UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION I
475 ALLENDALE ROAD
KING OF PRUSSIA, PENNSYLVANIA 19406-1415

August 14, 2007

EA-07-149

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

SUBJECT: SALEM NUCLEAR GENERATING STATION, UNIT NOS. 1 AND 2 - NRC INTEGRATED INSPECTION REPORT 05000272/2007003 and 05000311/2007003 AND NOTICE OF VIOLATION

Dear Mr. Levis:

On June 30, 2007, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at the Salem Nuclear Generating Station, Unit Nos. 1 and 2. The enclosed integrated inspection report documents the inspection results that were discussed on July 6, 2007, with Mr. Gellrich and other members of your staff.

This 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.

Based on the results of this inspection, the NRC has determined that a Severity Level IV violation of NRC requirements occurred. The violation was evaluated in accordance with the NRC Enforcement Policy included on the NRC's web site at www.nrc.gov; select What We Do, Enforcement, then Enforcement Policy. The violation is cited in the enclosed Notice of Violation (Notice) and the circumstances surrounding it are described in detail in the subject inspection report. The violation is being cited in the Notice because PSEG Nuclear LLC did not meet the requirements of 10 Code of Federal Regulations (CFR) 50.55a(g)(5)(iii) and 10 CFR 50.55a(g)(5)(iv) for Salem Nuclear Generating Station, Unit 2, which affected the ability of the NRC to perform its regulatory function. This violation is a result of PSEG Nuclear LLC' s failure to apply for a relief request for the inservice inspection (ISI) program within 12 months after the completion of the second ISI interval.

You are required to respond to this letter and you should follow the instructions specified in the enclosed Notice when preparing your response. In addition to the information required in the Notice, your reply should include: (1) an evaluation demonstrating that Salem Unit 2 systems affected by this failure were operable during the period from November 23, 2003, to the present; and (2) an assessment of the effect of the incomplete inspections on the current ISI interval 3 which began on November 24, 2003. The NRC will use your response, in part, to determine whether further enforcement action is necessary to ensure compliance with regulatory requirements.

The report also documents one NRC-identified finding and three self-revealing findings of very low safety significance (Green). Three of these findings were determined to involve violations of NRC requirements. If you contest any non-cited violations (NCVs) 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, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; 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, 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/

Arthur L. Burritt, Chief
Projects Branch 3
Division of Reactor Projects

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

Enclosures:
1. Notice of Violation
2. Inspection Report 05000272/2007003 and 05000311/2007003
   w/attachment: Supplemental Information

cc w/encl:
T. Joyce, Senior Vice President - Salem and Hope Creek
R. Braun, Site Vice President - Salem
G. Gellrich, Salem Plant Manager
B. Clark, Director of Finance
K. Chamblis, Director of Nuclear Oversight
J. Keenan, General Solicitor, PSEG
M. Wetterhahn, Esquire, Winston and Strawn, LLP
L. Peterson, Chief of Police and Emergency Management Coordinator
P. Mulligan, Acting-Manager, NJ Bureau of Nuclear Engineering
P. Baldauf, Assistant Director, NJ Radiation Protection Programs
H. Otto, Ph.D., Administrator, DE Interagency Programs, DNREC Div of Water Resources,
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DATE	08/13/07		08/13/07		08/13/07		08/14/07	

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NOTICE OF VIOLATION

PSEG Nuclear LLC
Salem Nuclear Generating Station, Unit No. 2

Docket No. 50-311
License No. DPR-75
EA-07-149

During an NRC inspection conducted between April 2, 2007, and April 27, 2007, a violation of NRC requirements was identified. In accordance with the NRC Enforcement Policy, the violation is listed below:

> 10 CFR 50.55a(g)(5)(iv) states in part that where an examination requirement by the code or addenda is determined to be impractical by the licensee and is not included in the revised inservice inspection (ISI) program as permitted by paragraph (g)(4) of this section, the basis for this determination must be demonstrated to the satisfaction of the Commission not later than 12 months after the expiration of the initial 120-month period of operation from start of facility commercial operation and each subsequent 120-month period of operation during which the examination is determined to be impractical.
>
> 10 CFR 50.55a(g)(5)(iii) states in part that if the licensee has determined that conformance with certain code requirements is impractical for its facility, the licensee shall notify the Commission and submit, as specified in Section 50.4, information to support the determinations.
>
> Contrary to the above, PSEG Nuclear LLC determined that conformance with the code requirement for 100% inspection of 69 Class 1 welds and 29 Class 2 welds at Salem Nuclear Generating Station, Unit 2, during ISI interval 2 (May 10, 1992 - November 23, 2003), was impractical, however, (1) the basis for the termination was not demonstrated to the satisfaction of the Commission within 12 months after the expiration of ISI interval 2; and, (2) while PSEG notified the Commission of its determination on March 21, 2006, 28 months after the end of ISI interval 2, it did not submit the information necessary to support the determinations.
>
> This is a Severity Level IV violation (Supplement I).

