February 3, 2005

Mr. William Levis
Senior Vice President and Chief Nuclear Officer
PSEG LLC - N09
P. O. Box 236
Hancocks Bridge, NJ 08038

SUBJECT: SALEM NUCLEAR GENERATING STATION - NRC INTEGRATED INSPECTION REPORT 05000272/2004005 and 05000311/2004005

Dear Mr. Levis:

On December 31, 2004, the US Nuclear Regulatory Commission (NRC) completed an inspection at your Salem 1 & 2 reactor facilities. The enclosed integrated inspection report documents the inspection findings, which were discussed on January 7, 2005, with Mr. Michael Brothers 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 two NRC-identified findings and three self-revealing findings of very low safety significance (Green). Three of these findings were determined to involve violations of NRC requirements. However, because of the very low safety significance and because they are entered into your corrective action program, the NRC is treating these three findings as non-cited violations (NCVs) consistent with Section VI.A of the NRC Enforcement Policy. Additionally, licensee-identified violations which were determined to be of very low safety significance are listed in this report. If you contest any NCV in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001; with copies to the Regional Administrator, Region I; the Director, Office of Enforcement, and the NRC Resident Inspector at the Salem Nuclear Generating Station.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosure, and your response (if any) will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

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

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

Enclosure: Inspection Report 05000272/2004005 and 05000311/2004005
w/Attachment: Supplemental Information

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U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket Nos:	05000272, 05000311
License Nos:	DPR-70, DPR-75
Report No:	0500272/2004005, 05000311/2004005
Licensee:	PSEG LLC
Facility:	Salem Nuclear Generating Station, Units 1 & 2
Location:	P.O. Box 236 Hancocks Bridge, NJ 08038
Dates:	October 1 - December 31, 2004
Inspectors:	J. Daniel Orr, Senior Resident Inspector George J. Malone, Resident Inspector Marc S. Ferdas, Resident Inspector Joseph G. Schoppy, Senior Reactor Engineer John G. Caruso, Senior Operations Engineer Nancy T. McNamara, EP Inspector Joseph T. Furia, Senior Health Physicist Robert J. Prince, Health Physicist Aniello Della Greca, Senior Reactor Engineer Amar Patel, Reactor Engineer Marlone Davis, Reactor Inspector
Approved By:	Eugene W. Cobey, Chief Projects Branch 3 Division of Reactor Projects

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SUMMARY OF FINDINGS

IR 05000272/2004005, 05000311/2004005; 10/01/2004 - 12/31/2004; Public Service Electric Gas Nuclear LLC, Salem Units 1 and 2; Maintenance Effectiveness, Surveillance Testing, Temporary Plant Modifications, and Event Followup.

The report covered a 13-week period of inspection by resident inspectors, and announced inspections by a regional radiation specialist, reactor inspectors, and an emergency preparedness inspector. Additionally, emergency plan revisions and the licensed operator requalification program were reviewed in-office by regional inspectors. Three Green non-cited violations (NCVs), and two green findings 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. A self-revealing finding was identified when the Salem Unit 2 reactor automatically tripped on September 9, 2004, in response to a generator protection trip. PSEG failed to incorporate vendor recommended daily and weekly inspections of the Salem Unit 2 exciter brushes. A brush failure resulted in a generator protection trip. The finding was not a violation of NRC requirements, in that the performance deficiency occurred on a non-safety related system.

  Traditional enforcement does not apply because the issue did not have any actual safety consequences or potential for impacting the NRC's regulatory function and was not the result of any willful violation of NRC requirements. The finding is greater than minor because it affected the equipment performance attribute and impacted the initiating events cornerstone objective to limit the likelihood of those events that upset plant stability. In accordance with IMC 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," the inspectors conducted a Phase 1 SDP screening and determined the finding to be of very low safety significance (Green). The finding screened to Green because the issue did not involve a loss-of-coolant accident or external event initiator, and mitigation equipment was also not involved. (Section 4OA3.3)

Cornerstone: Mitigating Systems

- Green. A self-revealing finding was identifed when the 26 service water pump was rendered inoperable due to biological fouling of the suction trash rack on September 22, 2004. A large amount of biological growth had previously been identified on the trash rack during an inspection on August 2, 2004; however, PSEG did not clean the trash rack following the inspection. The finding was determined to be a non-cited violation of 10 CFR Part 50, Appendix B, Criterion XVI, “Corrective Action.”

Traditional enforcement does not apply because the issue did not have any actual safety consequence or potential for impacting the NRC’s regulatory function and was not the result of any willful violations of NRC requirements. The finding was more than minor because it was associated with the equipment availability attribute of the mitigating systems cornerstone objective to maintain the availability of systems that respond to initiating events to prevent undesirable consequences. In accordance with IMC 0609, Appendix A, “Significance Determination of Reactor Inspection Findings for At-Power Situations,” the inspectors conducted a Phase 1 SDP screening and determined that a Phase 2 evaluation was required because the performance deficiency degraded both the initiating event and mitigating systems cornerstones. However, the inspectors were unable to evaluate the finding using Phase 2, because the Risk-Informed Inspection Notebook for Salem Generating Station did not evaluate loss of service water initiating events. The Region I Senior Reactor Analyst (SRA) conducted a Phase 3 analysis which determined that the finding was of very low safety significance (Green). (Section 1R12)

- Green. The inspectors identified a failure to implement effective corrective actions following repetitive failures of the gas turbine control system. The finding was not a violation of NRC requirements because it pertained to non-safety related equipment.

  Traditional enforcement does not apply because the issue did not have any actual safety consequences or potential for impacting the NRC's regulatory function and was not the result of any willful violation of NRC requirements. The finding was more than minor because it was associated with the equipment performance attribute of the mitigating systems cornerstone. This finding affected the mitigating cornerstone objective, in that, it reduced the availability and reliability of a system that responds to initiating events to prevent undesirable consequences. The finding was determined to be of very low safety significance based upon a SDP Phase 3 analysis. (Section 1R12)

- Green. A self-revealing finding was identified when tubing on a temporary test gauge ruptured from being over-pressurized and sprayed the inside of the 13 turbine driven auxiliary feedwater (TDAFW) pump panel with water resulting in pump unavailability. This finding involved inadequate procedural adherence and was a non-cited violation of 10 CFR 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings.”

  Traditional enforcement does not apply because the issue did not have any actual safety consequences or potential for impacting the NRC's regulatory function and was not the result of any willful violation of NRC requirements. The finding was more than minor because it was associated with the equipment performance attribute of the mitigating systems cornerstone and affected the objective to maintain the availability of systems that respond to initiating events to prevent undesirable consequences. The inspectors determined that the finding was of very low safety significance using the Phase 1 screening in Appendix A of Inspection Manual Chapter 0609, "Determining the Significance of Reactor Inspection Findings for At-Power Situations." The finding represented a loss of safety function of a single train of auxiliary feedwater for less than the technical specification allow outage time. The finding was also not a design or qualification deficiency that resulted in a loss of function, did not result in an actual loss of safety function, and was not screened as potentially risk significant from external events. (Section 1R22)

- Green. The inspectors identified a failure to properly translate temporary modification (TM) instructions into the associated work order. As a result, incorrect sealant was applied around seven floor drain covers in Salem Unit 1 and Unit 2 auxiliary buildings. The covers protected safety-related systems, structures, and components in mild areas of the auxiliary building from being exposed to the harsh environment (higher temperature and humidity) associated with a main steam line break. The finding was determined to be a non-cited violation of 10 CFR Part 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings.”

  Traditional enforcement does not apply because the issue did not have any actual safety consequence or potential for impacting the NRC’s regulatory function and was not the result of any willful violations of NRC requirements. The finding was more then minor because it was associated with the design control attribute of the mitigating systems cornerstone and affected the objective to maintain the reliability and availability of systems that respond to initiating events to prevent undesirable consequences in the auxiliary building from being exposed to a harsh environment. In accordance with Inspection Manual 0609, Appendix A, “Significance Determination of Reactor Inspection Findings for At-Power Situations,” the inspectors conducted a Phase 1 SDP Screening and determined the finding to be of very low safety significance (Green). The finding screened to Green because the issue was a qualification deficiency confirmed not to result in a loss of function. (Section 1R23)

B. Licensee-Identified Violations

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

REPORT DETAILS

Summary of Plant Status

Unit 1 began the period at 100 percent (%) power. On December 3, 2004, operators initiated a plant shutdown prior to the plant being impacted by a tanker oil spill in the Delaware River. Unit 1 was restarted on December 16, 2004. Unit 1 achieved 60% power on December 17, but power was reduced to about 14% on December 20 to facilitate repairs on a steam generator feed pump. Following the repairs, Unit 1 attained 60% power on December 22, but a downpower to about 25% on December 26 was necessary for similar steam generator feed pump repairs. Unit 1 was returned to 100% power on December 30, 2004.

Unit 2 began the period at 100%. On December 3, 2004, operators initiated a plant shutdown prior to the plant being impacted by a tanker oil spill in the Delaware River. Unit 2 was restarted on December 13, 2004. Unit 2 was returned to 100% power on December 16, 2004.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

a. Inspection Scope (2 samples)

On November 26, 2004, the oil tanker ATHOS reported a significant spill to the Delaware River in the Philadelphia area. On December 2, 2004, PSEG decided that Salem 1 and 2 would be shutdown on December 3, 2004, as a precautionary measure for potential oil impact on the plant cooling water systems. NRC inspectors maintained a continuous site coverage for the Salem and Hope Creek plants from December 3 to 16, 2004. The inspectors referenced NRC Inspection Procedure 71111.01, “Adverse Weather Protection,” to evaluate PSEG’s measures to protect mitigating systems, particularly cooling water systems and components, from the oil in the Delaware River. The inspectors frequently walked down the service water intake structure, auxiliary feedwater system, and the charging pumps and observed hoses and fans staged for alternate cooling to risk significant equipment. The inspectors frequently interviewed operators, engineers, chemistry technicians, managers, and PSEG response teams to assess the Delaware River conditions. The oil in the Delaware River did not have a significant adverse impact on Salem or Hope Creek cooling systems from December 3 to 31, 2004.

The inspectors performed an inspection for adverse weather protection, including detailed reviews of winter readiness procedures and a review of Salem’s preparation for winter readiness. The inspectors reviewed past notifications to identify cold weather challenges to plant equipment and to verify that PSEG addressed those issues prior to the next cold weather period. The inspectors toured portions of systems that are particularly susceptible to cold weather, including the service water system, circulating water system, reactor water storage tanks, auxiliary feedwater storage tanks, and primary water storage tanks. The inspectors interviewed the winter readiness team manager. Documents reviewed to verify adverse weather readiness are listed in the

Supplemental Information Attachment to this report.

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Salem station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the following additional inspection sample was performed. The inspectors reviewed a corrective action program evaluation to ensure PSEG adequately evaluated and corrected a condition affected by adverse weather. The additional evaluation reviewed was 70029296.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04)

a. Inspection Scope (4 partial walkdown samples)

The inspectors performed the following four partial system walkdowns:

- 1B and 1C Emergency Diesel Generators (EDG) and supporting systems, including fuel oil and service water, starting air, and electrical switch lineups, while the 1A EDG was out of service on October 12, 2004;
- 2A and 2B Emergency Diesel Generators and supporting systems, including fuel oil and service water, starting air, and electrical switch lineups, while the 2C EDG was out of service on October 27, 2004;
- Observation of alternate cooling water contingencies for the Unit 1 and Unit 2 emergency core cooling system pumps on December 3, 2004; and
- Frequent walkdowns of the Unit 1 and Unit 2 service water systems, auxiliary feedwater systems, charging pumps, and emergency diesel generators from December 3, 2004 to December 16, 2004, while the inspectors maintained continuous site coverage for a Delaware River oil spill.

Documents reviewed to verify proper alignment are listed in the Supplemental Information Attachment to this report.

