PSEG identified the error on March 26, 2003. The administrative problems were documented in notification 20137129. The inspectors reviewed the associated evaluation (Order 70030473) and concluded that the missed retest resulted from human performance and problem identification and resolution (PI&R) cross-cutting issues.

On March 20, 2003, 15SW72 was stroke time tested in the closed direction. The closing stroke time was measured at 17.53 seconds which was in excess of the required action value of five seconds. The valve was declared inoperable, the appropriate TS action statement was entered and the problem was entered into the corrective action program (CAP) as a repeat failure via notification 20136501. Corrective maintenance (CM) that included troubleshooting and replacement of the air booster relay was performed in accordance with Order 60035586. An engineering evaluation (Order 70029988) determined that there was no preventive maintenance (PM) scheduled for the air booster relay and a corrective action was identified to develop a PM. Post-maintenance testing (PMT) was completed on March 21, 2003, with a stroke time of 5.37 seconds. A new baseline stroke time should have also occurred, but administrative errors prevented the new baseline stroke time from being incorporated into procedures for future use. Telephone conversations between operations personnel and IST implementation engineers did occur on March 21, 2003, to discuss the acceptability of the new stroke time.

Testing of the 15SW72 was again performed on March 22, 2003, to complete the quarterly IST surveillance. This test resulted in a closing stroke time of 5.82 seconds; however, the test was terminated and the valve was declared inoperable because the valve would not reopen following testing. PSEG subsequently declared (Order 70030341) the valve to operable but degraded based on its safety function to close. The 15SW72 valve was stroke tested three times on March 23, 2003, with closing stroke times ranging from 4.78 to 5.03 seconds. The stroke time was considered acceptable based on comments in the March 21, 2003 test record that documented a telephone conversation indicating that the 5.37 seconds plus or minus 50 percent was accepted by IST engineering.

On June 10, 2003, PSEG personnel performed a routine scheduled surveillance of the Unit 1 CFCU valves and recorded a stroke time of 5.87 seconds for 15SW72. This exceeded the required action range of 5 seconds specified in the acceptance criteria specified by the effective revision of S1.RA-ST.SW-0010(Q). The TS limiting stroke time of 10 seconds was not exceeded. The valve was declared inoperable and Notification 20148078 was written to replace the valve in accordance with Order 60031890. Operators and engineers applied incorrect acceptance criteria based on the outdated baseline stroke time. The baseline stroke time was intended to be revised following maintenance on March 21, 2003. The 5.87 seconds were actually an acceptable value.

During the valve replacement, the inspector inspected the old valve and discussed the inspection results with valve engineering and maintenance personnel. Silt was found in the shaft to bushing interface area and was suspected of binding the valve.

The inspectors concluded that PSEG inadequately implemented the ASME OMa-1988 , Part 10 (OM-10) requirements for inservice testing of valves. Therefore, 15SW72 was administratively inoperable from the time the valve entered the action range on March 20, 2003, until the valve was replaced and re-baselined on June 12, 2003. Section 3.4 of OM-10 specifies that when a valve or its controls have been replaced, a new reference value shall be determined or the previous value reconfirmed by an inservice test run prior to the time it is returned to service (declared operable). OM-10 further requires that deviations between the previous and new reference values shall be identified, evaluated and documented. Following replacement of the air booster relay (Order 60035586) on March 20 and 21, 2003, PSEG did not properly establish a new baseline closing stroke time or reconfirm the previous value. A reference value was also not established following additional maintenance on March 22 and 23, 2003. The as-left stroke time as documented in S1.OP-ST.SW-0010(Q) on March 23, 2003, was 5.03 seconds and in the required action range. Further deviations between the baseline value and the as-left closing stroke time were not identified, evaluated or documented.

Analysis. A contributing cause to the inadequate implementation of OM-10 was the inadequate implementation of the site and departmental administrative procedures for the inservice testing program. Therefore, this finding is considered a human performance cross-cutting issue. A previous instance of inadequate implementation of the site and departmental administrative procedures for the inservice testing program was documented (Notification 20125186) on December 18, 2002, and was evaluated in Order 70028724. Extent of condition and corrective actions were inadequate to prevent recurrence of the failure to follow these administrative procedures. Therefore, this finding is also considered a problem identification and resolution cross-cutting issue. The inspectors determined that this event was more than minor, because it affected the human performance attribute of the Barrier Integrity Cornerstone. The inoperability resulting from a failure of 15SW72 to cycle with a closing stroke time below the required action range for an indeterminate period of time following its last successful test on

December 29, 2002, affected the availability and reliability of the containment isolation safety function. Since the finding did not represent an actual open pathway in the physical integrity of the reactor containment, this finding screens to Green (very low safety significance).

