November 10, 2003

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

SUBJECT: SALEM NUCLEAR GENERATING STATION UNIT 1 AND UNIT 2 NRC INTEGRATED INSPECTION REPORT 05000272/2003007 AND 05000311/2003007

Dear Mr. Anderson:

On September 27, 2003, the US Nuclear Regulatory Commission (NRC) completed an inspection at your Salem Unit 1 and Unit 2. The enclosed integrated inspection report documents the inspection findings, which were discussed on October 9, 2003 with Mr. John Carlin 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 one self-revealing findings of very low safety significance (Green). This finding was determined to involve a violation of NRC requirements. However, because of the very low safety significance and because this issue has been entered into your corrective action program, the NRC is treating this finding as a non-cited violation (NCV) consistent with Section VI.A of the NRC Enforcement Policy. If you contest any NCV in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001; with copies to the Regional Administrator, Region I; the Director, Office of Enforcement, and the NRC Resident Inspector at the Salem Nuclear Generating Station.

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

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

Sincerely,

/RA/

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

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

Enclosure: Inspection Report 05000272/2003007 and 05000311/2003007
w/Attachment: Supplemental Information

cc w/encl:
W. F. Sperry, Director - Business Support
J. T. Carlin, Vice President - Nuclear Assurance
D. F. Garchow, Vice President - Engineering and Technical Support
G. Salamon, Manager - Licensing
A. C. Bakken, Senior Vice President - Site Operations
C. J. Fricker, Salem Plant Manager
R. Kankus, Joint Owner Affairs
J. J. Keenan, Esquire
Consumer Advocate, Office of Consumer Advocate
F. Pompper, Chief of Police and Emergency Management Coordinator
M. Wetterhahn, Esquire
State of New Jersey
State of Delaware
N. Cohen, Coordinator - Unplug Salem Campaign
E. Gbur, Coordinator - Jersey Shore Nuclear Watch
E. Zobian, Coordinator - Jersey Shore Anti Nuclear Alliance

Distribution w/encl:
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U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket Nos:	50-272, 50-311
License Nos:	DPR-70, DPR-75
Report No:	05000272/2003007, 05000311/2003007
Licensee:	PSEG LLC
Facility:	Salem Nuclear Generating Station, Unit 1 and Unit 2
Location:	P.O. Box 236 Hancocks Bridge, NJ 08038
Dates:	June 29, 2003 - September 27, 2003
Inspectors:	J. Daniel Orr, Senior Resident Inspector George J. Malone, Resident Inspector Joseph T. Furia, Senior Health Physicist Steven W. Shaffer, Project Engineer C. Fred Lyon, Project Manager, NRR/DLPM G. Scott Barber, Senior Project Engineer G. C. Smith, Physical Security Inspector Stephen M. Pindale, Senior Reactor Engineer John G. Caruso, Senior Operations Engineer
Approved By:	Glenn W. Meyer, Chief Projects Branch 3 Division of Reactor Projects

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SUMMARY OF FINDINGS

IR 05000272/2003-007, 05000311/2003-007; 06/29/2003 - 09/27/2003; Public Service Electric Gas Nuclear LLC, Salem Unit 1 and Unit 2; Maintenance Effectiveness.

The report covered a 13-week period of inspection by resident inspectors, and announced inspections by a senior health physicist, physical security inspector, and a senior operations engineer. Two Green non-cited violations (NCVs) were identified. The significance of most findings is indicated by their color (Green, White, Yellow, or Red) using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" (SDP). Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Mitigating Systems

- Green. A self-revealing finding made apparent a non-cited violation of Technical Specification (TS) 6.8.1 for failure to properly plan and perform maintenance in accordance with written procedures for a turbine driven auxiliary feedwater pump (13 AFWP) steam admission valve (1MS132). 1MS132 had been reassembled without adequate work instructions to ensure the actuator to valve stem coupling remained tight. The loose stem coupling was the root cause of an AFW pump trip during surveillance testing.

  This finding is greater than minor, because it affected the Mitigating System Cornerstone objective of equipment reliability, in that the erratic opening of 1MS132 caused the 13 AFWP to trip during surveillance testing one out of four times. The finding is of very low safety significance, because operators had been trained and adequate procedures existed to provide assurance of recovering a tripped turbine driven auxiliary feedwater pump. Additionally, during recovery the steam admission valve would not need to stroke open, as it would be established full open when operators controlled steam admission with the turbine trip valve. (Section 1R12)

- TBD. A self-revealing finding made apparent a violation of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action," for failure to promptly correct a condition causing a service water pump strainer (13 SWP strainer) trip. An established troubleshooting plan, developed as a corrective action from previous inadequacies in identifying strainer problems, had not been used. The cause of the strainer tripping in February was not fully identified. The 13 SWP strainer again tripped in April and required disassembly in May to remove metal debris that ultimately bound strainer rotation.

  This finding is an unresolved item pending completion of the significance determination process. This finding is more than minor, because it affected service water system reliability and availability, an equipment performance attribute of the Initiating Events and Mitigating Systems Cornerstones. Service water also supports the containment fan coil units and therefore barrier performance of the Barrier Integrity Cornerstone was also affected.

(Section 1R12)

B. Licensee-Identified Violations

- None

REPORT DETAILS

Summary of Plant Status

Unit 1 began the period at 100% power and remained there until July 29, 2003, when the reactor automatically tripped due to a 500kV breaker failure in the Salem switchyard. Unit 1 was placed online on August 3 and operators achieved 100% reactor power on August 4. On September 20, 2003, operators manually shut down Unit 1 to hot standby conditions due to switchyard insulator arcing caused by salt deposits from Hurricane Isabel. Unit 1 was placed online on September 27 and operators achieved 100% reactor power on September 29, 2003.

Unit 2 began the period at 100% power and remained there until September 20, 2003, when operators manually shut down Unit 2 to hot standby conditions due to switchyard insulator arcing caused by salt deposits from Hurricane Isabel. Unit 2 was placed online on September 26 and operators achieved 100% reactor power on September 29, 2003.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

a. Inspection Scope

The inspectors performed two adverse weather protection inspections and reviewed PSEG's preparation for seasonal hot weather, and PSEG's preparation and response to Hurricane Isabel.

During the week of August 11-15 the inspectors performed a detailed review of the Salem Unit 1 and Unit 2 program to prepare for high temperature conditions during the summer months. The inspectors walked down the Salem Unit 1 and Unit 2 service water (SW) system and primary component cooling water (CCW) system, including verification of compensatory measures directed by operations procedure, SC.OP-AB.ZZ-0001(Q), "Adverse Environmental Conditions," for river temperatures above 82 F. Heat exchanger performance data was also reviewed by the inspectors for systems cooled by SW and CCW.

During the week of September 15, 2003, Hurricane Isabel was forecast to potentially impact the Salem Units with hurricane force winds on September 19, 2003. PSEG implemented its Severe Weather Guide procedure, NC.OP-DG.ZZ-0002. The inspectors observed PSEG's preparation and readiness meetings. The inspectors focused on PSEG's preparations to eliminate missile hazards, maintain buildings watertight, maximize essential systems available, and prestage self-relieving operations, maintenance, and emergency facility personnel. The inspectors walked down outside areas surrounding safety-related water storage tanks, the service water intake structure, and the auxiliary building. These structures were important to maintain systems operable that could be used to remove decay heat without offsite power. Such systems included the emergency diesel generators (EDGs) and turbine-driven auxiliary feedwater. The inspectors reviewed identified operator workarounds and operability determinations to verify that equipment deficiencies were not additionally susceptible to severe weather. The inspectors remained on site September 18 and 19 as tropical storm winds approached the site. The inspectors walked down the service water intake structure and the auxiliary buildings and did not identify any adverse impact from the high winds, about 40 mph, and rainfall.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04)

a. Inspection Scope

Partial System Walkdown. The inspectors performed three partial system walkdowns. On August 8, 2003, the inspectors performed a partial system walkdown on the Salem 2B EDG while the 2C EDG was inoperable due to scheduled preventive maintenance. On August 13 the inspectors walked down the 21 and 23 component cooling water (CCW) pumps while the 22 CCW pump was out of service for scheduled maintenance. On August 27 the 22 charging pump was walked down while planned maintenance rendered the 21 CV pump inoperable. To evaluate operability of the selected components or trains, the inspectors observed system operating parameters and checked correct valve, switch and power alignments to the operating procedures listed below:

- S2.OP-SO.CVC-0001, “Charging, Letdown and Seal Injection”
- S2.OP-SO.CC-0001, “Component Cooling System Operation”
- S2.OP-SO.DG-0002, “Diesel Generator Operation”

