February 12, 2004

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

SUBJECT: SALEM NUCLEAR GENERATING STATION - NRC INTEGRATED INSPECTION REPORT 05000272/2003009 AND 05000311/2003009

Dear Mr. Anderson:

On December 31, 2003, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Salem 1 and 2 reactor facilities. The enclosed integrated inspection report documents the inspection findings, which were discussed on January 23, 2004 with Mr. Fricker and other members of your staff.

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

This report documents seven self-revealing findings and two NRC-identified 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 nine findings as non-cited violations (NCVs) consistent with Section VI.A of the NRC Enforcement Policy. If you contest any NCV in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, D.C. 20555-0001; with copies to the Regional Administrator, Region I; the Director, Office of Enforcement, and the NRC Resident Inspector at the Salem Nuclear Generating Station.

Since the terrorist attacks on September 11, 2001, the NRC has issued five Orders and several threat advisories to licensees of commercial power reactors to strengthen licensee capabilities, improve security force readiness, and enhance access authorization. In addition to applicable baseline inspections, the NRC issued Temporary Instruction 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 nuclear power plants during 2002, and the remaining inspection activities for Salem Generating Station were completed in 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, 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/

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 05000272/2003009 and 05000311/2003009
w/Attachment: Supplemental Information

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U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket Nos:	50-272, 50-311
License Nos:	DPR-70, DPR-75
Report No:	05000272/2003009, 05000311/2003009
Licensee:	PSEG, LLC
Facility:	Salem Nuclear Generating Station, Units 1 and 2
Location:	P.O. Box 236 Hancocks Bridge, NJ 08038
Dates:	September 28, 2003 - December 31, 2003
Inspectors:	J. Daniel Orr, Senior Resident Inspector George J. Malone, Resident Inspector Neil L. Della Greca, Senior Reactor Engineer Jason C. Jang, Senior Health Physicist Joseph T. Furia, Senior Health Physicist Nancy T. McNamara, Emergency Preparedness Specialist Stephen M. Pindale, Senior Reactor Inspector Frederick Jaxheimer, Resident Inspector, Susquehanna Timothy O’Hara, Reactor Inspector
Approved By:	Glenn W. Meyer, Chief, Projects Branch 3 Division of Reactor Projects

CONTENTS

SUMMARY OF FINDINGS

IR 05000272/2003009 and 05000311/2003009; 09/28/2003 - 12/31/2003; Public Service Electric Gas Nuclear LLC, Salem Units 1 and 2; Inservice Inspection (ISI) Activities, Maintenance Effectiveness, Maintenance Risk Assessments and Emergent Work Control, Operability Evaluations, Permanent Plant Modifications, Refueling and Other Outage Activities, Event Followup, Other.

The report covered a three-month period of inspection by resident inspectors with support from regional reactor inspectors, and announced inspections by a regional radiation specialist, an emergency preparedness (EP) 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. Deferral of vendor recommended design changes (fuse uprating) on the control drive mechanisms led to a November 23, 2003, manual reactor trip due to a dropped rod during startup physics testing. A self-revealing NCV was identified for ineffective corrective actions.

  This finding is greater than minor, because it caused an actual plant transient. The finding is of very low safety significance, because all mitigation systems were unaffected (Section 1R17).

Cornerstone: Mitigating Systems

- Green. A compressor air leak on the starting air system for the Unit 2 A EDG was not properly evaluated and corrected, such that the removal of the other compressor for maintenance resulted in the 2A EDG being inoperable. This resulted in a Green self-revealing NCV for ineffective corrective actions.

  This finding is greater than minor, because it affected the Mitigating System Cornerstone objective of equipment reliability, in that the 2A EDG was rendered inoperable due to a support system failure. The finding is of very low safety significance, because other EDGs remained unaffected and shutdown risk was not significantly affected (Section 1R12).

- Green. In February 2003, PSEG identified equipment failures related to corrosion products in the control air system. On October 22, 2003 a Unit 2 chilled water compressor (23 chiller) tripped, because its control air was restricted by corrosion products. This self-revealing finding represented an NCV for ineffective corrective actions.

This finding is greater than minor, because it affected the chilled water system availability, an equipment performance attribute of the Mitigating Systems Cornerstone. The finding is of very low safety significance, because the 23 chiller inoperability duration was short, about an hour, and one train of control room emergency air conditioning remained operable (Section 1R13).

- Green. Ineffective problem evaluation regarding a known air pocket in the Unit 2 residual heat removal (RHR) system resulted in a waterhammer on the RHR and containment spray (CS) systems during a CS full flow test. This self-revealing finding represented an NCV for corrective actions.

  This finding is greater than minor, because it affected the Mitigating System Cornerstone objective of equipment reliability, in that the RHR system was unnecessarily subjected to an additional waterhammer and the associated hydraulic stresses and strains. The finding is of very low safety significance, because it did not render the RHR system inoperable (Section 1R15.1).

- Green. Ineffective corrective actions existed regarding an identified problem, in that the RHR system operating procedure had an insufficient cooldown period to preclude steam void conditions from developing after RHR flow was secured and this error was not corrected prior to its use. PSEG calculations in May 2003 had identified that the cooldown period should be increased from 15 minutes to 21 minutes. Operators restarted the Unit 2 RHR system on November 19, 2003, after cooling it down for less than 21 minutes, and a waterhammer occurred.

  This finding is greater than minor, because it affected the Mitigating System Cornerstone objective of equipment reliability, in that the residual heat removal system was started with potential steam void conditions present. The finding is of very low safety significance, because it did not render the RHR system inoperable (Section 1R20).

- Green. Corrective actions were untimely, in that analyses to determine the stresses on the Unit 2 RHR system from repeated waterhammers were not completed until November 25, 2003. The waterhammer had been first identified on May 10, 2002. The inspectors also identified loose RHR pipe support hangers, which had not been identified by PSEG during system walkdowns in support of the waterhammer issue. This represented an NCV for ineffective corrective actions.

This finding is greater than minor, because it affected the Mitigating System Cornerstone objective of equipment reliability, in that the RHR system was operated with unevaluated conditions due to repeated waterhammers and degraded pipe supports. The finding is of very low safety significance, because it did not render the RHR system inoperable (Section 4OA5.4).

- Green. Ineffective corrective actions existed following a service water pump strainer (13 SWP strainer) trip in February. An established troubleshooting plan, developed as a corrective action from previous inadequacies in identifying strainer problems, was not used, and the cause of the strainer tripping was not fully identified. The 13 SWP strainer tripped again in April and required disassembly in May to remove metal debris that had ultimately bound strainer rotation. This self-revealing finding represented an NCV for ineffective corrective actions.

  This issue was more than minor, because it was associated with the equipment performance attribute of the Initiating Events and Mitigating Systems Cornerstones. This finding was evaluated by a Phase 3 significance determination process and determined to be of very low safety significance (Section 4OA5.5)

Cornerstone: Barrier Integrity

- Green. Untimely placement of identified steam generator tube plug deficiencies into the corrective action program represented an NCV for TS procedure requirements.

  This performance deficiency was more than minor, because if left uncorrected the degraded SG tube plugs could have led to a more significant problem such as a SG tube failure. The inspectors evaluated the significance of this issue using the guidance contained in the draft Appendix J to the Significance Determination Process, “Steam Generator Tube Integrity Findings.” The inspectors determined that this condition was bounded by the column in the SG Tube Integrity SDP matrix associated with “one or more tubes that should have been repaired as a result of previous inspection.” As a result this condition was determined to be of very low risk (Section 1R08).

- Green. Foreign material, a 3" long stud, jammed a feedwater regulating valve (FRV) in its full open position, which rendered the FRV inoperable for its containment isolation function, and caused a reactor shutdown. This self-revealing finding represented an NCV of procedures for foreign material exclusion.

This finding is greater than minor, because it had an actual impact of jamming an FRV open, which is designed to close on a safety injection signal and minimize the energy release to containment on a main steam line break. The finding is of very low safety significance, because a redundant valve and a main feed pump trip feature were unaffected (Section 4OA3.1).

B. Licensee Identified Violations

- None

REPORT DETAILS

Summary of Plant Status

Unit 1 began the period at approximately 100% power. On October 15 operators manually shut down the unit to hot standby conditions to facilitate a SG feed regulating valve repair. Unit 1 was placed back online on October 18 and achieved approximately 100% power on October 19. Several downpowers occurred in November and December to support electrical grid line outages and circulating water system maintenance.

Unit 2 began the period at approximately 100% power and remained there until October 9, when the unit was shut down for a refueling outage. Unit 2 was placed back online on November 27 and achieved approximately 100% power on December 1.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity

1R04 Equipment Alignment (71111.04 - 2 samples)

a. Inspection Scope

The inspectors performed two partial system walkdowns. On October 20, 2003, the inspectors performed a partial system walkdown of the Salem Unit 2 fuel pool cooling system. A complete core off load had just been completed and the spent fuel pit was not connected to the reactor vessel (RV) cavity. On October 20 and 22, 2003, the inspectors walked down the 2A and 2C EDGs and the fuel oil storage and transfer system while the 2B EDG and 22 fuel oil transfer pump were out of service for planned maintenance. To evaluate operability of the selected components or trains, the inspectors observed system operating parameters and checked correct valve, switch and power alignments to operating procedures listed below:

- S2.OP-SO.SF-0002, “Spent Fuel Cooling System Operation”
- S2.OP-SO.DG-0001, “2A Diesel Generator Operation”
- S2.OP-SO.DG-0003, “2C Diesel Generator Operation”
- S2.OP-SO.FO-0001, “Emergency Diesel Fuel Oil System Operation”

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05 - 8 samples)

a. Inspection Scope

The inspectors walked down the following eight 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.”

- 21, 22, 23, 24 reactor coolant pump oil collection systems on October 21, 2003
- Unit 2 containment inside bioshield on October 21, 2003
- Unit 2 containment annulus outside bioshield on October 21, 2003
- Unit 1 residual heat removal pump and valve rooms on November 13, 2003
- Unit 1 and Unit 2 100' elevation relay and battery rooms and corridor on November 20, 2003
- Unit 1 and Unit 2 84' elevation 460 Volt switchgear rooms and corridor on November 21, 2003

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures (71111.06 - 1 sample)

a. Inspection Scope

The inspectors performed an inspection of the flood protection measures for internal flooding in the auxiliary building. Several Unit 1 and Unit 2 auxiliary building areas were walked down, and various features to protect the vital electric power systems from internal flooding were assessed. The inspectors reviewed the Salem Updated Final Safety Analysis Report (UFSAR) and the Probabilistic Risk Assessment to identify areas susceptible to internal flooding. Salem procedures S1.OP-AB.ZZ-0002 and S2.OP-AB.ZZ-0002, “Flooding,” SC.MD-PM.ZZ-0036, “Watertight Door Inspection and Repair,” SC.FP-SV.FBR-0026, “Flood and Fire Barrier Penetration Seal Inspection” were reviewed. The inspectors reviewed data from SC.FP-SV.FBR-0026 performed on June 15, 2002. Engineering evaluation S-C-A900-MEE-0158-0, “Internal Flooding of Power Plant Buildings - INPO-SOER 85-05 Recommendations 1 and 2" were reviewed. The analysis contained in S-C-ZZ-SDC-1203 for water removal from Unit 1 and Unit 2 84' elevation electrical switchgear area were reviewed. Electrical and wall penetrations and drainage capabilities were inspected in the Unit 1 and Unit 2 64' elevation electrical switchgear room. Watertight doors on the 113' elevation of the auxiliary building were inspected.

b. Findings

Introduction. An unresolved item (URI) was identified involving degraded internal flood mitigation equipment. This issue remains unresolved pending PSEG review of internal flooding vulnerabilities in the associated area.

Description. On October 27, 2003, the inspectors observed that flood mitigation curbing did not exist at the main entrances to both Unit 1 and Unit 2 84' elevation switchgear rooms. Each 84' elevation switchgear room houses all three trains of vital ac and dc power. Flood mitigation features, by design, do not exist within the rooms to protect the electrical components from internal flooding, and eliminating water intrusion into the rooms is essential.

The Unit 1 and Unit 2 84’ elevation switchgear rooms are separated by a corridor that contains several medium energy water pipes including fire protection and demineralized water. Floor drains within this corridor exist to work in conjunction with the switchgear room’s curbings and protect against a medium energy pipe break. Also, the inspectors observed on October 27 that this drain feature was degraded. Of two floor drains, one was plugged and the other drain was restricted by a strainer.

PSEG entered these deficiencies into the corrective action program as notifications 20164760, 20170724, 20171697, 20170949, 20171612, 20167048, 20170217, 20167603, 20170196, 20169101, 20167604. PSEG did not believe that the missing curbs were an immediate safety concern, because an adjacent stairwell and elevator shaft would likely drain any water from a pipe break. PSEG installed new curbs on January 12, 2004 and also removed the floor drain plug on November 7, 2003.

The deficient flood mitigation features on the 84' elevation have likely existed for years. PSEG could not identify any activity through work order records that would have modified the configurations. The inspectors considered that the curbing was likely modified during an unrelated maintenance activity as it could hinder the access of some equipment to or from the switchgear room. The basis behind the floor drain modification was less obvious, as the two drains were inconsistently modified: one plugged, the other restricted with a strainer.

Pending further PSEG evaluation of the associated internal flooding vulnerabilities and subsequent inspector review, this issue is unresolved and identified as URI 50-272&311/03-09-01, Degraded Internal Flooding Mitigation Equipment for Vital Switchgear Rooms.

1R07 Heat Sink Performance (71111.07 - 1 sample)

a. Inspection Scope

The inspectors selected the Unit 2 containment fan coil units (CFCUs) for a heat sink performance review. The inspectors reviewed performance trending results for all five CFCUs, procedure S2.OP-PT.SW-0007(Q), “Service Water Biofouling Monitoring Containment Fan Coil Units,” and calculation S-C-CBV-MDC-1637, “Containment Fan Cooler Unit Design Basis Capacity.” System walkdowns and observations of CFCU equipment were performed at various times during the Fall 2003 Unit 2 refuel outage. The inspectors interviewed the service water system program manager, and discussed the testing methodology and test acceptance criteria with design engineers responsible for monitoring the thermal-hydraulic performance of the CFCUs.