Pursuant to the provisions of 10 CFR 2.201, PSEG Nuclear LLC is hereby required to submit a written statement or explanation to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001 with a copy to the Regional Administrator, Region I, and a copy to the NRC Resident Inspector at the facility that is the subject of this Notice, within 30 days of the date of the letter transmitting this Notice of Violation (Notice). This reply should be clearly marked as a “Reply to a Notice of Violation EA-07-149” and should include: (1) the reason for the violation, or, if contested, the basis for disputing the violation or severity level; (2) the corrective steps that have been taken and the results achieved; (3) the corrective steps that will be taken to avoid further violations; and (4) the date when full compliance will be achieved.

Your response may reference or include previous docketed correspondence, if the correspondence adequately addresses the required response. If an adequate reply is not received within the time specified in this Notice, an order or a Demand for Information may be issued as to why the license should not be modified, suspended, or revoked, or why such other action as may be proper should not be taken. Where good cause is shown, consideration will be given to extending the response time.

If you contest this enforcement action, you should also provide a copy of your response, with the basis for your denial, to the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001.

Because your response will be made available electronically for public inspection in the NRC Public Document Room or from the NRC's document system (ADAMS), accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html, to the extent possible, it should not include any personal privacy, proprietary, or safeguards information so that it can be made available to the public without redaction. If personal privacy or proprietary information is necessary to provide an acceptable response, then please provide a bracketed copy of your response that identifies the information that should be protected and a redacted copy of your response that deletes such information. If you request withholding of such material, you must specifically identify the portions of your response that you seek to have withheld and provide in detail the bases for your claim of withholding (e.g., explain why the disclosure of information will create an unwarranted invasion of personal privacy or provide the information required by 10 CFR 2.390(b) to support a request for withholding confidential commercial or financial information). If safeguards information is necessary to provide an acceptable response, please provide the level of protection described in 10 CFR 73.21.

In accordance with 10 CFR 19.11, you may be required to post this Notice within two working days.

Dated this 14TH day of August 2007

U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket Nos:	50-272, 50-311
License Nos:	DPR-70, DPR-75
Report No:	05000272/2007003 and 05000311/2007003
Licensee:	PSEG Nuclear LLC (PSEG)
Facility:	Salem Nuclear Generating Station, Unit Nos. 1 and 2
Location:	P.O. Box 236 Hancocks Bridge, NJ 08038
Dates:	April 1, 2007 through June 30, 2007
Inspectors:	D. L. Schroeder, Senior Resident Inspector H. Balian, Resident Inspector J. G. Schoppy, Jr., Senior Reactor Inspector J. T. Furia, Senior Health Physicist M. Patel, Reactor Engineer A. Patel, Reactor Engineer A. Ziedonis, Reactor Inspector T. L. O'Hara, Reactor Inspector M. Snell, Reactor Inspector G. Ottenberg, Reactor Inspector
Approved By:	Arthur L. Burritt, Chief Projects Branch 3 Division of Reactor Projects

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SUMMARY OF FINDINGS

IR 05000272/2007003, 05000311/2007003; 04/01/2007 - 06/30/2007; Salem Nuclear Generating Station, Unit Nos. 1 and 2; Inservice Inspection Activities, Maintenance Effectiveness, Maintenance Risk Assessments and Emergent Work Control, Operability Evaluations, Event Followup.

The report covered a 13-week period of inspection by resident inspectors and announced inspections by regional specialist inspectors. One Severity Level IV cited violation (NOV), three green NCVs, and one green finding 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 4, dated December 2006.