Complete System Walkdown. On August 4 and 5, 2003, inspectors performed a detailed walkdown of the Unit 2 control area air-conditioning system to verify equipment alignment and to identify any discrepancies that could impact system operability. The system was selected based on risk insights from the Salem Generating Station Probabilistic Risk Assessment, Revision 3. Inspectors reviewed operating procedure S2.OP-SO.CAV-0001(Q), “Control Area Ventilation Operation,” the system health report, and outstanding notifications on the system to identify any issues that could challenge system operability.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

a. Inspection Scope

Fire Protection Walkdowns. The inspectors toured eleven fire areas to evaluate conditions related to control of transient combustibles and ignition sources, fire protection systems operational status and the fire barriers used to prevent fire damage or fire propagation. As part of the inspection, the inspectors reviewed Salem Pre-Fire Plans to determine (1) 10 CFR Part 50, Appendix R, safe shutdown equipment; (2) construction and fire barrier information; (3) fire detection equipment; (4) fire suppression equipment; and (5) diagrams of the fire area. The first seven areas were walked down the weeks of June 30 and July 7, the remaining four areas were walked down on July 29 and 30:

- Unit 3 Jet Combustion Turbine
- Fire/Fresh Water Pump House
- Station Black-Out Air Compressor Building
- Unit 1 and 2 Demineralizer Ion Exchange Area
- Unit 1 and 2 Diesel Fuel Oil Storage Area
- Unit 1 and 2 4160V Switchgear Rooms and Battery Rooms, Elevation 64'-0"
- Unit 1 and 2 Auxiliary Feedwater Pumps Area, Elevation 84'-0"July 29-30, 2003

Fire Brigade Drill Annual Observation. The inspectors observed an unannounced , off-hours fire drill on September 10, 2003. The drill involved the fire brigade responding to a simulated electrical switchgear fire on the 84' elevation of Salem Unit 2. 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 with the control room, and use of fire plans. Additionally, the inspectors observed the drill brief and post-drill critique.

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures (71111.06)

a. Inspection Scope

The inspectors performed an internal flood protection measures inspection and reviewed the Salem Updated Final Safety Analysis Report, the Salem Probabilistic Risk Assessment (PRA), Revision 3, and plant procedures to verify that PSEG flood protection measures were consistent with design bases and risk assumptions. The inspectors performed a detailed review of the Unit 1 and Unit 2 84' elevation of the auxiliary building. This elevation of both units' auxiliary buildings have risk significant pumps for internal flooding. The inspectors toured the areas to determine whether flood vulnerabilities existed and to assess the physical and material condition of flood barriers and drainage pathways. Recent notifications involving flood protection were reviewed.

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance (71111.07)

a. Inspection Scope

The inspectors performed an annual review of performance monitoring activities for the Unit 1 and 2 charging pump lube oil and gear oil coolers to verify that PSEG had adequately identified and resolved heat sink performance problems that could result in initiating events or affect multiple heat exchangers in mitigating systems and thereby increase risk. Inspectors reviewed Unit 1 and Unit 2 performance test procedures S1.OP-PT.SW-0004 (Q) and S2.OP-PT.SW-0004(Q), “Service Water Biofouling Monitoring - Safety Injection and Charging Pumps” and the primary plant equipment operator logs. The inspectors also discussed the testing methodology, test acceptance criteria, and trend results from the past year with the system and design engineers. In addition, inspectors reviewed the service water system health reports and recent notifications and walked down the charging pumps to assess material condition and to ensure that PSEG was appropriately identifying and resolving potential problems.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11)

a. Inspection Scope

Biennial Operator Requalification Inspection. The following inspection activities were performed using NUREG-1021, Rev. 8, “Operator Licensing Examination Standards for Power Reactors,” Inspection Procedure Attachment 71111.11, “Licensed Operator Requalification Program,” and NRC Manual Chapter 0609, Appendix I, “Operator Requalification Human Performance Significance Determination Process (SDP),” as acceptance criteria. These inspection activities were performed for both units.

The inspectors reviewed documentation of operating history since the last requalification program inspection. Documents reviewed included NRC inspection reports and PSEG deficiency reports. The inspectors also discussed facility operating events with the resident staff. The inspectors did not detect operational events that were indicative of possible training deficiencies.

Inspectors reviewed examples of the comprehensive written exams and observed the administration of annual operating tests. The quality of the written exams and the annual operating tests met or exceeded the criteria of the Examination Standards and 10 CFR 55.59.

For the site specific simulator the inspectors observed simulator performance during the conduct of the examinations, and reviewed simulator performance tests (e.g., steady state performance tests, selected transient tests, and LOR program scenario-based tests), and discrepancy reports to verify compliance with the requirements of 10CFR55.46.

The inspectors reviewed a sample of operators' records related to requalification training attendance, license reactivations, and medical examinations, and confirmed the operators were in compliance with license conditions and NRC regulations.

Instructors, training/operations management personnel, and a sample of individual licensed operators were interviewed for feedback regarding the implementation of the licensed operator requalification program.

On October 2, 2003, the inspectors conducted an in-office review of PSEG requalification exam results. These results included the annual operating test only (i.e., the comprehensive written exam was administered last year). The inspection assessed whether pass rates were consistent with the guidance of NRC Manual Chapter 0609, Appendix I, "Operator Requalification Human Performance Significance Determination Process (SDP)." The inspectors verified that:

- Crew pass rate was greater than or equal to 80%. (pass rate was 100%)
- Individual pass rate on the dynamic simulator test was greater than or equal to 80%. (pass rate was 98.6%)
- Individual pass rate on the walk-through test was greater than or equal to 80%. (pass rate was 100%)
- Overall pass rate among individuals for all portions of the operating exam was greater than or equal to 75%. (pass rate was 98.6%.)

Quarterly Operator Requalification Inspection. On August 14, 2003, the inspectors observed a licensed operator simulator training scenario administered to two different operating crews to assess operator performance and the evaluators' critique. The scenario involved a steam generator feed pump (SGFP) trip, stuck open pressurizer spray valve, and a steam generator tube rupture (SGTR) concurrent with a steam line break. The trip of the SGFP required the crew to execute procedure S1.OP-AB.CN-0001, "Main Feedwater/Condensate System Abnormality." This was followed by a stuck open pressurizer spray valve which caused entry into S1.OP-AB.PZR-0001, "Pressurizer Pressure Malfunction," and directed a reactor trip and entry into emergency operating procedure (EOP) 1-EOP-TRIP-1, "Reactor Trip or Safety Injection." The steam line break and concurrent STGR caused the crew to enter EOPs 1-EOP-LOSC-1, "LOSS OF SECONDARY COOLANT," 1-EOP-SGTR-1, "Steam Generator Tube Rupture," and subsequently 1-EOP-SGTR-3, "SGTR with LOCA - Subcooled Recovery." The inspectors observed the post-scenario critique and reviewed the areas for improvement that were entered into the operator training critique database.

b. Findings

An unresolved item is being opened regarding the potential inadequacy of required simulator testing and documentation. In accordance with PSEG's Simulation Facility Certification Program, revision 00, the simulation facility requires compliance with 10

CFR 55.46 and standard ANSI/ANS-3.5-1993 as endorsed by the NRC Regulatory Guide 1.149, revision 2.

ANSI/ANS-3.5-1993, section 4.4.2, states that Simulator Operability Testing shall be conducted once per calender year which includes Transient Performance Tests and refers to Appendix B (Guidelines for Simulator Operability Test Requirements) which provides examples of acceptable simulator operability tests. Four of these tests listed in Appendix B, "(2) Transient Performance Tests," were not being performed by PSEG at the time of this inspection (i.e., Simultaneous trip of all feedwater pumps, Maximum rate power ramp from 100% down to approximately 75% and back up to 100%, Slow primary system depressurization to saturated condition using pressurizer relief or safety valve stuck open, Load rejection). The simulator supervisor indicated that these tests were last conducted in 1996 and in PSEG's Simulation Facility Certification Program, section III.3.bii, "Transient Testing," transients may be removed from the list if the transient has little value to the training program and for the most part are covered by other tests. PSEG's Simulation Facility Certification Program, section IV, "Exceptions," provides a list of justified exceptions to standard ANSI/ANS-3.5-1993. However, these four transient tests are not listed in this section as technically justified exceptions for the Salem simulator. In addition, PSEG is conducting malfunction testing using scenario-based testing which is not specifically approved as an acceptable testing methodology in ANSI/ANS-3.5-1993. The inspector questioned the acceptability of this approach and will review further with NRR input and expertise.