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection Activities (71111.08 - 5 samples)

a. Inspection Scope

The inspected area included reactor coolant system (RCS) penetration piping, RV, SG tubes, emergency core cooling system (ECCS) connections to the RCS, and risk informed ISI program examinations.

The inspectors reviewed PSEG's commitments regarding SG repair criteria, eddy current testing, in-situ pressure testing, FME exclusion controls and the results from the previous operating cycle performance (i.e., primary to secondary leakage). The inspectors observed selected portions of SG 24 in-situ pressure testing and reviewed the associated in-situ tube selection screening parameters. The inspectors also reviewed the in-situ pressure test procedure and test results to determine whether PSEG's in-situ pressure test program was consistent with industry guidelines.

The inspectors observed the penetrant test of six locations on the safety injection system. Four of these welds were on the support legs for a charging pump, one weld was on the inlet line, and one weld was from the outlet piping. The inspectors also witnessed ultrasonic test examinations of two pressurizer pipe to elbow welds on three inch lines. These examinations were added to the outage scope as part of the risk informed ISI program. The inspectors reviewed the qualification records for the personnel performing these examinations and procedural controls, and independently assessed the equipment calibration and field results to ensure that these activities were adequately performed.

The inspectors reviewed four radiographs of 14 inch inside diameter, schedule 100 groove butt welds and evaluated the film and examination records to assess whether the radiographs met code requirements and whether the acceptance criteria were appropriate. These radiographs were part of a feedwater pipe and elbow replacement project developed to mitigate the effects of flow accelerated corrosion.

PSEG's activities performed in response to NRC Order EA-03-009 issued February 11, 2003, were inspected against the requirements of Temporary Instruction (TI) 2515/150, "Reactor Pressure Vessel Head and Vessel Head Penetration Nozzles." The detailed description of this scope and the results are found in Section 4OA5 as specified by the TI. Additionally, PSEG's activities performed in response to NRC Bulletin 2003-02, "Leakage from Reactor Pressure Vessel Lower Head Penetrations and Reactor Coolant Pressure Boundary Integrity," were inspected against the requirements of TI 2515/152. The detailed description of this scope and the results are found in Section 4OA5 as specified by the TI.

The inspectors verified that plant staff was aware of significant ISI industry operating experience items and that an appropriate assessment for applicability to Salem had been performed. The inspectors also reviewed whether PSEG identified ISI problems at an appropriate threshold and entered them into the corrective action program. The appropriateness and completeness of the corrective actions for a sample of four ISI-related notifications were reviewed.

b. Findings

Introduction. A Green NCV was identified for failure to properly implement procedures for inspection of SG tube plugs as prescribed in TS 6.8.1.

Description. Between October 14 and October 17, 2003, while performing SG eddy current inspections, PSEG identified eight leaking SG tube plugs. Specifically, PSEG observed that the SG tube plugs exhibited boric acid deposits indicating the presence of primary coolant leakage. These inspections were performed in accordance with procedure SC.SG-TI.RCE-0002(Q), Rev. 2, “Steam Generator Tube Plug Visual Examination.” Step 5.2.7 of this procedure specified that PSEG evaluate any abnormalities noted in accordance with administrative procedure NC.WM-AP.ZZ-0002(Q) which required the issuance of a notification to formally enter the item into the corrective action program. The inspectors also noted that procedure NC.RA-DG.ZZ-8805(Z), Rev. 0, “Boric Acid Corrosion Management Program Corrective Action Process Guidelines,” directed that all boric acid deposits observed in the plant were to be entered into the notification process and the boric acid corrosion program within 24 hours.

On October 24, 2003, the inspectors identified that the leaking SG plugs had not been entered into the corrective action program. The inspectors questioned PSEG regarding this observation, and the issues were subsequently entered into the corrective action program. PSEG indicated that they had planned to address these conditions adverse to quality by following an informal process where the issues would be entered into the corrective action program following vendor review. The inspectors noted that this practice circumvented the review and disposition process established in the corrective action program and also that it was also contrary to PSEG’s procedure.

Analysis. This performance deficiency is more than minor, because if left uncorrected the degraded SG tube plugs could have led to a more significant problem such as a SG tube failure. Failure to properly address this problem using the site corrective action process potentially affected the resolution of this issue.

The inspectors evaluated the significance of this issue using the guidance contained in the draft Appendix J to the Significance Determination Process, “Steam Generator Tube Integrity Findings.” The inspectors determined that this condition was bounded by the column in the SG Tube Integrity SDP matrix associated with “one or more tubes that should have been repaired as a result of previous inspection.” As a result this condition was determined to be of very low risk (Green).

Enforcement. Salem Unit 2 TSs, Section 6.8.1.a., “Procedures and Programs” requires that written procedures be developed and implemented as recommended in Appendix A of Regulatory Guide 1.33, Revision 2, Feb. 1978. Regulatory Guide 1.33 requires that written procedures be developed for inspection of the RCS pressure boundary.

Contrary to the above, in October 2003, PSEG failed to properly implement SG tube plug inspection procedures.

Because this failure to comply with TS 6.8.1.a. was of very low safety significance (Green) and since the issue has been entered into the corrective action process (notification 20163747), this violation is being treated as an NCV consistent with Section VI.A of the NRC Enforcement Policy: NCV 50-311/03-09-02, Failure to Properly Implement RCS Inspection Procedures.

1R11 Licensed Operator Requalification (71111.11 - 1 sample)

a. Inspection Scope

On November 19, 2003, the inspectors observed a licensed operator simulator training scenario to assess the operators' performance and the evaluators' and participants' critiques. The scenario involved a chemical and volume control system equipment failure and a non-isolable steam line break in containment. The inspectors verified that the operators' actions were consistent with the appropriate Salem operating, alarm response, abnormal, and emergency procedures. Salem Training Scenario S-SG-0341 was referenced and included all applicable procedure references.

b. Findings

No findings of significance were identified.

1R12 Maintenance Implementation (71111.12 - 4 samples)

a. Inspection Scope

The inspectors reviewed notifications documenting past operating problems, system health reports, and maintenance rule performance criteria to determine if PSEG had effectively monitored the performance of the four risk significant systems. The inspectors also interviewed system engineers and maintenance rule program coordinators to determine the effectiveness of established and proposed corrective actions. Documents reviewed during the inspection samples are listed in the Attachment. 10 CFR 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" were referenced to ascertain acceptability of PSEG's maintenance rule application.

- Unit 1 and Unit 2 station air and control air systems
- Unit 1 and Unit 2 redundant air panel
- Unit 3 gas turbine
- 2A EDG failure related to starting air on September 27, 2003

b. Findings

Introduction. A compressor air leak on the starting air system for the Unit 2 A EDG was not properly evaluated and corrected, such that the removal of the other compressor for maintenance resulted in the 2A EDG being inoperable. This resulted in a Green self-revealing NCV.

Description. On September 27, 2003, an air leak was identified on the 21B starting air compressor for the 2A EDG and entered into the corrective action program. However, no corrective actions had occurred prior to November 8, when the 21A starting air compressor was removed from service for maintenance. Later that day the main control room received an urgent alarm for the 2A EDG. Equipment operators discovered starting air receiver pressures at 105 psig, below the minimum required for operability, 160 psig. The 21B starting air compressor was running continuously and was unable to maintain pressure due to the previously identified air leak on the compressor head. The 21A starting air compressor was restored from maintenance, starting air pressure was restored, and about four hours later the 2A EDG was declared operable.

Analysis. The deficiency associated with this 2A EDG issue was inadequate evaluation of degraded equipment and delayed corrective actions, which led to the unexpected equipment unavailability and inoperability. This finding was greater than minor, because it rendered an EDG inoperable and without sufficient starting air pressure to start. The inspectors used Appendix G, Shutdown Operations to NRC IMC 0609, Significance Determination Process to assess the significance of this finding. Salem Unit 2 was in cold shutdown with the RCS closed and steam generators available for decay heat removal. Because two EDGs remained operable and all three offsite ac power sources remained available, this was evaluated as very low safety significance (Green).

Enforcement. 10 CFR 50, Appendix B, Criterion XVI, Corrective Action, requires defective equipment be promptly corrected. Contrary to the above, an air leak on the 21B starting air compressor, identified on September 27, 2003, was not promptly corrected and rendered the 2A EDG inoperable for about four hours on November 8, 2003, when the 21A starting air compressor was removed from service. Because this failure to promptly correct is of very low safety significance and has been entered into PSEG's corrective action program (Notifications 20167133 and 20167134), this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 50-311/03-09-03, Failure to Promptly Correct an EDG Deficiency.

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. 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 TS and work control requirements.

The activities selected were based on plant maintenance schedules and systems that contribute to plant risk. Regulatory Guide 1.182, “Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants” was referenced to verify adequacy. The inspectors also referenced PSEG procedure SH.OP-AP.ZZ-0027, “Online Risk Assessment.”

- 12SW21 motor operated valve repairs on October 9, 2003
- Unit 2 reactor coolant system mid-loop operations with reactor core not off-loaded on October 13, 2003
- 22 spent fuel pool cooling pump and 22 fuel handling building exhaust fan maintenance with full core off-load on October 20, 2003
- 2B vital electrical busses deenergized for maintenance on October 20, 2003
- 23 chilled water compressor trip on October 22, 2003
- Concurrent maintenance on the 11 component cooling heat exchanger, gas turbine, and No. 1 station air compressor on November 6, 2003
- 21 chilled water compressor condenser service water outlet valve (21SW102) emergent repairs on December 10, 2003

b. Findings

Introduction. The inspectors identified a finding in that a Unit 2 chilled water compressor (23 chiller) unexpectedly shutdown due to a degraded control air system condition.

Description. PSEG was in the process of isolating the 2A control air (CA) header for scheduled maintenance on October 22, 2003. The maintenance affected portions of control air in redundant control air panel 356-23 including control air for the 23 chiller. When the 2A control air header was secured, the panel should have automatically swapped to the 2B header. The panel failed to swap automatically and the 23 chiller shutdown at 6:52 p.m.

PSEG later identified a 1/4 inch sensing line orifice clogged with corrosion products. Corrosion products in the CA header have caused past, similar equipment failures. Prior to 1992 water was chronically introduced into the CA system due to undersized CA dryers. These dryers were replaced in 1992 with dryers of larger capacity. PSEG identified that corrosion products were causing equipment problems in February 2003. The corrective action implemented from the investigation of the February 2003 failure (notification 20133239) was to conduct periodic blowdowns of the CA header to identify, trend, and remove corrosion products. Operators manually aligned control air to the 23 chiller and restored it to service at 2009. PSEG entered this issue into the corrective action program as notification 20163560.

Analysis. The performance deficiency associated with the 23 chiller failure was ineffective problem resolution. PSEG had not maintained the control air system free of corrosion products and equipment reliability was impacted. The finding was greater than minor, because it had an actual impact on the equipment performance attribute of the mitigating systems cornerstone. Because Unit 2 was defueled, the 23 chiller actually had no impact on Unit 2 risk. However, the 23 chiller supports the control room emergency air-conditioning system (CREACS), which is common to both Unit 1 and Unit 2. Unit 1 was at power for the duration of the 23 chiller failure and operated with only one CREAC train operable. The inspectors used Phase 1 of the significance determination process and this issue screened to Green, very low safety significance, because the 23 chiller and Unit 2 CREACS (common to Unit 1) were inoperable for less than the Unit 1 TS allowed outage time.

Enforcement. 10 CFR 50 Appendix B, Criterion XVI, "Corrective Action" states that measures shall be established to assure that conditions adverse to quality are promptly corrected, and that corrective actions taken shall preclude repetition. Contrary to the above, in February 2003, PSEG identified equipment failures related to corrosion products in the control air system and did not take adequate corrective actions to preclude repetition; the 23 chiller was rendered inoperable on October 22, 2003, due to the same adverse condition. Because this failure to maintain the control air system clean is of very low safety significance and has been entered into the corrective action program (Notification 20163560), this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 50-272/03-09-04, Failure to Maintain the Control Air System Clean.

1R14 Operator Performance During Non-routine Evolutions and Events (71111.14 - 3 samples)

a. Inspection Scope

The inspectors observed control room operators during the performance of three 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 October 9 and 10, 2003, the inspectors observed control room operators shut down Unit 2 from power operations to cold shutdown conditions to begin a refuel outage.
- On October 13, 2003, the inspectors observed control room operators and in-plant equipment operators establish reactor coolant system mid-loop operations with the core not yet offloaded.
- On October 15, 2003, the inspectors observed control room operators shut down Unit 1 from full power to hot standby conditions. The shutdown was in response to a stuck 14 SG feed regulating valve. This issue is also described in Section 4OA3 of this inspection report. The shutdown required unique manual control of SG level that the control room operators had practiced on the simulator prior to commencing the actual plant shutdown.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15 - 4 samples)

1. Unit 2 Containment Spray Waterhammer on October 15, 2003.

a. Inspection Scope

The inspectors reviewed notifications 20162554, 20166095 and 20116666, and engineering analyses supporting the operability of the containment spray (CS) and residual heat removal (RHR) systems after a waterhammer that occurred on October 15, 2003. The inspectors also performed a system walkdown and interviewed system engineers. Procedure SH.OP-AP.ZZ-0108, "Operability Assessment and Control Program" was reviewed to assess PSEG's application to this particular issue. The inspectors also reviewed S2.OP-ST.CS-0005(Q), "Inservice Testing Containment Spray Pump Full Flow Test and Containment Spray Check Valves" and drawings 205334-A-8763-56, 205332-A-8763-30, and 205335-A-8763-39.

b. Findings

Introduction. A Green self-revealing NCV was identified for failure to correct a known air pocket that caused a waterhammer in the 22 containment spray and residual heat removal trains.