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Initiating Events

- Green. A self-revealing finding for improper maintenance on a demineralizer sight glass was identified when the sight glass catastrophically failed and initiated a condensate system transient that resulted in a reactor trip. Contrary to vendor recommendations that each sight glass be installed and torqued in place only one time, maintenance technicians had re-installed the sight glass on the demineralizer following vessel maintenance. PSEG replaced all Unit 2 demineralizer sight glasses before the subsequent Unit 2 startup. The finding is greater than minor because it is associated with the equipment performance attribute of the Initiating Events cornerstone, and because it adversely affects the cornerstone objective of limiting the likelihood of those events that upset plant stability and challenge critical safety functions during power operations. The inspectors conducted a Phase 1 SDP screening in accordance with IMC 0609 and determined that the finding is of very low safety significance.

  The finding has a cross-cutting aspect in the area of human performance because PSEG did not ensure that complete, accurate, and up to date design documentation, procedures, and work packages were available (H.2.c). Specifically, vendor documentation for the demineralizer sight glass was not available on site, and as a result, PSEG did not incorporate appropriate vendor guidance regarding reinstallation and torque requirements for the sight glass into plant procedures. (Section 4OA3)

Cornerstone: Mitigating Systems

- Green. A self-revealing NCV for failure to comply with 10 CFR 50, Appendix B, Criterion V, "Instruction, Procedures, and Drawings," was identified when operators discovered the 21 CAC in an inoperable condition on May 1, 2007. In accordance with post-maintenance testing procedures for the 22 CAC, operators placed the 21 CAC in the pump down mode. When the test of the 22 CAC was aborted, operators did not return the 21 CAC to operable status in accordance with procedures. The 21 CAC was inoperable for approximately six hours. PSEG restored the 21 CAC to operable status and entered the issue into the corrective action program (CAP) as notifications 20322784 and 20322793. This finding is greater than minor because the performance deficiency is associated with the equipment performance attribute of the Mitigating Systems cornerstone, and affected the cornerstone objective to ensure the availability and reliability of systems that respond to initiating events to prevent undesirable consequences. The inspectors conducted a Phase 1 SDP screening in accordance with IMC 0609, and determined the finding is of very low risk significance.

The finding has a cross-cutting aspect in the area of human performance because PSEG personnel did not use human error prevention techniques (H.4.a). Specifically, an operator did not identify an incorrect switch position because the operator did not verify the expected system response when placing the 21 CAC switch to run. (Section 1R13)

- <u>Green</u>. A self-revealing NCV for failure to comply with 10 CFR, Appendix B, Criterion V, “Instruction, Procedures, and Drawings,” was identified when operators discovered a significant leak in the copper oil filter tubing on the 22 CAC on May 1, 2007, that made the 22 CAC inoperable. PSEG had not inspected or replaced the affected tubing as specified in the maintenance procedure. PSEG replaced the tubing and returned the 22 CAC to service. This resulted in ten hours of unplanned unavailability on the 22 CAC. The finding is greater than minor because it is associated with the equipment performance attribute of the Mitigating Systems cornerstone, and affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. The inspectors conducted a Phase 1 SDP screening in accordance with IMC 0609 and determined that the finding is of very low safety significance.

  The finding has a cross-cutting aspect in the area of problem identification and resolution because PSEG did not take appropriate corrective actions to address safety issues and adverse trends in a timely manner commensurate with their safety significance (P.1.d). Specifically, corrective actions to prevent CAC tubing failures were ineffective because the visual inspections required by the procedure revision incorporated after previous CAC oil tubing failures, may not have identified degraded copper tubing in time to prevent tubing failure. (Section 1R12)

- <u>Green</u>. The inspectors identified an NCV for failure to comply with 10 CFR 50, Appendix B, Criterion V, “Instruction, Procedures, and Drawings,” when operators did not implement additional log readings for service water (SW) heat exchangers (HXs) as specified by plant procedures during extended periods of high river detritus from March through May of 2007. This required PSEG to take the 12 CC HX out of service for 45 hours to complete system flushes in May and June 2007 to restore full operability. The finding is more than minor because it is associated with the equipment performance attribute of the Mitigating Systems cornerstone and affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. The inspectors conducted a Phase 1 SDP screening in accordance with IMC 0609 and determined that the finding is of very low safety significance.