The inspector reviewed Manual Chapter 0612, "Power Reactor Inspection Reports," Appendix E and noted that this issue is potentially more than minor based on example 1.c when required testing is not performed. The inspector used NRC Inspection Manual, Manual Chapter (MC) 0612, "Power Reactor Inspection Reports," Appendix B, section 4, Reactor Safety, Operator Requalification, question (4) Is the finding related to simulator fidelity based on a yes response to the question entered MC 0609, Appendix I, "Operator Requalification Human Performance Significance Determination Process (SDP)." The potential performance deficiency would be failure to conduct and/or properly document required simulator testing in order to maintain simulator fidelity in violation 10 CFR 55.46 and the guidance in the standard ANSI/ANS-3.5-1993. In order to maintain continued assurance of simulator fidelity, 10 CFR 55.46(d)(1) requires, in part, "Facility licensees that maintain a simulation facility shall conduct performance testing throughout the life of the simulation facility in a manner sufficient to ensure that paragraphs (c)(2)(ii), as applicable and (d)(3) of this section are met."

The potential performance deficiency is an operator requalification issue related to functional fidelity of the simulator (Appendix I flowchart block # 6, a "YES" response which leads to flowchart block #12). The potential performance deficiency could indicate a potential "Green Finding." This item will be treated as unresolved pending further evaluation by the NRC to determine Salem simulator testing and documentation adequacy. **(URI 50-272&311/03-07-01)**

1R12 Maintenance Implementation (71111.12)

13 Auxiliary Feedwater Pump Trip

a. Inspection Scope

The inspectors assessed PSEG's immediate actions and subsequent evaluation of the 13 auxiliary feedwater pump (AFWP) trip during quarterly inservice testing on May 23, 2003. This issue was also briefly detailed and determined to be an unresolved item in NRC Inspection Report 05000272/2003005 and 05000311/2003005 section 1R12. The matter was unresolved pending further review and an anticipated Licensee Event Report.

The inspectors reviewed applicable sections of the updated final safety analysis report, TSs, and engineering evaluations. The inspectors interviewed engineers, maintenance technicians, operators, and managers to understand the 13 AFW pump trip.

The inspectors reviewed applicable PSEG records documenting the 13 AFWP trip, and subsequent investigations, work orders, and corrective actions. Additionally, the inspectors interviewed the apparent cause analysis team and personnel associated with the testing, troubleshooting and repair activities. Plant management knowledgeable of the decision making processes that transpired during the 13 AFWP trip event response were also interviewed.

The inspectors reviewed notifications, surveillance test records, and work orders associated with prior maintenance and testing activities to understand the reliability and availability of the 13 AFWP prior to its trip on May 23, 2003. Work orders were reviewed to assess the most recent maintenance affecting 13 AFWP performance.

The inspection activities mostly occurred the week of June 23, 2003. A primary objective of the inspection was to ascertain if performance deficiencies led to the 13 AFWP trip and also to determine if PSEG could have otherwise foreseen the unreliable 13 AFWP performance. Documents reviewed are listed in the Supplemental Information section of this inspection report.

b. Findings

Introduction. A Green self-revealing NCV was identified for failure to comply with Salem Unit 1 TS 6.8.1.a., i.e., to properly perform maintenance on the 13 AFWP steam admission valve, 1MS132.

Description

Event

PSEG performed routine quarterly inservice testing of the 13 AFWP on May 23, 2003. (The 13 AFWP had last operated successfully during a quarterly IST on February 28 at 5:17 p.m.) On May 24 at 12:24 a.m., the turbine tripped moments after being started by the control room operators. At the time of the trip, the control room operators observed an increase in pump speed and subsequently noted that the pump trip throttle valve (1MS52) had gone closed. The nuclear equipment operators (NEOs) located at the pump noted that 1MS132 had not stroked open smoothly, but had popped open. PSEG assembled a Transient Assessment Response Plan (TARP) Team (Notification 20146103) to investigate the cause of the failure and develop a corrective action plan.

Maintenance technicians identified that the position indication arm for the 1MS132 was rotated from its normal position and needed adjustment. The 1MS52 valve and linkage exhibited no anomalies. PSEG determined that looseness in the 1MS132 actuator to valve stem coupling, evident by the rotated position indication arm, caused binding during valve operation. PSEG believed that a rapid change in valve position, following the 1MS132 valve binding, resulted in a sudden increase in steam flow and vibrated the 1MS52 trip latch loose, tripping the 13 AFWP.

On May 24 two attempts were made to tighten the actuator stem to valve stem coupling. The coupling is a split block arrangement with a single bolt and nut at the center between threaded holes for each stem. The split block threads are identical to the stem threads and provide positive vertical engagement for stem travel adjustment. After the first tightening, the 1MS132 valve still jumped when opening, but to a lesser extent. 13AFWP started without tripping. Afterwards, maintenance technicians observed that the valve stem could be rotated by hand. 1MS132 was tightened an additional time and operated smoothly and 13 AFWP successfully operated. Control room operators declared the 13 AFWP operable on May 24 at 11:35 p.m.

The inspectors identified performance deficiencies in three areas that contributed to the 1MS132 valve failure: maintenance practices that reassembled the split block coupling on October 29, 2002, inservice testing program management, and a problem identification and resolution weakness. The inspectors believed human performance in maintenance practices to be the most apparent cause. The inspectors classified the human performance errors in the inservice testing program management and problem identification and resolution as opportunities to previously identify the degraded 1MS132 condition.

<u>Inadequate Maintenance Practices, An Apparent Cause</u>

The inspectors concluded that a performance deficiency had occurred, in that inadequate maintenance instructions had been used to reassemble 1MS132 on October 29, 2002. 1MS132 had been reassembled in an unreliable condition, and the loose valve actuator stem coupling impacted the steam admission to the 13 AFWP during its May 23, 2003, surveillance test, in which the pump tripped. Two attempts were needed on May 23, 2003, to adequately tighten the stem coupling, also validating the existence of the performance deficiency.

Corrective and preventive maintenance was performed on 1MS132 during the refuel outage in October 2002 under work order 30037646, the last activity which addressed the split block coupling. Work order 30037646 included instructions for the valve and actuator work using a procedure (SH.IC-GP.ZZ-0002, Disassembly, Inspection, Reassembly and Testing of Masoneilan Model 37/38 Air Operated Actuators), which was specific for 1MS132. While the procedure specified that the coupling be tightened during reassembly, it did not provide any torque values or any in-progress check of the tightening (such as confirming that neither stem would rotate). Nonetheless, this procedure referenced a general procedure for torquing (SC.MD-GP.ZZ-0022, Bolt Torquing and Bolting Sequence Guidelines), which contained applicable torque values. There is no evidence in the work order or otherwise that the coupling was adequately tight following the reassembly, i.e., that specific torque values were used or that its tightness was checked. To the contrary, all the evidence suggests the coupling's looseness on May 24 caused the pump trip.

In LER 272/03-001dated July 18, 2003, PSEG determined that the pump trip had been caused by the valve stem not being properly restrained at the split block coupling and that the "split block on the 1MS132 was found to be loose and required tightening. During the [PSEG] investigation of this event, it was determined that the maintenance procedure for Masoneilan valve actuators does not provide any guidance regarding the tightening of the split block bolt(s); thus, leaving the tightening of this connection to the skill-of-the-craft."

Further, the inspectors learned that the tightening of the coupling following the May 24 AFW pump trip was completed without a torque wrench and no torque values were recorded. A tightness check was done to determine if the stems could rotate, and this was what found the inadequate tightening of the first attempt to repair 1MS132.

Based on the above, the inspectors determined that a performance deficiency had occurred on October 29, 2002, in that inadequate maintenance instructions were used to reassemble 1MS132.

<u>Inadequate Inservice Testing Reviews, A Contributing Cause</u>

The inspectors reviewed several post-maintenance testing and inservice testing results associated with 1MS132. S1.OP-ST.AF-0003, "Inservice Testing - 13 Auxiliary Feedwater Pump," was performed on October 29, 2002, to test the closing time and containment isolation function of 1MS132 required by TS 4.6.3.1.1 and 4.6.3.1.4 and transition to Mode 4, Hot Shutdown. Salem Unit 1 entered Mode 4 on October 30, 2002, at 1:40 p.m. The test was not intended to operate 13 AFWP as hot shutdown plant conditions would not support turbine operation. The closing stroke time was 6.03 seconds versus a previous established reference value of 6.13 seconds. The opening stroke was 21.7 seconds versus a previously established reference value of 17.6 seconds. Comments in the test procedure indicated that the stroke time was within the acceptable band (developed by previous established reference values and less than 26.4 seconds), but was high and would be evaluated by engineers.