Description. The Unit 2 RHR system had an air pocket trapped in the hot leg injection line since the previous plant refueling activities and had been identified on May 10, 2002. This condition was causing waterhammer events in the RHR system during surveillance testing of the 21 or 22 RHR pumps. PSEG understood the root cause of the waterhammer events and had evaluated the waterhammer conditions as acceptable in engineering report S-2-RHR-MEE-1804, "Salem 2 RHR Waterhammer Event Report" and notification 20162554. On October 15, 2003, PSEG performed S2.OP-ST.CS-0005, "Inservice Testing Containment Spray Pump Full Flow Test and Containment Spray Check Valves." This surveillance required that the CS system be aligned such that portions of the RHR piping containing the air pocket were connected to the 22 CS pump discharge piping. During the 22 CS pump startup, operators witnessed a waterhammer event. As the 22 RHR system was partially aligned to containment spray, it would also have experienced the waterhammer pressure pulses. Prerequisite 2.14.2 of S2.OP-ST.CS-0005 specifies that the RHR system be filled and vented. Contrary to prerequisite 2.14.2, the RHR system was not filled and vented, resulting in waterhammer.

Analysis. The performance deficiency associated with the waterhammer was ineffective problem evaluation in that a known deficiency, air entrapment in the RHR system, was not properly determined to potentially affect the CS system. The 22 CS and 22 RHR trains were unnecessarily subjected to waterhammer during a surveillance test. The finding adversely impacted the residual heat removal system reliability. Because the finding affected the reactor safety mitigating system cornerstone objective, the finding is greater than minor. The inspectors used Appendix G, Shutdown Operations to NRC IMC 0609, Significance Determination Process to assess the significance of this finding.

Salem Unit 2 was in mode 6, refueling with greater than 23' of water above top of active fuel. The containment spray system was not required for current plant conditions, but residual heat removal was of concern. PSEG engineers, through system walkdowns and analysis also concluded that the containment spray and residual heat removal systems did not experience any degradation, long or short term, from the October 15 waterhammer. This issue was evaluated as very low safety significance (Green), because the 22 RHR train remained operable and the 21 RHR train was not affected.

Enforcement. 10 CFR 50 Appendix B, Criterion XVI, "Corrective Action" states that measures shall be established to assure that conditions adverse to quality are promptly corrected and that corrective actions taken shall preclude repetition. Contrary to the above, following a May 10, 2002 waterhammer, PSEG determined that an air pocket existed in the Unit 2 RHR system, but the air pocket was not removed and resulted in a waterhammer on the 22 CS train and the 22 RHR train on October 15, 2003. Because the failure to prevent the waterhammer recurrence is of very low safety significance and has been entered into the corrective action program (Notification 20162554), this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 50-311/03-09-05, Failure to Promptly Correct an RHR Waterhammer Condition.

2. Unit 1 Emergency Diesel Generator Failure to Stop on Demand

a. Inspection Scope

The inspectors reviewed notification 20159538 and the engineering analyses supporting the operability assessment of the 1B EDG. The inspectors also reviewed associated wiring and logic diagrams, interviewed management and engineering personnel, and performed a walkdown of selected EDG system components. The review verified that the operability determination was in accordance with the above PSEG operability assessment procedure. In conjunction with this review, the inspectors also reviewed notifications 20153697, 20051715, and 20089867, and associated analyses and troubleshooting activities pertaining to similar EDG 1B and 2C failures.

b. Findings

Introduction. An Unresolved Item was identified involving the potential failure to promptly identify and correct a condition adverse to quality related to the 1B EDG. Troubleshooting activities were incomplete more than two months after the September 22, 2003, EDG failure to stop on demand. The results of circuit analyses and troubleshooting by PSEG had not confirmed that the anomalies which caused the EDG failure to stop would not have prevented the EDG from starting when called upon in an emergency. This issue remains unresolved pending PSEG completion of troubleshooting activities and confirmation of the EDG operability.

Description. On September 22, 2003, PSEG performed a surveillance test of the 1B EDG in accordance with surveillance procedure S1.OP-ST.DG-0002(Q), "1B Diesel Generator Surveillance Test." At the conclusion of the test, the diesel failed to stop when the local switch was placed to the ‘Stop’ position. The diesel was stopped subsequently using the control room ‘Stop’ button that acts in parallel with the local switch through stop relay contacts. Based on observations made by the operating staff and subsequent evaluations of the EDG control schematics by the engineering staff, the failure of the diesel to stop was attributed to either a misoperation of the local ‘Stop-Start’ switch or a partial failure of the shutdown (SDR) relay. The SDR is a dual coil Westinghouse relay, each coil operating three form C contacts. Engineering believed that potentially one of the two coils had failed. Both the notification and the engineering evaluation recommended troubleshooting, but at the time of the NRC follow-up inspection, no troubleshooting had taken place. The diesel had been declared operable on the assumption that a failure of either component would not prevent the diesel from starting. Based on the inspectors’ concern that the incorrect positioning of one of the SDR contacts might prevent the diesel from starting, PSEG confirmed the correct positioning of all contacts.

Subsequent to the inspection, on October 19 and November 15, 2003, PSEG performed monthly surveillance tests of the 1B EDG. Both times the EDG operated as expected and stopped when the local switch was placed in the ‘Stop’ position. During the November 15, 2003 surveillance, PSEG also conducted troubleshooting of suspected portions of the EDG control circuitry without success. Specifically, PSEG monitored the operation of the local control switch and SDR relay, and found that both operated as expected. However, based on discussions with engineering personnel, the troubleshooting did not address external wiring or the shutdown solenoid itself, a normally-energized coil that is part of the Woodward governor. A failure of this solenoid to actuate could prevent the diesel from starting, albeit in each of the previous surveillance tests the solenoid appeared to actuate correctly when de-energized to start the diesel. This issue remains open pending PSEG completion of troubleshooting activities and NRC review of the troubleshooting results. (URI 50-272/03-09-06)

3. <u>Other Operability Evaluations</u>

a. <u>Inspection Scope</u>

The inspectors reviewed two additional operability determinations. 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 (CRFAs) were reviewed and compared to applicable TS, the UFSAR, and associated design and licensing basis documents. The following operability issues were reviewed:

- Excessive ECCS leakage outside containment from an RHR valve (22RH19) packing stem as documented in OD 70035146.
- 22 RHR heat exchanger mechanical flange leakage as documented in OD 70035145.

b. Findings

No findings of significance were identified.

1R16 Operator Work-Arounds (71111.16 - 1 sample)

a. Inspection Scope

During the weeks of December 1 and 8, 2003, the inspectors performed a review of the Unit 1 and Unit 2 PSEG-identified operator workarounds and assessed the potential for any adverse impact on the operators' ability 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 the operations superintendent turnover checklists 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.

1R17 Permanent Plant Modifications (71111.17 - 1 sample)

a. Inspection Scope

The inspectors reviewed a manual reactor trip on November 23, 2003, during Unit 2 physics testing, which was related to control rod mechanism power cabinet modifications. The inspectors interviewed design engineers and plant managers to understand the delays in incorporating a plant modification that would have precluded control rod drops due to a known fuse deficiency. The inspectors reviewed notifications 20167798, 20167889, and 20167830, and associated troubleshooting activities and evaluations.

b. Findings

Introduction. Deferral of vendor recommended design changes (fuse uprating) on the control drive mechanisms led to a manual reactor trip due to a dropped rod during startup physics testing. A self-revealing NCV was identified for ineffective corrective actions.

Description. On November 22, 2003, while withdrawing control rod banks in preparation for Unit 2 startup physics testing, control room operators observed that rod 2D5 did not move. Technicians determined a blown power supply fuse had caused the rod to be immovable. Further troubleshooting did not identify related circuit problems and PSEG concluded that the fuse had failed during the beginning of its useful life, i.e., “infant mortality.”

PSEG resumed control rod withdrawals and physics testing on November 22 at 10:13 p.m. At 5:04 a.m. on November 23, control rod 1D4 dropped. Control room operators manually tripped the Unit 2 reactor at 5:19 a.m. in response to the abnormal control rod configuration during physics startup testing. The reactor trip was uneventful.

PSEG further investigated the control rod drops and determined that the fuses being applied, 10 amp fuses, did not have adequate margin to prevent failure during maximum peaking current periods. PSEG also concluded that a complete control rod fuse replacement during the recent outage may have introduced fuses that were more responsive at the 10 amp rating. This could explain why blown fuses and rod drops suddenly became frequent. In 2001 PSEG had considered a control rod fuse improvement program based on Westinghouse recommendations through industry experience. The 10 amp fuses were recommended to be replaced with 25 amp fuses. The fuse replacement project was initially scheduled for the outage just completed, but the project was delayed. PSEG had not completed an engineering analysis to support the increased fuse rating.

PSEG expedited the design change package for the Unit 2 control rod fuse improvement and installed 25 amp fuses. Control rod withdrawals and a reactor startup were resumed on November 25, 2003 with no further blown fuses or rod drops.

Analysis. The performance deficiency associated with the control rod drops is untimely corrective actions. The finding is greater than minor, because the initiating events' cornerstone objective to limit the likelihood of events that upset plant stability was affected. The finding screened to Green in SDP Phase 1, because only the likelihood of a plant upset increased and mitigation equipment remained unaffected.

Enforcement. 10 CFR 50 Appendix B, Criterion XVI, "Corrective Action" states that measures shall be established to assure that conditions adverse to quality are promptly corrected and that corrective actions taken shall preclude repetition. Contrary to the above, despite industry experience on dropped rods and a vendor recommendation to uprate fuses to preclude these events, PSEG delayed corrective actions on the control rod drive fuses, which resulted in a manual reactor trip in response to a control rod drop during physics testing. Because the failure to correct the unreliable control rod fuses was of very low significance and has been entered into the corrective action program (Notification 20167830), this violation is being treated as an NCV consistent with Section VI.A of the NRC Enforcement Policy: NCV 50-311/03-09-07, Failure to Promptly Correct a Control Rod Power Supply Deficiency.

1R19 Post Maintenance Testing (71111.19 - 3 samples)

a. Inspection Scope

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

- Overhaul of redundant air panel 700-1M (supports 12 auxiliary feedwater pump) on November 21, 2003
- Valve stem repack of air operated valve 22RH18, (22 residual heat removal train flow control valve) on October 25, 2003
- 2A vital 125Vdc battery replacement on November 4, 2003

b. Findings

No findings of significance were identified.

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

a. Inspection Scope

The inspectors reviewed the Salem 2R13 Schedule Review Final Risk Assessment Report for the Unit 2 refueling outage (October 9 - November 27, 2003) 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
- Refueling activities, including fuel off-load and sipping to detect a fuel assembly leak
- 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 ECCS suction strainer
- Problem identification and resolution related to refueling outage activities

b. Findings

Introduction. A Green self-revealing NCV was identified for failure to implement corrective actions and prevent steam void waterhammering the residual heat removal system.

Description. On November 18, 2003, Unit 2 was in mode 4, hot shutdown, with reactor coolant temperature at 335 degrees Fahrenheit and pressure at 1550 psig. At 11:24 p.m. RCS cooling using the RHR system was terminated in accordance with procedure S2.OP-SO.RHR-0002, "Terminating RHR." Operators cooled down the RHR system for about 15 minutes consistent with procedure requirements. The specified cool down was to ensure steam voids would not develop in the RHR system after the RHR pumps were secured. At 2:07 p.m. on November 19, 2003, the 22 RHR pump was started to support a valve leak test. A waterhammer was reported by plant operators following the pump start.

During review of the event, PSEG discovered an error in the "Terminating RHR" procedure. The procedure specified that RHR operate fifteen minutes after the RHR heat exchanger cooled down below 200 degrees Fahrenheit. After investigating the reported RHR waterhammer on November 19, PSEG engineers found through a corrective action database review that the correct cooldown time requirement should have been 21 minutes per engineering calculation S-1-RHR-MEE-1593, "Analysis of the RHR System Waterhammer Event." The 15 minute cooldown time was found to be incorrect in May 2003 by a design engineer who calculated the new value of 21 minutes. It was documented in May 2003 in notification 20143463 that procedures S1(S2).OP-SO.RHR-0002 should be updated promptly to correct the error and preclude steam void waterhammer. The procedure revision did not occur. PSEG entered this problem into the corrective action program as Notification 20174146. System engineers performed a complete system walkdown after the waterhammer and did not identify any degraded components.

Analysis. The performance deficiency associated with the waterhammer was untimely corrective action. The finding is greater than minor, because the waterhammer potentially affected the reliability of the RHR system, associated with the equipment performance attribute of the mitigating system cornerstone. The inspectors used Appendix G, Shutdown Operations to NRC IMC 0609, Significance Determination Process to assess the significance of this finding. Salem Unit 2 was in cold shutdown with the RCS closed and steam generators available for decay heat removal. Because two loops of RHR remained operable, this was evaluated as very low safety significance (Green).

Enforcement. 10 CFR 50 Appendix B, Criterion XVI, "Corrective Action" states that measures shall be established to assure that conditions adverse to quality are promptly corrected and that corrective actions taken shall preclude repetition. Contrary to the above, on November 19, 2003, PSEG failed to eliminate potential steam void conditions in the 22 RHR train as had occurred previously and restarted the 22 RHR pump under conditions where steam voids were calculated to occur. A waterhammer occurred.

Corrective actions to eliminate the steam void conditions had been developed in May 2003 but not implemented. Because the failure to correct and eliminate steam void conditions is of very low safety significance and has been entered into the corrective action program (Notification 20174146), this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 50-311/03-09-08, Failure to Preclude Steam Void Conditions in the RHR System.