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Salem station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the following additional inspection sample was performed. The inspectors reviewed corrective action program notifications and evaluations identifying plant system configuration control problems to ensure PSEG adequately evaluated and corrected the associated conditions. The additional notifications and evaluations reviewed were 20193198, 20202782, 20193752, 20216069, 20214830, 70039851, 70043821, 70028126 and 70043821.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

a. Inspection Scope (1 annual fire drill observation and 9 routine fire protection walkdowns)

The inspectors observed one fire drill and performed nine fire area walkdowns. The inspectors observed an off-hours fire drill on October 13, 2004 to determine the readiness of PSEG's fire brigade to prevent and respond to fires. The drill involved an electrical fire in the No. 2 Salem Service Water Bay. The inspectors verified the timeliness of the fire brigade response, the proper selection and placement of firefighting equipment, proper communication techniques between fire team members and the control room, and use of fire plans. Additionally, the inspectors observed the drill brief and post-drill critique.

The inspectors walked down nine fire areas and evaluated the adequacy of combustible material control, fire detection and suppression equipment availability and compensatory measures. The inspectors referenced Salem pre-fire plans and NC.DE-PS.ZZ-0001-A6-GEN, "Programmatic Standard Salem Fire Protection Report-General." The inspectors reviewed applicable documents associated with these equipment alignments as listed in the Supplemental Information Attachment to this report. The following plant areas were inspected:

- Unit 1 and 2 spent fuel/component cooling heat exchanger and pump area;
- Unit 1 and 2 turbine generating area, elevation 88';
- Unit 1 and 2 turbine generating area, elevation 100';
- Unit 1 and 2 turbine generating area, elevation 120'; and
- Unit 2 auxiliary equipment area, elevations 45' and 55'.

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Salem station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the following additional inspection sample was performed. The inspectors reviewed corrective action program notifications identifying fire pump material conditions to ensure they were adequately evaluated and corrected. The additional notifications reviewed were 20154906, 20176671 and 20176308.

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures (71111.06)

a. Inspection Scope (1 sample)

The inspectors evaluated internal flood protection measures for the Unit 1 and 2 residual heat removal pump and heat exchanger rooms. The inspectors toured the area to determine whether flood vulnerabilities existed and to assess the physical condition of flood barriers, floor drains, and sump pumps. The inspectors reviewed maintenance and calibration records for flood protection equipment. In addition, the inspectors reviewed procedures to determine whether operators could mitigate the consequence of an internal flood. The inspectors also reviewed notifications associated with flood protection measures. Documents reviewed to verify proper flood prevention measures are listed in the Supplemental Information Attachment to this report.

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Salem station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the following additional inspection sample was performed. The inspectors reviewed corrective action program notifications 20050752, 20159186, 20159188, and 20202390 and evaluation 70041204. The inspectors validated that internal flood mitigation equipment deficiencies were being resolved through notification reviews and discussions with PSEG Quality Assurance personnel.

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance (71111.07)

a. Inspection Scope (2 samples)

The inspectors reviewed PSEG's programs and processes for assuring that safety-related heat exchangers were operationally maintained and capable of performing their design functions. The inspectors specifically selected the 21 charging pump associated lube oil cooler and gear box oil cooler and the 11 containment fan cooler unit.

For the 21 charging pump coolers, the inspectors reviewed PSEG's methods for monitoring heat exchanger performance. The current performance characteristics and test results were compared to the design requirements and PSEG's response to Generic Letter 89-13, "Service Water System Problems Affecting Safety-Related Equipment." The heat exchanger inspection, cleaning, and maintenance methods and frequencies were discussed with the Generic Letter 89-13 program manager and engineers. Results were reviewed for degradation trends. The performance test criteria were reviewed to ensure that testing methods predicted design condition performance. Performance calculations were reviewed to verify test instrument inaccuracies and differences were considered. PSEG's chemical treatment program was also reviewed to verify that potential bio-fouling mechanisms had been identified, treatments were conducted as scheduled, and results were monitored for effectiveness. PSEG procedure S1.OP.PT.SW-0004, "Service Water Fouling Monitoring Safety Injection and Charging Pumps," and 21 charging pump biological fouling performance data from the PSEG intranet were reviewed.

The inspectors reviewed the service water biological fouling monitoring for the 11 containment fan coil unit to verify that the system was not adversely impacted and remained operable due to the presence of oil in the Delaware River from a tanker oil spill. The inspectors independently verified performance calculations and compared the results to the test acceptance criteria. The inspectors reviewed Salem procedure, S1.OP.PT.SW-0007, "Service Water Fouling Monitoring Containment Fan Coil Units," performed on December 8, 2004, and the Updated Final Safety Analysis Report (UFSAR) Sections 6.2.2.2 and 15.4.8.

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Salem station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the following additional inspection sample was performed. The inspectors reviewed corrective action program notifications identifying heat sink problems to ensure they were adequately evaluated and corrected. The additional notifications reviewed were 20182083 and 20206789.

b. <u>Findings</u>

No findings of significance were identified.

1R11 <u>Licensed Operator Requalification</u> (71111.11)

a. <u>Inspection Scope (1 biennial program review and 1 quarterly training activity review)</u>

During the week of December 6, 2004, an in-office review of Salem's requalification examination administration for 2004 was conducted.

The following inspection activities were performed using NUREG 1021, Rev. 9, "Operator Licensing Examination Standards for Power Reactors," Inspection Procedure Attachment 71111.11, "Licensed Operator Requalification Program," Appendix A "Checklist for Evaluating Facility Testing Material." This inspection activity represented one sample.

The training department was contacted by phone to discuss recent examination results and any security issues during the exam preparation or administration. None was reported to have occurred.

A review of unusual or atypical conditions that occurred or may have occurred during the testing cycle was completed. None were identified.

The results of the annual operating tests for 2004 were reviewed in-office for grading. An assessment of whether pass rates were consistent with the guidance of NUREG-1021, Revision 9, “Operator Licensing Examination Standards for Power Reactors” and NRC Manual Chapter 0609, Appendix I, “Operator Requalification Human Performance Significance Determination Process (SDP),” was also performed. The SDP review verified the following:

- Crew failure rate on the dynamic simulator examination was less than 20% (Failure rate was 6.7%);
- Individual failure rate on the comprehensive biennial written examination was less than 20% (Failure rate was 3.8%) ;
- Individual failure rate on the walk-through (JPMs) was less than 20% (Failure rate was 0%); and
- More than 75% of the individuals passed all portions of the exam (91.0% of the individuals passed all portions of the examination).

The resident inspectors observed a simulator training scenario on November 9, 2004, to assess operator performance and training effectiveness. The scenario involved a failure of two governor valves, a loss of the No. 3 station power transformer and 2A vital bus, and an inadvertent safety injection and associated automatic reactor trip. The inspectors verified operator actions were consistent with operating, alarm response, abnormal, and emergency procedures. The inspectors assessed simulator fidelity and verified that evaluators identified deficient operator performance where appropriate. Documents reviewed to verify proper operator performance and training effectiveness are listed in the Supplemental Information Attachment to this report.

On August 23, 2004, the NRC’s Executive Director for Operations approved a deviation from the NRC’s Action Matrix to provide a greater level of oversight for the Salem/Hope Creek station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the following additional inspection sample was performed. The inspectors reviewed PSEG’s Business Objective SCWE01.OPS-02.08, “Present Operator Responsibility Training.” Specifically, the inspectors observed Salem operations department training on principles of effective “operational decision making.” The training involved discussions on operational decisions recently made due to recent equipment problems and plant events at Salem and Hope Creek. The inspectors also reviewed the training material used by the Hope Creek operations department for similar training sessions.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope (4 samples)

The inspectors performed four maintenance effectiveness inspections and reviewed notifications documenting past operating problems, system health reports, and maintenance rule performance criteria to determine if PSEG had effectively evaluated the equipment issues. The issues reviewed were the loss of 26 service water pump due to trash rake biological fouling, spurious output breaker trips for the gas turbine generator, loss of 26 service water pump due to a clogged traveling water screen (notifications 20207512 and 20207513), and an emergent failure of the 22 control area chiller compressor due to a freon leak (notifications 20206865 and 20206953). The inspectors also referenced 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," to ascertain the acceptability of PSEG's maintenance rule application.

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Salem station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the following additional inspection sample was performed. The inspectors reviewed corrective action program notifications for equipment problems to ensure they were adequately evaluated in the maintenance rule program. The additional notifications and evaluation reports reviewed were 20195527, 20197021, 20205824, 20207512, 20205874, 70040264, 70040426, and 70040334. Additionally, the inspectors reviewed the results of PSEG's improvement plans with regards to Business Plan WM.01.PS.02.13, "Eliminate Overdue Preventive Maintenance Tasks," to determine if these plans were effective in controlling overdue preventive maintenance tasks.

b. Findings

1. Loss of Suction Head to 26 Service Water Pump

Introduction. A Green self-revealing non-cited violation (NCV) of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action" was identified on September 21, 2004, when the 26 service water (SW) pump was rendered inoperable due to excessive biological growth on its trash rack. A large amount of biological growth had been identified on the trash rack during an inspection on August 2, 2004; however PSEG did not clean the trash rack following the inspection.

Description. At 9:35 a.m. on September 22, 2004, control room operators noticed the motor current and discharge pressure on the 26 SW pump oscillating abnormally. Operators confirmed the pressure oscillations locally and heard a banging noise from the associated service water pump room. The pump was secured and declared inoperable at 10:01 a.m. on September 22, 2004. The pump was made available at 4:31 p.m. on

September 27, 2004.

Divers conducted an inspection of the 26 service water bay on September 23, 2004, and discovered large amounts of biological growth on the trash rack to 26 SW pump. This blockage restricted flow of water to the 26 SW pump. The purpose of the trash rack serves as a large strainer for the suction of the pump. When the trash rack became heavily fouled with biological growth, the 26 SW pump cavitated.

On August 2, 2004, PSEG performed scheduled preventive maintenance to remove silt from the 26 SW pump bay. The divers recorded in the procedure comment section that the trash rack was 100% corroded at the tidal zone and that there was 95% blockage at the bottom of the rack due to heavy biological growth. It was also recorded that the rack needed to be replaced. The rack was not replaced or cleaned appropriately. Biological growth continued to accumulate on the rack until the 26 SW pump no longer had enough suction head to operate properly on September 22, 2004.

Analysis. The performance deficiency has a problem identification and resolution cross cutting aspect (identification). PSEG identified that the 26 SW pump trash rack was degraded on August 2, 2004, yet did not enter the deficiency into the corrective action program. Because the problem was not corrected, the fouled rack rendered the 26 SW pump inoperable for 126 hours.

Traditional enforcement does not apply because the issue did not have any actual safety consequences or potential for impacting the NRC's regulatory function, and it was not the result of any willful violation of NRC requirements. This issue was more than minor because it was associated with the equipment performance attribute, and it affected the initiating events and mitigating systems cornerstone objectives. In accordance with IMC 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," the inspectors conducted a Phase 1 SDP screening and determined that a Phase 2 evaluation was required because the performance deficiency degraded both the initiating event and mitigating systems cornerstones. However, the inspectors were unable to evaluate the finding using Phase 2, because the Risk-Informed Inspection Notebook for Salem Generating Station did not evaluate loss of service water initiating events.

The Region I Senior Reactor Analyst (SRA) conducted a Phase 3 analysis which determined that the finding was of very low safety significance (Green). The analysis used the NRC's Standardized Plant Analysis Risk (SPAR) model, Revision 3.11, dated December 2004, for the Salem facility and assumed that the 26 SW trash rack was out-of-service for 126 hours and that the loss of service water initiating event frequency increased during this time because of lost redundancy in the SW trains as a result of the performance deficiency. The increase in core damage frequency due to internally initiated events was in the high E-8 range (an increase in the core damage frequency in the range of 1 core damage accident in 12,000,000 years of reactor operation). The dominant accident sequence involved a loss of offsite power initiating event followed by failures of the three Salem emergency diesel generators and the gas turbine generator leading to a station blackout. Core damage then results following a reactor coolant pump seal failure due to lack of cooling and the failure of high pressure recirculation.