ASME/ANSI OMa-1988, "Inservice Testing of Pumps and Valves in Light Water Reactor Power Plants," part OM-10, paragraph 3.4 specifies that when a valve or its controls have undergone maintenance, a new reference value shall be determined or the previous value reconfirmed by an inservice test run prior to the time the valve is returned to service or declared operable. OM-10, paragraph 3.3, further specifies that deviations between the previous and new reference values shall be determined from tests performed under conditions as near as practicable to those expected during subsequent inservice testing. The inspectors noted deficiencies associated with establishing new reference stroke time values for 1MS132.

- Reference values obtained on October 29, 2002, were not changed until April 4, 2003, under notification 20119972 and order 80054453.
- Deviations in reference values were not evaluated or reconciled in either notification or order.
- Stroke tests performed on October 29, 2002, to establish new reference values were performed without steam flow. These tests were not performed under conditions as near as practicable to those expected during subsequent inservice testing, with steam flow initiated.

Inservice testing was performed with steam flow on November 1, 2002, for TS 4.7.1.2.b.2 and 4.7.1.2.c and for transition to Mode 3, Hot Standby. Salem Unit 1 entered Mode 3 on November 1, 2002, at 2:17 a.m. Testing was also performed on December 6, 2002, and February 28, 2003, to satisfy routine inservice testing requirements. These three surveillance tests also included 13 AFWP operation and testing. In each instance the 1MS132 stroke times were compared to an old reference value, the reference values were not changed until April 4, 2003. Each recorded open stroke value met PSEG's criteria for a significant change, defined by SH.RA-RP.AP.ZZ-0105, "IST Program Management," as a six percent change from the last test result or reference value. SH.RA-AP.ZZ-0105 also specified that a notification be initiated to evaluate significant test result deviations. For each inservice test, no notifications were written to evaluate the changes.

<u>Problem Identification and Resolution Weakness, A Contributing Cause</u>

The inspectors determined that PSEG had a missed opportunity to prevent the problem as part of the extent of condition review on the same problem on this valve design in a non-safety related application. On March 18, 2003, the 13 heater drain pump discharge flow control valve (13HD15) failed when an instrument line connection failed. Notification 20136429 documented the valve failure as well as a rotated position feedback arm, similar to the 1MS132 rotated position indication arm. The 13HD15 is nearly identical in design to the 1MS132 valve, but in a balance-of-plant application. Notification 20136429 also documented three previous observations of valve stem rotations on heater drain pump discharge flow control valves. The observations probably occurred soon before the 13HD15 valve failure, but were not previously documented in PSEG's corrective action program. Evaluation work order 70030295, completed in response to notification 20136429 did not document an extent of condition review for potential Salem safety-related applications. The apparent cause evaluation focused on the 13HD15 instrument line failure and did not address potential issues with a rotated valve stem.

Analysis. This finding adversely impacted the auxiliary feedwater system equipment reliability. The 13 AFWP was made unreliable when inadequate maintenance practices did not properly reassemble the 13 AFWP steam admission valve and actuator stem coupling. The inadequate maintenance practices were a human performance cross-cutting issue. Human performance errors also occurred in inservice testing program application and review. Specified inservice reference value re-baselining evaluations were not performed after the same 1MS132 valve maintenance activity. A problem identification and resolution weakness occurred in March 2003, in that PSEG did not investigate similar valve problem symptoms on balance of plant applications for the same valve design. The weaknesses in inservice testing and problem identification and resolution were contributing causes that could have earlier identified the unreliable 1MS132 condition.

In accordance with Inspection Manual Chapter (IMC) 0612, Appendix B, “Issue Disposition Screening,” the inspectors determined that the issue was more than minor, because it was associated with the equipment performance attribute of the Mitigating Systems Cornerstone objective. Specifically, the reliability of the turbine-driven auxiliary feedwater (TDAFW) pump was adversely impacted by inadequate maintenance practices on the TDAFW pump steam admission valve (1MS132). In accordance with IMC 0609, Appendix A, “Significance Determination of Reactor Inspection Findings for At-Power Situations,” the inspectors performed an SDP Phase 1 screening and determined that an SDP Phase 2 evaluation was needed, because the performance deficiency resulted in an actual loss of safety function of the TDAFW pump train for greater than the Technical Specification allowed outage time.

The inspectors performed an SDP Phase 2 evaluation of the risk significance of the performance deficiency and determined that the finding was of low to moderate safety significance (White). The inspectors used the following assumptions in the Phase 2 evaluation.

- The TDAFW pump would fail to start given any demand since the last successful demonstration of functionality on February 28, 2003. Therefore, an exposure time of greater than 30 days was used in the analysis.

- The TDAFW pump was able to be recovered, because once the steam admission valve (1MS132) opened, it would remain open, which would allow the operators to re-latch the trip throttle valve (1MS52) and manually start the TDAFW pump. Recovery credit was assumed because sufficient time was available for the operators to manually start the TDAFW pump using the guidance in Emergency Operating Procedures; operators had been trained on these procedures in both the initial licensing and requalification training programs; environmental conditions did not adversely impact these recovery actions; and no special equipment was needed to perform these recovery actions.

The inspectors reviewed the Phase 2 results and concluded that they were approximately two orders of magnitude conservative for two reasons. First, the characterization as White was due to the application of the counting rule which adds the solved Phase 2 accident sequences in a conservative, simplified manner. Second, the Phase 2 SDP only allowed a recovery credit of 1; however, for this case more credit was appropriate. As a result, the inspectors determined that a Phase 3 analysis of this finding was appropriate.

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

- The failure of the TDAFW pump to start was attributed to inadequate maintenance practices associated with reassembly of the steam admission valve (1MS132) during maintenance on October 29, 2002. The result was that the valve would hang up while opening due to movement in the valve stem until the forces in the valve overcame the binding and caused the valve to pop open. The rapid opening of the valve caused a steam transient and resulted in the trip throttle valve (1MS52) unlatching and tripping the turbine.

While the circumstances which created this failure mode existed since the maintenance was performed on October 29, 2002, the TDAFW pump successfully started on 3 previous occasions. Therefore, the analyst determined that the reliability of the TDAFW pump was degraded and the probability of the TDAFW pump failing to start was approximately 1 in 4.

- The analyst determined that the reliability of the TDAFW pump had been degraded from when maintenance had been performed on October 29, 2002, until the steam admission valve was repaired following the failure on May 24, 2003. The analyst determined that the exposure time for this performance deficiency was approximately 4,795 hours, which accounted for the brief periods of time that Salem Unit 1 was not operating at power between these dates.

- The analyst determined that the failure probability for operator recovery of the TDAFW pump was approximately 1.2E-2 using the Accident Sequence Precursor Human Reliability Analysis methodology.

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

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

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

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

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

- The NRC's SPAR model success criteria for emergency AC power is 2 of 3 onsite emergency diesel generators (EDGs) or the gas turbine providing power to the 4160 volt AC buses. This criteria is consistent with PSEG's probabilistic risk assessment (PRA) model. It is based upon the assumption that 2 service water pump trains are needed for safe shutdown and one EDG cannot supply enough AC power for more than one service water pump train.

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

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

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

The analyst revised the model to reflect the Phase 3 assumptions (stated above), determined a revised core damage frequency for the exposure period and calculated the change in core damage frequency (ΔCDF) for this finding due to internal initiating events. The analyst determined that the ΔCDF for this finding was 9.9E-8 per year. The dominant accident sequence involved a loss of offsite power event, failure of the emergency power system, failure of the TDAFW pump, failure of the operators to recover the TDAFW pump, and failure to recover offsite power prior to core damage. As a result, the analyst determined that inadequate maintenance practices associated with the steam admission valve were of very low safety significance (Green).

Enforcement. Salem Unit 1 TS 6.8.1.a. requires that written procedures shall be established covering the activities in Appendix A of Regulatory Guide 1.33, Revision 2, February 1978, which specifies that maintenance that can affect the performance of safety-related equipment should be properly planned and performed in accordance with written procedures, documented instructions, or drawings appropriate to the circumstances. Contrary to the above, on October 29, 2002, the 13 AFWP steam admission valve, 1MS132, was reassembled without adequate work instructions to ensure the actuator to valve stem coupling remained tight. Because the failure to properly perform maintenance on 1MS132 was determined to be of very low significance and has been entered into the corrective action program (notification 20146321), this violation is being treated as a non-cited violation consistent with Section VI.A of the NRC Enforcement Policy: Therefore, unresolved item URI 50-272/03-05-02 will be closed and **NCV 50-272/03-07-02** will be issued, Failure to Properly Perform Maintenance on 13 Auxiliary Feedwater Pump.