Enforcement. Technical Specification 4.0.5 states that the applicable surveillance requirements for the testing of an ASME Code valve shall be in accordance Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda as required by 10 CFR 50.55a(g). ASME Section XI (ASME/ANSI OMa-1988, Addenda to the ASME/ANSI OM-1978 Edition, Part 10 - “Inservice Testing of Valves in Light Water Power Plants,” Section 3.4, specifies that when a valve or its controls have been replaced, a new reference value shall be determined or the previous value reconfirmed by an inservice test run prior to the time it is returned to service (declared operable). OM-10 further requires that deviations between the previous and new reference values shall be identified, evaluated and documented. Contrary to the above, PSEG failed to establish a new reference value or reconfirm the previous reference for 15SW72 following maintenance between March 20 and 23, 2003. PSEG also did not identify, evaluate and document deviations between the previous reference value (established May 11, 2001) and the values obtained by an inservice testing between March 20 and March 23, 2003. This violation is associated with an inspection finding that was characterized by the Significance Determination Process as having very low risk significance (Green) and has been entered into the PSEG corrective action program (Notification 20150507), this violation is being treated as a Non-Cited Violation (NCV), consistent with Section VI.A.1 of the NRC Enforcement Policy: **NCV 50-272/03-05-05**, Inadequate Implementation of TS 4.0.5 for Inservice Testing of Valve 15SW72.

Other Post Maintenance Testing Activities

a. Inspection Scope

The inspectors reviewed several post-maintenance testing activities to assess 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:

- S1.OP-ST.SW-0001(Q), “Inservice Testing - 11 Service Water Pump” on April 9, 2003, following pump replacement on 11 service water pump with Order 60033873
- S2.OP-ST.CC-0003, “Inservice Testing - 23 Component Cooling Pump” on May 14, 2003, following pump bearing replacement on 23 Component Cooling Pump with Order 60036525

- S1.OP-ST.SW-0010(Q), "Inservice Testing - Containment Fan Cooler Unit (CFCU) Service Water Valves" on June 12, 2003, following maintenance on 15SW72 in accordance with Order 60031890
- S1.OP-ST.DG-0003(Q), "1C Diesel Generator Surveillance Test" on June 4, 2003, following maintenance on 1C EDG in accordance with Order 60033146

b. Findings

No findings of significance were identified

22 Auxiliary Feedwater Pump Packing Performance

a. Inspection Scope

The inspectors reviewed PSEG's evaluation to identify the potential cause of overtightened packing on the 22 AFW pump. The overtightened packing concerned PSEG engineers, because it was identified on March 13, 2003, during a pump startup after the 22 AFW pump had been left in standby for several weeks. Pump packing adjustments should not be made without operating the pump. PSEG's evaluation also included a review of 22 AFW pump past-operability assuming no operator or maintenance worker intervention to loosen the packing from its as-found condition. The inspectors also interviewed component engineers involved in the 22 AFW pump investigation and operability review.

PSEG was unable to exactly determine any activity that could have improperly adjusted the 22 AFW pump packing. The past operability review was contained in Order 70030232 and concluded that the packing gland follower was only slightly overtightened, the packing would remain adequately cooled, and that the condition would not worsen.

b. Findings

No findings of significance were identified. URI 50-311/03-03-04 is closed.

1R22 Surveillance Testing

a. Inspection Scope

Service Water Header Cross Connect Valve (12SW17) Torque Switch Contacts. The inspectors observed selected portions of the testing and reviewed the test results for the 15 service water pump to assess whether the surveillance testing satisfied TS, Updated Final Safety Analysis Report, or PSEG procedural requirements. The inspectors assessed whether the testing appropriately demonstrated that the equipment was operationally ready and capable of performing their intended safety functions. The following test, activities and documents were reviewed:

- S1.OP-ST.SW-0005(Q), "Inservice Testing - 15 Service Water (SW) Pump" on May 5, 2003

- SH.OP-AP.ZZ-0008(Q), “Operations Troubleshooting and Evolutions Plan Development”
- Notification 20141285, “15 SW Pump Troubleshooting”

b. Findings

Introduction. A Green self-revealing NCV was identified for inadequate corrective actions to prevent recurrence of the motor operator failure on the service water discharge header cross-connect valve (12SW17).