The finding has a cross-cutting aspect in the area of human performance because PSEG personnel did not follow plant procedures (H.4.b). Specifically, operators did not implement additional log readings for SW HXs as specified by plant procedures during extended periods of high river detritus from March through May of 2007. (Section 1R15)

Cornerstone: Barrier Integrity

- Green. The inspectors identified a Severity Level IV cited violation of 10 CFR 50.55a(g)(5)(iv) and 10 CFR 50.55a(g)(5)(iii). PSEG did not submit needed relief requests for ASME code required inspections for Salem Unit 2 within 12 months after the end of the second ten year inservice inspection (ISI) interval and when PSEG notified the Commission of its determination on March 21, 2006, 28 months after the end of ISI interval 2, it did not submit the information necessary to support the determinations. This finding is handled under traditional enforcement because PSEG's actions impacted the NRC regulatory process. The finding is of very low significance because no actual safety consequences occurred. (Section 1R08)

B. Licensee Identified Violations

None.

REPORT DETAILS

Summary of Plant Status

Salem Nuclear Generating Station, Unit No. 1 (Unit 1) began the period shut down in mode 6 for refuel outage 1R18. Unit 1 returned to service on April 20, 2007, and reached 80 percent power for fuel conditioning on April 22, 2007. Unit 1 was manually tripped from 40 percent power on April 24, 2007, in response to a degraded circulating water system. The unit returned to service on April 26, 2007. On April 30, 2007, Unit 1 was manually tripped from 80 percent power due to circulating water system degradation. Unit 1 was returned to service on May 3, 2007, and reached 100 percent power on May 12, 2007, following fuel conditioning. Unit 1 remained at 100 percent power for the remainder of the inspection period.

Salem Nuclear Generating Station, Unit No. 2 (Unit 2) began the period at 100 percent power and remained at full power until May 24, 2007, when the unit tripped automatically due to low steam generator levels. Unit 2 was returned to service on June 2, 2007, and reached 100 percent power on June 4, 2007. Unit 2 remained at 100 percent power for the remainder of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

a. Inspection Scope (1 sample)

The inspectors reviewed PSEG's completed procedure SC.OP-PT.ZZ-0002, "Station Preparations for Seasonal Conditions," for hot weather conditions. Inspectors reviewed Unit 1 and Unit 2 system specific documentation for auxiliary building ventilation, component cooling (CC), and station air and interviewed responsible system engineers. The inspectors also reviewed operability determinations potentially impacted by hot weather and interviewed station personnel responsible for implementing severe weather preparations. Documents reviewed are listed in the Attachment.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment

.1 Partial Walkdown (71111.04)

a. Inspection Scope (5 samples)

The inspectors performed partial walkdowns of five systems to verify the operability of redundant or diverse trains and components when safety equipment was inoperable. The inspectors focused their review on potential discrepancies that could impact the function of the system, and therefore, potentially increase risk. The inspectors reviewed applicable operating procedures, walked down control systems components, and verified that selected breakers, valves, and support equipment were in the correct position to support system operation. The inspectors also verified that PSEG had properly identified and resolved equipment alignment problems that could cause initiating events or impact the capability of mitigating systems or barriers and entered them into the CAP. Documents reviewed are listed in the Attachment. The following systems were walked down:

- Unit 1 service water (SW) header No. 12 during the No. 11 SW header outage;
- Unit 1 component cooling water (CCW) system dechromation process prior to RFO S1R18;
- Unit 1 Station Power Transformer (SPT) No. 14 during SPT No. 13 outage;
- Unit 1 Residual Heat Removal (RHR) system No. 12 during RHR No. 11 outage; and
- Unit 1 CCW HX No. 11 after restoration during RFO S1R18.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05AQ)

.1 Fire Protection - Tours

a. Inspection Scope (10 samples)

The inspectors conducted tours of the ten areas listed below to assess the material condition and operational status of fire protection features. The inspectors verified that combustibles and ignition sources were controlled in accordance with PSEG's administrative procedures; fire detection and suppression equipment was available for use; that passive fire barriers were maintained in good material condition; and that compensatory measures for out-of-service, degraded, or inoperable fire protection equipment were implemented in accordance with PSEG's fire plan. Documents reviewed are listed in the Attachment.

- Unit 1 and Unit 2 Pre-Fire Plan FRS-II-421, 4160V Switchgear Rooms & Battery Rooms
- Unit 1 and Unit 2 Pre-Fire Plan FRS-II-435, Diesel Fuel Oil Storage Area
- Unit 1 and Unit 2 Pre-Fire Plan FRS-II-423, Auxiliary Building Ventilation Units, Elevation: 122' - 0"
- Unit 1 and Unit 2 Pre-Fire Plan FRS-II-911, SW Intake Structure, Elevations: 92' & 112'
- Unit 1 and Unit 2 Pre-Fire Plan FRS-II-452, Control Room Area

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures (71111.06)

a. Inspection Scope (1 sample)

The inspectors performed one external flood protection measures inspection for Unit 1 and 2. Numerous watertight flood protection doors, exterior penetrations, the yard drainage system, and the SW intake structure were walked down to verify operational readiness. The inspectors assessed the readiness of portable sump pumps and interviewed operations personnel on the usage of flooding procedures. Documents reviewed are listed in the Attachment.