Enforcement. 10 CFR 50 Appendix B, Criterion XVI, “Corrective Action,” requires that measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and nonconformances are promptly identified and corrected. Contrary to the above, on August 2, 2004, PSEG failed to correct an adverse biological fouling condition on the 26 service water trash rack that resulted in the inoperability of 26 SW pump on September 22, 2004. Because this finding is of very low safety significance and has been entered into the corrective action program in notification 20204551, this violation is being treated as a NCV, consistent with section VI.A of the NRC Enforcement Policy: **NCV 05000311/2004005-01, Trash Rack Biological Fouling Renders 26 Service Water Pump Inoperable.**

2. Repeat Unavailability of the Gas Turbine due to Generator Breaker Trips

Introduction. The inspectors identified a failure to implement effective corrective actions following repetitive failures of the gas turbine control system. The finding was of very low safety significance (Green). Because the corrective action issues involved non-safety related equipment, there was no violation of regulatory requirements. Nevertheless, the Mitigating Systems Cornerstone objectives were impacted. The inspectors determined that the corrective action deficiencies were also not attributable to maintenance rule implementation. A licensee-identified maintenance rule violation associated with the gas turbine generator is documented in Section 4OA7 of this report.

Description. The gas turbine (GT) is a high-risk significant, non safety-related system that is relied upon for electrical power during a loss of offsite power (LOOP) event when the three emergency diesel generators (EDGs) have failed, that is a station blackout (SBO) event. During an annual period between November 2003 and November 2004 the GT experienced several failures to start or run during routine testing. The GT was routinely started twice each month and run for fifteen minutes on every other start to verify availability. Three failures from November 2003 to November 2004 were attributed to repeated erroneous control system signals which resulted in the GT being unavailable as troubleshooting was conducted. Similar control system problems have caused GT unreliability and unavailability over the last several years.

The three testing related failures occurred on February 3, 2004, July 16, 2004, and November 5, 2004 (notifications 20165460, 20198799, and 20210679 respectively).

On November 5, 2003, (notification 20165460) the GT tripped one minute after starting. PSEG determined that the trip was caused by an erroneous control system signal. No corrective maintenance was performed on the GT to return it to service. The GT was run again and declared available 22 hours later.

On July 16, 2004, (notification 20198799) the GT tripped and subsequently tripped several times during troubleshooting. PSEG determined that the cause of the trips was intermittent control circuit failures due to aging, heat, or voltage fatigue. The associated July 16 corrective action evaluation stated that some new parts were not available and some repairs were challenging. Corrective actions prescribed replacement and upgrade of the control system. The GT was unavailable for approximately 368 hours.

On November 5, 2004, (notification 20210679) the GT tripped due to a generator fault signal from the control system. PSEG determined that the trip signal was erroneous and again due to an aging and obsolete control system. Corrective actions included reinstating two preventive maintenance tasks that involved cleaning electrical components in the control system, and replacing the control system. The GT was reset, restarted 30 minutes later, and declared available.

The inspector also noted an additional failure On February 3, 2004, (notification 20176274). The GT tripped due to a high vibration alarm while the GT was in a standby condition. PSEG determined the cause to be an erroneous signal from the control system. Corrective maintenance was not performed, the alarm was reset, and the GT was subsequently declared available.

Analysis. Failure to take corrective actions to address repeated control system failures on the highly risk significant GT was a performance deficiency. Specifically, because of the lack of adequate corrective action the GT was unavailable for approximately 420 hours (17.5 days) during the annual period ending in November 2004. PSEG procedure NC.WM-AP.ZZ-0002, "Corrective Action Process," described in part details to be followed for continuous improvement in safety and reliability. The GT should be maintained reliable for improved plant safety. Contrary to NC.WM-AP.ZZ-0002, immediate and interim corrective actions were not adequate to prevent recurrent failures of the GT due to control system failures. Long term corrective actions were not complete. This finding has a problem identification and resolution cross cutting aspect and specifically corrective action implementation.

Traditional enforcement does not apply because the issue did not have any actual safety consequences or potential for impacting the NRC's regulatory function, and it was not the result of any willful violation of NRC requirements. This finding was more than minor because it was associated with the equipment performance attribute of the mitigating systems cornerstone. This finding affected the mitigating system cornerstone objective in that it reduced the availability and reliability of a system that responds to initiating events to prevent undesirable consequences. In accordance with IMC 609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," the inspectors conducted a Phase 1 SDP screening and determined that a Phase 2 SDP evaluation was required because the finding impacted the mitigating systems cornerstone and represented an actual loss of safety function of one or more non-technical specification trains of equipment designated as risk significant per 10CFR50.65, for greater than 24 hours.

The Phase 2 SDP, conduced using Revision 1 of the Salem Risk Informed Inspection Notebook, assumed that the GT was unavailable for 30 days. The Phase 2 analysis estimated the increase in core damage frequency in the low-E-6 range (an increased frequency of approximately one core damage accident in 600,000 years of reactor operation). This included an increase of one order of magnitude to satisfy a Table 2 note. The note indicated that the Phase 2 notebook underestimated the risk of a GT finding by one order of magnitude.

A Phase 3 risk analysis conducted by the Region I SRA determined that the finding was of very low safety significance (Green). This analysis estimated a mid-E-7 range increase in core damage frequency (an increased frequency of approximately one core damage accident in 2,000,000 years of reactor operation) using Revision 3.11 to the Salem SPAR model, assuming that the GT was unavailable for the actual 17.5 days. The dominate core damage sequence was an SBO (LOOP with subsequent failure of the EDGs and the GT), resulting reactor coolant pump seal failures, leading to core damage if offsite power or an EDG is not recovered within four hours. The SRA reviewed the Salem IPEEE for seismic and fire initiating events that could cause a LOOP, determining that the GT was not credited during a seismically induced LOOP and that for the dominant LOOP fire scenarios did not credit the GT because the fire damage would prevent getting the GT power to the safety busses.

Enforcement. The finding was not a violation of NRC requirements, in that the corrective action deficiencies involved non-safety related equipment. The corrective action deficiencies were also not attributable to maintenance rule implementation. A licensee-identified maintenance rule violation associated with the gas turbine generator is documented in Section 4OA7 of this report. Separate treatment of the maintenance rule finding and the corrective action deficiency finding is consistent practice for a Category II issue as described in NRC Inspection Procedure 71111 Attachment 12, "Maintenance Effectiveness" Appendix A, "Routine Maintenance Effectiveness Inspection Detailed Guidance." **FIN 05000272&05000311/2004005-02, Repeat Unavailability of the Gas Turbine due to Control System Faults.**

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

a. Inspection Scope (7 samples)

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 technical specification and work control requirements. The activities selected were based on plant maintenance schedules and systems that contributed to plant risk. The inspectors also referenced Regulatory Guide 1.182, "Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants," and PSEG procedure SH.OP-AP.ZZ-0027, "On-Line Risk Assessment." The following plant configurations were inspected:

- No. 11 component cooling water heat exchanger and the gas turbine generator

concurrent out-of-services on October 5, 2004;
- 12 charging pump planned maintenance on October 25, 2004;
- Emergent unavailability of the 2C emergency diesel generator on October 27, 2004;
- Concurrent emergent unavailabilities of the 11 control area chiller and the gas turbine generator 'A' engine on November 4, 2004;
- Planned unavailabilities of the 11 control area chiller and the 1A emergency diesel generator concurrent with an inoperability of the 11 component cooling water pump due to elevated vibrations on November 9, 2004;
- Unavailability of the 23 charging pump for greater than 30 days on November 18, 2004; and
- Unit 1 and Unit 2 total plant configuration from December 3 through December 16, 2004, while Salem remained in a heightened awareness due to Delaware River conditions for a tanker oil spill that occurred in the Philadelphia area on November 26, 2004.

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Salem station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the following additional inspection sample was performed. The inspectors reviewed corrective action program notifications identifying risk assessment problems to ensure they were adequately evaluated and corrected. The additional notifications reviewed were 20176343, 20186045, 20196450, 20202521, and 20204347.

b. <u>Findings</u>

No findings of significance were identified.

1R14 <u>Operator Performance During Non-routine Evolutions and Events</u> (71111.14)

a. <u>Inspection Scope (3 samples)</u>

On November 26, 2004, the oil tanker ATHOS reported a significant spill to the Delaware River in the Philadelphia area. PSEG decided on December 2, 2004, that Salem 1 and 2 would be shutdown on December 3, 2004, as a precautionary measure for potential oil impact on the plant cooling water systems. NRC inspectors maintained a continuous site coverage for the Salem and Hope Creek plants from December 3 to 16, 2004. The oil in the Delaware River did not have a significant adverse impact on Salem or Hope Creek cooling systems performance from December 3 to 31, 2004. In addition to frequently monitoring plant systems and river conditions, the inspectors observed significant portions of the following non-routine evolutions.

- On December 3, 2004, the inspectors observed control room operators shut down Unit 2 from power operations to hot standby conditions.
- On December 12, 2004, the inspectors observed control room operators perform

a Unit 2 reactor startup, achieve criticality, and stabilize power at 2% to facilitate balance of plant equipment startups.

C On December 14, 2004, the inspectors observed control room operators perform a Unit 1 reactor coolant system heatup in hot standby conditions to normal operating temperature and pressure.

Documents reviewed to verify proper operator performance are listed in the Supplemental Information Attachment to this report.

b. <u>Findings</u>

No findings of significance were identified.

1R15 <u>Operability Evaluations</u> (71111.15)

a. <u>Inspection Scope (5 samples)</u>

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

C Failure of the 11 chiller condenser recirculation pump (notification 20207002/OD 70041839) ;

C Operability of the 21 and 22 charging pumps due to leakage past the 23 charging pump discharge check valve, CV-63 (notification 20207054/order 70042001);

- 13 turbine-driven auxiliary feedwater pump oscillations (notification 20207024);
- Operability of the Unit 1 and Unit 2 emergency diesel generator (EDG) cooling water isolation valves in regards to an identified degraded condition on the 2C EDG cooling water isolation valve (23SW39) (notification 20209163/OD 70041840); and
- EDG local panel switch failures (generic to all Salem EDGs) (orders 70040713, 70041577, and 70042668).

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Salem station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the following additional inspection sample was performed. The inspectors reviewed PSEG's Business Plan Initiative CAP.02.PS.01.04., "Corrective Action Backlog Evaluation," to verify that PSEG appropriately reevaluated and reclassified corrective action notifications during their backlog reviews. The inspectors additionally reviewed corrective maintenance notification 20204481 and corrective maintenance orders 60048868, 60043231 and 60047589 to assess PSEG's progress in correcting known deficiencies that contribute towards the operability determination backlog.

b. Findings

No findings of significance were identified.

1R16 Operator Work-Arounds (71111.16)

a. Inspection Scope (2 cumulative reviews of identified operator work-arounds and 5 individual operator work-around reviews)

The inspectors reviewed five operator work-around (OWA) conditions or potential OWAs to determine if the functional capability of the system was affected or human reliability in responding to initiating events was impacted. The inspectors reviewed OWAs associated with:

- Unit 1 and 2 auxiliary building ventilation supply fan start logic (notification 20057562);
- 2A control header containment isolation valve (21CA330) failure to re-open after closure (notification 20172374);
- Component cooling (CC) flow balance upset identified during 22 CC pump inservice testing (notification 20211551);
- 12, 21 and 22 charging pump auxiliary oil pump deficiencies (notifications 20192598, 20195551, and 20202013); and
- 11 and 14 safety injection accumulator minor level changes (notifications 20200411 and 20200413).