Description. On April 9, 2003, 12SW17 failed to cycle in the open or closed directions. Maintenance personnel investigated and replaced parts, including two seal-in relays and the torque switch (Notification 20143115/Order 60036669) for the motor operator. The valve was retested and returned to service. On May 5, 2003, 12SW17 failed to close during unrelated service water system testing in accordance with procedure (S1.OP-ST.SW-005(Q)). The valve initially started to move but stopped shortly after moving off of its open limit.

A transient analysis response plan (TARP) team was formed to investigate the event. PSEG’s investigation (Notification 20143144/Order 70031413) concluded that the closing torque switch contacts did not make up and the valve motion stopped when the torque switch bypass circuit timed-out. At the direction of the TARP team, maintenance personnel examined the torque switch and found the contacts dirty (Notification 20143115/Order 60036669). Maintenance technicians cleaned the contacts and tightened the spring tension on the torque switch as immediate corrective actions. The inspectors noted that the torque switch had been replaced in April 2003. PSEG’s apparent cause evaluation (Order 70031413) concluded that dirty contacts prevented the torque switch from completing the closing circuit. The planned corrective actions included providing information to maintenance technicians and revising maintenance procedures to check the condition of new parts upon installation.

Analysis. PSEG determined that 12SW17 failed to fully stroke on May 5, 2003, due to loose springs and dirty contacts on the motor operator torque switch. A contributing cause to this failure was the failure to identify and correct the loose springs and dirty contacts when the torque switch was replaced after 12SW17 failed to open on April 9, 2003. Therefore, this finding is considered a PI&R cross-cutting issue.

The inspectors determined that this event was more than minor, because it affected the equipment performance attribute of the Mitigating System Cornerstone. The 12SW17 and a redundant cross-connect valve (11SW17) are necessary to maintain service water bay flooding capabilities. The failure of 12SW17 to close on demand on May 5, 2003, affected the availability, reliability and operability of one train of service water for mitigating systems. An investigation determined that the 12SW17 was cycled three times after being returned to service on April 11, 2003. There was less than 72 hours of fault exposure time since 12SW17 was last successfully cycled on May 3, 2003. The finding represented an actual loss of the safety function for one train (12 service water loop) of a TS system for less than the 72 hour allowed outage time. Therefore, this finding screens to Green (very low safety significance).

Enforcement. 10 CFR 50, Appendix B, Criterion XIV, “Corrective Action,” states that measures shall be established to assure that failures, malfunctions and defective material and equipment are promptly identified and corrected. The measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition. Contrary to the above, PSEG’s corrective actions in response to the 12SW17 motor-operated valve’s failure to cycle on April 9, 2003, were inadequate to prevent recurrence of the 12SW17 valve’s failure to cycle closed on May 5, 2003. This violation is associated with an inspection finding that was characterized by the Significance Determination Process as having very low risk significance (Green) and has been entered into the PSEG corrective action program (Notification 200143144), this violation is being treated as a Non-Cited Violation (NCV), consistent with Section VI.A.1 of the NRC Enforcement Policy: **NCV 50-272/03-05-06**, Inadequate Corrective Actions to Prevent Recurrence of a Service Water Motor-operated Valve (12SW17) Failure.

a. Inspection Scope

Other Surveillance Testing. The inspectors observed testing or reviewed the test results for several risk significant equipment to assess whether the surveillance testing satisfied TS, Updated Final Safety Analysis Report, or PSEG procedural requirements. The inspectors assessed whether the testing appropriately demonstrated that the equipment was operationally ready and capable of performing their intended safety functions. The following tests and activities were reviewed:

- SC.MD-ST.125-0003(Q), “Quarterly Inspection and Preventive Maintenance of Units 1, 2, and 3 125 Volt Station Batteries” on April 30, 2003
- S1.OP-ST.SW-0004(Q), “Inservice Testing - 14 Service Water Pump” on May 22, 2003
- S1.OP-ST.RCS-0001(Q), “Reactivity Control System Rod Control Assemblies” on May 23, 2003
- S2.IC-ST.SSP-0013(Q), “Reactor Trip Breakers and Reactor Bypass Breakers Operability Test - Train A and Train B” on May 23, 2003
- S1.OP-ST.SW-0002(Q), “Inservice Testing - 12 Service Water Pump”
- S2. OP-ST.DG-0014, “2C Diesel Generator Endurance Run” and S2.OP-ST.DG-0003, “2C Diesel Generator Surveillance Test” on June 13, 2003
- S1.OP-ST.SW-0010(Q), “Inservice Testing - Containment Fan Cooler Unit (CFCU) Service Water Valves” on June 10, 2003 (Related finding discussed in Report Section 1R19)