13 Service Water Pump Strainer Failures

a. Inspection Scope

The inspectors reviewed a service water pump strainer failure to confirm that the failure was properly addressed per the Maintenance Rule and to ensure that appropriate corrective actions were implemented. The inspectors referenced NUMARC (Nuclear Management and Resources Council) 93-01, Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants and 10 CFR 50.65, Requirements for monitoring the effectiveness at nuclear power plants.

b. Findings

Introduction. The inspectors identified a self-revealing finding for failure to promptly correct a condition that rendered the 13 service water pump (13SWP) strainer unreliable. This finding is an unresolved item pending completion of the significance determination process.

Description. On May 10, 2003, main control room operators were alerted to a trouble indication on the 13SWP strainer. Equipment operators responded and identified the 13SWP strainer not rotating and a high differential pressure across the strainer existed. A restart on the 13SWP strainer was made after equipment operators reset the thermal overloads, but the strainer motor again tripped. The 13 SWP strainer was tagged out of service for maintenance activities and investigation. The maintenance technicians discovered a thin metal shard, about four inches by one-half inch, had caused the strainer drum to jam. The 13 SWP strainer was placed back in service and the strainer rotated without further problems.

PSEG engineers completed an evaluation of the issue for corrective actions and Maintenance Rule application. The evaluation was documented in order 70031456. The evaluation noted that the 13 SWP strainer had recently tripped on motor overloads on February 10, 2003, and April 16, 2003. The evaluation was critical of the maintenance performed in February, in that established troubleshooting plans were not followed. The maintenance response to the April strainer failure was adequate compared to PSEG's established plan for troubleshooting strainers, in that a single reset on the motor overloads allowed the strainer to continue operation. The evaluation also recognized that the previous corrective actions were knowledge based and not process driven, and this ultimately led to the incomplete investigation of the 13 SWP strainer failure on February 10, 2003.

The engineers concluded that the 13 SWP strainer failure was a repeat maintenance preventable failure and that earlier corrective actions for similar strainer failures were not effective. The similar strainer failures occurred in July 2001 and January 2000. Shortly after the July 2001 failure, corrective actions were established that developed a standard troubleshooting response to strainer trips. Specifically, the troubleshooting plan required that SWP strainer drums be pulled and inspected if a strainer continually trips on overload with associated low differential pressure. The troubleshooting plan also cautioned against using manual reverse rotation to clear the binding without further drum inspection. This was the case on February 10, 2003; reverse rotation cleared the bound condition, but the drum was not pulled for complete inspection. PSEG entered these deficiencies into the corrective action program as notification 20144330.

Analysis. The finding adversely impacted service water system reliability and unavailability. This finding is more than minor, because it affected the equipment performance attribute of the Initiating Events and Mitigating Systems Cornerstones. Service water also supports the containment fan coil units and therefore barrier performance of the Barrier Integrity Cornerstone was also affected.

Enforcement. 10 CFR 50 Appendix B Criterion XVI, “Corrective Action” requires that measures shall be established that assure deficiencies are promptly identified and corrected. Contrary to the above, PSEG failed to fully identify the deficiency causing a service water pump to trip on February 10, 2003, and correct the deficiency before a failure again occurred on May 10, 2003. Pending determination of the finding’s safety significance, this finding is identified as **URI 50-272/03-07-03**, Untimely Service Water Pump Strainer Corrective Actions.

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

a. Inspection Scope

The inspectors selected five maintenance activities listed below for review through direct observation and document review, (PSEG probabilistic safety assessment (PSA) risk evaluation forms), control room operating logs, and personnel interviews. This review was performed to determine whether PSEG properly assessed and managed plant risk, and performed activities in accordance with applicable TS and work control requirements. The inspectors also walked down the protected equipment and maintenance locations to verify that risk was managed in accordance with PSEG’s risk evaluation forms. The activities selected were based on plant maintenance schedules and systems that contribute to plant risk. Regulatory Guide 1.182, “Assessing and Managing Risk Before Maintenance Activities at Nuclear Power Plants” was referenced to verify adequacy.

- Planned maintenance on the Unit 2 component cooling water cross-connect valve (2CC31) on July 15, 2003
- Planned maintenance on the 22 safety injection pump on September 4, 2003
- Planned maintenance on the 2C emergency diesel generator on September 4, 2003
- Planned maintenance and emergent troubleshooting on the 12 auxiliary feedwater pump on September 10, 2003
- Planned maintenance on the Unit 2 spent fuel pool heat exchanger on September 10, 2003

b. Findings

No findings of significance were identified.

1R14 Operator Performance During Non-Routine Evolutions and Events (71111.14)

a. Inspection Scope

Unit 1 Reactor Trip and Loss of Offsite Power. On July 29, 2003, at 1:29 p.m. Salem Unit 1 automatically tripped on a generator load reject due to a ground fault in the Salem 500kV switchyard. An Unusual Event was declared when operators observed that all vital busses were being supplied by the emergency diesel generators versus an offsite power source. The inspectors were onsite and responded to the main control room within minutes of the automatic trip. The inspectors observed main control room operators execute emergency operating procedures 1-EOP-TRIP-1, "Reactor Trip or Safety Injection" and 1-EOP-TRIP-2, "Reactor Trip Response." The inspectors' further observed control room operators stabilize the reactor plant in Mode 3, Hot Standby, with operating procedure S1.OP-IO.ZZ-0008, "Maintaining Hot Standby." Discussions between senior reactor operators and senior plant management regarding emergency plan event classification were witnessed. The inspectors later observed at 9:47 p.m. main control room operators transfer vital bus power from the emergency diesel generators to the normal offsite power sources, thus providing the conditions to terminate the Unusual Event. This event is the subject of a separate special inspection.

Unit 1 Reactor Startup. Inspectors observed portions of the reactor startup on August 1, 2003, following the automatic trip that occurred on July 29, 2003. Inspectors observed the pre-evolution brief and subsequent entry into Mode 2, approach to criticality, and stabilization of power at about 1 percent. Power was held at about 1 percent for post-maintenance testing of main steam isolation valve 14MS167 before continuing the power ascension. Inspectors verified that activities were performed in accordance with S1.OP-IO.ZZ-0003(Q), Rev.12, "Hot Standby to Minimum Load." Management oversight was provided by the assistant operations manager. Inspectors noted that the pre-evolution brief was comprehensive and that startup activities were well-controlled by the senior reactor operator.

Unit 1 and Unit 2 Reactor Shutdown. Inspectors observed portions of Unit 1 and Unit 2 manual reactor shutdowns on September 20, 2003. Both units were shut down in response to abnormal conditions in the 500kV switchyard as a result of adverse weather conditions. Hurricane Isabel had deposited a salt film from the Delaware River during high winds with little rainfall on September 19, 2003. After nightfall on September 19, 2003, plant operators observed arcing on Salem switchyard insulators. Hope Creek, the adjacent power plant and switchyard, experienced an automatic reactor scram due to a transmission line isolation from a switchyard fault induced by the salt deposits. PSEG management assessed the Hope Creek situation and the switchyard arcing, and determined that Salem plant shutdowns were appropriate for the circumstances. The inspectors verified that the plant shutdowns were performed in accordance with S1.OP-IO.ZZ-0005 and S2.OP-IO.ZZ-0005, "Minimum Load to Hot Standby."