1R22 Surveillance Testing (71111.22 - 4 samples)

a. Inspection Scope

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

- S2.OP-ST.AF-0001, “21 Auxiliary Feedwater Pump In-Service Test” performed on October 3, 2003
- S2.OP-ST.SSP-0004(Q), “SEC Mode Ops Testing 2C Vital Bus” performed on October 10, 2003
- S2.OP-ST.SJ-0006(Q), “Inservice Testing Safety Injection Valves Mode 6" performed on October 15, 2003
- S2.OP-ST.SJ-0015(Q), “Intermediate Head Hot Leg Throttle Valve Flow Balance Verification” performed on October 30, 2003

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

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope

On November 14, 2003, the inspectors reviewed a listing of all temporary modifications installed on Salem Unit 1 and Unit 2. No new modifications were installed or had been installed that warranted inspection on the basis of risk insights. Throughout the inspection period the inspectors walked down all areas of the plant and did not identify the installation of any unauthorized temporary modifications.

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness [EP]

1EP2 Alert and Notification System Testing (71114.02)

a. Inspection Scope

An onsite review of PSEG's alert and notification system (ANS) testing was conducted to ensure prompt notification of the public for taking protective actions. The inspection included a review of the following procedures: (1) NC.EP-DG.ZZ-0007(Z), Siren Test Process; and (2) Alert Notification System Daily Operational Guideline. In addition, the inspector interviewed the siren program technicians, and reviewed maintenance and 2002/2003 test records to determine if test failures were being immediately assessed and repaired, and sirens were being routinely maintained. The inspection was conducted in accordance with NRC Inspection Procedure 71114, Attachment 02, and the applicable planning standard, 10 CFR 50.47(b)(5) and its related 10 CFR 50, Appendix E requirements were used as reference criteria.

b. Findings

No findings of significance were identified.

1EP3 Emergency Response Organization (ERO) Augmentation (71114.03)

a. Inspection Scope

An onsite review was performed of PSEG's ERO augmentation staffing requirements and the process for notifying the ERO to ensure the readiness of key staff for responding to an event and timely facility activation. The inspector reviewed the 2002/2003 communication pager test records and associated condition reports (CRs). A review was also conducted of the backup notification systems that would be used in case of a power outage. An interview was conducted with the EP training instructor to determine the adequacy of the lesson plans used for training ERO, which included detailed lesson plans and lessons learned from past drills for correcting ERO performance problems. Finally, the emergency plan qualification records for key ERO positions were reviewed to ensure all ERO's qualifications were current. The inspection was conducted in accordance with NRC Inspection Procedure 71114, Attachment 03, and the applicable planning standard, 10 CFR 50.47(b)(2) and its related 10 CFR 50, Appendix E requirements were used as reference criteria.

b. Findings

No findings of significance were identified.

1EP4 <u>Emergency Action Level and Emergency Plan Changes</u> (71114.04)

a. <u>Inspection Scope</u>

A regional in-office review of revisions to the emergency plan, implementing procedures and EAL changes was performed for determining that changes had not decreased the effectiveness of the plan. The revisions covered the period from January - December 2003. Onsite the inspector evaluated the associated 10 CFR 50.54(q) reviews in which PSEG Nuclear determined that a decrease in the effectiveness had not occurred. The inspection was conducted in accordance with NRC Inspection Procedure 71114, Attachment 04, and the applicable requirements in 10 CFR 50.54(q) were used as reference criteria.

b. <u>Findings</u>

No findings of significance were identified.

1EP5 <u>Correction of Emergency Preparedness Weaknesses and Deficiencies</u> (71114.05)

a. <u>Inspection Scope</u>

The inspector reviewed corrective actions identified by PSEG Nuclear pertaining to findings from 2002/2003 drill/exercise reports and the associated CRs to determine the significance of the issues and to determine if repeat problems were occurring. Also, various quality assurance (QA) audit reports from 2002 and 2003 were reviewed to assess PSEG Nuclear's ability to identify issues, assess repetitive issues and the effectiveness of corrective actions through their independent audit process. In addition, the inspector reviewed 2002/2003 self assessment reports to assess PSEG's ability to be self critical, thus avoiding complacency and degradation of their EP program. A list of the audit and self assessment reports are contained in an attachment to this report. Finally, the inspector reviewed several trending reports generated for tracking various program activities, ERO qualifications and ERO exercise/drill performance breakdowns. The reports are an assessment tool used for identifying program problem areas, management briefings and identifying topics for self assessments. This inspection was conducted according to NRC Inspection Procedure 71114, Attachment 05, and the applicable planning standard, 10 CFR 50.47(b)(14) and its related 10 CFR 50, Appendix E requirements were used as reference criteria.

b. <u>Findings</u>

No findings of significance were identified.

1EP6 Drill Evaluation (71114.06 - 1 sample)

a. Inspection Scope

The inspectors observed an EP drill from the Salem control room simulator and emergency operations facility on November 25, 2003. The inspectors evaluated the conduct of the EP drill including performance of initial and escalated classifications, required notifications, and protective action recommendations. The inspectors also observed and evaluated the post-drill critique and notifications 80066144, 80066146, 80066147, and 20168355. The inspectors reviewed the Salem/Hope Creek Emergency Plan and the Salem Event Classification Guide. The inspectors referenced Nuclear Energy Institute (NEI) 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 (DEP).

The Hope Creek resident inspectors also performed EP drill evaluations on May 28, 2003 and October 16, 2003, which assessed additional drills or simulator-based training evolutions that contributed toward the site common DEP PI. Those inspection activities were described in NRC Inspection Reports 05000354/2003004 and 2003006.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2OS1 Access Control to Radiologically Significant Areas (71121.01)

a. Inspection Scope

During the period of October 15-16 and October 22-24, 2003, the inspector reviewed exposure significant work areas (i.e., High Radiation Areas and Airborne Radioactivity Areas) in the plant and associated controls and surveys of these areas to determine if the controls (e.g., surveys, postings, barricades) were acceptable. For these areas, the inspector reviewed radiological job requirements and attended job briefings to determine if radiological conditions in the work area were adequately communicated to workers through briefings and postings. The inspector also verified radiological controls, radiological job coverage, and contamination controls to ensure the accuracy of surveys and applicable posting and barricade requirements. The inspector determined if prescribed radiation work permits (RWPs), procedure and engineering controls were in place; whether surveys and postings were complete and accurate; and if air samplers were properly located. The inspector reviewed RWPs used to access exposure significant work areas to identify the acceptability of work control instructions or control barriers specified. The inspector reviewed electronic pocket dosimeter alarm set points (both integrated dose and dose rate) for conformity with survey indications and plant policy. The controls implemented were compared to those required under plant TSs (TS 6.12) and 10 CFR 20, Subpart G, for control of access to high and locked high radiation areas.

The primary focus of this inspection was the Salem Unit 2 refueling outage (2R13). Outage activities in exposure significant areas observed included: shielding activities inside the containment bioshield; eddy current testing in all four steam generators; sludge lancing in all four steam generators; reactor disassembly; defueling; and reactor coolant pump motor replacement (RCP #22).

This inspection activity represents the completion of 16 samples relative to this inspection area.

b. Findings

No findings of significance were identified.

2OS2 ALARA Planning and Controls (71121.02)

a. Inspection Scope

The inspector reviewed ALARA job evaluations, exposure estimates, and exposure mitigation requirements and compared ALARA plans with the results achieved. A review was conducted of: the integration of ALARA requirements into work procedures and radiation work permit documents; the accuracy of person-hour estimates and person-hour tracking; and generated shielding requests and their effectiveness in dose rate reduction.

A review of actual exposure results versus initial exposure estimates for current work was conducted including: comparison of estimated and actual dose rates and person-hours expended; determination of the accuracy of estimations to actual results; and determination of the level of exposure tracking detail, exposure report timeliness and exposure report distribution to support control of collective exposures to determine conformance with the requirements contained in 10 CFR 20.1101(b).

The exposure goal for 2R13 had been established at 108.5 person-rem with a stretch goal of 97.7 person-rem. Major work activities and their dose goals include: nozzle dam installation/removal (8.325 person-rem); eddy current testing (7.665 person-rem); sludge lancing (2.675 person-rem); in-service inspections (11.718 person-rem); and, reactor disassembly (5.850 person-rem). Through the first two weeks of the outage, exposures were closely tracking estimates.

This inspection activity represents the completion of 1 sample relative to this inspection area.

b. Findings

No findings of significance were identified.

2OS3 Radiation Monitoring Instrumentation (71121.03)

a. Inspection Scope

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

This inspection activity represents the completion of 1 sample relative to this inspection area.

b. Findings

No findings of significance were identified.

Cornerstone: Public Radiation Safety [PS]

2PS1 Radioactive Gaseous and Liquid Effluent Treatment and Monitoring Systems (71122.01)

a. Inspection Scope

The inspector reviewed the following documents to evaluate the effectiveness of the licensee’s radioactive gaseous and liquid effluent control programs. The requirements of the radioactive effluent controls are specified in the Technical Specifications/Offsite Dose Calculation Manual (TS/ODCM).

- 2002 Radiological Annual Effluent Release Reports including projected public dose assessments;
- current ODCM (Revision 15) and technical justifications for ODCM changes;
- implementation of IE Bulleting 80-10, Contamination of Non-Radioactive System and Resulting Potential for Unmonitored, Uncontrolled Release of Radioactivity to environment;
- selected 2003 analytical results for radioactive liquid, charcoal cartridge, particulate filter, and noble gas samples;
- selected 2003 radioactive liquid and gaseous release permits;
- implementation of the compensatory sampling and analysis program when the effluent radiation monitoring system (RMS) is out of service;
- trending evaluations of the availability for effluent RMS;
- calibration records for chemistry laboratory measurements equipment (gamma and liquid scintillation counters);

- implementation of the measurement laboratory quality control (QC) program, including control charts;
- implementation of the interlaboratory comparisons by the licensee and the contractor laboratory;
- 2003 QA Audits (Audit Report Numbers 2003-0175 and 2003-0012) and corrective actions;
- most recent Channel Calibration and Channel Functional Test results for the radioactive liquid and gaseous effluent RMS and its flow measurement devices which are listed in the ODCM Tables 4.3-12 and 4.3-13.

  <u>RMS (Units 1 and 2)</u>

  - Liquid Radwaste Effluent Line Monitors;
  - SG Blowdown Line Monitors;
  - Containment Fan Coolers-Service Water Line Discharge Monitors;
  - Chemical Waste Basin Monitor, Common for both units;
  - Waste Gas Holdup System Noble Gas Monitors;
  - Containment Purge and Pressure-Vacuum Relief Noble Gas Monitors;
  - Plant Vent Noble Gas Monitors; and
  - Plant Vent Intermediate and High Range Noble Gas Monitors.

  <u>Flow Rate Measuring Device (Units 1 and 2)</u>

  - Liquid Radwaste Effluent Lines;
  - SG Blowdown Effluent Lines; and
  - Plant Vent Flow Rate Monitors.

- Most recent surveillance testing results (visual inspection, delta P, in-place leak testings for HEPA and charcoal filters, air capacity test, and the laboratory test for iodine collection efficiency) for the following air treatment systems for Units 1 and 2:

  - TS 3/4.7.6 Control Room Emergency Filtration Systems;
  - TS 3/4.7.7 Auxiliary Building Exhaust Air Filtration Systems; and
  - TS 3/4.9.12 Fuel Handling Area Ventilation Systems;

The inspector also toured and observed the following activities to evaluate the effectiveness of the radioactive gaseous and liquid effluent control programs.

- walkdown for determining the availability of radioactive liquid/gaseous effluent RMS and for determining the equipment material condition;
- walkdown for determining operability of air cleaning systems and for determining the equipment material condition; and
- observed the training process for the gamma spectrometry measurements techniques.

b. <u>Findings</u>

No findings of significance were identified.

2PS2 Radioactive Material Processing and Shipping (71122)

a. Inspection Scope (6 Samples)

The inspector reviewed the solid radioactive waste system description in the FSAR and the recent radiological effluent release report for information on the types and amounts of radioactive waste disposed. The inspector reviewed the scope of PSEG's audit program to verify that it meets the requirements of 10 CFR 20.1101(c).

The inspector walked-down the liquid and solid radioactive waste processing systems and determined that the current system configuration and operation agree with the descriptions contained in the FSAR and in the Process Control Program. The inspector reviewed the status of any radioactive waste process equipment that is not operational and/or is abandoned in place. The inspector verified that the changes were reviewed and documented in accordance with 10 CFR 50.59, as appropriate. The inspector reviewed current processes for transferring radioactive waste resin and sludge discharges into shipping/disposal containers to determine if appropriate waste stream mixing and/or sampling procedures, and methodology for waste concentration averaging provide representative samples of the waste product for the purposes of waste classification as specified in 10 CFR 61.55 for waste disposal. Systems/subsystems reviewed included: chemistry & volume control; spent fuel pool clean-up; floor drain; equipment drain; miscellaneous waste; and, solid waste processing. The inspector also toured current and abandoned in-place radwaste equipment and facilities, and interim storage locations used for processed radwaste. Areas toured are listed at Table 1.

The inspector reviewed the radio-chemical sample analysis results for each of PSEG's radioactive waste streams. The inspector reviewed PSEG's use of scaling factors and calculations used to account for difficult-to-measure radionuclides. The inspector verified that PSEG's program assures compliance with 10 CFR 61.55 and 10 CFR 61.56 as required by Appendix G of 10 CFR Part 20. The inspector reviewed PSEG's program to ensure that the waste stream composition data accounts for changing operational parameters.

The inspector observed shipment packaging, surveying, labeling, marking, placarding, vehicle checks, emergency instructions, disposal manifest, shipping papers provided to the driver, and licensee verification of shipment readiness. Shipments observed included: 03-146 and 03-147. The inspector verified that the requirements of any applicable transport cask Certificate of Compliance have been met. The inspector verified that the receiving licensee is authorized to receive the shipment packages. The inspector observed radiation workers during the conduct of radioactive waste processing and radioactive material shipment preparation activities. The inspector determined that the shippers are knowledgeable of the shipping regulations and that shipping personnel demonstrated adequate skills to accomplish the package preparation requirements for public transport with respect to NRC Bulletin 79-19 and 49 CFR Part 172 Subpart H.

The inspector verified that PSEG’s training program provides training to personnel responsible for the conduct of radioactive waste processing and radioactive material shipment preparation activities.