Other documents reviewed were:

- SH.OP-AP.ZZ-0008(Q), “Operations Troubleshooting and Evolutions Plan Development
- Notification 20143761, “14 SW Pump Troubleshooting”

- Notification 20145073, “12 SW Pump Troubleshooting”

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications

a. Inspection Scope

During the week of April 7, 2003, the inspectors reviewed all temporary modifications installed at Salem Unit 1 and Unit 2. The inspectors did not identify any installed temporary modifications that involved systems important to safety. The inspectors were alert to any unauthorized plant modification during plant status reviews and also did not identify any additional temporary modifications.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Public Radiation Safety

2PS2 Radioactive Material Processing and Transportation

a. Inspection Scope

On June 5 and June 17, 2003, the inspector observed two shipments of Type B quantities of radioactive material for disposal at the Barnwell Low-Level Radioactive Waste Management Facility (Shipments #SA 03-56 and HC03- 53). The shipment was made using a NRC-licensed Type B packaging [USA/9168/B(U)]. This detailed review was made against the requirements contained in 10 CFR Parts 20, 61 and 71, 49 CFR Parts 100-177, and the Barnwell Site License.

b. Findings

No findings of significance were identified.

3. SAFEGUARDS

Cornerstone: Physical Protection

3PP4 Security Plan Changes

a. Inspection Scope

An in-office review was conducted of changes to PSEG's Security Plan identified as Revision 17, 18, and 19. These documents were submitted to the NRC on November 1, 2002, October 10, 2002, and April 11, 2003, respectively, in accordance with the provisions of 10 CFR 50.54(p). The review confirmed that the changes were made in accordance with 10 CFR 50.54(p), and did not decrease the effectiveness of the above listed plans. The NRC recognizes that some requirements contained in these program plans may have been superceded by the February 2002 Interim Compensatory Measures Order.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification

a. Inspection Scope

The inspectors sampled PSEG submittals for the reactor coolant system (RCS) activity, reactor coolant system leakage, and safety system functional failure (SSFF) performance indicators (PIs) for the period from April 2002 through March 2003. To verify the accuracy of the PI data reported during that period, PI definitions and guidance contained in NEI 99-02, "Regulatory Assessment Indicator Guideline," Rev. 1, were used to verify the basis in reporting for each data element. The inspectors reviewed the method used by control room operators for determining RCS leakage. The inspectors verified the RCS leakage PI data submitted through review of S1 and S2.OP-ST.RC-0008(Q), "Reactor Coolant System Water Inventory Balance" procedure results. The inspectors reviewed the RCS activity PI data submitted through review of spreadsheets maintained by the shift technical advisors. All licensee event reports were reviewed for the SSFF PI.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems

a. Inspection Scope

Annual Sample Review. The inspectors selected two notifications, 20138455 and 20138509, for detailed review. The notifications involved a single CC motor-operated valve (MOV) failure identified during inservice testing on April 8, 2003. The associated apparent cause evaluation, maintenance and testing procedures, maintenance history, work orders and intended corrective actions were reviewed to ensure that the full extent of the issue was identified, an appropriate evaluation was performed, and appropriate corrective actions were specified and prioritized. Additionally, personnel were interviewed about the surveillance failure. The inspectors evaluated PI&R performance regarding this issue against procedure NC.WM-AP.22-0002, "Performance Improvement Process."

b Findings

Introduction. PSEG did not identify the correct apparent cause of the surveillance test failure. The NRC inspectors identified that inadequate maintenance practices caused hardened grease to exist on 1CC17. PSEG subsequently issued a new notification (20150497) on June 12, 2003. The inspectors also judged PSEG's extent of condition review to be narrow and only included the component cooling system MOV. A Green NCV was identified for failure to follow maintenance procedures. This maintenance procedure problem caused 1CC17 to fail mid-stroke during a quarterly surveillance test on April 4, 2003.

Description. Work Order 30011424 was issued in May 2002 to perform preventive maintenance on valve 1CC17 (component cooling water pump suction cross-connect valve). The procedure, SC.MD-PM.ZZ-0118, "Valve Stem Lubrication for Motor Operated Rising Stem Valves, specified in the work order required the valve stem to be cleaned and re-lubricated. The maintenance supervisor used a separate procedure, SH.MD-GP.ZZ-0010, "Motor Operated Valve Troubleshooting, Data Collection And Turnover." This procedure allowed MOV technicians to perform, or not perform, maintenance steps based upon their experience. In the case of MOV 1CC17 the mechanic visually inspected the stem grease and decided that cleaning and re-lubing was not necessary, contrary to the preventive maintenance and direction provided in the work order.