Unit 1 and Unit 2 Reactor Startup. Inspectors observed portions of the reactor startup on both Unit 1 and Unit 2 on September 26, 2003. The Salem units were restarted after switchyard cleaning was completed to remove the salt deposits caused by Hurricane

Isabel. Inspectors observed control rod withdrawal to criticality and the subsequent power increase to the point of adding heat on both units. The startup was staggered between units such that Unit 2 was stable near 1% prior to Unit 1 beginning reactor startup. Inspectors verified that activities were performed in accordance with S2.OP-IO.ZZ-0003 and S1.OP-IO.ZZ-0003, "Hot Standby to Minimum Load." The inspectors also verified that the control room activities were completed without distraction.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors reviewed five operability determinations (ODs) or other equipment deficiencies with potential operability issues. The review assessed technical adequacy, the use and control of compensatory measures, and compliance with the licensing and design basis. The inspectors' review included a verification that the operability determinations were made as specified by PSEG's Procedure SH.OP-AP.ZZ-0108, "Operability Assessment and Equipment Control Program." The technical content of the ODs and the follow-up operability assessments (CRFAs) were reviewed and compared to applicable TS, the UFSAR, and associated design and licensing basis documents. The following operability issues were reviewed:

- Notifications 20151654, 20151760 and 20152086 for the slow to open 2C emergency diesel generator service water supply valve, (23SW39) on July 10, 2003
- Operability Determination 03-010, "Component Cooling Water System Leak into SFP" dated August 5, 2003
- Operability Determination 03-011, "22 Component Cooling Water Pump Oil Leak" dated August 7, 2003
- Notifications 20158262 and 20158263 for an overpressurization condition on the 12 auxiliary feedwater pump suction piping on September 10, 2003
- Continued Unit 2 residual heat removal (RHR) water hammer events. This issue was first documented in NRC Inspection Report 50-272/02-09, 50-311/02-09 Section 4OA2 and described water hammer that reoccurs on each 21 and 22 RHR pump start because of entrained air from refueling activities in May 2002.

b. Findings

The Unit 2 RHR system experienced water-hammer after plant refuel activities on May 10, 2002. Several notifications have been written to document the water hammer events, troubleshooting methods and results, and other issues related to the recurring problem and are listed in Attachment A. The inspectors additionally witnessed the water hammer occur during a surveillance test of the 22 RHR pump on August 29, 2003. No findings of significance were identified; however, the inspectors were still unable to quantitatively assess any impact the recurring water-hammer events may have had on the long term structural integrity absent a stress analysis by PSEG. This issue will remain unresolved pending completion of PSEG's evaluation of the structural integrity of the RHR system. **(URI 50-311/03-07-04)**

1R19 Post Maintenance Testing (71111.19)

a. Inspection Scope

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

- Control loop isolator replacement for the 22 auxiliary feedwater pump with Order 60036948 on July 1, 2003. The post-maintenance acceptance criteria were verified within the work order.
- S2.OP-ST.DG-0006, “2A Diesel Auxiliaries - Air Start Valve Test” on August 20, 2003, following air start motor replacements on the 2A EDG with Order 30016295.
- S2.OP-ST.DG-0001, “2A Diesel Generator Surveillance Test” on August 20, 2002, following service water supply valve replacement on the 2A EDG with Order 60028415.
- Design change package (DCP) to improve the stroke time of the 11 service water pump strainer blowdown valve with order 60033887 on August 12, 2003. The stroke acceptance criteria was verified within DCP 80054885.
- S2.OP-ST.CC-0002, “Inservice Testing - 22 Component Cooling Pump” on August 13, 2003, following 22 component cooling water pump outboard bearing oil seal repairs with order 60038401.
- S2.OP-PT.HSD-0002, “Hot Shutdown Panel/Local Panel Functional Test” on August 26, 2003, following 12 component cooling water pump remote control switch repairs with order 60032284

b. Findings

No findings of significance were identified.

1R20 Refueling and Outage Activities (71111.20)

a. Inspection Scope

The inspectors reviewed the forced outage scope for dual unit manual shutdowns on September 20, 2003. The manual shutdowns were in response to Hurricane Isabel and salt deposited on Salem switchyard insulators. Details of this event are also described in Sections 1R14 and 4OA3 of this inspection report. The most risk significant maintenance activities included de-energizing portions of the Salem switchyard and cleaning associated insulators; these activities reduced available redundant offsite power sources. The inspectors reviewed PSEG's risk management of the switchyard activities. The inspectors were sensitive to any maintenance activity potentially affecting the operability of the emergency diesel generators, available offsite power sources, and the turbine-driven auxiliary feedwater pumps. The inspectors also attended PSEG's station operations review committee (SORC) on September 24, 2003, to review the reliability of the Salem and Hope Creek switchyards. The inspectors performed a Unit 1 containment walkdown outside of the biological shield on September 23, 2003. The inspectors selected Unit 1 for a containment walkdown considering the availability of the Unit 2 containment during its refuel outage scheduled on October 9, 2003. The inspectors walked down the Unit 1 containment to assess general material condition.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

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

- S2.OP-ST.CVC-0004, "Inservice Testing - 22 Charging Pump" on July 11, 2003
- S2.OP-ST.DG-0001, "2A Diesel Generator Surveillance Test" on August 20, 2003
- S2.OP-ST.SW-0005, "Inservice Testing - 25 Service Water Pump," on August 6, 2003
- S2.OP-ST.PZR-0002, "Inservice Testing - PORV Block Valves Modes 1-6," on August 12, 2003
- S1.IC-CC.RC-0055, "Reactor Coolant Wide Range Temperature" (a channel calibration for cold leg instrument 1TE423B) on August 26, 2003
- S2.OP-ST.SSP-0009, "Engineered Safety Features SSPS Slave Relays Test Train A on August 28, 2003
- S2.OP-ST.RHR-0002, "Inservice Testing - 22 Residual Heat Removal Pump" on August 28, 2003

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

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope

On September 18, 2003, the inspectors reviewed a listing of all temporary modifications installed on Salem Unit 1 and Unit 2. No new modifications were installed that warranted inspection on the basis of risk insights. Throughout the inspection period the inspectors walked down all areas of the plant and did not identify the installation of any unauthorized temporary modifications.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2OS1 Access Control to Radiologically Significant Areas (71121.01)

a. Inspection Scope

During the period from July 7-10, 2003, the inspector reviewed exposure significant work areas (i.e., High Radiation Areas and Airborne Radioactivity Areas) in the plant and associated controls and surveys of these areas to determine if the controls (e.g., surveys, postings, barricades) were acceptable. For these areas, the inspector reviewed radiological job requirements and attended job briefings to determine if radiological conditions in the work area were adequately communicated to workers through briefings and postings. The inspector also verified radiological controls, radiological job coverage, and contamination controls to ensure the accuracy of surveys and applicable posting and barricade requirements.

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

The inspector reviewed electronic pocket dosimeter alarm set points (both integrated dose and dose rate) for conformity with survey indications and plant policy. The controls implemented were compared to those required under TS 6.12 and 10 CFR 20, Subpart G, for control of access to high and locked high radiation areas.

On July 9 & 10, 2003, the inspector observed the transfer of spent resins from the Unit 2 spent resin storage tank to the radwaste processing area (July 9) and from the Unit 1 spent fuel pool filter to the spent resin tank (July 10). Transfer of these materials created temporary increases in radiological conditions on the 84' and 100' elevations of the auxiliary building. Inspector observations included: reviewing the pre and post-job survey maps; reviewing alarm set points for electronic dosimeters; attending the pre-job radiological and safety briefing; observing radiation protection technicians performing surveys and establishing radiological boundaries; and, post-job verification that radiological conditions had returned to normal levels. Also on July 9, 2003, the inspector observed work ongoing in the Unit 2 spent fuel pool (SFP) in preparation for the 2R13 outage. Activities involved movement of materials within the SFP and required the radiation protection staff to institute hot particle controls for this work.

b. Findings

No findings of significance were identified.

2OS2 ALARA Planning and Controls (71121.02)

a. Inspection Scope

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

A review of actual exposure results versus initial exposure estimates for current work was conducted including: comparison of estimated and actual dose rates and person-hours expended; determination of the accuracy of estimations to actual results; and determination of the level of exposure tracking detail, exposure report timeliness and exposure report distribution to support control of collective exposures to determine conformance with the requirements contained in 10 CFR 20.1101(b). The inspector also reviewed the exposure goal for Unit 2 refueling outage (110 person-rem) which was established prior to the identification of the outage work scope. At 95 days prior to the commencement of the outage, one major project (under vessel inspection) which can have significant impact on the outage dose had not been fully incorporated into the outage scope and schedule. At the time of this inspection, estimates by PSEG's ALARA staff was for the outage to be between 130-150 person-rem.

b. Findings

No findings of significance were identified.

2OS3 Radiation Monitoring Instrumentation (71121.03)

a. Inspection Scope

The inspector reviewed field radiological controls instrumentation utilized by radiation protection (RP) technicians and plant workers to measure radioactivity, including portable field survey instruments, friskers and portal monitors. The inspector conducted a review of selected radiation protection instruments observed in the radiologically controlled area (RCA). Items reviewed were verification of proper function and certification of appropriate source checks and calibration for these instruments used to ensure that occupational exposures are maintained in accordance with 10 CFR 20.1201. The inspector also reviewed PSEG's program for minimizing uptakes of radionuclides through the use of respiratory protection devices, and the measurement of internal uptakes through the use of whole body counting. This review included examination of PSEG documents related to medical examinations and training of personnel for utilization of respirators; calibration of respiratory fit testing equipment; daily checks performed on the whole body counter; and, annual full system calibration of the whole body counter.