The inspector reviewed 5 non-excepted package shipment (LSA I, II, III, SCO I, II, Type A, or Type B) records. The inspector reviewed these records for compliance with NRC and DOT requirements. Shipments reviewed included: 03-29, 03-56, 03-75, 03-96, and 03-138.

The inspector reviewed PSEG’s notifications, audits, and self-assessments related to the radioactive material and transportation programs performed since the last inspection (Quality Assurance Assessment Report 2003-0229, Quality Assessment Monitoring Feedbacks 2003-0036, 2003-0042, 2003-0153, 2003-0168, 2003-0178, 2003-0181, and 2003-0192). The inspector determined that identified problems are entered into the corrective action program for resolution. The inspector reviewed corrective action reports written against the radioactive material and shipping programs since the previous inspection.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator (PI) Verification (71151)

a. Inspection Scope

The inspectors sampled PSEG submittals for the performance indicators (PIs) listed below. To verify the accuracy of the PI data reported, 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.

Reactor Safety Cornerstone

- Unplanned Scrams per 7,000 Critical Hours
- Scrams with Loss of Normal Heat Removal
- Unplanned Transients per 7000 Critical Hours

The inspectors reviewed PSEG power history charts, Licensee Event Reports, NRC Monthly Operating Reports, and control room logs to determine whether PSEG had adequately identified the number of scrams and unplanned power changes greater than 20 percent that occurred during the previous four quarters, third quarter 2002 to third quarter 2003. This number was compared to the number reported for the PI during the current quarter. The inspectors also verified the reported critical hours accuracy. The inspectors interviewed PSEG personnel associated with PI data collection, evaluation, and distribution.

Emergency Preparedness Cornerstone

The inspector reviewed the procedure for developing the data for the 2003 EP PIs which are: (1) DEP; (2) ERO Drill Participation; and (3) ANS Reliability. The inspector also reviewed the 2003 drill/exercise reports, training records and ANS testing data to verify the accuracy of the reported data. The review was conducted in accordance with NRC Inspection Procedure 71151. The acceptance criteria used for the review were 10 CFR 50.9 and NEI 99-02, Revision 1, Regulation Assessment PI Guideline.

Occupational Radiation Safety Cornerstone

The inspector reviewed a listing of PSEG event reports for the period January 1, 2003 through December 15, 2003 for issues related to the Occupational Exposure Control Effectiveness PI. The information contained in these records was compared against the criteria contained in NEI 99-02, Regulatory Assessment PI Guideline, Revision 1, to verify that all conditions that met the NEI criteria were recognized, identified, and reported as a PI.

Public Radiation Safety Cornerstone

The inspector reviewed the following documents to ensure PSEG met all requirements of the RETS/ODCM Radiological Effluent Occurrences PI from the second quarter 2002 to the second quarter 2003 for all units:

- monthly projected dose assessment results due to radioactive liquid and gaseous effluent releases;
- quarterly projected dose assessment results due to radioactive liquid and gaseous effluent releases; and
- associated procedures.

The information contained in these records was compared against the criteria contained in NEI 99-02, Regulatory Assessment PI Guideline, Revision 1 to verify that all conditions that met the NEI criteria was recognized, identified, and reported as a PI.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

1. Annual Sample Review (2 samples)

a. Inspection Scope

The inspectors completed two sample reviews regarding PSEG’s evaluation of biofouling of the Unit 1 No. 12B component cooling water (CCW) system heat exchanger on March 27, 2003, and a control air transient on February 25, 2003. The

12B CCW heat exchanger, in combination with the associated 12A heat exchanger being out of service for valve maintenance, caused operators to declare one train of the CCW system inoperable. The control air transient involved deficient station air conditions that challenged the operators and resulted in a chemistry and volume control (CVCS) system relief valve lifting to the pressurizer relief tank. The inspectors reviewed the notifications associated with these events (Biofouling issue: 20137474, 20137565, 20137616 & Control air issue: 20133239) to ensure that the full extent of the issues were identified, an appropriate evaluation was performed, and appropriate corrective actions were specified and prioritized. The inspectors evaluated PSEG's actions against the corrective action program as delineated in procedure NC.WM-AP.ZZ-0002(Q), "Performance Improvement Process," Rev. 6 and 10 CFR 50, Appendix B, Criterion XVI (Corrective Action).

b. <u>Findings</u>

No findings of significance were identified.

However, the inspectors noted that PSEG missed a prior opportunity to address the biofouling issue. Specifically, about two weeks prior to the March 27, 2003, 12B CCW heat exchanger biofouling, operators responded to increased differential pressure associated with the 12B CCW heat exchanger. With the 12A CCW heat exchanger out of service for a valve problem (See NRC Inspection Report 50-272&311/2003-05), operators rebalanced CCW system flow between the two operating CCW loops and were able to reduce the 12B CCW heat exchanger differential pressure. However, this challenge did not result in either operations or maintenance personnel assigning a higher priority to fix the 12A CCW heat exchanger degraded valve or cleaning the 12B CCW heat exchanger in a more timely fashion. No additional safety or risk significance occurred as a result of the delayed actions, and the performance issue associated with the 12A CCW heat exchanger valve problem was identified and addressed in NRC Inspection Report 50-272 and 311/2003-05. The performance issue associated with the control air transient was identified and addressed in NRC Inspection 50-272 and 311/2003-03.

2. <u>Cross-References to PI&R Findings Documented Elsewhere</u>

Section 1R08 describes a finding for untimely corrective actions related to SG tube plug deficiencies.

Section 1R12 describes a finding for ineffective problem evaluation that rendered an EDG inoperable. A starting air compressor air leak was not properly assessed or corrected in a timely manner. When the redundant air compressor was removed for planned maintenance, the air leak was significant and bled down the starting air receivers below minimum pressure required for starting.

Section 1R13 describes a finding for ineffective problem evaluation that resulted in an inoperable chilled water compressor. In February 2003 PSEG identified corrosion products in the control air system to have caused equipment control problems.

Following corrective actions, on October 22, 2003, the 23 chiller tripped due to corrosion products fouling a control air orifice.

Section 1R15.1 describes a finding with ineffective problem evaluation and a CS and RHR system waterhammer. PSEG had evaluated an air pocket during the previous operating cycle which was causing waterhammers each time the RHR system was operated. The CS and RHR systems unnecessarily experienced a waterhammer during a refuel activity for CS full flow testing. Opportunities existed to remove the air pocket prior to CS full flow testing.

Section 1R17 describes a finding with ineffective problem evaluation that resulted in a manual reactor trip in response to a dropped rod during startup physics testing. A control rod power supply design change package to correct a known fuse deficiency was deferred.

Section 1R20 describes a finding for untimely corrective actions for RHR steam void conditions. PSEG engineers in May 2003 had calculated that steam void conditions could occur in the RHR system under the current operating guidance for securing RHR. Procedure revisions never occurred and the RHR system was restarted on November 19, 2003 after an insufficient cooldown had occurred. A waterhammer resulted.

Section 4OA5.4 describes a finding with inadequate problem identification and evaluation. PSEG was slow to evaluate the root cause for residual heat removal system waterhammer and did not promptly complete evaluations of the stresses induced during pump starts. PSEG also did not promptly identify degraded pipe hanger conditions that existed following waterhammer events.

Section 4OA5.5 describes a finding for untimely corrective actions that rendered a 13 SWP strainer unreliable due to foreign material intrusion. PSEG did not follow an established troubleshooting plan that had been developed from earlier corrective actions related to SWP strainer trips.

4OA3 Event Followup (71153)

1. Jammed Steam Generator Feed Regulating Valve (FRV) at Full Power

a. Inspection Scope

On October 15, 2003, the inspectors interviewed the operations department and plant managers to understand initial operability determinations and troubleshooting plans for a degraded 14 SG main FRV (14BF19). The inspectors later observed control room operators shut down Unit 1 after PSEG concluded through troubleshooting that the 14BF19 valve was jammed. The inspectors observed the control room briefing, control room operators coordinate SG level using manual SG speed control, and operators maintain average reactor coolant system temperature with control rods in manual. The inspectors were present in the main control room until hot standby conditions were established. As part of the followup to this event, the inspectors witnessed the foreign material which jammed the 14BF19, and interviewed engineers and plant managers to understand the source of this foreign material. The following procedures were referenced to evaluate the operators' performance in controlling SG water levels and shutting down the plant.

- S1.OP-AB.CN-0001, "Main Feedwater/Condensate System Abnormality
- S1.OP-AB.LOAD-0001, "Rapid Load Reduction"
- S1.OP-IO.ZZ-0005, "Minimum Load to Hot Standby"
- 1-EOP-TRIP-1, "Reactor Trip or Safety Injection"
- 1-EOP-TRIP-2, "Reactor Trip or Safety Injection"
- S1.OP-IO.ZZ-0008, "Maintaining Hot Standby"

b. Findings

Introduction. A metal stud of unknown origin jammed the 14 SG main FRV (14BF19) and resulted in a Unit 1 reactor shutdown. The inspectors determined this self-revealing condition to represent a Green NCV.

Description. On October 15, 2003 at 3:16 a.m., control room operators noticed that the 14BF19 was not responding to automatic control and manual control. After 12 hours of evaluation and troubleshooting, PSEG determined that 14BF19 was immovable and that a reactor shutdown was needed within an hour to comply with TSs and to repair the valve.

Maintenance technicians later opened and inspected the 14BF19 valve internals, and discovered a threaded stud approximately 3" long wedged between the valve disc and seat. PSEG engineers could not positively identify the stud characteristics or material composition, or relate it to any plant application within the feed or condensate systems. As such, PSEG concluded that the stud was foreign material that likely entered the feed system during a system opening when inadequate cleanliness controls existed.

Analysis. The deficiency associated with this issue was human performance during maintenance activities. This finding is greater than minor, because it rendered an FRV, 14BF19 inoperable for closing. 14BF19 has a design function to close during a steam or feed line break in containment, thereby limiting the energy release to containment. The finding is in the barrier integrity cornerstone and was of very low safety significance (Green), because it did not represent an actual open pathway in the physical integrity of the reactor containment (inboard valve remained operable) and did not affect systems that would be used for containment pressure control.

Enforcement. 10 CFR 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) - Rev 7, "FME Exclusion" establishes instructions and requirements to prevent foreign material intrusion from causing component failures. Contrary to the above, SH.MD-AP.ZZ-0052 was not followed, in that the 14 SG main feed regulating valve was jammed internally from foreign material on October 14 and 15,

2003. Because this failure to follow procedure instructions is of very low safety significance and has been entered into the corrective action program (Notification 20163339), this violation is being treated as an NCV consistent with Section VI.A of the NRC Enforcement Policy: NCV 50-272/03-09-09, Inadequate foreign material Fails a SG Feed Regulating Valve.

2. (Opened/Closed) LER 05000272/2003003-00, Shutdown Required by Technical Specification 3.0.3

The event related to this LER is described in the preceding section of this inspection report. The LER was reviewed by the inspectors and found acceptable. This LER is closed.

3. (Opened/Closed) LER 05000272/2003001-01, Plant Operation for Greater than 72 Hours with 13 AFW Pump Inoperable

This LER revision corrected an error in the original LER submittal. The original LER credited a previous successful run of the 13 turbine driven auxiliary feedwater pump (TDAFWP) on April 8, 2003. The inspectors had identified that PSEG had confused a valve surveillance test with operating the 13 TDAFWP. The error did not impact the NRC's ability to correctly characterize the risk significance of this TDAFWP inoperability, and this LER revision was submitted to correct the error. This is a minor violation of NRC requirements. This LER is closed.

4OA4 Cross Cutting Aspects of Findings

Section 4OA3.1 describes inadequate maintenance practices that rendered a SG feed regulating valve inoperable and a green finding that was related to human performance.

4OA5 Other

1. TI 2515/150 - Reactor Pressure Vessel (RPV) Head and Vessel Head Penetration nozzles (NRC Order EA-03-009)

a. Inspection Scope

The inspectors reviewed PSEG's activities to detect circumferential cracking of RPV head penetration nozzles as required by NRC Order EA-03-009 and as specified by TI 2515/150. The activities included interviews with analyst personnel and other technical staff, reviews of qualification records, procedures, and the direct observation of the RV closure head visual examination. The inspectors also reviewed the plant's susceptibility calculation to verify that appropriate plant-specific information was used in the calculation. In accordance with TI 2515/150, the inspectors verified that deficiencies and discrepancies associated with the RCS pressure boundary or the examination process were identified and placed in PSEG's corrective action process.

b. Findings

No findings of significance were identified.

The following input addresses the specific reporting requirements of TI 2515/150:

a.1. The examination was performed by qualified and knowledgeable personnel. The inspection technique utilized for bare metal visual examination was as described in PSEG's Bulletin 2002-02 response.

a.2. The visual examination was in accordance with approved and adequate procedures.

a.3. The examination was adequate to identify, disposition and resolve deficiencies.

a.4. The examination performed was capable of identifying the primary water stress corrosion cracking phenomenon described in Order EA-03-009.

b. The general condition of the RV head was clean bare metal with some localized grit or fibrous debris on the uphill side of several nozzles. This debris appeared to be a mixture of inert foreign material/dirt and did not contain any evidence of boric acid. The insulation configuration provided relatively easy access for visual examination. No significant visual obstructions were encountered during the bare metal inspection.

c. Small boron deposits, as described in Bulletin 2001-01, could be identified and characterized by the visual examination technique used. None were found during this visual inspection.

d. No material deficiencies were identified that required repair.

e. No significant items were identified that could impede effective examination.

f. The Salem reactor vessel head closure temperatures were calculated by Westinghouse using the Westinghouse Owner's Group program guidance, "Technical Support of Generic Letter 97-01, Response for RV Head Penetration Alloy 600 PWSCC." PSEG verified the plant specific inputs utilized remained current before using the vendor calculated head temperatures in the susceptibility ranking calculation.

g. Not applicable. Non-visual examinations were not performed.

h. Several procedures existed to facilitate the identification of any potential boric acid leaks from pressure-retaining components above the RPV head. Although no boric acid leaks were identified during the RV closure head visual examination, it was noted that station procedure NC.RA-DG.ZZ-8805(Z), Rev. 0, "Boric Acid Corrosion Management Program Corrective Action Process Guidelines," directed that all boric acid deposits observed in the plant be entered into the corrective action program and the boric acid corrosion program within 24 hours.

i. Not applicable. There were no indications of boric acid leaks from pressure retaining components above the RPV head.