Subsequent to this maintenance activity, on April 4, 2003, during surveillance testing, 1CC17 failed mid-stroke and did not fully close. PSEG attributed the 1CC17 failure to aged and hardened grease on the valve stem threads.

Analysis. The deficiency associated with this problem is inadequate maintenance practice. This finding is more than minor, because it affected the equipment performance attribute of the Mitigating Systems Cornerstone. The reliability of the CC system was impacted.

1CC17 is a normally open component cooling water pump suction cross-connect valve. The CC system provides cooling water to several safety-related loads: residual heat removal (RHR) heat exchangers, charging pump mechanical seal coolers, safety injection pump seal coolers, and RHR pump seal coolers. During the cold leg recirculating phase of a loss of coolant accident, the component cooling water system should be separated into two trains, each of which can function independently and remove residual heat from the recirculated sump water. The separation of the CC system into two trains includes closing 1CC17. Redundant MOVs would provide two independent trains even with 1CC17 open.

The inspector screened this finding using Phase 1 of the SDP and answered no to each of the mitigating system column questions and no to the seismic, fire, flooding, and severe weather screening criteria. The finding screened to Green (very low safety significance) because it did not result in the actual loss of a safety function of a single train. Redundant CC MOVs would have maintained two independent trains.

Enforcement. Salem Unit 1 TS Section 6.8.1. requires that written procedures be established, implemented and maintained for the applicable procedures recommended in Appendix "A" of Regulatory Guide 1.33, Revision 2, February 1978. Appendix "A" of Regulatory Guide 1.33 requires procedures for performing maintenance that can affect the performance of safety-related equipment. Contrary to the above, on May 14, 2002, maintenance technicians failed to follow preventive maintenance instructions, and did not clean and lubricate the 1CC17 valve stem. Because the failure to properly perform maintenance on 1CC17 was determined to be of very low significance and has been entered into the corrective action program (notification 20150497), this violation is being treated as a non-cited violation consistent with Section VI.A of the NRC Enforcement Policy: **NCV 50-272/03-05-07**, Failure to Properly Perform Maintenance on Component Cooling Cross-Connect Valve, 1CC17.

Cross-Reference to PI&R Findings Documented Elsewhere

Section 1R22 describes a finding for inadequate corrective actions to prevent recurrence of the service water discharge header cross-connect valve (12SW17) motor operator's failure to change state due to torque switch problems. Maintenance technicians could have been reasonably expected to identify that the torque switch contacts were dirty and the springs were loose when the torque switch was replaced the previous month.

Section 1R19 describes a finding for inadequate implementation of inservice testing requirements. Inadequate implementation of site and departmental administrative procedures for the inservice testing program by PSEG personnel was a contributing cause. A previous instance of inadequate implementation of the site and departmental administrative procedures for the inservice testing program was documented and evaluated. However, the extent of condition and extent of cause reviews, as well as, the corrective actions were inadequate to prevent recurrence of the failure to follow these administrative procedures.

4OA3 Event Followup

1. (Open/Closed) LER 50-311/03-001-00, Manual Reactor Trip Due to Degradation of Condenser Heat Removal

On March 29, 2003, Salem Unit 2 was manually tripped by control room operators in response to multiple circulating water pumps becoming unavailable during excessively high Delaware River debris levels. Plant response to the manual reactor trip was normal. All Unit 1 and Unit 2 service water system components remained available during the high river water debris levels. This event was also described in NRC

Inspection Report 50-272/03-03, 50-311/03-03, Section 1R14.4 Personnel Performance During Non-routine Plant Evolutions. This LER was reviewed by the inspector, and no findings of significance or violations of NRC requirements were identified. This LER is closed.

2. 13 Auxiliary Feedwater Pump Tripped During Quarterly Surveillance Testing

During IST of the 13 AFW pump on May 23, 2003, the turbine tripped moments after being started by the control room operator. At the time of the trip, the control room operator observed an increase in pump speed and subsequently noted that the turbine trip throttle valve (1MS52) had gone closed. The nuclear equipment operator (NEO) located at the pump noted that the steam inlet valve (1MS132) had not stroked open smoothly but had popped open. PSEG assembled a TARP Team (Notification 20146103) to investigate the cause of the failure and develop a corrective action plan.