In addition, the inspectors performed cumulative reviews of Unit 1 and Unit 2 PSEG identified operator workarounds during the week of November 21 and November 28, 2004. The inspectors assessed the potential for any cumulative impact of OWAs and operator concerns to affect the operators' ability to properly respond to a plant transient or accident. The inspectors also walked-down the Unit 1 and Unit 2 main control room panels and reviewed all tagged equipment deficiencies for potential unidentified operator workarounds. Control room operator and equipment operator turnover sheets were also reviewed for tracked equipment deficiencies. The inspectors reviewed the Salem Night Order Book to verify that guidance contrary to established written procedures was not being used.

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Salem station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the following additional inspection samples were performed. The inspectors reviewed PSEG's performance indicators for OWA and operator concerns to determine if an adverse trend exists. The inspectors also reviewed additional corrective action program notifications identifying potential OWA and operator concerns or burdens to ensure the problems were adequately evaluated and corrected. The additional notifications reviewed were 20203897, 20167817, 20195557, 20202013.

b. Findings

No findings of significance were identified.

1R19 Post Maintenance Testing (71111.19)

a. Inspection Scope (9 samples)

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

- 12 charging pump lube oil cooler cleaning on October 15, 2004;
- 13 auxiliary feedwater pump steam admission valve (MS132) maintenance on October 19, 2004;
- 2C emergency diesel generator cooling water isolation valve (23SW39) replacement on October 27, 2004;
- 23 Service water pump strainer preventative maintenance on October 28, 2004;
- 11 Control area chiller compressor preventative maintenance and overhaul on November 1, 2004;
- 26 service water traveling water screen level instrument outboard/high side bubbler replacement on November 16, 2004;
- 11 residual heat removal heat exchanger hot retorque on December 5, 2004;
- 12 component cooling water heat exchanger outlet isolation valve (1CC31) preventive maintenance and inspection on December 10, 2004; and
- 13 auxiliary feedwater pump turbine casing relief valve (1MS51) replacement on December 20, 2004.

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 documentation; (4) test instrumentation had current calibration, 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. Documents reviewed to verify post maintenance testing adequacy are listed in the Supplemental Information Attachment to this report.

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Salem station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the following additional inspection samples were performed. The inspectors reviewed notifications 20195660, 20196155, 20196574, 20196683, 20198691, 20199210, and 20199261. The notifications were initiated after July 2004 and were selected by the inspectors to assess PSEG's recent corrective action program effectiveness for post maintenance testing issues.

b. Findings

No findings of significance were identified.

1R20 Refueling and Other Outage Activities (71111.20)

a. Inspection Scope (2 samples)

On November 26, 2004, the oil tanker ATHOS reported a significant spill to the Delaware River in the Philadelphia area. PSEG decided on December 2, 2004, that Salem 1 and 2 would be shutdown on December 3, 2004, as a precautionary measure for potential oil impact on the plant cooling water systems. NRC inspectors maintained a continuous site coverage for the Salem and Hope Creek plants from December 3 to 16, 2004. The oil in the Delaware River did not have a significant adverse impact on Salem or Hope Creek cooling systems performance from December 3 to 31, 2004. In addition to frequently monitoring plant systems and river conditions, the inspectors observed portions of the shutdown and cooldown processes and monitored PSEG controls over the following Unit 1 and Unit 2 outage activities:

- 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 configurations and controls;
- Decay heat removal operability and operation;
- Reactivity controls;
- Startup and ascension to full power operation;
- Tracking of mode change and startup prerequisites;
- Walkdown of the Unit 2 primary containment to verify that debris had not been left which could block the emergency core cooling system suction strainer; and
- Problem identification and resolution related to outage activities.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope (2 samples)

The inspectors observed portions and reviewed results of the 22 residual heat removal pump inservice test on October 22, 2004, and the 13 auxiliary feedwater pump inservice test on October 27, 2004. The inspectors reviewed these surveillance tests to ensure that the selected components were capable of performing their intended functions and to assess their operational readiness. Documents reviewed to verify surveillance testing adequacy are listed in the Supplemental Information Attachment to this report.

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Salem station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the following additional inspection samples were performed. The inspectors reviewed notifications 20202234, 20203074, 20204002, 20205103, 20207272, 20207710, 20208193, 20208797, 20208913, and 20211977. The notifications were initiated after July 2004 and were selected by the inspectors to assess PSEG's recent corrective action program effectiveness for surveillance testing issues.

b. Findings

Introduction. A self-revealing finding was identified when a temporary test gauge tube ruptured from being over-pressurized and sprayed the inside of the 13 turbine-driven auxiliary feedwater (TDAFW) pump panel. This finding was of very low safety significance (Green), involved inadequate procedural adherence, and was a non-cited violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings."

Description. During performance of the 13 TDAFW pump surveillance test on October 27, 2004, tubing on a temporary test gauge used to record the pump's discharge pressure ruptured from being over-pressurized and sprayed the inside of the associated local instrument panel (Panel 207-1) with water. Several instruments, components, and switches used to operate the pump remotely and locally were sprayed with water. Operators tripped the 13 TDAFW pump and declared the pump inoperable and unavailable. Operators removed the water from the panel and wiped down equipment within the panel. Maintenance technicians opened and inspected instrument covers. Additionally, electrical components were blown down with dry instrument air. The surveillance test was re-performed and the pump was declared operable several hours later that day.

PSEG determined that maintenance technicians installed a temporary test gauge with tubing that was not rated high enough for the parameters being tested. PSEG procedure SH.MD-DG.ZZ-0007, "Maintenance Standards," section 5.4.8 stated that tubing should be selected that has a marked pressure and temperature rating that is at least 10%

greater than the job requirements. The maintenance technicians selected tubing that was rated for 240 psig. The surveillance procedure required measuring and test equipment (M&TE) with a pressure range of 0 to 3000 psig. The maintenance technicians selected the incorrect rated tubing and incorrectly assumed that the “HP” stamped on the tubing meant high pressure, it did not. PSEG initiated corrective actions which involved just-in-time training to refresh maintenance technicians on the proper use, type, and fittings for tubing.

Analysis. The performance deficiency had a human performance cross cutting aspect (personnel) and involved a failure to comply with maintenance procedure requirements. On October 27, 2004, maintenance technicians installed tubing on a test gauge that was not rated for the job requirements. The tubing ruptured and sprayed water on electrical components in the 13 TDAFW instrument panel. The 13 TDAFW pump was rendered inoperable and unavailable while operators, maintenance technicians, and engineers dried and inspected the panel components.

Traditional enforcement does not apply because the issue did not have any actual safety consequences or potential for impacting the NRC's regulatory function and was not the result of any willful violation of NRC requirements. This finding was more than minor because it was associated with the equipment performance attribute of the mitigating systems cornerstone and affected the objective to maintain the availability of mitigating systems. The inspectors determined that the finding was of very low safety significance (Green) using a Phase 1 screening in Appendix A of Inspection Manual Chapter 0609, "Determining the Significance of Reactor Inspection Findings for At-Power Situations." The finding represented a loss of safety function of a single train of auxiliary feedwater for less than the technical specification allow outage time. The finding was also not a design or qualification deficiency that resulted in a loss of function, did not result in an actual loss of safety function, and was not screened as potentially risk significant from external events.

Enforcement. 10 CFR 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings” requires, in part, that activities affecting quality shall be prescribed by documented procedures and shall be accomplished in accordance with these procedures. Contrary to the above, on October 27, 2004, PSEG maintenance technicians failed to install the appropriate rated tubing on test equipment in accordance with maintenance procedure, SH.MD-DG.ZZ-0007, “Maintenance Standards,” section 5.4.8 while performing a 13 TDAFW pump surveillance test. However, because the finding was of very low significance and has been entered into the corrective action program in notifications 20208841, 20208797, and 20210209, this finding is being treated as a non-cited violation, consistent with section VI.A of the NRC Enforcement Policy: **NCV 05000272/2004005-03, Maintenance Practices Render Auxiliary Feedwater Pump Inoperable**

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope (2 samples)

The inspectors reviewed two temporary plant modifications (TM): Installation of Dow Corning Sealant Around Auxiliary Building Floor Drains (TM 04-027 and 04-028) and Installation of a Screenless Flexitallic Gasket in Auxiliary Feed Pump Steam Supply Drain Line (TM 04-030). The inspectors verified the modifications were consistent with the design and licensing bases of the affected systems and that the performance capability of these systems were not degraded by these modifications. The inspectors also reviewed the modifications to verify applicable technical specification operability requirements were met during installation. The inspectors verified that the installation of the temporary modification was consistent with the modification documents through plant walkdowns of accessible portions of the affected equipment. The inspectors further reviewed notifications documenting problems associated with equipment affected by temporary modifications (20209659 and 20209660). The inspectors also reviewed applicable documents associated with temporary plant indications as listed in the Supplemental Information Attachment to this report.

On August 23, 2004, the NRC's Executive Director for Operations approved a deviation from the NRC's Action Matrix to provide a greater level of oversight for the Salem station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the following additional inspection samples were performed. The inspectors reviewed notifications 20197371, 20197394, 20197803, 20197822, 20198123, 20198262, 20198267, 20198268, 20195660, 20196155, 20196574, 20196683, 20198691, 20199210, and 20199261. The notifications were initiated after July 2004 and were selected by the inspectors to assess PSEG's recent corrective action program effectiveness for permanent or temporary plant modification issues.

b. Findings

Introduction. The inspectors identified a failure to properly translate temporary modification details into work order instructions which resulted in the installation of incorrect sealant around seven floor drain covers in Salem Unit 1 and Unit 2 auxiliary buildings. This finding was of very low safety significance (Green) and determined to be a non-cited violation of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings."

Description. On September 20, 2004, PSEG installed sealant around covers to close gaps on seven floor drains in Salem Unit 1 and Unit 2 auxiliary buildings (notification 20201334 from August 24, 2004). PSEG developed TM packages 04-027 and 04-028 to provide procedure and administrative controls. The seven floor drains affected were located in the inboard penetration, mechanical penetration, and electrical penetration areas. The design of the covers consisted of a steel plate that was supported by three steel tabs. This left a gap in the area where the steel plate did not contact the steel tabs.

PSEG installed covers on these seven floor drains in 1999 under design change packages (DCP) 70000440 and 70000441 to prevent steam flow propagation through floor drains to mild areas of the auxiliary building from a main steam line break (MSLB). The covers protected safety related systems, structures, and components in mild areas of the auxiliary building from being exposed to the harsh environment (higher temperature and humidity) associated with a MSLB.

The inspectors performed a walkdown of the areas described in the TM on November 2, 2004, to verify that the sealant was installed in accordance with the TM package. The inspectors observed that Dow Corning® 732 Multi Purpose Sealant - White was installed, however, the TM package required the use of Dow Corning® 732 Multi Purpose Sealant - Black. The Dow Corning® 732 Multi-Purpose Sealant is a general purpose sealant that acts as a space-filling rubber adhesive. PSEG determined that a lack of communication contributed to the incorrect sealant being placed in the work order (60048045 and 60048046) to install the TM. The TM required that Dow Corning® 732 Multi-Purpose Sealant-black be installed because it was rated for intermittent use up to 450°F versus the white sealant which was rated up to 400°F. However, this detail was not translated into work order instructions which were utilized during field installation. The inspectors also noted that engineers did not verify the correctness of installation as required by PSEG procedure NC.DE-AP.ZZ-0030, “Control of Temporary Modifications.” PSEG initiated notifications 20209660 and 20209659 to address these concerns.

On November 11, 2004, PSEG removed the sealant around the floor drains and installed the Dow Corning® 732 Multi Purpose Sealant - Black as stated in the TM packages under work order 60049542.

Analysis. The performance deficiency associated with the incorrect TM installation has a human performance personnel error cross cutting aspect. Specifically, work planners did not translate TM details into the associated work order.