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance (71111.07A)

a. Inspection Scope (1 sample)

The inspectors reviewed performance data and interviewed the program manager responsible for implementation of NRC Generic Letter (GL) 89-13 to verify that potential HX or heat sink deficiencies were identified and that PSEG adequately resolved heat sink performance problems. Specifically, the inspectors reviewed 11 CC HX performance data. Inspectors evaluated trending data and verified that equipment would perform satisfactorily under design basis conditions. The method of performance monitoring was compared against NRC GL 89-13, “Service Water System Problems Affecting Safety-Related Equipment,” and EPRI NP-7552, “Heat Exchanger Performance Monitoring Guidelines,” for conformance to these guidance documents. Additional documents reviewed are listed in the Attachment.

The inspectors walked down the selected components and the SW intake structure to assess the general material condition of the selected HXs and associated SW components. The inspectors also inspected the internal components of 11 CC HX, which was open for preventive maintenance, and observed the type and quantity of material present within the HX. The inspectors reviewed photographs of the 11 CC HX internals taken before and after cleaning and preservation activities. The inspectors reviewed a sample of notifications related to SW HXs to ensure that problems related to these components were appropriately identified, characterized, and corrected. Documents reviewed are listed in the Attachment.

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection Activities (71111.08P)

a. Inspection Scope (8 samples)

The scope of the inspection is limited to the reactor vessel, reactor vessel internals, reactor coolant system (RCS) pressure boundary, piping connected to the RCS, risk significant piping system boundaries and containment system boundaries. The following system risk priorities were used to guide selection of inspection samples: primary coolant system, steam generators, charging system, auxiliary feedwater (AFW), SW, RHR, high pressure coolant injection, low pressure coolant injection and the containment system.

The inspectors observed selected samples of nondestructive examination (NDE) activities in process. Also, the inspectors reviewed selected additional samples of completed NDE and repair/replacement activities. The sample selection was based on the inspection procedure objectives and risk priority of those components and systems where degradation would result in a significant increase in risk of core damage. The observations and documentation reviews were performed to verify the activities were performed in accordance with the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code requirements. The inspectors reviewed a sample of inspection reports and notifications initiated as a result of problems identified during ISI examinations. Also, the inspectors evaluated the effectiveness of the resolution of problems identified during selected ISI activities. The inspectors reviewed PSEG's boric acid corrosion control program.

The inspectors observed the performance of two in-process NDE activities and reviewed documentation and examination reports for an additional 16 NDE activities. The inspectors reviewed two samples of welding activities on a pressure boundary and reviewed the package for a repair performed in accordance with the ASME Code during the previous operating cycle. (1 sample)

The inspectors observed the ultrasonic test performed on the girth weld on the pressurizer top dome to vessel. The inspectors also witnessed the visual examination of the primary containment penetrations on the 78 ft elevation. The inspectors observed manual ultrasonic testing (UT) activities to verify the effectiveness of the examiner, process, and equipment to identify degradation of risk significant systems, structures and components and to evaluate the activities for compliance with the requirements of ASME Section XI of the Boiler and Pressure Vessel Code.

The inspectors reviewed two samples of NDE evaluations which had been initially rejected and subsequently accepted after evaluation. The inspectors also reviewed the radiograph data sheets of radiographs taken on the fabrication of replacement sections of piping in the boiler feed system. (1 sample)

The inspectors reviewed report "A Steam Generator Degradation Report for Salem Unit 1." This report documented the SG degradation measured in refueling outage 1R16 and gave the technical basis for the inspections conducted during this refueling outage 1R18. Additionally, the inspectors observed the collection of eddy current data, and the operation of the eddy current testing equipment in the containment. The inspectors also reviewed the summary results of all eddy current testing, the final plugging list and the one tube which met the criteria for in situ pressure testing. PSEG applied a conservative 33 percent through wall indication criteria as a plugging limit, resulting in a total number of 95 tubes that required plugging. This conservative limit was used, rather than the 40 percent through wall limit, in order to skip eddy current testing during the next Unit 1 outage. The inspectors reviewed the record of the in situ pressure test conducted on tube R54C65 in SG 13. The test showed structural integrity, but the tube was subsequently plugged and removed from service. (1 sample)