The inspector reviewed the PSEG program for utilization of atmosphere supplying suits to meet the requirements of 10 CFR 20.1703(f). Paragraph 5.5.3 of PSEG procedure NC.NA-AP.ZZ-0045(Q), Rev 5, "Respiratory Protection Program," contains instructions for the establishment of protective measures and the use of stand-by personnel to effect removal of personnel in airline supplied respirators in the event of a loss of supply air. Airline supplied respirators are used at Salem during entries into the primary side of the steam generators. The controls described in NC.NA-AP.ZZ-0045(Q) have been verified by the inspector during inspections of the Unit 1 and 2 refueling outages (1R15 and 2R12 respectively), conducted in 2002.

b. Findings

No findings of significance were identified.

3. SAFEGUARDS

Cornerstone: Physical Protection

3PP2 Access Control (71130.02)

a. Inspection Scope

The inspectors verified that PSEG had effective site access controls and equipment in place designed to detect and prevent the introduction of contraband (firearms, explosives, incendiary devices) into the protected area as measured against 10 CFR 73.55(d) and the Physical Security Plan and Procedures.

On September 10, 2003, the inspectors reviewed Safeguards Log entries and event reports for the previous twelve months that were associated with the Access Control Program. A review was performed of the testing and maintenance procedures used for periodic performance testing of all search equipment to determine if the testing program was sufficiently challenging and implemented in accordance with the Physical Security Plan and associated procedures.

Site access control activities were observed. This included personnel and package processing through the search equipment during two peak ingress periods on September 10, 2003. Observation of vehicle search activities and testing of all access control equipment (including metal detectors, explosive material detectors, and x-ray examination equipment) were observed.

The Annual Security Audit, several self-assessment documents, and associated Event Reports (ER) were reviewed to verify that any issues associated with the access control and search programs were entered into the corrective action program as appropriate and that these issues were effectively resolved.

b. Findings

No findings of significance were identified.

3PP3 Response to Contingency Events (71130.03)

a. Inspection Scope

The following activities were conducted to determine the effectiveness of Salem/Hope Creek's response to contingency events, as measured against the requirements of 10 CFR 73.55 and the Salem Hope Creek Safeguards Contingency Plan:

On September 10, 2003, the inspectors reviewed documentation associated with the Salem/Hope Creek Annual Response Force Self-Assessments, which included force-on-force exercises. The review included documentation of training exercises and the critiques for the exercises conducted in 2003.

Performance testing of the Salem/Hope Creek intrusion detection and alarm assessment systems was conducted. This testing was accomplished by one inspector who toured the plant perimeter, selected zones, and observed performance tests of areas of potential vulnerability in the intrusion detection system. Concurrently, a second inspector observed both the audible alarms and the alarm assessment capabilities from the Central Alarm Station. During the walkdown of the intrusion detection system, 7 zones were performance tested by a combination of 2 walk, 2 run, and 6 crawl tests.

The Annual Security Audit and several self-assessment documents were reviewed to verify that any issues associated with the response to contingency events were entered into the corrective action program as appropriate and that these issues were effectively resolved.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

a. Inspection Scope

The inspectors sampled PSEG submittals for the performance indicators (PIs) listed below. To verify the accuracy of the PI data reported, PI definitions and guidance contained in NEI 99-02, "Regulatory Assessment Indicator Guideline," Rev. 1, were used to verify the basis in reporting for each data element.

Reactor Safety Cornerstone

- Emergency AC Power System Unavailability
- High Pressure Injection System Unavailability
- Heat Removal System Unavailability
- Residual Heat Removal System Unavailability

On a sampling basis the inspectors reviewed out-of-service logs, operating logs, maintenance rule database to determine the accuracy and completeness of the reported unavailability data for Unit 1 and Unit 2 for April 2002 through June 2003. The inspectors also discussed system unavailability questions and trends with responsible PSEG staff.

Physical Protection Cornerstone

- Protected Area Equipment
- Personnel Screening Program
- FFD/Personnel Reliability Program

The inspectors reviewed PSEG's tracking and trending reports and security event reports and performed personnel interviews for the PI data collected from April 2002 through July 2003.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

1. Annual Sample Review

a. Inspection Scope

The inspectors selected notifications and other reports associated with two issues for detailed review. The issues were associated with 1) a March 2003 Unit 2 reactor trip due to circulating water intake grassing (order 70030483); and 2) PSEG's identification of long-standing boric acid buildup on the 21 spent fuel pump inlet valve 21SF67 (order 70030579). The orders 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 evaluated PSEG's actions against the requirements of PSEG's corrective action program as delineated in procedure NC.WM-AP.ZZ-0002(Q), "Performance Improvement Process," and 10 CFR 50, Appendix B, Criterion XVI (Corrective Action).

b. Findings and Observations

There were no findings identified associated with the two samples reviewed; however, the inspectors identified that both issues represented long-standing equipment issues. The inspectors verified that the root cause evaluations and associated corrective actions taken and planned were appropriate relative to the identified problems; therefore, no violation of regulatory requirements or findings were identified. The inspectors noted that PSEG had been working towards identifying the causes and corrective actions for the deficiencies; however, additional action was needed to fully and effectively correct the problems.

2. Cross-Reference to PI&R Findings Documented Elsewhere

Section 1R12 describes a finding for inadequate maintenance practices that rendered the Unit 1 turbine driven auxiliary feedwater pump steam admission valve inoperable. The inspectors also concluded that problem identification and resolution weakness in March 2003 was a contributing cross-cutting weakness. PSEG engineers did not investigate similar valve problem symptoms on balance of plant applications for the same design valve. This weakness was a contributing cause that could have earlier identified the unreliable 1MS132 condition.

Section 1R12 describes a finding for inadequate corrective actions and service water pump strainer failures. An established troubleshooting plan was not used, despite having been developed as a corrective action from previous inadequacies in identifying strainer problems. The previous corrective actions were knowledge based, and the involved personnel were unaware.

4OA3 Event Followup (71153)

1. Unit 1 Reactor Trip on July 29, 2003

a. Inspection Scope

On July 29, 2003, at 1:29 p.m. Salem Unit 1 automatically tripped due to a generator protection and turbine trip. The cause of the event was an indicated ground fault on the 500kV 1-5 breaker which caused protective relaying to actuate resulting in a generator and turbine trip which initiated the reactor trip. Additionally, all vital busses were transferred to the emergency diesel generators. Control room operators declared an Unusual Event in accordance with Salem's emergency plan when the available offsite power infeed did not maintain power to the Unit 1 vital busses. The inspectors arrived in the main control room shortly after the automatic reactor trip and observed the licensed operator responses, including operator briefings, emergency operating procedure implementation, monitoring of plant conditions, establishing stable plant conditions in hot standby, and restoring all vital busses to an available offsite infeed. The inspectors remained onsite (primarily within the main control room) until stable hot standby conditions were achieved and after the Unusual Event was terminated with vital electric power returned to offsite power. The following documents were reviewed and used as criteria for evaluating the operators' response to this event:

- 1-EOP-TRIP-1, "Reactor Trip or Safety Injection"
- 1-EOP-TRIP-2, "Reactor Trip Response"
- S1.OP-IO.ZZ-0008, "Maintaining Hot Standby"
- Salem Event Classification Guide
- Salem Event Classification Guide Technical Basis

b. Findings

The details of this event were communicated to the Region I managers and senior risk analysts in regard for the correct followup inspection effort consistent with the reactor oversight process. The senior risk analysts considered the offsite power response. Management Directive 8.3, "NRC Incident Investigation Program" was referenced and a determination was made that the details of this event would warrant a special inspection. A special inspection was convened on August 18, 2003. The details of that inspection will be documented in NRC Inspection Report 05000272/2003010.

2. (Opened) LER 50-272/03-002-00, Reactor Trip due to Turbine Trip Caused by a 500kV Switchyard Breaker Trip

Details of the initial response to this July 29, 2003 event is described in Section 1R14 and 4OA3.1 of this inspection report. This LER will remain open pending completion of a special inspection performed in accordance with NRC Inspection Procedure 93812, "Special Inspection." The details of that inspection will be documented in NRC Inspection Report 05000272/2003010.