Traditional enforcement does not apply because the issue did not have any actual safety consequence or potential for impacting the NRC’s regulatory function and was not the result of any willful violations of NRC requirements. The finding was more than minor because it was associated with the design control attribute of the mitigating systems cornerstone and affected the objective to maintain the reliability and availability of safety related systems, structures, and components in the auxiliary building from being exposed to a harsh environment resulting from steam propagating through the floor drains during a MSLB. The white sealant was rated for intermittent use up to 400°F, however the TM package indicated the post-steamline break temperatures could initially reach 450°F. The white sealant was not fully qualified for the environment it was utilized in, therefore the reliability of the sealant to perform its function was reduced. In accordance with IMC 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," the inspectors conducted a Phase 1 SDP Screening and determined the finding to be of very low safety significance (Green). The finding was a qualification deficiency confirmed not to result in a loss of function.

Enforcement. 10 CFR Part 50, Appendix B, Criterion V, “Instructions, Procedures, and Drawings” requires, in part, that activities affecting quality shall be prescribed by documented instructions, procedures, or drawings, of a type appropriate to the circumstances and shall be accomplished in accordance with these instructions, procedures, or drawings. Contrary to the above, on September 20, 2004, during the installation of TM packages 04-027 and 04-28, PSEG applied an incorrect sealant, which was not qualified for the expected environmental conditions during a main steam line break event, because the work instructions were not appropriate to the circumstances. Specifically, the sealant specifications contained in the TM packages were not translated into work order 60049542 which was used to install the TMs in the field. However, because the violation was of very low safety significance (Green) and has been entered into the corrective action program (notifications 20209660 and 20209659), this finding is being treated as a non-cited violation consistent with Section VI.A of the NRC Enforcement Policy: **NCV 05000272&05000311/2004005-04, Incorrect Temporary Modification Installation**

Cornerstone: Emergency Preparedness [EP]

1EP4 Emergency Action Level and Emergency Plan Changes (71114.04)

a. Inspection Scope (1 sample)

A regional in-office review was conducted of PSEG-submitted revisions to the emergency plan, implementing procedures and emergency action levels (EALs) which were received by the NRC during the period of April - December 2004. A thorough review was conducted of plan aspects related to the risk significant planning standards (RSPS), such as classifications, notifications and protective action recommendations. A cursory review was conducted for non-RSPS portions. These changes were reviewed against 10 CFR 50.47(b),"11 Emergency Plans," and the requirements of Appendix E, "Emergency Planning and Preparedness For Production and Utilization Facilities," and they are subject to future inspections to ensure that the combination of these changes continue to meet NRC regulations. The inspection was conducted in accordance with NRC Inspection Procedure 71114, Attachment 4, and the applicable requirements in 10 CFR 50.54(q) were used as reference criteria.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Public Radiation Safety [PS]

2PS2 Radioactive Material Processing and Transportation (71122.02)

a. Inspection Scope (1 sample)

The inspectors observed shipment packaging, surveying, labeling, marking, placarding, vehicle checks, emergency instructions, disposal manifest, shipping papers provided to the driver, and PSEG verification of shipment readiness. The inspectors verified that the requirements of any applicable transport cask certificate of compliance had been met and that PSEG was authorized to receive the shipment packages. The inspectors also observed radiation workers during the conduct of radioactive waste processing and radioactive material shipment preparation activities.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES [OA]

4OA1 Performance Indicator Verification (71151)

a. Inspection Scope (9 samples)

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 2003 to third quarter 2004. 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

- Drill and Exercise Performance
- Emergency Response Organization (ERO) Drill Participation
- Alert Notification System (ANS) Reliability

The inspectors reviewed documentation from drills in 2003 and 2004, ERO drill participation rosters and ANS testing results to verify the accuracy of the reported data. Data generated since the December 2003 EP PI verification was reviewed during this inspection.

4OA2 Problem Identification and Resolution (71152)

As required by Inspection Procedure 71152, "Identification and Resolution of Problems," and in order to help identify repetitive equipment failures or specific human performance issues for follow-up, the inspectors performed a daily screening of items entered into PSEG's corrective action program. This review was accomplished by reviewing hard copies of each condition report, attending daily screening meetings, or accessing PSEG's computerized database.

On August 23, 2004, the NRC’s Executive Director for Operations approved a deviation from the NRC’s Action Matrix to provide a greater level of oversight for the Salem station than would typically be called for by the Action Matrix. One provision of the deviation memorandum provided for the enhancement of existing reactor oversight process baseline inspections. In accordance with this deviation, the following additional inspection sample was performed. The inspectors reviewed PSEG’s Business Plan Initiative CAP.02.PS.04.01, “Corrective Action Program Performance Indicators,” to verify that adverse trends did not exist. The inspectors specifically reviewed Corrective Action Closure Board Acceptance Rate, Nuclear Condition Report Average Age, Evaluation Timeliness, and Self-Identification of Issues performance indicators.

1. Annual Sample Review (3 samples)

a. Inspection Scope

CMC Switches. The inspectors selected five notifications (20205463, 20205153, 20210528, 20210475, and 20210740) for detailed review. The issues identified in these notifications were associated with a specific control switch type (also known as CMC switches) and involved degradations or failures at emergency diesel generator (EDG) local control panels. This issue was selected for review because several risk significant components utilize CMC switches at local control panels. The notifications were reviewed 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 interviewed plant personnel involved in corrective action development.

Service Water Valve, 1SW26. The inspectors reviewed notifications and condition reports associated with a service water butterfly valve 1SW26 found out of configuration which subsequently caused a condition prohibited by technical specification 3.6.1.1, “Containment Integrity.” This issue and its enforcement aspects were described in NRC Inspection Report 05000272/2004004 and 05000311/2004004 section 4OA5.3 dated November 9, 2004. This issue was selected for review to ascertain PSEG corrective actions related to a non-cited violation and issues generic to valve maintenance. The inspectors interviewed plant personnel involved in corrective action development and verified satisfactory completion of several corrective actions. The inspectors evaluated PSEG's actions against the requirements of PSEG's corrective action program as delineated in procedure NC.WM-AP.ZZ-0002, "Corrective Action Process," and 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action."

Unit 1 July 29, 2003, Partial Loss of Offsite Power. The inspectors reviewed PSEG evaluation 70032799 to ensure that corrective actions for an issue involving a partial loss of offsite power to Unit 1 on July 29, 2003 were appropriate. This issue was selected for review to examine PSEG corrective actions for issues identified through a NRC special team inspection (NRC Inspection Report 05000272/2003008 and 05000311/2003008 dated January 30, 2004). The event was also the subject of Licensee Event Report (LER) 2003-002-00, dated September 24, 2003. The special inspection team concluded that the root cause analysis was acceptable. However, the team also identified design control weaknesses and inconsistent application of the Salem corrective action program. During the current review, the inspectors once again reviewed the event evaluation performed by PSEG, including the apparent and root cause evaluation and verified that the corrective actions were commensurate with the significance of the issue, reasonable, adequately supported by PSEG's analyses, and correctly implemented. The inspectors also reviewed PSEG's actions regarding extent of condition, generic implications, timeliness of corrective action, actions to prevent recurrence, and identification of the root and contributing causes of the problem. Applicable records, including maintenance and test activities were reviewed, as necessary.

b. Findings and Observations

CMC Switches. There were no findings identified with this issue and the reviewed notifications. The CMC switch failures had not resulted in equipment being unable to perform its safety function. However, the inspectors noted weaknesses with PSEG's initial evaluation of the issue. Specifically, the initial extent of condition review performed by PSEG did not contain detailed inspection criteria to adequately identify all degraded CMC switches. After a subsequent CMC switch failure on the 1A EDG and also after the completion of the initial extent of condition review, a second more detailed extent of condition review was performed. PSEG identified additional degraded conditions with the enhanced criteria provided by engineers. The inspectors verified that an adequate root cause analysis was performed and corrective actions were appropriate and properly prioritized relative to the identified problem. The inspectors concluded that no significant findings or violations of regulatory requirements occurred.

Service water valve, 1SW26. There were no new findings associated with this issue and the notifications reviewed. However, the inspector observed that a corrective action to revise procedure SH.MD-GP.ZZ-0242, "Limitorque Valve Actuator Removal and Installation," was not yet completed and appropriate interim compensatory measure were not in place. A compensatory measure such as an administrative procedural hold, would have precluded the procedure to be used with the deficiencies. The procedure revision was to proceduralize the use of match marking techniques to positively identify the valvedisc position. The inspectors also noted that PSEG's extent of condition review did not include ball valve applications. PSEG initiated a corrective action to proceduralize match marking techniques in all ball valve procedures. The inspectors verified that an adequate root cause analysis was performed and corrective actions were appropriate and executed in a timely manner relative to the identified problem. The inspectors concluded that no significant findings or violations of regulatory requirements occurred.

Unit 1 July 29, 2003, Partial Loss of Offsite Power. The inspectors' review of the order and related documentation concluded that PSEG conducted an appropriate investigation of the event and its causes and that resolution of the issues and corrective actions were reasonable. However, the inspectors also concluded that some design control and corrective action program weakness identified by the special team persisted. For instance, the revision of two calculations was delayed pending a modification of the circulating water system power source system, but no reference had been made in the document support system to ensure that interim evaluations would be used in lieu of the outdated calculations. Also, a plan and procedure had been prepared to address extent of condition reviews, however, the actual review of selected calculations had not begun. Additionally, in the past, required calculation revisions were being banked rather than implemented. In some cases, the accumulated revisions over several years exceeded twenty. A recent procedure changed this policy, but a backlog still existed. The inspector noted that PSEG was addressing the backlog issue. Finally, corrective actions associated with notifications were sometimes transferred to other implementing methods. Although tracking mechanisms existed to ensure completion, the actions could be delayed beyond the original schedule. The inspectors concluded that no significant findings or violations of regulatory requirements occurred.

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

a. Inspection Scope

The inspectors evaluated problem identification and resolution trending for an issue pertaining to repetitive failures of control air tubing supplying control air to various air operated valves. The inspectors reviewed component health reports, interviewed component and design engineers, and reviewed corrective actions associated with the individual component failures. Documents reviewed by the inspectors are listed in the Supplemental Information Attachment to this report.

b. Findings and Observations

No findings of significance were identified.

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

Section 1R12 describes a finding for failure to correct biological fouling on the 26 service water trash rack. Excessive biological fouling was identified on August 2, 2004, during a diver inspection, but the issue was not entered into the corrective action program for resolution. The 26 SW pump cavitated on September 22, 2004, as the excessive trash rack fouling continued. This finding had a problem identification and resolution cross-cutting aspect specifically with identification.

Section 1R12 also describes a finding where long-standing reliability problems with the gas turbine generator control system were identified, but corrective actions were not effectively implemented. Several gas turbine generator trips recurred as a result of control system problems. This finding had a problem identification and resolution cross-cutting action specifically with corrective actions.

4OA3 Event Followup (71153 - 3 samples)

1. (Closed) LER 05000272/2004001-00 & 01, As Found Value for Main Steam Safety Valve Lift Setpoint Exceeds Technical Specification Allowable Limit

On April 9, 2004, during a refueling outage, PSEG discovered that a main steam system safety valve (MSSV) failed its as-found lift setpoint test. The Technical Specification Table 3.7-1 required actuation pressure was 1110 psig +/- 3%. The as-found lift setpoint was 1076 psig, or -3.1% of the setpoint. The failed MSSV was replaced with a pre-tested and certified spare. This LER and its supplement were reviewed by the inspectors. The inspectors verified that there were no current operability concerns with installed main steam safety valves. The inspectors reviewed PSEG's apparent cause evaluation associated with corrective action notification 20185263. The out of specification as-found lift setpoint constitutes a technical specification violation of minor significance that is not subject to enforcement action in accordance with Section IV of the NRC's Enforcement Policy. This LER is closed.