The inspectors reviewed the ECP for replacement of the reactor upper internals control of guide tube split pins. Additionally, the inspectors observed the disassembly of the control rod guide tubes. During the split pin change out PSEG documented the discovery of one broken split pin in guide tube K4 (notification 20319713). All pieces of the pin were retrieved and the pin was replaced with a new pin. (1 sample)

The inspectors reviewed several NDE data sheets that reported indications or defects identified by several NDE methods and subsequently verified that PSEG appropriately dispositioned those indications.

The inspectors reviewed two examples (20008368 and 20116971) of rejectable indications/defects identified during previous ISI periods that were accepted for continued service without repair or rework. The inspectors verified the acceptance and technical justification was appropriate and reflected engineering involvement. (1 sample)

The inspectors reviewed data sheets of radiographs for welds performed during the present outage. The inspectors verified the welding and acceptance were performed in accordance with the code requirements. Radiographs will be selected based on system risk level. (1 sample)

The inspectors reviewed two examples (60055945 and 60059073) of ASME Section XI Code repairs and replacements from previous outages. The inspectors verified that the repair and replacement activities were in accordance with the Code requirements. (1 sample)

The inspectors reviewed two examples of non code repairs conducted during the current refueling outage and verified that the non-code repairs were performed in accordance with PSEG commitments concerning the repairs. (1 sample)

The inspectors reviewed PSEG review of the operating experience from the recent nozzle cracking event at Duane Arnold. PSEG's program evaluated the event for applicability at Salem Unit 1 and 2 and determined that no additional inspections were needed.

The inspectors reviewed PSEG actions and commitments to meet MRP-139, "Materials Reliability Program: Primary System Piping Butt Weld Inspection and Evaluation Guidelines." PSEG had a program that identified all applicable components and their inspection needs. PSEG met the MRP-139 requirements.

The inspectors reviewed the relief requests for the previous ISI interval for Salem Unit 1 and Unit 2 to understand the reason for several incomplete weld inspections. The inspectors reviewed the relief request submittals and noted that PSEG's request for Unit 2 was not in compliance with 10 CFR 50.55(a) and the ASME Boiler & Pressure Vessel Code requirements. The inspectors verified that PSEG's request for Unit 1 met the requirements.

b. Violation

Introduction. A Severity Level IV violation of 10 CFR 50.55a(g)(5)(iii) and 10 CFR 50.55a(g)(5)(iv) was identified for PSEG's failure to submit a relief request, in a timely manner, for incomplete inspections during ISI interval 2 for Unit 2 and for failing to provide sufficient information to demonstrate impracticality of inspection. PSEG withdrew the original relief requests and remains in noncompliance with the regulations.

Description. Unit 2's second ISI interval ran from May 10, 1992, to November 23, 2003. PSEG submitted relief requests for incomplete inspections during interval 2 via letter LR-N06-0024 on March 21, 2006 (S2-I2-RR-BO1 (69 Class 1 welds), and S2-I2-RR-CO1 (29 Class 2 welds). March 21, 2006, was 28 months after the end of interval 2.

During NRC review of the submitted relief requests, the reviewer could not determine PSEG's basis for determining that several welds could not be inspected and NRR asked for additional information from PSEG. PSEG did not respond to the requests for additional information and eventually retracted the relief requests on March 26, 2007. Thus, the nonconforming condition has continued from November 23, 2003, to the present. The third ISI interval began on November 24, 2003, and it is not apparent what, if any, adjustments were made to the third interval inspection plan since the required second interval relief was not obtained.

PSEG did not identify this Code nonconformance in March 2006, when the relief requests were submitted. At that time the relief requests were already past the 12 month requirement in 10 CFR 50.55a(g)(5)(iii). Additionally, PSEG conducted an ISI Program Self Assessment in March 2004 and did not identify that the relief request had been submitted after the required date of November 23, 2004 (12 months after November 23, 2003).

PSEG has not performed a detailed evaluation on the operability of the plant with numerous incomplete weld examinations and the plant's noncompliance with the ASME Code requirements.