Evaluation of the 1MS132 valve identified that the feedback arm for the 1MS132 was rotated from its normal position and needed adjustment. Initial inspection of the 1MS52 valve and linkage showed no anomalies. Preliminarily, PSEG determined that looseness in the actuator to valve stem coupling of the 1MS132 caused binding during valve operation. PSEG believed that a rapid change in valve position and the resulting sudden increase in steam flow vibrated the 1MS52 unlatched and tripped closed. The feedback arm was re-aligned, the split coupling block was re-tightened, and the 13 AFW pump was retested without further problems. Order 70031717 was initiated to perform an apparent cause evaluation for this event. Additional issues regarding this event are documented in report Section 1R12. This event will be closed after receipt and review of PSEG's LER for this event.

4OA4 Cross Cutting Aspects of Findings

Section 1R14 describes a plant transient that was initiated by an operator error and a green finding that was related to human performance.

Section 1R19.1 describes configuration control errors that degraded an auxiliary feedwater flow control valve and a green finding that was related to human performance.

Section 1R19.2 describes inadequate implementation of inservice testing requirements for a service water motor operated valve and a green finding that was related to human performance.

Section 4OA2.1 describes inadequate maintenance practices that rendered a component cooling water motor operated valve inoperable and a green finding that was related to human performance.

4OA5 Other Activities

The inspectors reviewed the World Association of Nuclear Operators (WANO) Peer Review for Salem/Hope Creek Generating Station. The report discussed WANO's August 2002 assessment and PSEG's response.

4OA6 Meetings, Including Exit

On July 14, 2003, the resident inspectors presented the inspection results to Mr. O'Connor, Mr. Carlin, Mr. Garchow and other members of their staff who acknowledged the findings. The inspectors confirmed that proprietary information was not provided or examined during the inspection.

4OA7 Licensee Identified Violations

The following finding of very low significance was identified by PSEG and is a violation of NRC requirements which meets the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as a Non-Cited Violation (NCV).

- 10 CFR 50 Appendix B, Criterion III, Design Control, requires that measures shall be established for the selection of materials, parts, equipment, and processes that are essential to the safety-related functions of the structures, systems and components. Contrary to this, PSEG installed an inadequate oiler design on all Salem Unit 1 and Unit 2 component cooling pump bearings. The modifications occurred over several months and the discrepant design was identified on March 31, 2003, during a routine component cooling pump oil change. The oiler did not drain as the bearing housing was drained. This issue was identified in PSEG's corrective action program as notification 20137782. This finding is of very low safety significance, because it did not render any component cooling pumps inoperable.

If you deny this non-cited violation, you should provide a response with the basis for your denial, within 30 days of the date of this inspection report, 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 facility.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee personnel

Bill Campbell, Manager - Mechanical Maintenance
John Carlin, Vice President - Engineering
Terry Cellmer, Manager - Radiation Protection
Carl Fricker, Salem Operations Manager
Dave Garchow, Vice President - Projects and Licensing
John Garecht, Salem Operations Superintendent
Doug McCullom, Reliability Engineer
Timothy O'Connor, Vice President - Operations
Duane Phillips, Manager - Maintenance Controls
Lon Waldinger, Director - Operations
Pat Walsh, Manager - System Engineering

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-272/03-05-02	URI	13 auxiliary feedwater pump trip due to mechanical binding of the steam inlet valve. (Section 1R12.3)
50-272/03-05-01	NCV	Failure to promptly correct a condition that rendered the 12B component cooling water heat exchanger inoperable. (Section 1R12.1)
50-311/03-05-03	NCV	Failure to follow surveillance instruction to prevent a continuous pressurizer spray event. (Section 1R14)
50-272/03-05-04	NCV	Failure to promptly correct a condition that degraded the auxiliary feedwater flow control valve to the 12 steam generator from the turbine auxiliary feedwater pump (13 AFW pump). (Section 1R19.1)
50-272/03-05-05	NCV	Inadequate implementation of technical specification required procedures for the inservice testing program as applied to the 15 CFCU outlet isolation valve (15SW72). Section 1R19.2)

50-272/03-05-06	NCV	Inadequate corrective actions to prevent recurrence of a service water motor-operated valve (12SW17) failure. (Section 1R22.1)
50-272/03-05-07	NCV	Failure to properly perform maintenance on component cooling cross-connect valve, 1CC17. (Section 4OA2.1)

Opened/Closed

50-311/03-0001-00	LER	Manual reactor trip due to degradation of condenser heat removal. (Section 4OA3.1)

Closed

50-311/03-03-04	URI	22 auxiliary feedwater pump packing performance. (Section 1R19.4)

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 1R06: Flood Protection Measures