2. (Closed) LER 05000272/2004006-00, Operation in a Condition Prohibited by Technical Specification - Containment Isolation Valves

On September 15, 2004, during quarterly inservice testing of the 11 containment fan coil unit (CFCU) service water (SW) inlet valve, 11SW58, the valve failed to indicate closed as expected and exceeded its required action stroke time value. In accordance with plant procedures, 11SW58 was declared inoperable at 9:17 p.m. on September 15, 2004, and Technical Specification 3.6.3.1, "Containment Isolation Valves," was entered. After stroking the valve a number of times, control room operators declared 11SW58 operable and Technical Specification 3.6.3.1 was exited at 10:41 p.m. on September 15, 2004. On September 17 inservice test engineers determined that actions taken on September 15, 2004, were inappropriate such that 11SW58 should still be considered inoperable and Unit 1 was not in compliance with technical specifications. Further PSEG investigation determined that the 11SW58 upper bearing seal had failed and allowed service water to enter the valve bearing. The upper valve bearing was damaged. This finding is more than minor because the valve's reduced reliability and availability affected the structures, systems, and component and barrier performance attribute of the Barrier Integrity cornerstone. This finding was of very low safety significance (Green) because the finding did not represent a degradation of the radiological barrier function provided for the control room, auxiliary building, or spent fuel pool, did not represent a degradation of the barrier function of the control room against smoke or a toxic atmosphere, and did not represent an actual open pathway in the physical integrity of reactor containment, or involve an actual reduction in the defense-in-depth for the atmospheric pressure control or hydrogen control functions of the reactor containment. 11SW58 remained intact, but was inoperable for an internal mechanical condition that affected its ability to stroke closed. This licensee-identified finding involved a violation of Technical Specification 3.6.3.1. The enforcement aspects of this issue are described in Section 4OA7 of this inspection report. The inspectors did not identify any additional issues in this LER. This LER is closed.

3. (Closed) LER 05000311/2004008-00, Unplanned Reactor Trip Due to Main Generator Exciter Brush Failure

a. Inspection Scope

On September 9, 2004, Salem Unit 2 automatically tripped from 100% power due to a turbine trip associated with a generator protection trip. Plant response to the automatic reactor trip was normal. This event was also described in NRC Inspection Report 05000272/2004004 and 05000311/2004004, Section 4OA3.8. This LER was reviewed by the inspectors. The inspectors also reviewed PSEG's associated root cause evaluation 70041281 and interviewed root cause evaluators.

b. Findings

Introduction. A Green self-revealing finding was identified on September 9, 2004, when the Salem Unit 2 reactor automatically tripped from a turbine trip. PSEG failed to incorporate frequent vendor recommended inspections of the Salem Unit 2 exciter brushes and a brush failure resulted in a turbine trip from generator differential and loss of field trip signals. Because the equipment involved was not safety related there was no violation of regulatory requirements, however, the Initiating Events Cornerstone objectives were impacted.

Description. On September 9, 2004, at 1:06 a.m., Salem Unit 2 reactor tripped as designed from an unplanned turbine trip. All control rods fully inserted and all safety related systems were available and functioned as designed. The turbine trip was due to a generated on generator differential and loss of field trip signals.

In followup troubleshooting efforts to the event, PSEG engineers identified that an alterrex exciter's brush assembly had failed. PSEG engineers determined that the brushes were severely worn and degraded to a point that severe arcing occurred. Arching caused a gap between the brush and collector ring which resulted in a loss of generator field.

PSEG initiated root cause evaluation 70041281 to investigate the root cause and contributing causes, and to develop subsequent corrective actions. Two root causes were determined: vendor recommended daily operator inspections and weekly maintenance inspections were not implemented when the generator was installed in 1986, and lessons learned from a Hope Creek alterrex brush failure in 1993 were not similarly applied to Salem. The root cause evaluation further stated that flashover is a progressive condition and it is necessary to recognize and heed the early warning signals during routine maintenance to prevent serious trouble.

Analysis. The performance deficiency associated with this finding was a failure to incorporate vendor recommended daily and weekly inspections of the alterrex brushes and rigging. This issue was more than minor because it was associated with the equipment performance attribute and it affected the Initiating Events Cornerstone objective. In accordance with IMC 0609, Appendix A, "Significance Determination of Reactor Inspection findings for At-Power situations," the inspectors conducted a Phase 1 SDP screening and determined the finding to be of very low safety significance (Green). The finding screened to Green because the issue did not involve a loss-of-coolant accident or external event initiator, and mitigation equipment was also not involved.

Enforcement. The performance deficiency did not constitute a failure to meet a regulatory requirement. The alterrex is not a safety related component and thus did not fall under the purview of 10 CFR 50, Appendix B, "Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants." No violation of regulatory requirements occurred. This LER is closed. **FIN 05000311/2004005-05, Salem Unit 2 Automatic Reactor Trip on September 9, 2004**

4OA4 Cross Cutting Aspects of Findings

Section 1R22 describes a finding with inadequate procedural adherence that resulted in unavailability of the 13 turbine-driven auxiliary feedwater pump. This maintenance technicians' error had a human performance personnel error cross cutting aspect.

Section 1R23 describes a finding where work planners did not translate temporary modification details into a work order that resulted in the wrong sealant being applied. The sealant closed gaps to floor drain covers that were installed to provide a barrier between harsh and mild environment areas of the Salem auxiliary buildings. The wrong sealant was not appropriately rated. This work planners' error had a human performance personnel error cross cutting aspect.

4OA5 Other

1. Review of Cask Storage Construction and Other Modifications For Independent Spent Fuel Storage Installation (ISFSI)

a. Inspection Scope (IP 60853)

The inspectors reviewed design calculations associated with the installation of sub-surface elements under construction that will support the ISFSI storage pad. The evaluation consisted of interviews with cognizant personnel, review of contractor reports and design documents, and field inspections of construction activities.

b. Observations

Prior to the onsite inspection, the inspector reviewed the following ISFSI-related design calculations and drawings:

- Engineering Change Package No: 80057739, “ISFSI Pad Design”, Rev. 1, October 27, 2004;
- Calculation No. A-5-DCS-CDC-1960, “ISFSI Pad Design”, Rev. 01R1, October 5, 2004;
- Calculation No. A-5-DCS-CDC-1964, “Soil Structure Interaction and Time History Calculation”, Rev. 01R1, October 6, 2004;
- Calculation No. A-5-DCS-CDC-1978, “Soil Parameters for ISFSI Pad Area”, Rev. 01R2, October 28, 2004; and
- Drawings: PSEG 700005 A-B, 700006 A-A, 700009 A-A; and Raito Drawing 04-201-1001, dated August 10, 2004.

These documents are associated with the installation of the sub-surface elements required for soil stabilization purposes. The purpose of the soil stabilization is to improve the load sustaining capacity of the sub-surface soil to support the construction of the ISFSI reinforced concrete pads. The ISFSI storage pads are designed to accommodate the storage of approximately 200 spent fuel storage casks. As part of the pre-inspection document reviews the inspectors contacted PSEG project personnel, and cognizant contractor representatives from Sargent and Lundy and HOLTEC, among others, to discuss specific details relating to design documentation.

The inspectors observed drilling, mixing, grouting, and boring of core samples and field testing of samples of stabilized soil. The inspectors discussed design specifications with cognizant personnel in the field and the basis for various design parameters. Contractor personnel were knowledgeable of their respective responsibilities and pertinent material and design specifications associated with the ISFSI project.

The inspectors noted that Project Design Specification A-5-DCS-CDS-0410, Revision 1, dated October 15, 2004, has a requirement to randomly select the location from which a core sample is obtained from the elements for testing purposes. The inspectors noted that the selection of the location of soil elements was based on engineering selection, however the core locations within the element were pre-selected and not randomly based. PSEG personnel stated that they would revise the methodology to ensure the random selection of core sample locations within the tested elements.

A total of 1,387 soil-column elements will be constructed as part of the soil stabilization project. This total consists of 703 elements 45 feet long and 684 elements 22 feet long. Approximately 15% of the 45-foot long elements will be core sampled for field and laboratory testing purposes. As of early November 2004, a total of six (6) core samples had been obtained. Preliminary test results made on these samples were available for review. Based on this very limited and preliminary data, the inspectors noted that the 28-day compression test data results indicate soil element average minimum strength considerably greater (in the range of 500 to 700 psi) than design estimates (in the range of 125 to 150 psi). It was also postulated by inference that the 80-day test results will also exceed design estimates based on the design mix currently used. These results, together with other test data results, will be utilized to determine the effective modulus of elasticity of subgrade soil. The modulus of elasticity is a measure of the degree of settlement experienced by the sub-surface soil based on the pressure exerted by the ISFSI pad and the Dry Cask Storage System (DCSS) components.

NUREG/CR-6608 provides a summary and evaluation of low-velocity impact tests of dry casks onto concrete pads. DCSS vendors have, in general, followed the guidance provided in this NUREG when evaluating the effect of a cask-drop accident onto a reinforced concrete pad. During DCSS handling, an accident is postulated whereby a cask is assumed to undergo a non-mechanistic tip-over event, impacting the ISFSI pad with deceleration experienced by the cask. In the tip-over and the end-drop analysis, the cask surface and the elasto-plastic damage characteristics of the concrete pad and the drop height determine this deceleration. To satisfy this deceleration limit, cask vendors typically require (prior to ISFSI concrete pad installation) that the maximum upper limit of the site-specific effective modulus of elasticity of subgrade soil be determined. One of the proposed vendors (Holtec) for this site requires the effective modulus of elasticity of subgrade soil (Table 2.2.9 of HOLTEC, HI-STORM FSAR Report HI-2002444 Rev. 1) not to exceed 28,000 psi. The impactive and impulsive loads of these events must be less than those calculated by the dynamic models used in the structural qualifications of a given cask design. The independent laboratory test results, along with other test data, are utilized to determine the effective modulus of elasticity of subgrade soil.

Even though very limited data is available at this time, the inspector discussed with PSEG personnel and a HOLTEC personnel the importance of ensuring that soil element strengths are compatible with the license basis of the selected DCSS vendor. PSEG personnel acknowledged that they were cognizant of the situation and would monitor test results as more data became available.

Project Design Specification A-5-DCS-CDS-0410, Revision 1, dated October 15, 2004, requires that independent testing of core samples be performed for the 45-foot long soil elements. Based on review of the primary contractor and the sub-contractor organizations the inspector emphasized the importance with PSEG personnel of ensuring that sufficient independence existed between the primary contractor and the sub-contractor responsible for sample analysis, testing and reporting of test results. PSEG personnel stated that their quality assurance group would assess the situation to ensure that an adequate degree of independency existed to meet the intent of the design specifications.

c. <u>Conclusions</u>

Appropriate engineering and construction activities associated with the stabilization of the in-situ sub-surface soil to support the construction of the Hope Creek/Salem ISFSI installation are in progress. Field installation activities were adequately controlled and monitored in accordance with procedural requirements to ensure compliance with design specifications.

II. Review of Safety Conscious Work Environment Improvement Plans and Performance Indicators

A group of NRC regional and headquarters based personnel reviewed Safety Conscious Work Environment improvement plans and performance indicators from November 15, 2004 through November 18, 2004. This on-site review was provided to support enhanced NRC oversight of work environment issues specified in the August 23, 2004, reactor oversight process deviation memorandum for Salem and Hope Creek work environment issues.

3. (Closed) URI 05000272, 311/2004004-03, Service Water Desilting Practices

This unresolved item was opened to review PSEG's operability evaluation for a condition regarding the 15 service water (SW) pump. An excessive silt level measurement was recorded for the 15 SW bay on June 15, 2004. PSEG entered this issue into the corrective action program as notifications 20202848 and 20202849. The inspectors reviewed the operability evaluation and determined that the 15 SW pump had operated almost continuously and without issue for the period of concern. The inspectors concluded that no findings of significance existed. This item is closed.

4. (Closed) URI 05000272/2004004-04: 1CV52 Back Leakage

This unresolved item was opened to review PSEG's evaluation of surveillance testing methodology for the 11, 12 and 13 charging pump discharge check valves. This issue was entered into PSEG's corrective action program as notifications 20192278 and 20193182. The inspectors reviewed PSEG's analysis of the impact of the check valve back leakage on the operability of adjacent charging pumps and their ability to function during design basis accidents. The inspectors also reviewed documents justifying characterization and placement of the valve in the In-Service Testing Program. Documents reviewed by the inspectors are listed in the Supplemental Information Attachment to this report. The inspectors concluded that no findings of significance existed. This item is closed.