Analysis. PSEG's failure to file the required relief requests within the required 12 month interval, the failure to respond to requests for additional information, and the retraction of the relief requests, have impacted the NRC's ability to perform its regulatory function. This finding has the potential to affect RCS barrier integrity through potential undetected degradation in Class 1 and Class 2 welds. The reduced examinations of the welds has been left uncorrected since November 23, 2003, which could result in undetected flaws affecting Class 1 and 2 system pressure boundary welds.

In accordance with MC 0612, Appendix B, Section 2, this finding has the potential to impact the NRC's ability to perform its regulatory function since PSEG did not submit the required relief request within the required time period, and as a result, impeded the NRC's ability to evaluate and decide on the relief requests in a timely manner.

This violation was considered to be greater than minor because of the potential impact on the operability of safety-related equipment. In accordance with Supplement 1 of the Enforcement Policy, the violation was characterized as Severity Level IV because it involved a failure to meet regulatory requirements that have more than minor safety significance, but is not considered as significant as a Severity Level I, II, or III violation.

This Severity Level IV violation is being dispositioned as a Notice of Violation (NOV), per Section VI. A. 1. a. of the Enforcement Policy because PSEG did not restore compliance within a reasonable time after the violation was identified. In this case, PSEG initiated a Notification 20268549 on January 18, 2006, when the problem was identified. However, the corrective actions from this Notification have not restored compliance.

Enforcement. 10 CFR 50.55a(g)(5)(iv) states "Where an examination requirement by the code or addenda is determined to be impractical by the licensee and is not included in the revised ISI program as permitted by paragraph (g)(4) of this section, the basis for this determination must be demonstrated to the satisfaction of the Commission not later than 12 months after the expiration of the initial 120-month period of operation from the start of facility commercial operation and each subsequent 120-month period of operation during which the examination is determined to be impractical."

Also, 10 CFR 50.55a(g)(5)(iii) states "If the licensee has determined that conformance with certain code requirements is impractical for its facility, the licensee shall notify the Commission and submit, as specified in Section 50.4, information to support the determinations."

Contrary to the above, PSEG determined that conformance with the code requirement for 100% inspection of 69 Class 1 welds and 29 Class 2 welds at Salem Unit 2, during ISI interval 2 (May 10, 1992 - November 23, 2003), was impractical, but did not submit the basis for this relief request within 12 months after the end of ISI interval 2. Also, after PSEG submitted the basis on March 21, 2006, it subsequently withdrew its request, and therefore, did not submit the information necessary to support the basis for the determination. The NRC notes that PSEG resubmitted the relief requests again on June 29, 2007.

Because this performance deficiency affected the ability of the NRC to perform its regulatory function this violation is being handled under the traditional enforcement process. Normally, Severity Level IV violations would be treated non-cited violations consistent with the NRC Enforcement Policy. However, since the NRC has determined that PSEG did not restore compliance in a reasonable time after the violation was identified, this violation is being cited. **(NOV 05000311/2007003-01, Failure to Notify the NRC of Incomplete Weld Inspections and Failure to Obtain Relief Request for Incomplete Inspection of Class 1 and Class 2 Welds for the Second ISI Interval Within the Required Time Period)**

1R11 Licensed Operator Requalification Program (71111.11Q)

a. Inspection Scope (1 sample)

The inspectors observed a simulator training scenario conducted on June 28, 2007, to assess operator performance and training effectiveness. The scenario involved a reduction of grid voltage, loss of control air to the turbine building, and a security event that required operators to manually trip the reactor. 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. The inspectors observed the simulator instructors' critique of operator performance. Documents reviewed are listed in the Attachment.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12Q)

a. Inspection Scope (2 samples)

The inspectors reviewed performance monitoring and maintenance effectiveness issues for two systems. The inspectors assessed whether PSEG was adequately monitoring equipment performance to ensure that preventive maintenance was effective. The inspectors verified that the components were monitored in accordance with the maintenance rule program requirements. The inspectors compared documented functional failure determinations and unavailability hours to those being tracked by PSEG to evaluate the effectiveness of PSEG's condition monitoring activities and to determine whether performance goals were met. The inspectors reviewed applicable work orders (WO), notifications, and preventive maintenance tasks. Documents reviewed are listed in the Attachment. The following two samples were completed:

- Unit 2 CACs; and
- Unit 1 and 2 station air compressors high air temperature issues.

b. Findings

Introduction. A self-revealing Green NCV for failure to comply with 10 CFR, Appendix B, Criterion V, “Instruction, Procedures, and Drawings,” was identified when operators discovered a significant leak in the copper oil filter tubing on the 22 CAC on May 1, 2007, that made the 22 CAC inoperable. PSEG had not inspected or replaced the affected tubing as specified in the maintenance procedure.