Salem Updated Final Safety Analysis Report, Section 3.4 Flood Protection Design
Salem Unit 1 & 2, Technical Specification, Section 3/4.7.5 Flood Protection
Regulatory Guide 1.102, Flood Protection for Nuclear Power Plants
S-C-FP-FEE-1275, Rev. 0; Inaccessible Barriers and Penetration Seals
SC.FP-SV.FBR-0026(Q)-Rev. 2; Flood and Fire Penetration Seal Inspection
S2.OP-AB.ZZ-0002(Q)-Rev. 2; Flooding
S1.OP-AB.ZZ-0002(Q)-Rev. 2; Flooding
SGS EAL/RAL Technical Basis, Section 9.7 Flooding
SC.OP-AB.ZZ-0001(Q)-Rev. 2; Adverse Environmental Conditions
SC.MD-PM.ZZ-0036(Q)-Rev. 5; Watertight Door Inspection and Repair
NC.OP-DG.ZZ-0002(Q)-Rev. 1; Severe Weather Guide
SC.DE-TS.ZZ-2034(Q); Technical Requirements For Construction of Electrical Installation
Salem Generating Station
Cycle 7 Penetration Seal Inspection List
Cycle 8 Penetration Seal Inspection List
Notification 20102951; Penetration Seal E-15401-001 Damaged
TS980925168-0010 Disposition Penetration Seal S2FBR-F-25513-023
Notification 20097797 Flooding from 25 CFCU in 78'
Notification 20024003 Mismatch in PSA Flooding documents
Notification 20048528 Water flooding into work area

Inspection Report S-IR-6A5-0001, Rev. 3; Results of Annual Inspection of Artificial Island Shoreline
Notification 20114270, Hope Creek Loading Dock Barge Bumpers
Notification 20114362, Salem Circ Water Fish Trough return pipe
Notification 20114361, Salem sheet pile shoreline degradation

<u>Section 1R12: Maintenance Rule Implementation</u>

Notification 20146103, Salem Unit 1 TARP Report, 13 AFW Pump Trip During Start
Order 70031717, 13 AFW Pump Trip on Start - N1 20146103
Notification 20146321, 13 AFW Pump Trip on Start - N1 20146103
Notification 20146105, 13 AFW Pump Valve (70031717)
Notification 20119972, Revise S1.RA-ST.AF-0003(Q), revision 9
Order 80054453, Revise S1.RA-ST.AF-0003(Q), revision 9
Order 30079158, 3Y 1MS52 Clean and Inspect - Trip Solenoid
Notification 20134665, 3Y 1MS52 Clean and Inspect - Trip Solenoid
PM006228, 1MS132-Valve Assembly Overhaul [Task not implemented]
PM007144, 2MS132-Valve Assembly Overhaul [Task not implemented]
S1.OP-ST.AF-0003(Q), Inservice Testing - 13 Auxiliary Feedwater Pump [records of tests performed on 10/29/03, 11/1/2003, 12/6/03, 2/28/03, 5/23/03 and twice on 5/24/03]
S1.RA-ST.AF-0003(Q), Inservice Testing - 13 Auxiliary Feedwater Pump Acceptance Criteria [revisions 9 and 10]
SH.ER-DG.ZZ-0001(Z), Preventable and Repeat Preventable System Functional Failure Determination
SH.ER-DG.ZZ-0002(Z), Maintenance Rule (a)(1) Evaluations and Goal Monitoring
SH.ER-DG.ZZ-0003(Z), Processing Maintenance Rule Reliability Data
Salem Unit 1, Auxiliary Feedwater System Health Status Report [period 11/01/2002 - 01/31/2003]
NC.ER-AP.ZZ-0075(Q), Valve Programs
Salem PSA System Notebook - Auxiliary Feedwater System and Main Feedwater System
SE.MR.SA.01, Salem System Function and Risk Significant Guide
SE.MR.SA.02, Salem System Function Level Maintenance Rule vs. Risk Reference
Notification 20114985, 1MS132 parent seat leakage
Order 30037646, 1R PM: 1MSE3/ Overspeed Test
SH.RA-AP.ZZ-0105(Q), “IST Program Management”
NC.NA-AP.ZZ-0070(Q), “Inservice Testing (IST) Program”
NC.WM-AP.ZZ-0002(Q), “Performance Improvement Process”
SH.MD-AP.ZZ-9005(Q), “Air Operated Valve Program”
Notification 20149336, TARP Procedure Non-Compliance [13 AFW Pump Trip TARP]
QA Assessment Monitoring Feedback 2003-0161
Salem 1 - 1MS132 Fact Finder in Relation to Inservice Testing [performed by IST Program Mgr.]
Vendor Technical Document (VTD) 301693, Masoneilan Spring-Diaphragm Actuator Instructions for # 9, 11, 13, 15, 18 and 24.
Vendor Technical Document (VTD) 301686, Masoneilan Instruction and Maintenance Manual Spring-Diaphragm Actuator Instructions
Order 30079158, 3Y 1MS52 Clean and Inspect - Trip Solenoid