4OA6 Meetings, Including Exit

EDO Site Visit. On October 26, 2004, a site visit was conducted by Mr. Luis Reyes, Executive Director of Operations for the NRC. During Mr. Reyes' visit, he toured the Salem and Hope Creek plants, and met with PSEG managers.

Public Meeting - SCWE. On December 2, 2004, the NRC conducted a meeting with PSEG to review PSEG's actions to improve performance in the areas of safety conscious work environment, problem identification and resolution, procedure adherence, quality of engineering products, and role and function of quality assurance. These areas were identified in NRC's July 30, 2004, letter regarding work environment at Salem and Hope Creek (ML042120284) and in the NRC's August 30,2004, letter that transmitted the mid-cycle assessments of performance at Salem and Hope Creek (ML042440233 and 042440244). The meeting occurred in New Castle, Delaware at the Bridgeview Inn and was open for public observation. A copy of slide presentations can be found in ADAMS under accession numbers ML043480237 and ML043480232.

Exit Meeting. On January 7, 2005, the resident inspectors presented the inspection results to Mr. Mike Brothers and other members of his staff who acknowledged the findings. The inspectors confirmed that proprietary information was not provided or examined during the inspection.

4OA7 Licensee-Identified Violations

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

C Technical Specification (TS) 3.6.3.1 requires that an inoperable containment isolation valve be restored to operable or the affected penetration isolated within four hours by a deactivated automatic valve or a manual valve or flange. Contrary to this requirement, the 11SW58, a containment isolation valve was inoperable and the affected penetration not isolated from September 15, 2004, at 10:41 p.m. to September 17, 2004, at 12:50 p.m. This issue was identified in PSEG's corrective action program as notification 20204060. This issue was more than minor because the valve's reduced reliability and availability affected the structures, systems, and component barrier performance attribute of the barrier integrity cornerstone. 11SW58 is an 11 CFCU SW isolation valve. Traditional enforcement does not apply because the issue did not have any actual safety consequence or potential for impacting the NRC's regulatory function and was not the result of any willful violations of NRC requirements. In accordance with IMC 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," the inspectors conducted a Phase 1 SDP Screening and determined the finding to be of very low safety significance (Green). This finding screened to Green because the issue did not represent a degradation of the radiological barrier function provided for the control room, auxiliary building, or spent fuel pool, did not represent a degradation of the barrier function of the control room against smoke or a toxic atmosphere, and did not represent an actual open pathway in the physical integrity of reactor containment, or involve an actual reduction in the defense-in-depth for the atmospheric pressure control or hydrogen control functions of the reactor containment. 11SW58 remained intact, but was inoperable for an internal mechanical condition that affected its ability to stroke closed. This issue is also described in Section 4OA3.1 of this inspection report and LER 05000272/2004001-01.

- Technical Specification 6.2.2.d, "Organization - Facility Staff" requires that controls shall be included in approved administrative procedures such that overtime shall be reviewed monthly by the plant manager, or his designee, to make sure that excessive hours have not been assigned. Contrary to this requirement and prior to March 2004, administrative procedures did not control this requirement and the Salem plant manager or his designee did not perform this monthly review. This issue was identified in PSEG's corrective action program as notification 20180520. This issue was determined to be more than minor and was similar to more than minor example 2.h in Appendix E, "Examples of Minor Issues" to NRC Inspection Manual Chapter 0612, "Power Reactor Inspection Reports." Traditional enforcement does not apply because the issue did not have any actual safety consequence or potential for impacting the NRC's regulatory function and was not the result of any willful violations of NRC requirements. Because this finding was not appropriately evaluated by the SDP, NRC management reviewed the issue and determined the finding to be of very low safety significance (Green). The inspectors did not identify any significant fatigue related human performance errors.

- 10 CFR 50.65 paragraph (a)(1) requires, in part, that licensees shall monitor the performance of systems against licensee established goals in a manner sufficient to provide reasonable assurance that such systems are capable of performing their intended function. Contrary to the above, the gas turbine (GT) generator was being monitored in (a)(1) since March 2003, without goals sufficient to provide reasonable assurance the GT was capable of performing its intended function. PSEG did not establish reliability goals yet reliability was an issue with the GT generator in September 2004. This finding was more than minor because it was associated with the equipment performance attribute of the mitigating systems cornerstone. This finding affected the mitigating system cornerstone objective in that it reduced the availability and reliability of a system that responds to initiating events to prevent undesirable consequences. Traditional enforcement does not apply because the issue did not have any actual safety consequence or potential for impacting the NRC's regulatory function and was not the result of any willful violations of NRC requirements. The inspectors determined that the finding was of very low safety significance (Green) using a phase 1 analysis in Appendix A of Inspection Manual Chapter 0609, "Determining the Significance of Reactor Inspection Findings for At-Power Situations", because the finding was not a design or qualification deficiency, did not represent a loss of system safety function, did not represent an actual loss of safety function of one or more non-Tech Spec Trains of equipment designated as risk-significant per 10 CFR 50.65 for greater than 24 hours, and did not screen as potentially risk significant due to external events. PSEG documented this deficiency in notification 20203878.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee personnel:
C. Banner, EP Supervisor
M. Brothers, Site Vice President
D. Boyle, Maintenance Rule Coordinator
D. Burgin, EP Manager
W. Campbell, Maintenance Manager
M. Conroy, Maintenance Rule Program Manager
S. Davies, Component Engineer
C. Fricker, Plant Manager
G. Gardner, System Engineer
R. Gary, Radiation Protection Manager
J. Gomeringer, Shipping Supervisor
M. Gwirtz, Acting-Operations Manager
M. Kafantaris, Salem Operations Training Supervisor
A. Khanpour, Systems Engineering Manager
J. Morrison, Reliability Engineer
D. Naik, System Engineer

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened/Closed

05000311/2004005-01	NCV	Trash Rack Biological fouling Failing Renders 26 SW Pump Inoperable (Section 1R12)
05000272&311/2004005-02	FIN	Repeat Unavailability of the Gas Turbine due to Control System Faults (Section 1R12)
05000272/2004005-03	NCV	Maintenance Practices Render Auxiliary Feedwater Pump Inoperable (Section 1R22)
05000272&311/2004-005-04	NCV	Incorrect Temporary Modification Installation (Section 1R23)
05000311/2004005-05	FIN	Salem Unit 2 Automatic Reactor Trip on September 9, 2004 (Section 4OA3.3)
05000272/2004001-00	LER	As Found Value for Main Steam Safety Valve Lift Setpoint Exceeds Technical Specification Allowable Limit (Section 4OA3.1)

05000272/2004001-01	LER	As Found Value for Main Steam Safety Valve Lift Setpoint Exceeds Technical Specification Allowable Limit (Section 4OA3.1)
05000272/2004006-00	LER	Operation in a Condition Prohibited by Technical Specification - Containment Isolation Valves (Section 4OA3.2)
05000311/2004008-00	LER	Unplanned Reactor Trip Due to Main Generator Exciter Brush Failure (Section 4OA3.3)

<u>Closed</u>

05000272&311/2004004-03	URI	Service Water Desilting Practices (Section 4OA5.3)
05000272/2004004-04	URI	1CV52 Back Leakage (Section 4OA5.4)

LIST OF DOCUMENTS REVIEWED

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

<u>Section 1R01 documents reviewed</u>:
SC.OP-AB.ZZ-0001, “Adverse Environmental Conditions”
SC.OP-PT.ZZ-0002, “Station Preparation for Seasonal Conditions”
SH.OP-DG.ZZ-0011, “Station Seasonal Readiness Guide”
SC.OP-AB.ZZ-0003, “Component Fouling”
SH.OP-AP.ZZ-00084, “Conduct of Infrequently Performed Tests or Evolutions”
Salem Station ATHOS Oil Spill Startup Criteria Evaluation, S-C-ZZ-MEE-1900 Dated 12/9/2004
Condition reports: 70029296
Notifications: 20129538, 20129203, 20129431, 20215787, 20215231
SC.OP-PM.CW-001, "Cleaning Condenser Water Boxes"

<u>Section 1R04 documents reviewed</u>:
1B Diesel Generator Operation (S1.OP-SO.DG-0002)
1C Diesel Generator Operation (S1.OP-SO.DG-0003)
2A Diesel Generator Operation (S2.OP-SO.DG-0001)
2B Diesel Generator Operation (S2.OP-SO.DG-0002)
Loss of RHR (S1.OP-AB.RHR-0001)
Loss of RHR (S2.OP-AB.RHR-0001)
Loss of All Service Water (S1.OP-AB.SW-0005)
Loss of All Service Water (S2.OP-AB.SW-0005)
Spent Fuel Pool Emergency Fill (S1.OP-SO.SF-0006)
Spent Fuel Pool Emergency Fill (S2.OP-SO.SF-0006)
Drawings 203002 and 205249
WCD 4137946

Section 1R05 documents reviewed:
Salem - Unit 1, (Unit 2) - Pre-Fire Plan FRS-II-432, "Spent Fuel/Component Cooling Heat Exchanger & Pump Area, Elevation 84'"
Salem - Unit 1, (Unit 2) - Pre-Fire Plan FRS-III-211, "U-1 (U-2) Turbine Generator & Service Bldg. Areas, Elevation 88'"
Salem - Unit 1, (Unit 2) - Pre-Fire Plan FRS-III-221, "U-1 (U-2) Turbine Generator Area, Elevation 100'"
Salem - Unit 1, (Unit 2) - Pre-Fire Plan FRS-III-231, "Turbine Generating Area, Elevation 120'"
Salem - Unit 1, (Unit 2) - Pre-Fire Plan FRS-II-411, "Reactor Plant Auxiliary Equipment Area Elevations 45' & 55'"

Section 1R06 documents reviewed:
Salem Updated Final Safety Analysis Report, Section 3.4 Flood Protection Design
Salem Updated Final Safety Analysis Report, Section 3.6 Protection Against Dynamic Effects Associated with the Postulated Rupture of Piping.
Salem Generating Station Probabilistic Risk Assessment
P&ID - No.1 Unit Floor Drains - Contaminated (205226)
P&ID - No.2 Unit Floor Drains - Contaminated (205326)
Internal Flooding of Power Plant Buildings - INPO-SOER 85-05 Recommendation 1 and 2 (S-C-A900-MEE-0158-0)
Adverse Environmental Conditions (SC.OP-AB.ZZ-0001)
Severe Weather Guide (NC.OP-DG.ZZ-0002)
Flooding (S2.OP-AB.ZZ-0002)
Notifications: 20206158, 20210736, 20211977, 20211004, 20050752, 20202390
Orders: 30098149, 30102535, 70035516, 70035867, 70041830

Section 1R07 documents reviewed:
Primary Plant Logs (S1.OP-DL.ZZ-0006) dated October 11, 2004
S1.OP.PT.SW-0004, "Service Water Fouling Monitoring Safety Injection and Charging Pumps"
S2.OP.PT.SW-0004, "Service Water Fouling Monitoring Safety Injection and Charging Pumps"
S2.OP-SO.CVC-0002, "Charging Pump Operations"
workorders: 30102701,30101529,30100533,30099506,30099405

Section 1R11 documents reviewed:
Scenario Guide -0482, Failure of 2 Governor Valves, Loss of 3 Station Power Transformer and 2A Vital Bus, and Inadvertent Safety Injection
Turbine Generator Startup Operations (S2.OP-SO.TURB-0001)
Circulating Water System Malfunctions (S2.OP-AB.CW-0001)
Partial Loss of Offsite Power (S2.OP-AB.LOOP-0003)
Loss of 2A VItal Bus (S2.OP-AB.4KV-0001)
Reactor Trip or Safety Injection (S2-EOP.TRIP-1)
Post Safety Injection - System Restoration (S2.OP-SO.SJ-0004)

Section 1R12 documents reviewed:
SC.MD-GP.SW-0001, REV. 8, "Service Water Silt Survey"
SC.MD-GP.SW-0001, REV. 9, "Service Water Silt Survey"

SH.OP-AP.ZZ-0110, Unit 1 Control Room Narrative Logs, dated September 22-25, 2004.
Service Water System Health Report, 3rd Quarter, 2004.
Salem Unit 3 Gas Turbine System Health Report, 3rd Quarter, 2004.
S3 Gas Turbine Reliability and Unavailability data from PSEG intranet.
work orders: 30106230, 30111375, 60015370, 30104961, 30109337, 80074826
notifications: 20204551, 20208580, 20205728, 20204551, 20215688, 20212115, 20197057, 20193230, 20198471, 20197925, 20210679, 20175905, 20165460, 20175905, 20176274, 20197515, 20194673, 20163106, 20162211, 20210782, 20170956, 20177215, 20206543, 20171576, 20179926, 20182954, 20185127, 20186990, 20203878, 20163215, 20162211, 20163106, 20194673, 20176312, 20169120
condition reports: 70042106, 70042587, 70040533, 70036692, 70036598, 70034193, 70035429
Unit 2 control room logs dated 9/22/2004, 9/25/2004, 9/26/2004, 9/27/2004
SE.MR.SA.02, "Salem Station System Function Level Maintenance Rule vs Risk Reference"
Technical Issues Fact Sheet: "Salem 3, Tripped 3 times, 86GER on Start-up"
Salem Expert Panel Meeting Minutes dated 6/25/1998 and 9/15/2004.