2. TI 2515/152 - Reactor Pressure Vessel Lower Head Penetration Nozzles

a. Inspection Scope

The inspectors reviewed PSEG's activities in response to Bulletin 2003-02, "Leakage from Reactor Pressure Vessel Lower Head Penetrations and Reactor Coolant Pressure Boundary Integrity," as required by TI 2515/152 for pressurized water reactors. This included interviews with analyst personnel as well as a review of qualification records and plant inspection procedures. Additionally, the inspectors independently reviewed the results of the visual examination, in the form of photographs and a video taken during the inspection, which was witnessed by the resident inspector.

In accordance with TI 2515/152, the inspectors verified that deficiencies and discrepancies associated with the RCS structures were identified and placed in PSEG's corrective action process. The inspectors reviewed PSEG's assessment of boric acid residue and rust residue found on the lower head, which was attributed to reactor cavity seal leakage. This included a review of PSEG's chemical analysis of the deposits, taken off of the walls surrounding the vessel lower head and scrapings from the inner insulation.

b. Findings

No findings of significance were identified.

The following input addresses the specific reporting requirements of TI 2515/152:

a.1. The examination was performed by qualified and knowledgeable personnel. A review of personnel qualification records indicated that the personnel performing the visual inspection were appropriately qualified in visual examination.

a.2. The visual examination was conducted in accordance with approved and adequate procedures.

a.3. The examination was adequate to identify, disposition, and resolve deficiencies.

a.4. The examination performed was capable of identifying the pressure boundary leakage as described in Bulletin 2003-02 and RV lower head corrosion.

b. The general condition of the lower RV head was clean with a layer of gray silicone aluminum coating covering the bottom head and the upper portion of some of the nozzles. The coating was blistered and chipping off in some areas.

There were trails of boric acid residue and rust residue running down the lower head, around nozzles and also on some of the nozzles. On the downhill sides of ten of the lower head penetrations were rust stains, which covered a small area adjacent to the annulus and in some cases ran down the penetrations. On the penetrations which were observed to have a small amount of coating residue, extending from the vessel onto the nozzle itself, it appeared to be from brush strokes when the weld pads surrounding the nozzles were coated. None of the brush marks extended 360^{o} around the nozzle material. There was little or no debris on the lower head. PSEG had completely removed the insulation package from the lower head and erected scaffolding to provide access. White crystallized substances were found on the walls of the reactor sump room and on the insulation directly below the lowest point of the RV bottom head. No white crystallized substances were found on the RV bottom head or at any bottom mounted instrumentation (BMI) locations.

c. The visual inspection was conducted using direct visual examination by personnel and also by taking photographs of some of the penetrations, areas of the lower head and insulation. A video was taken also. The examiners used a mirror to look around the penetrations that did not allow direct visual access.

d. Small boric acid deposits representing RCS leakage, as described in the Bulletin 2003-02, were able to be identified and characterized. No white crystallized substances were found on the RV bottom head or at any BMI locations.

e. There were no material deficiencies identified that required repair.

f. No impediments to effective examinations were identified.

3. <u>TI 2515/153 - Reactor Containment Sump Blockage (NRC BULLETIN 2003-01)</u>

a. <u>Inspection Scope</u>

The inspectors reviewed 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. The inspectors also observed related PSEG Unit 2 containment and sump activities in the Fall 2003 Unit 2 refuel outage. The inspectors will perform similar inspection activities for Unit 1 in the Spring 2004 refuel outage. The inspectors interviewed material engineers, observed containment trough boroscope inspections, observed the as-found condition of the sump internals through photographs and infield 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. Documents reviewed are listed in the Attachment.

b. <u>Findings</u>

No findings of significance were identified.

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

a. Unit 2 entered a refueling outage on October 9, 2003 and returned to power on November 27, 2003. A containment walkdown to quantify potential debris sources was conducted by PSEG during the refueling.

b. Not applicable.

c. Unit 1 will enter a refueling outage in Spring 2004. Established PSEG procedures require a containment walkdown performed prior to power operations. PSEG has committed to update the containment walkdown procedures to add emphasis based on NRC Bulletin 2003-01.

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.

This temporary instruction will remain an unresolved item pending completion of similar NRC inspection activities after Unit 1 enters its Spring 2004 refuel outage and after PSEG has performed licensed operator training and emergency plan procedure changes and training as committed in PSEG's Bulletin 2003-01 response. (URI 50-272 and 311/03-09-10)

4. <u>(Closed) URI 05000311/2003007-04 Residual Heat Removal Waterhammer After Plant Refuel Activities on May 10, 2002</u>

a. <u>Inspection Scope</u>

The inspectors reviewed notifications (20160790, 20160896, 20161506, 20161488, 20161704, 20161663, 20166757, 20167400, 20168975) and associated engineering evaluations related to repeated waterhammers of the Unit 2 RHR system during surveillance testing. The Unit 2 RHR system experienced repeated waterhammer events following plant refueling activities on May 10, 2002. Several notifications had been written to document the individual events, troubleshooting methods and results, and engineering evaluations. This item was determined an unresolved item in NRC Inspection Report 05000272/2003007 and 05000311/2003007 section 1R15 pending completion of a PSEG stress calculation and subsequent inspector review. The issue had also been previously inspected as an annual problem identification and resolution sample review in NRC Inspection Report 05000272/2002009 and 05000311/2002009 section 4OA2. Surveillance test S2.OP-ST.RHR-0001, "Inservice Testing - 21 Residual Heat Removal Pump" was observed by the inspectors on October 2, 2003. The inspectors specifically observed pump starts and resultant pipe waterhammer in the 21 and 22 RHR pump rooms. The inspectors performed a system walkdown of the RHR system after the surveillance.

b. Findings

Introduction. The corrective actions to address repeated Unit 2 RHR waterhammers involved untimely problem evaluation (evaluations not completed for 1½ years) and inadequate problem identification (all damaged equipment not identified). This represented a Green self-revealing NCV.

Description. PSEG first identified waterhammer in the RHR system on May 10, 2002. In August 2002, as documented in NRC Inspection Report 05000272/2002009 and 05000311/2002009, PSEG had delayed troubleshooting activities for waterhammer of the Unit 2 RHR system. On August 28, 2002, PSEG identified the source of the waterhammer to be an air pocket in the hot leg injection line. In September 2003 stress analysis to understand the immediate and long term potential adverse effects on the RHR system were not yet complete. PSEG had also performed several RHR system walkdowns and inspected piping and supports to support initial and continued operability assessments. The walkdown results were documented as satisfactory in April 2003, yet NRC inspectors identified two loose piping hangers in the 21 RHR pump room on October 2, 2003. On November 25, 2003, PSEG completed a waterhammer and stress analysis and documented the results in S-2-RHR-MEE-1804, “Salem 2 RHR Waterhammer Event Report.” The stress analysis concluded that RHR system parameters remained within design limits and therefore remained operable following each waterhammer event. Inspectors verified that PSEG flushed the air pocket from the RHR system on October 26, 2003 during the Fall 2003 refuel outage.

Analysis. The performance deficiencies for this finding were inadequate problem evaluation and problem identification. PSEG unnecessarily delayed evaluations several months to understand the root cause of Unit 2 RHR system waterhammer repeated events. PSEG further delayed a stress analysis to determine immediate and long term potential adverse effects of repeated waterhammer. The NRC inspectors further identified deficient system walkdowns to support continued operability when two loose RHR pipe hangers were observed. The waterhammer affected the reliability of the RHR system. The finding is greater than minor, because it affected the equipment performance attribute of the mitigating systems cornerstone. The SDP Phase 1 worksheet was used to characterize the significance of the finding. The significance of the finding is Green, because the RHR system was ultimately determined to be operable.

Enforcement. 10 CFR 50 Appendix B, Criterion XVI, “Corrective Action,” states that measures shall be established to assure that conditions adverse to quality are promptly identified and corrected. Contrary to the above, on October 2, 2003 PSEG had failed to identify loose Unit 2 RHR pipe support hangers even when repeated waterhammer events were occurring since May 10, 2002. Corrective actions to determine the stresses repeated on the RHR system were not completed in a timely manner and delayed until November 25, 2003. Because this failure to comply with 10 CFR 50 Appendix B, Criterion XVI, is of very low safety significance and has been entered into the corrective action program (Notification 20157732), this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 50-311/03-09-11, Failure to Promptly Perform RHR Waterhammer Corrective Actions.

5. (Closed) URI 05000272/2003007-03 Untimely Service Water Pump Strainer (SWP) Corrective Actions

Introduction. A Green NCV was identified for failure to promptly correct a condition that rendered the 13 SWP strainer unreliable.

Description. During the third quarter integrated inspection period (NRC Inspection Report 05000272 and 311/2003007 dated November 10, 2003), the inspectors identified a finding involving multiple cornerstones. The inspectors had determined that PSEG failed to follow earlier established corrective actions for troubleshooting SWP strainer trips. Specifically, the root cause for a 13 SWP strainer trip was not determined on February 10, 2003, and the 13 SWP strainer again failed on May 10, 2003 due to foreign material. The finding was unresolved pending a Phase 3 significance determination process.

Analysis. In accordance with IMC 0612, Appendix B, “Issue Disposition Screening,” the inspectors determined that the issue was more than minor, because it was associated with the equipment performance attribute of the initiating events and mitigating systems cornerstones. Specifically, the availability and the reliability of the 13 SWP train were adversely impacted by inadequate corrective actions for previous failures of the 13 SWP strainer. In accordance with IMC 0609, Appendix A, “Significance Determination of Reactor Inspection Findings for At-Power Situations,” the inspectors conducted an SDP Phase 1 screening and determined that an SDP Phase 2 evaluation was required, because the performance deficiency degraded two cornerstones (initiating event and mitigating systems). However, the inspectors were not able to evaluate this finding using the SDP Phase 2 notebook for Salem station, because the notebook did not contain a worksheet for loss of service water initiating events. The notebook did not contain this worksheet because of an assumption that these events would proceed to core damage. As a result, the inspectors determined that a Phase 3 analysis of this finding was appropriate.

The regional Senior Reactor Analyst conducted the SDP Phase 3 analysis using the following assumptions.

- The 13 SWP train was unavailable for a period of approximately 31 hours due to the failures of the pump strainer on April 16 and May 10, 2003. This unavailability was attributable to the licensee’s failure to implement appropriate corrective actions for a prior failure on February 10, 2003.

- The 13 SWP train was not recoverable.

- This performance deficiency did not result in an increased likelihood of failure of the remaining SWP trains due to common cause mechanisms.

- The unavailability of the 13 SWP train resulted in an increased likelihood of a loss of service water initiating event. The analyst assumed that the frequency of this initiating event increased by the same ratio as the increase in failure probability of the system due to the unavailability of the 13 SWP train. Therefore, the analyst assumed the loss of service water initiating event frequency increased from 9.7E-4 per year to 1.43E-3 per year.

The analysts used the NRC SPAR model, Revision 3.02, to evaluate the significance of this finding. The analyst revised the model to reflect licensee procedures and operating experience as follows:

- NUREG/CR-5496, "Evaluation of Loss of Offsite Power Events at Nuclear Power Plants: 1980 - 1996," contains the NRC's current best estimate of both the likelihood of each of the LOOP classes (i.e., plant-centered, grid-related, and severe weather) and their recovery probabilities.

- Reactor coolant pump (RCP) seal behavior was consistent with the Rhodes Model as documented in Appendix A of NUREG/CR-5167, "Cost/Benefit Analysis for Generic Issue 23: Reactor Coolant Pump Seal Failure." The Salem Unit 1 RCP seals contain a mixture of both high and low temperature o-rings as follows.

RCP	O-Ring Type Installed
11 RCP	All seals have high temperature o-rings installed
12 RCP	First stage seal has high temperature o-rings installed while the remainder have low temperature o-rings installed
13 RCP	First stage seal has high temperature o-rings installed while the remainder have low temperature o-rings installed
14 RCP	First stage seal has high temperature o-rings installed while the remainder have low temperature o-rings installed

In accordance with NUREG/CR-5167, Appendix A, the first stage seal is inherently stable; however, it is very susceptible to high leakage should the back pressure drop due to a failure of the second stage seal. In addition, no credit is given for the ability of the third stage seal to survive if subjected to a differential pressure greater than the normal operating differential pressure of greater than a few psid, which would occur given the failure of the first two seals. Therefore, the analyst used the Rhodes Model results for low temperature o-rings because in 3 of 4 RCPs the second stage seal would fail after 2 hours due to the failure of the low temperature o-rings, which would in turn result in failure of the first and third stage seals.

- The NRC's SPAR model success criteria for emergency AC power is 2 of 3 onsite emergency diesel generators (EDGs) or the gas turbine providing power to the 4160 volt AC buses. This criteria is consistent with the licensee's probabilistic risk assessment (PRA) model. It is based upon the assumption that

2 SWP trains are needed for safe shutdown and one EDG cannot supply enough AC power for more than one SWP train.

PSEG completed an informal engineering analysis (NUTS Order 80058688), which the staff reviewed that demonstrated only one SWP train is needed to provide service water cooling following a LOOP, provided that the nonessential service water loads are automatically isolated from the essential service water loads. The PSEG determined that under these conditions a flow rate of approximately 13,935 gallons per minute (gpm) is needed to cool the essential service water loads. This flow rate is within the capacity of one SWP, approximately 14,400 gpm. The nonessential service water loads are isolated by motor-operated valves (i.e., 11SW20, 1SW26, and 13SW20 which are powered from the 1A, 1B, and 1C EDGs, respectively) that automatically close following a LOOP. In order to isolate the nonessential loads, either the 1SW26 valve or the 11SW20 and 13SW20 valves must close. Therefore, the analyst assumed that the success criteria for emergency AC power was either the 1B EDG or the 1A and 1C EDGs or the gas turbine providing power to the 4160 volt AC buses.