NC.NA-AP.ZZ-0022(Q), Nuclear Procedure System
SC.MD-GP.ZZ-0022(Q), Bolt Torquing and Bolting Sequence Guidelines
SH.IC-GP.ZZ-0002(Q), Disassembly, Inspection, Reassembly and Testing of Masoneilan Model 37/38 Air Operated Actuators
ASME OM Code, OM-10, Inservice Testing of Valves in Light-water Reactor Power Plants

<u>Section 1R19: Post-Maintenance Testing</u>

NC.NA-AP.ZZ-0050(Q), “Station Testing Program”
NC.NA-AP.ZZ-0070(Q), “Inservice Testing (IST) Program”
NC.WM-AP.ZZ-0002(Q), “Performance Improvement Process”
SH.RA-AP.ZZ-0105(Q), “IST Program Management”
S1.RA-ST.SW-0010(Q), Revision 16, effective date December 24, 2002, “Inservice Testing Containment Fan Cooler Unit (CFCU) Service Water Valves Acceptance Criteria”
ASME OM Code, OM-10, Inservice Testing of Valves in Light-water Reactor Power Plants
Notification 20065261, “15SW72 Won’t Stroke Open”
Notification 20112853/Order 60031890, “Replace 15SW72 with 6% Moly Spare”
Notification 20116400, “15SW72 Won’t Operate Correctly”
Order 60032442, “Troubleshoot and Repair - 15SW72 Won’t Operate Correctly”
Notification 20119861, “Create NUCM DC Order for 15SW72 Replacement”
Order 60033266, “Create NUCM DC Order for 15SW72 Replacement”
Notification 20116415, “15SW72 Need to be Retested Following”
Notification 20126124, “15SW72 (15 CFCU) Failed (70028828)”
Order 70028828, “15SW72 (15 CFCU) Failed (20126124)”
Notification 20126100, “Perform ST on 15SW72 in 45 Days”
Notification 20136501, “15SW72 Is In Its Required Action Range (70029988)”
Order 60035586, “15SW72 Slow Stroke Time - Troubleshoot and Repair”
Notification 20136559, “15SW72 Is In Its Required Action Range (20136501)”
Notification 20136731/Order 70030341, “15SW72 Failed to Reopen (2013673)”
Notification 20136733, “Repair 15SW72 (70030364)”
Notification 20137021, “Repair 15SW72 (20136733)”
Order 70030364, “Repair 15SW72 (20136733)”
Notification 20137129/Order 70030473, “Failure to Take Required Interim Corrective Action”
Notification 20148078, “15SW72 Failed Its Closed Stroke Time (70032029)”
Order 60037259, “15SW72 Failed Its Closed Stroke Time”
Notification 20148160, “15SW72 Failed Its Closed Stroke Time (20148078)”
Order 30017372, “15SW72 Internal Inspection 89-013 Letter”

LIST OF ACRONYMS

AFW	Auxiliary Feedwater
ASME	American Society of Mechanical Engineers
CAP	Corrective Action Program
CC	Component Cooling
CFCU	Containment Fan Cooler Unit

CFR	Code of Federal Regulations
CM	Corrective Maintenance
EDG	Emergency Diesel Generator
ICMs	Interim Compensatory Measures
IST	Inservice Testing
LER	Licensee Event Report
MOV	Motor Operated Valve
NCV	Non-cited Violation
NRC	Nuclear Regulatory Commission
ODs	Operability Determinations
PARS	Publicly Available Records
PI&R	Problem Identification and Resolution
PIs	Performance Indicators
PM	Preventive Maintenance
PMT	Post-Maintenance Testing
PSEG	Public Service Electric Gas
PSIG	Pounds Per Square Inch Gauge
RCS	Reactor Coolant System
RHR	Residual Heat Removal
SDP	Significance Determination Process
SI	Safety Injection
SROs	Senior Reactor Operators
SSFF	Safety System Functional Failure
SW	Service Water
TARP	Transient Analysis Response Plan
TI	Temporary Instruction
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
WANO	World Association of Nuclear Operators