3. <u>(Opened/Closed) LER 50-272/03-001-00</u>, Plant Operation for Greater than 72 Hours with 13 AFW Pump Inoperable

Details of this issue were introduced in NRC Inspection Report 05000272/2003005 and 050003111/2003005 sections 1R12 and 4OA3. This issue is completely described in section 1R12 of this inspection report. This LER was reviewed by the inspectors and a minor error, not a violation of regulatory requirements, was identified. The LER credited a successful run of the 13 turbine driven auxiliary feedwater pump (TDAFWP) to occur on April 8, 2003. The inspectors identified that PSEG had confused a valve surveillance test with operating the 13 TDAFWP. PSEG entered this LER deficiency into the corrective action program and intended to submit an LER revision. The error did not impact the NRC's ability to correctly characterize the risk significance of this TDAFWP inoperability. This LER is closed.

4OA4 Cross Cutting Aspects of Findings

Section 1R12 describes inadequate maintenance practices that rendered a turbine driven auxiliary feedwater pump inoperable and a green finding that was related to human performance.

4OA6 Meetings, Including Exit

On October 9, 2003, the resident inspectors presented the inspection results to Mr. John Carlin and other members of his staff who acknowledged the findings. The inspectors confirmed that proprietary information was not provided or examined during the inspection.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee personnel:

C. Fricker	Plant Manager - Salem Operations
T. Straub	Security Manager
M. Ivanick	Security Operations Supervisor
A. Khanpour	Salem System Engineer Manager
W. Campbell	Salem Maintenance Manager
J. Reid	Operator Training Leader
A. Faulkner	NRC Exam Development Supervisor
M. Gwirtz	Salem Licensed Operator Training Superintendent
G. Gauding	Licensed Operator Exam Development
M. Swartz	Simulator Supervisor
P. Williams	Salem Simulator Lead
T. Cellmer	Radiation Protection Manager
D. Kelly	Radiation Protection Technical Supervisor - Budgets/Instruments
M. Hassler	Radiation Protection Operations Superintendent - Salem
B. Sebastian	Radiation Protection Technical Superintendent - ALARA Support
K. Watson	Radiation Protection Technical Supervisor - ALARA Support

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-272&311/03-07-01	URI	Potential inadequacy of required simulator testing and documentation. (Section 1R11)
50-272/03-07-03	URI	Untimely service water pump strainer corrective actions. (Section 1R12)
50-311/03-07-04	URI	Residual heat removal water-hammer after plant refuel activities on May 10, 2002. (Section 1R15)
50-272/03-002-00	LER	Reactor trip due to turbine trip caused by a 500kV switchyard breaker trip. (Section 4OA3.2)

Opened/Closed

50-272/03-07-02	NCV	Failure to properly perform maintenance on 13 auxiliary feedwater pump. (Section 1R12)
50-272/03-001-00	LER	Plant operation for greater than 72 hours with 13 AFW pump inoperable. (Section 40A3.3)

Closed

50-272/03-05-02	URI	Failure to properly perform maintenance on 13 auxiliary feedwater pump. (Section1 R12)

LIST OF DOCUMENTS REVIEWED

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

Section 1R15: Operability Evaluations

Notifications for U2 RHR water hammer: 20099566, 20099608, 20101499, 20102194, 20102647, 20102648, 20104986, 20108950, 20109152, 20110575, 20111363, 20113051, 20113054, 20113361, 20115684, 20125507, 20152990, 20155896, 20157102

Section 1R12: Maintenance Rule Implementation

References for 13 AFW Pump Trip:
Notification 20146103, Salem Unit 1 TARP Report, 13 AFW Pump Trip During Start
Order 70031717, 13 AFW Pump Trip on Start - N1 20146103
Notification 20146321, 13 AFW Pump Trip on Start - N1 20146103
Notification 20146105, 13 AFW Pump Valve (70031717)
Notification 20119972, Revise S1.RA-ST.AF-0003(Q), revision 9
Order 80054453, Revise S1.RA-ST.AF-0003(Q), revision 9
Order 30079158, 3Y 1MS52 Clean and Inspect - Trip Soleniod
Notification 20134665, 3Y 1MS52 Clean and Inspect - Trip Soleniod
PM006228, 1MS132-Valve Assembly Overhaul [Task not implemented]
PM007144, 2MS132-Valve Assembly Overhaul [Task not implemented]
S1.OP-ST.AF-0003(Q), Inservice Testing - 13 Auxiliary Feedwater Pump [records of tests performed on 10/29/03, 11/1/2003, 12/6/03, 2/28/03, 5/23/03 and twice on 5/24/03]
S1.RA-ST.AF-0003(Q), Inservice Testing - 13 Auxiliary Feedwater Pump Acceptance Criteria [revisions 9 and 10]
SH.ER-DG.ZZ-0001(Z), Preventatable and Repeat Preventable System Functional Failure Determination
SH.ER-DG.ZZ-0002(Z), Maintenance Rule (a)(1) Evaluations and Goal Monitoring
SH.ER-DG.ZZ-0003(Z), Processing Maintenance Rule Reliability Data

Salem Unit 1, Auxiliary Feedwater System Health Status Report [period 11/01/2002 - 01/31/2003]
NC.ER-AP.ZZ-0075(Q), Valve Programs
Salem PSA System Notebook - Auxiliary Feedwater System and Main Feedwater System
SE.MR.SA.01, Salem System Function and Risk Significant Guide
SE.MR.SA.02, Salem System Function Level Maintenance Rule vs. Risk Reference
Notification 20114985, 1MS132 parent seat leakage
Order 30037646, 1R PM: 1MSE3/ Overspeed Test
SH.RA-AP.ZZ-0105(Q), "IST Program Management"
NC.NA-AP.ZZ-0070(Q), "Inservice Testing (IST) Program"
NC.WM-AP.ZZ-0002(Q), "Performance Improvement Process"
SH.MD-AP.ZZ-9005(Q), "Air Operated Valve Program"
Notification 20149336, TARP Procedure Non-Compliance [13 AFW Pump Trip TARP]
QA Assessment Monitoring Feedback 2003-0161
Salem 1 - 1MS132 Fact Finder in Relation to Inservice Testing [performed by IST Program Mgr.]
Vendor Technical Document (VTD) 301693, Masoneilan Spring-Diaphragm Actuator Instructions
for # 9, 11, 13, 15, 18 and 24.
Vendor Technical Document (VTD) 301686, Masoneilan Instruction and Maintenance Manual Spring-Diaphragm Actuator Instructions
Order 30079158, 3Y 1MS52 Clean and Inspect - Trip Solenoid
NC.NA-AP.ZZ-0022(Q), Nuclear Procedure System
SC.MD-GP.ZZ-0022(Q), Bolt Torquing and Bolting Sequence Guidelines
SH.IC-GP.ZZ-0002(Q), Disassembly, Inspection, Reassembly and Testing of Masoneilan Model 37/38 Air Operated Actuators

Notifications for 13 SWP Strainer Trip: 20147166, 20147085, 20147087, 20144330, 20144086, 20069961, 20017663

<u>Section 3: Safeguards</u>

Salem/Hope Creek Physical Security Plan
Security Plan Procedure 12 (SP-12), NC.SP-AP.ZZ-0012-Rev. 18, <u>Security System Testing and Maintenance</u>, August 22, 2003
Order/Operations Assigned to Security and In-Processing, September 1, 2002 - September 10, 2003
Business Support (Security) Quarterly Self Assessment Effectiveness Report, Jan.-Mar. 2003 and April- June 2003
Security Audit, QA Assessment Report 2003-0002 (QA-4A.137), February 21, 2003
Safeguards Event Log, September 2002 - September 2003

LIST OF ACRONYMS

AFW	auxiliary feedwater
ALARA	as low as is reasonably achievable
CCW	component cooling water
CDF	core damage frequency
CFR	code of federal regulations
CRS	control room supervisor
CY	calendar year
DCP	design change package
EDG	emergency diesel generator
EOP	emergency operating procedure
ER	event report
gpm	gallons per minute
ICMs	Interim Compensatory Measures
MDAFW	motor driven auxiliary feedwater
NCV	non-cited violation
NEI	Nuclear Energy Institute
NRC	U.S. Nuclear Regulatory Commission
ODs	operability determinations
PARS	Publicly Available Records Systems
PI	performance indicator
PMT	post-maintenance testing
PRA	probabilistic risk assessment
PSA	probabilistic safety assessment
PSEG	Public Service Electric Gas
RCA	radiologically controlled area
RCP	reactor coolant pump
RHR	residual heat removal
RP	radiation protection
RWP	radiation work permit
SDP	significance determination process
SFP	spent fuel pool
SGFP	steam generator feed pump
SGTR	steam generator tube rupture
SW	service water
TARP	Transient Assessment Response Plan
TDAFW	turbine-driven auxiliary feedwater
TS	Technical Specification(s)
UFSAR	Updated Final Safety Analysis Report