- The NRC SPAR model required service water cooling to the motor-driven auxiliary feedwater (MDAFW) pump room coolers for success of the MDAFW pump trains. This criteria is consistent with the PSEG PRA model. However, PSEG had completed Engineering Evaluation S-C-ABV-MEE-1472, “Effect of the Loss of Auxiliary Building Ventilation on Appendix R Safe Shutdown Electrical Equipment and the Heat Stress Effect on the Capability to Perform Manual Actions,” which the staff reviewed, that demonstrated the auxiliary building ventilation system would provide sufficient room cooling to support operation of the MDAFW pump trains following a loss of service water. Therefore, the analyst assumed that the MDAFW pump trains were dependent on either the service water system or the auxiliary building ventilation system for cooling.

- The analyst revised the human error probability for the operator failing to initiate feed and bleed cooling to more realistically account for the time available to perform the action. The analyst determined that the revised failure probability was approximately 2.0E-3 using the Accident Sequence Precursor Human Reliability Analysis methodology.

The analyst revised the model to reflect the Phase 3 assumptions (stated above), determined a revised core damage frequency (ΔCDF) for the exposure period and calculated the change in ΔCDF for this finding due to internal initiating events. The analyst determined that the ΔCDF for this finding was 6.0E-7 per year. The dominant accident sequence involved an unrecovered loss of service water event and failure of the reactor coolant pump seals to remain intact.

The risk significance of this finding due to fire events was dominated by electrical cabinet fires in the relay room that induce a reactor trip without the power conversion system, result in the spurious opening of a power operated relief valve, and rely on operator action to establish alternate shutdown. The risk significance of this finding due to seismic events was dominated by seismic induced loss of offsite power events with a failure of onsite emergency AC power due to failure of the service water system. However, the increase in ΔCDF due to fire and seismic events was substantially less (approximately 1E-8 per year) than the contribution due to internal events. This finding was also evaluated using IMC 0609, Appendix H, “Containment Integrity SDP.” Because Salem has a large dry containment and the dominant accident sequences did not involve either a SG tube rupture or an inter-system loss of coolant accident, the finding did not contribute to an increase in the large early release frequency for the facility.

As a result, the analyst determined that the inadequate corrective actions for previous failures of the 13 SWP strainer were of very low safety significance (Green).

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 the deficiency causing a SWP to trip on February 10, 2003, and correct the deficiency before a failure again occurred on May 10, 2003. Because this finding is of very low safety significance and has been entered into the corrective action program (Notification 20144330), this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 50-272/03-09-12, Untimely Service Water Pump Strainer Corrective Actions.

4OA6 Meetings, Including Exit

On January 23, 2004, the resident inspectors presented the inspection results to Mr. Fricker and other members of this staff who acknowledged the findings.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel:

Craig Banner, EP Supervisor
Dave Burgin, EP Manager
Jim Clancy, Chemical/Radiation Protection Manager
C.J. Connor, PSEG Eddy Current Level III
Mahesh Danak, RCS System Engineer
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Luis Gonzalez, Principal I&C Engineer
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Greg Halnon, Operations Manager
Abdy Khanpour, Salem System Engineering Manager
Heather Malikowski, Engineering
John O'Neil, ISI Program Administrator, Boris Acid Corrosion Control Program Owner
John Riddle, Chemistry
Randal Schmidt, Engineering
Vince Zabielski, SG Program Manager
Susanne Zeigler, ALARA Specialist

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-272&311/03-09-01	URI	Degraded Internal Flooding Mitigation Equipment for Vital Switchgear Rooms (Section 1R06)
50-272/03-09-06	URI	EDG Failure to Stop on Demand (Section 1R15.2)
50-272&311/03-09-10	URI	Reactor Containment Sump Blockage (Section4OA5.3)

Opened/Closed

50-311/03-09-02	NCV	Failure to Properly Implement RCS Inspection Procedures (Section 1R08)

50-311/03-09-03	NCV	Failure to Promptly Correct an EDG Deficiency (Section1R12)
50-311/03-09-05	NCV	Failure to Promptly Correct an RHR Waterhammer Condition (Section 1R15.1)
50-272/03-09-04	NCV	Failure to Maintain the Control Air System Clean (Section 1R13)
50-311/03-09-07	NCV	Failure to Promptly Correct a Control Rod Power Supply Deficiency (Section 1R17)
50-311/03-09-08	NCV	Failure to Preclude Steam Void Conditions in the RHR System (Section 1R20)
50-272/03-09-09	NCV	Inadequate FME Fails a SG Feed Regulating Valve (Section 4OA3.1)
50-311/03-09-11	NCV	Failure to Promptly Perform RHR Waterhammer Corrective Actions (Section 4OA5.4)
50-272/03-09-12	NCV	Untimely Service Water Pump Strainer Corrective Actions (Section 4OA5.5)
50-272/03-03-00	LER	Shutdown Required by TS 3.0.3 (Section 4OA3.2)
50-272/03-01-01	LER	Plant Operation for Greater Than 72 Hours with 13 AFW Pump Inoperable (Section 4OA3.3)

Closed

50-311/03-07-04	URI	Residual Heat Removal Waterhammer After Plant Refuel Activities on May 10, 2002 (Section 4OA5.4)
50-272/03-07-03	URI	Untimely Service Water Pump Strainer Corrective Actions (Section4OA5.5)

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 1R08: In-Service Inspection

NC.NA-AP.ZZ-0027(Q)-Rev. 7; In-service Inspection Program

NC.WM-AP.ZZ-0000(Q), Rev. 6: Notification Process (WMAP-0)
SER Risk Informed ISI For ASME Class 1 and 2 Piping Welds, 10/1/03
Engineering Evaluation Number: S-2-RC-MEE-1790, Rev. 0, SG Degradation Assessment Salem Unit 2 Refueling Outage 13 (2R13), October 2003.
SC.SG-AP.ZZ-0001(Q), Rev. 5; SG Group Conduct of Operations
SC.SA-AP.ZZ-0042(Q), Rev. 2; SG Management Program
SC.SA-AP.ZZ-0042(Q), Rev. 1; SG Management Program
WCAP-14797, Rev. 1; Generic W* Tube Plugging Criteria for Series 51 SG Tubesheet Region WEXTEX Expansions
NC.RA-DG.ZZ-8805(Z), Rev. 0; Boric Acid Corrosion Management Program Corrective Action Process Guidelines
NC.RA-TS.ZZ-8805(Q), Rev. 0; Boric Acid Corrosion Evaluations
SH.RA-AP.ZZ-8805(Q), Rev. 0; Boric Acid Corrosion Management Process
SH.RA-IS.ZZ-8805(Q), Rev. 0; Boric Acid Corrosion Visual Examination
SC.SG-TI.RCE-0002(Q), Rev. 2; SG Tube Plug Visual Examination
NC.WM-AP.ZZ-0002(Q), Rev. 6; Performance Improvement Process
S2.OP-AB.SG-0001(Q), Rev. 19; SG Tube Leak
Deviation 2R10-99-008, 4/12/99
Deviation 2R11-00-007, no date
SC.CH-AB.ZZ-1101(Q), Rev. 12; Detection and Determination of Primary-to-Secondary Leakage
Notification 20045174, Leaking Tube Plugs 21 & 23 SG, 10/28/00
PIRS 00960202211, 2/5/96, Eddy Current Probe Stuck in SG #21 Tube
Notification 20141308, OE15999: SG Large Radius U-bends, 4/24/2003, (includes SAP Order 80060482)
Notification 20089038, IN02-02: Experiences Plugged SG Tubes, 1/16/2002, (includes SAP Order 80040085)
Notification 20090953, Tech. Deviation - Cal. Standard Flaws, 2/28/2002, (includes SAP Order 80041192)
Notification 20145603, OE15778: SG Tube Plugging SCC, 5/20/2003, (includes SAP Order 80061436)
PIRS 00960224112, 2/28/96; 21 SG Secondary Side Inspection Nonconformance
PIRS 00960224116, 2/28/96; 22 SG Secondary Side Inspection Nonconformance
PIRS 00960224119, 2/28/96; 23 SG Secondary Side Inspection Nonconformance
PIRS 00960224121, 2/28/96; 24 SG Secondary Side Inspection Nonconformance
Emergency Evaluation Number S-2-RC-MEE-1673, Rev. 1, 5/30/2002; 2R12 SG Condition Monitoring & Operational Assessment
Engineering Evaluation Number S-1-RC-MEE-1730, Rev. 0, 12/19/2002; Salem Unit 1 SG Strategic Planning Evaluation
Notification 20159390, 9/20/2003; 2PS3 Has An Active Leak
Notification 20137688, 3/29/2003; S2RC-2PS3 Boron Around Valve
Notification 20149454, 6/20/2003; S2RC-2PS3 Valve Leakage - Boric Acid
Framatome ANP (Document 51-5029660-00), PSEG Nuclear Salem Unit 2 Generic Appendix H Eddy Current Technique Site Validation
Framatome ANP, SG Machine Vision System, Field Procedure; DWG 6026755
Framatome ANP, Operating Instructions For Roger In Recirculating SG (RSG); DWG 6002121A

Framatome ANP, Water Lance System 3 Process Trailer Operational Procedure; DWG 1246734A
Framatome ANP, Water Lance Operational Procedure For Salem Unit 2 Nuclear Station; DWG 1246746A
Framatome ANP, Design Change Notice 6028106, SG Nozzle Dam Installation and Removal Procedure For Busitech Nozzle Dams; Document Number 1277222A, Rev. 02
Framatome ANP, SG Nozzle Dam Installation and Removal Procedure for Busitech Nozzle Dams
S2.SG-ST.RCE-0001(Q), Rev. 6; SG Eddy Current Examination
Calculation Number S-2-RC-MDC-2002, Rev. 0; SG Tube Structural & Condition Monitoring Limits for Salem 2R13
Scientech Document Number 83A7564; Type WR SG Nozzle Dam Installation and Removal, Test, Operation and Maintenance Manual
NC.NA-AP.ZZ-0014(Q), Rev. 10; Training, Qualification and Certification
Engineering Evaluation Number S-2-RC-MEE-1731, Rev. 0; Salem Unit 2 SG Strategic Planning Evaluation
NC.WM-AP.ZZ-0001(Q), Rev. 9; Work Management Process
S1.OP-AB.SG-0001(Q), Rev. 12; SG Tube Leak
SC.SG-AP.ZZ-0001(Q), Rev. 6; SG Management Program
NC.NA-AP.ZZ-0030(Q), Rev. 3; Commitment Management
Framatone CR 6006025, Rev. 0; Salem Unit 2 Leaking Plugs, 10/23/00
Framatone CR 6014732, Rev. 0; Salem Unit 2 Leaking Plugs, 4/13/03; Notification 20097051
Framatone CR 6014733, Rev. 0; Salem Unit 2 Leaking Plugs, 4/13/02; Notification 20097034
Framatone CR 6014734, Rev. 0; Salem Unit 2 Leaking Plugs, 4/13/02; Notification 20097037
Framatone CR 6014735, Rev. 0; Salem Unit 2 Leaking Plugs, 4/13/02; Notification 20097033
B&W Nuclear Technologies, NCR 96-00037, Rev. 0; +Point Probe Left in SG 21 HL U-bend R2C45; 2/16/96
PIRS 960203082, 2/5/96; EC Probe Stuck In #24 SG HL, R2C3
PIRS 960202211, 2/5/96; EC Probe Stuck In #21 SG HL, R2C45
Notification 20163309, 10/21/03; Rust Found On RPV Bottom Nozzles
SC.CH-AB.ZZ-1101(Q), Rev. 12; Detection And Determination of Primary-to-Secondary Leakage
SC.SA-AP.ZZ-0051(Q), Rev. 1; Leakage Monitoring Program
SC.RP-TI.RM-0607(Q), Rev. 8; Primary To Secondary Leak Rate Response
NC.CH-AP.ZZ-0052(Q), Rev. 0; Water Chemistry Control Program
SC.RP-TI.RM-0603(Q), Rev. 8; Routine RMS Surveillance
S1.OP-AB.SG-0001(Q), Rev. 12; SG Tube Leak
NC.WM-AP.ZZ-0001(Q), Rev. 8; Work Management Process
NC.WM-AP.ZZ-0003(Q), Rev. 2; Regular Maintenance Process
Safety Evaluation For Amendment Number 197 To Facility Operating License Number DPR-75, Salem Nuclear Generating Station, Unit Number 2, Docket Number 50-311.
Salem Unit 2 TS 3/4.4.6 Steam Generators
Salem Unit 2 TS 3/4.4.7 Reactor Coolant System Leakage
VTD 326112, Framatome Document 51-5032554-00; Salem Unit 2 - 2R13 In Situ Testing Screening Parameters
VTD 326082, Structural Integrity Associates, Inc. (SALM-04Q-302); Evaluation of FAC Degraded Piping Components During Salem Unit 2 Fall 2003 Outage (2R13)