Section 1R14 documents reviewed:
S2.OP-IO.ZZ-0004, Power Operations
S2.OP-IO.ZZ-0005, Minimum Load to Hot Standby
S2.OP-IO.ZZ-0003, Hot Standby to Minimum Load
S1.OP-IO.ZZ-0002, Cold Shutdown to Hot Standby

Section 1R15 documents reviewed:
Salem Inservice Testing Program Basis Data Sheets - Valves
S1.OP-ST.CVC-0005, "Inservice Testing - 13 Charging Pump"
S-C-CVC-MDC-2016, High Head Safety Injection Pump Minimum Differential Pressure
notifications: 20207098, 20207054
condition report: 70042001

Section 1R16 documents reviewed:
Operator Burden Program (SH.OP-AP.ZZ-0030)
Notifications: 20129620, 20204052, 20183330, 20132979, 20202920, 20129620

Section 1R19 documents reviewed:
Station Post Maintenance Testing (NC.NA-AP.ZZ-0050)
Maintenance Testing Program Matrix (NC.NA-TS.ZZ-0050)
Work Management/Work Control (NC.WM-AP.ZZ-0003)
Post Maintenance Leakage Testing (SC.MD-GP.ZZ-0192)
Leakage Monitoring and Reduction Program (SC.RA-AP.ZZ-0051)
System Pressure at Normal Operating Pressure and Temperature (SH.MD-GP.ZZ-0240)
Pressure Relief Device Removal and Installation (SH.MD-CM.ZZ-0031)
Inservice Testing - 12 Charging Pump (S1.OP-ST.CVC-0004)
Inservice Testing - 13 Auxiliary Feedwater Pump (S1.OP.ST.AF-0003)
Inservice Testing - Component Cooling Valves (S1.OP-ST.CC-0004), dated 12/10/04
Inservice Testing - Component Cooling Valves Acceptance Criteria (S1.RA-ST.CC-0004), Rev. 4
IST - Remote Position Verification - Aux Bldg (S1.OP-ST.RPI-0001), dated 12/10/04

2C Diesel Generator Surveillance Test (S2.OP-ST.DG-0003), dated 10/27/04
P&ID - Salem Unit 1 & 2 - Service Water Intake External Tubing
Vendor technical document 306208, “Installation, Operating & Maintenance Manual” for service water strainers
SC.MD-PM.SW-0003, “Service Water Auto Strainer Adjustment, Inspection, Repair, and Replacement”
SH.MD-EU.ZZ-0002, “Coupling Alignment”
SH.MD-GP.ZZ-0022, “Bolt Torquing and Bolt Sequencing Guidelines”
Vendor technical document 130887, “Installation, Start-up, and Service Instructions” for control room chillers
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Orders: 60028553, 60046082, 60048829, 30011305, 30011179, 60050251, 30079287, 60049026, 30104793, 60049245

Section 1R20 documents reviewed:
Cold Shutdown to Hot Standby (S2.OP-IO.ZZ-0002)
Containment Walkdown (S2.OP-PT.CAN-0001), Rev. 13
WCD 4111412, 4127134, 4142194

Section 1R22 documents reviewed:
Inservice Testing - 22 Residual Heat Removal Pump (S2.OP-ST.RHR-0002)
Inservice Testing - 22 Residual Heat Removal Pump Acceptance Criteria (S2.RA.ST.RHR-0002)
Inservice Testing - 13 Auxiliary Feedwater Pump (S1.OP-ST.AF-0003)
Inservice Testing - 13 Auxiliary Feedwater Pump Acceptance Criteria (S1.RA-ST.AF-0003)
P&ID - U2 Residual Heat Removal (205332, Sheet 1)
P&ID - U2 Residual Heat Removal (205332, Sheet 2)
Notifications: 20205885, 20207866
Order:50073656, 50075920, 50078234, 50073363, 50076309, 50077910, 50079905, 70041715

Section 1R23 documents reviewed:
Control of Temporary Modifications (NC.DE-AP.ZZ-0030)
Temporary Modification Package - Installation Dow Corning Sealant Around Auxiliary Building Floor Drains (TM# 04-027), rev. 1
Temporary Modification Package - Steam Flow Reducing Plates for Penetration Area Drains (TM# 97-025)
Temporary Modification Package - Installation of Flexitallic Gasket Without Integral Screen Upstream of Flow Orifice (TM# 04-030)
Permanent Plugging of Floor Drains (ECA 70000440)
Permanent Plugging of Floor Drains (ECA 70000441)
P&ID - No.1 Unit Floor Drains - Contaminated (205226)
P&ID - No.2 Unit Floor Drains - Contaminated (205326)
P&ID - Main, Reheat, and Turbine Bypass Steam Unit 1 (205203)
Westinghouse Steam Systems Design Manual (VTD 313308)
Design Pressure Criteria for Salem Generating Station Barriers (Calc No. S-C-ZZ-MDC-0572)
Salem Generating Station Environmental Design Criteria (Calc. No. S-C-ZZ-SDC-1419)
Loop Seal of TDAFW Pump Enclosure Drain (S-2-WD-MDC-1630)

Effect of Steam from Floor Drains on Auxiliary Building Room Temperatures (Calc No. S-C-AUX-MDC-1786)
Notifications: 20209659, 20209660
Order: 60048045

Section 2PS2 documents reviewed:
Shipping Manifests SA-04-91 and SA-04-92

Section 4OA2 Documents Reviewed:
Procedures
NC.WM-AP.ZZ-0002(Q), Rev. 9 - Corrective Action Process
SH.MD-GP.ZZ-0242(Q), Rev. 0 - Limitorque Valve Actuator Removal and Installation
Vendor Manual 303225, Jamesbury IMO-302, Installation and Operating Instructions, 16" - 60", Wafer-Sphere Butterfly Valves

Drawings
205242 - Service Water System Drawing

Notifications
20194799, 20213364 , 20192093

Orders
70032799, 70039380, 70040192, 70043044, 80067160, 50080264, 50080451, 50080676, 60040561

Calculations

ES-8.007(Q)	Transformer Tap Changer Setting Calculation, Rev. 2
ES-15.004	Load Flow and Motor Starting, Rev 2
ES-15.008(Q)	Salem Units 1 & 2 Degraded Grid Study, Rev 4
ES-15.011	Salem Nuclear Plant Undervoltage Study - PTI Report No. R7-87, Dated March 1987
ES-15.012	Salem Units 1 & 2 Fast Bus Transfer Calc., Rev. 2
S-C-4KV-EEE-1792	Assessment of Salem Bus Transfer Capability (as a result of 7/29/03 failure), Rev 0
S-C-4KV-EEE-1795	Establishment of New Lower Voltage Limits for Vital Buses at Salem Stations, Rev 1
S-C-4kV-JDC-959	Degraded Vital Bus Undervoltage Setpoint, Rev 5

Engineering Changes

80067687	Unit 2 Circ Water Switchgear Electrical Reliability Improvement Modification

Licensee Event Reports

05000272/2003-002-00	Salem Generating Station Unit 1 Reactor Trip due to Turbine Trip Caused by a 500 KV Switchyard Breaker Trip, Rev 0, Dated September 24, 2003

05000272/2004-003-01	Completion of Plant Shutdown to Comply with Technical Specifications 3.6.1.1 “Containment Integrity”

Procedures

NC.CC-AP.ZZ-0001(Q)	Design Bases/Input for Engineering Changes, Rev.4
NC.CC-AP.ZZ-0080(Q)	Engineering Change Process, Rev. 13
NC.WM-AP.ZZ-0002(Q)	Corrective Action Process, Rev. 9
S1.OP-AB.LOOP-0001(Q)	Loss of Offsite Power, Rev 16
S1.OP-DL.ZZ-0003(Q)	Control Room Log - Modes 1 - 4, Rev 42
S1.OP-SO.4KV-0009(Z)	1CW 4KV Bus Operation, Rev 14
S1.OP-SO.DG-0002(Q)	1B Diesel Generator Operation, Rev 33

Completed Procedures

S1.MD-FT.4KV-0002(Q)	ESFAS Instrumentation Monthly Functional Test - 1B 4kV Vital Bus Undervoltage, Rev 23
S1.MD-FT.4KV-0003(Q)	ESFAS Instrumentation Monthly Functional Test - 1C 4kV Vital Bus Undervoltage, Rev 24

Other

Service Water System Health Report, 3rd Quarter, 2004

Section 4OA5 Documents Reviewed:

drawing 205228 sheet 2
S1.OP-ST.CVC-0004, “Inservice Testing - 12 Charging Pump”
S1.OP-ST.CVC-0005, “Inservice Testing - 13 Charging Pump”
S1.OP-ST.SJ-0016, ”High Head Cold Leg Throttling Valve Flow Balance Verification”
Salem 1 & 2 Interval 3 Program Inservice Testing Manual for Pumps & Valves
NUREG-1482, “Guidelines for Inservice Testing at Nuclear Power Plants”
ASME/ANSI, “Operations and Maintenance Standards”, Part 10, OMa-1988, “Inservice Testing of Valves in Light-Water Reactor Power Plants”
1CV52 Check Valve Leakage Assessment
notifications 20192278, 20193182, 20193098, 20196151, 20205295
condition report 70040263

LIST OF ACRONYMS

ANS	Alert and Notification System
ANSI	American National Standards Institute
ASME	American Society of Mechanical Engineers
CC	Component Cooling
CFCU	Containment Fan Coil Unit
CW	Circulating Water
DCP	Design Change Package
DCSS	Dry Cast Storage System
EAL	Emergency Action Level
EDG	Emergency Diesel Generator

EP	Emergency Preparedness
ERO	Emergency Response Organization
GT	Gas Turbine
ISFSI	Independent Spent Fuel Storage Installation
LER	Licensee Event Report
LOCA	Loss of Coolant Accident
M&TE	Measuring and Test Equipment
MSLB	Main Steam Line Break
MSSV	Main Steam Safety Valve
NCV	Non-cited Violation
NRC	Nuclear Regulatory Commission
ODs	Operability Determinations
OWA	Operator Workaround
PARS	Publicly Available Records
PI	Performance Indicator
PMT	Post Maintenance Testing
PSEG	Public Service Electric Gas
RSPS	Risk Significant Planning Standards
SDP	Significance Determination Process
SPAR	Standardized Plant Analysis Risk
SRA	Senior Reactor Analyst
SW	Service Water
TDAFW	Turbine-driven Auxiliary Feedwater
TM	Temporary Modifications
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
WCD	Work Clearance Document