B&W Nuclear Nonconformance (96-62), Rev. 0, (2/17/96); SG 21 UI Inspection Findings
B&W Nuclear Nonconformance (96-61), Rev. 0, (2/17/96); SG 22 UI Inspection Findings
B&W Nuclear Nonconformance (96-64), Rev. 0, (2/17/96); SG 23 UI Inspection Findings
B&W Nuclear Nonconformance (96-47), Rev. 01, (2/17/96); SG 21 UI Inspection Findings
Framatome CR 1999-000002, Rev. 0, 4/15/99; SG 21 UI Inspection Deficiencies
Framatome CR 1999-000011, Rev. 0, 5/1/99; SG 22 UI Inspection Deficiencies
Framatome CR 1999-12-0, Rev. 0, 5/3/99; SG 23 UI Inspection Deficiencies
PSEG 90 Day Response to GL 97-05, SG Tube Inspection Techniques, Salem Generating Station Facility Operating License Numbers DPR-70, DPR-75, Docket Numbers 50-272 and 50-311, dated 3/10/98
Notification 20163309, 10/21/03; Rust Found On RPV Bottom Nozzles
Notification 20163340, 10/21/03; Incorrect PIR's Referenced - 2R13 Degradation Assessment
VTD 326073, Framatome Technical Document, Stress Report 33-1179825-09 for 0.875" Threaded Rolled Plug (Alloy - 690) for W-RSG's
Work Order 80061539, Update For Revision 6 Of EPRI Guidelines; Level III Site Specific Performance Demonstration Exemption (SSPD), 9/8/03
Work Order 80062418, Update For Revision 6 Of EPRI Guidelines; Tech. Dev. - Analyst Performance Monitoring, 9/28/03
Work Order 80062416, Update For Revision 6 Of EPRI Guidelines; Tech. Deviation - Cal. Std. Flaws, 7/7/03
Work Order 80062417, Update For Revision 6 Of EPRI Guidelines; Tech. Deviation - Transfer Std. Voltage Normalize, 8/26/03
Work Order 80061542, Update For Revision 6 Of EPRI Guidelines; Tech. Deviation - Process Control/U2, 8/26/03
Work Order 80063948, Revision 6 AAPDD Deviation/Justification, 8/26/03
Work Order 80063949, Revision 6 DQV Deviation/Justification, 9/2/03
Notification 20163747, Timely notification of SG tube leaks, 10/24/2003
Framatome ANP Dwg. 1217919A, Rev. 11; Field Procedure And Operating Instructions For Installation Of A Flexible Stabilizer In A Recirculating SG
Framatome ANP Dwg. 1275284A, Rev. 05; Field Procedure For Remote Rolled Plugging Using The LAN SAP Box
Work Order-960311220, 5/29/1996; SG 22 In Situ Pressure Testing
Salem U2 Repair List, SG24 CL, April 2002, 2R12
Salem U2 Repair List, SG21, April 2002, 2R12
Salem U2 Repair List, SG22, April 2002, 2R12
Salem U2 Repair List, SG23 CL, April 2002, 2R12
51-5032554-00 Salem Unit 2 - 2R13 In-Situ Testing Screening Criteria
1007904 SG In-Situ Pressure Test Guidelines, Rev. 2 (EPRI)
Procedure 54-ISI-240-41, "Nondestructive Examination Procedure, Visible Solvent Removable Liquid Penetrant Examination" Framatome, ANP
- Washington Industrial Process Visual/Surface Inspection Certification
- Deposit Analysis Report from Salem Unit 2 Reactor Vessel Inspections, Updated Report, October 24, 2003
- Procedure SC.RA-IS-001, Rev. 0 "Vessel Head Penetration Examination"
- Procedure SH.ER.AS.ZZ-0001, Rev. 0 "Qualification and Certification for Nondestructive Examination (NDE) Personnel"
- Notification 20163309 "Rust Found on Reactor Pressure Vessel Bottom Nozzles"

- Notification 2016174
- Notification 20162301 “S2 Reactor Pressure Vessel Blistering on Bottom Head Coating”
- Federal Specification TT-P-28G “Paint, Aluminum, Heat Resisting (1200^{o}F)” Evaluation on Notification 20163309
- Reactor Coolant Leakage in the Salem 2 Reactor Sump Room Action Plan 10/23/2003

Section 1R08: Maintenance Effectiveness

Notifications 20165292, 20165245, 20157743, 20159420, 20160857, 20167133, 20167134, and 20169954, 20126895, 20127343, 20128812, 20130544, 20132314, 20132495, 20132828, 2013346, 20133916, 20149219
Transient Assessment Response Plan report, “#1 Station Air Compressor Trip During U2 RCS Vacuum Fill.”

Section 1R14: Operator Performance During Non-Routine Evolutions and Events

S2.OP-IO.ZZ-0006, “Hot Standby to Cold Shutdown”
S2.OP-SO.RC-0006, “Draining the Reactor Coolant System <101FT Elevation with Fuel in the Vessel”
S1.OP-AB.CN-0001, “Main Feedwater/Condensate System Abnormality
S1.OP-AB.LOAD-0001, “Rapid Load Reduction”
S1.OP-IO.ZZ-0005, “Minimum Load to Hot Standby”
1-EOP-TRIP-1, “Reactor Trip or Safety Injection”
1-EOP-TRIP-2, “Reactor Trip or Safety Injection”
S1.OP-IO.ZZ-0008, “Maintaining Hot Standby”

Section 1R15: Operability Evaluations

Drawings

203038-B-9772	1B EDG Schematic Controls, Rev. 26
223681-B-9789	No. 1B & 2B Diesel Generators Console Controls, Sheet 1, Rev. 3
223682-B-9789	No. 1B & 2B Diesel Generators Console Controls, Sheet 2, Rev. 7
223683-B-9789	No. 1B & 2B Diesel Generators Console Controls, Sheet 3, Rev. 21
223684-B-9789	No. 1B Diesel Generators Engine-Generator Controls, Rev. 29
223685-B-9789	No. 1B & 2B Diesel Generators Alarms, Rev. 16
223686-B-9789	No. 1B & 2B Diesel Generators Unit Trip & Bkr Failure Protection, Rev. 23
223697-B-4042	No. 1B & 2B Diesel Generators Blocking Relay & Valve Limit Indic, Rev. 8
226632-B-9790	No. 1 & 2 Units Diesel Generators Protection and Control, Rev. 11
226635-B-9605	Diesel Engine & Generator Control System Logic Diagram, Rev. 12
226636-B-9605	Diesel Engine & Generator Control System Logic Diagram, Sh.2, Rev. 6
226637-B-9605	Diesel Engine & Generator Control System Logic Diagram, Rev. 9
226638-B-9605	Diesel Engine & Generator Control System Logic Diagram, Sh. 4, Rev. 9
226639-B-9605	No. 1 Unit Diesel Engine & Generator Control System Logic Diagram, Sh. 1 of 2, Rev. 9

<u>Procedures</u>
S1.OP-ST.DG-0002(Q), 1B Diesel Generator Surveillance Test, Rev. 38

<u>Notifications</u>
20051715, 20089867, 20153694, 20153697, 20159538

<u>Evaluations</u>
70032780

<u>Orders</u>
60038329, 60039594

<u>Calculations</u>
S-C-ZZ-MDC-1807, S-C-ABV-MEE-1361.

Section 1R20: Refueling and Outage Activities

Salem 2R13 Schedule Review Final Risk Assessment Report
Salem 2 Cycle 14 Core Reload Readiness briefing package
Salem Shutdown and Startup Training Cycle 13/14 briefing package
Salem Unit 2 TS Tracking Action Statement Log Index 2R13
Calculation S-C-SF-MDC-1800, Decay Heat-up Rates and Curves (for the spent fuel pool)
Contingency Plant for Shutdown Cooling and Inventory Control, Front-end Midloop
Infrequently Performed Test or Evolution Briefing Package for Unit 2 Midloop with Fuel
S2.OP-PT.CAN-0001, “Containment Walkdown”
S2.OP-SO.RC-0006, “Draining the Reactor Coolant System <101FT Elevation with Fuel in the Vessel”
S2.OP-SO.RC-0002, “Vacuum Refill of the RCS”
S2.OP-IO.ZZ-0005, “Minimum Load to Hot Standby”
S2.OP-IO.ZZ-0006, “Hot Standby to Cold Shutdown”
S2.OP-IO.ZZ-0002, “Cold Shutdown to Hot Standby”
S2.OP-SO.SF-0002, “Spent Fuel Cooling System Operation”
Notifications 20162869, 20162870, 20162973, 20163215, 20163422, 20163425, 20163428, 20163818, 20164489, 20164529, 20164489, 20159411, 20164661, 20164680, 20164796, 20164821, 20164874, 20165039, 20165158, 20165245, 20165296, 20165409, 20165460, 20165503, 20165612, 20165329, 20165716, 20165726, 20166202, 20166494, 20166608, 20166652, 20167133, 20167133, 20167142, 20167634, 20167685, 20167817, 20167830, 20167889

Section 1EP: Emergency Preparedness

PSEG Nuclear Emergency Plan
Emergency Plan Implementing Procedures
NC.EP-DC.ZZ-0010, EP Self-assessment Guide
NEP-PER-02-001A, Ability to Perform Self-Assessments, July 18, 2002
NEP-PER-02-002A, ERO Qualifications Self Assessment, July 23, 2002
QA Assessment Report 2002-0210, 10 CFR 50.54(t) EP review, September 30, 2002

QA Assessment Monitoring Feedback 2002-0274, Unannounced Drill, September 23, 2002
QA Assessment Report 2003-0020, Salem Practice Exercise, March 12, 2003
QA Assessment Report 2003-0180, Unannounced Drill, June 25, 2003
QA Assessment Report 2003-0240, Hope Creek Drill
QA Assessment Report 2003-0197, NRC PIs
QA Emergency Preparedness Integrated Master Assessment Plan
NEP-PER-02-004A, Facilities and Equipment Readiness, 12/2002
NEP-PER–03-001A, Quality of Response to Plant Events or Drill/Exercise Scenarios, 4/2003
NEP-RV-03-001D, Observation of the Corrective Action Program in EP, 3/2003
NEP-RV-03-001B, Salem/HC Technical Document Room Program Capabilities, 3/2002
NEP-PER-03-001C, How effectively workers and their supervisors utilize operating experience information in Emergency Preparedness, 3/2003
NEP-PER-03-002B, Human Performance Action Plan Status, June/2003
CR No. 80063899-0050, Performance Issues in the TSC and Control Point
CR No. 80063897-0030, Conflicting Information at Joint News Center During Exercise
CR No. 20148989, Interface Between ERO Callout System and ERO Pager System
CR No. 20148989, Untimely Activation of TSC
CR No. 20146629, Accountability Problems

Section 2PS1: Radioactive Gaseous and Liquid Effluent Treatment and Monitoring Systems

- Notifications for Radiation Monitoring Systems (20161682, 20133905, 20118503, 20112345, 20092977, 20091444, and 20084969);
- Notifications for Routine Effluent Control Program (20132459, 20152700, 20148459, 20125327, 20124971, 20124966, 20124920, 20124972, and 20098713, 20145445); and
- Notifications for Air Cleaning Systems (2016052, 20157706, 20152240, 20150095, 20111308, and 20109335).

Section 4OA5.3 Other

NRC Bulletin 2003-01: Potential Impact of Debris Blockage on Emergency Sump Recirculation at Pressurized-Water Reactors
Salem Generating Station Units 1 and 2 60-Day Response to NRC Bulletin 2003-01 dated August 6, 2003
S2.OP-ST.SJ-0010, “ECCS - Containment Inspection for Mode 4"
S2.OP-ST.SJ-0011, “Emergency Core Cooling ECCS - Containment Sump Modes 5-6"
SC.SA-ST.ZZ-0001, “Salem Containment Entries in Modes 1 Through 4”
S2.OP-PT.CAN-0001, “Containment Walkdown”
NC.CC-AP.ZZ-0011, “Transient Loads”
PSEG Drawings 208915, 201275, 248195, 248196, 248199, 248200, 249559, 601691 and 601694
Notifications 20164489, 20164524, 20165726, 20166367, and 20170114

LIST OF ACRONYMS

ALARA	As Low As Is Reasonably Achievable
ANS	Alert and Notification System
BMI	Bottom Mounted Instrumentation
CA	Control Air
CCW	Component Cooling Water
ΔCDF	Core Damage Frequency
CFCU	Containment Fan Coil Unit
CFR	Code of Federal Regulations
CR	Condition Report
CRDM	Control Rod Drive Mechanism
CREACS	Control Room Emergency Air-Conditioning System
CS	Containment Spray
DEP	Drill and Exercise Performance
EAL	Emergency Action Level
ECCS	Emergency Core Cooling System
EDG	Emergency Diesel Generator
EP	Emergency Preparedness
ERO	Emergency Response Organization
FME	Foreign Material
FRV	Feedwater Regulating Valve
gpm	Gallons Per Minute
HEPA	High-Efficiency Particulate Air (filter)
IMC	Inspection Manual Chapter
ISI	Inservice Inspection
MDAFW	Motor-Driven Auxiliary Feedwater
NCV	Non-cited Violation
NEI	Nuclear Energy Institute
NRC	Nuclear Regulatory Commission
ODCM	Offsite Dose Calculation Manual
PARS	Publicly Available Records
PIs	Performance Indicators
PMT	Post Maintenance Testing
PRA	Probabilistic Risk Assessments
PSEG	Public Service Electric Gas
PWSCC	Primary Water Stress-Corrosion Cracking
QA	Quality Assurance
QC	Quality Control
RCP	Reactor Coolant Pump
RCS	Reactor Coolant System
RHR	Residual Heat Removal
RMS	Radiation Monitoring System
RP	Radiation Protection
RPV	Reactor Pressure Vessel
RV	Reactor Vessel
SDP	Significance Determination Process
SG	Steam Generator
SWP	Service Water Pump

TDAFWP	Turbine Driven Auxiliary Feedwater Pump
TI	Temporary Instruction
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item

TABLE 1

LISTING OF AREAS INSPECTED

Auxiliary Building elevation 64’, cubicles containing:

Chemistry and volume control system (CVCS) monitor tanks # 11, 12, 21 & 22 and pumps
Waste holdup tanks # 11, 12, 13, 21, 22 & 23 and pumps
CVCS holdup tanks # 11, 12, 13, 21, 22 & 23 and pumps

Auxiliary Building elevation 84’, cubicles containing:

Spent resin tanks and pumps

Auxiliary Building elevation 100’, cubicles containing:

Boric acid evaporator unit #1
Waste evaporator unit #1
Unit 1 demineralizer ion exchanger room
Unit 2 demineralizer ion exchanger room
Storage and bailing area
Drumming stations 1 & 2
Drum storage vaults north & south
Evaporator bottoms transfer pump