Description. The 22 CAC was declared operable following compressor replacement and post maintenance testing. The 22 CAC was placed in service, developed an oil leak and was declared inoperable less than two days after the chiller maintenance was completed. PSEG personnel identified that oil was leaking from a crack in the copper oil filter tubing. The crack was caused by fatigue of the tubing line. The filter was isolated, and the copper line was replaced. Repairs and post maintenance testing were completed in ten hours. The 22 CAC was inoperable during this unplanned maintenance period.

Replacement of the CAC compressor was performed using maintenance procedure SC.MD-PM.CH-0001, Revision 12, “Acme Chiller Compressor Inspection and Repair.” The maintenance on 22 CAC was documented under WO 60068569. Step 5.5.3, inspect oil filter lubricating oil tubing and replace the tubing when necessary, was marked as not required. Step 5.5.3 was added in Revision 12 of the procedure because of previous CAC oil tubing leaks. Copper tubing can become brittle over time, develop small cracks and eventually fail in service. Removal and reinstallation of this tubing added to the tubing stress and increased the probability of failure.

The inspectors determined that not inspecting or replacing tubing based on previous similar failures was a performance deficiency that caused ten hours of 22 CAC unavailability on May 12, 2007.

Analysis. The finding is greater than minor because it is associated with the equipment performance attribute of the mitigating systems cornerstone, and it affected the cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, incorrectly performed maintenance degraded both availability and reliability of the 22 CAC. The inspectors conducted a Phase 1 SDP screening in accordance with IMC 0609, Appendix A, “Significance Determination of Reactor Inspection Findings for At-Power Situations.” The finding was determined to be of very low safety significance (Green) because the finding did not represent an actual loss of safety function of a single train for greater than its technical specification (TS) allowed outage time.

The finding has a cross-cutting aspect in the area of problem identification and resolution because PSEG did not take appropriate corrective actions to address safety issues and adverse trends in a timely manner commensurate with their safety significance (P.1.d). Specifically, corrective actions to prevent CAC tubing failures were ineffective because the visual inspections required by the procedure revision incorporated after previous CAC oil tubing failures, may not have identified degraded copper tubing in time to prevent tubing failure.

Enforcement. 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," requires that activities affecting quality shall be accomplished in accordance with documented instructions, procedures, or drawings, of a type appropriate to the circumstances. Step 5.5.3 of SC.MD-PM.CH-0001, "Acme Chiller Inspection and Repair Procedure," directs inspection of the oil filter lube oil tubing, and replacement of the tubing when necessary. Contrary to the above, PSEG personnel did not accomplish the 22 CAC maintenance in accordance with prescribed procedures. Step 5.5.3 of the procedure to inspect the oil filter tubing was marked as not required, and the tubing cracked and leaked oil less than two days after 22 CAC was returned to service. Because this finding is of very low safety significance and has been entered into the corrective action process as notifications 20327748, this violation is being treated as a NCV, consistent with section VI.A of the NRC enforcement policy. **(NCV 05000311/2007003-02, Failure to Inspect Tubing on the 22 CAC)**

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

a. Inspection Scope (7 samples)

The inspectors reviewed seven maintenance activities to verify that the appropriate risk assessments were performed as required by 10 CFR 50.65(a)(4) prior to removing equipment for work. The inspectors reviewed the applicable risk evaluations, work schedules and control room logs for these configurations to verify that concurrent planned and emergent maintenance and test activities did not adversely affect the plant risk already incurred with these configurations. PSEG's risk management actions were reviewed during shift turnover meetings, control room tours, and plant walkdowns. The inspectors also used PSEG's on-line risk monitor (Equipment Out-Of-Service workstation) to gain insights into the risk associated with these plant configurations. Finally, the inspectors reviewed notifications documenting problems associated with risk assessments and emergent work evaluations. Documents reviewed are listed in the Attachment. The following plant configurations were assessed:

- Unit 3 Gas Turbine Generator and no. 2 SPT out of service coincident with heavy river grassing;
- TS 3.0.4.b risk assessment for mode ascension with two CACs out of service;
- Temporary station air compressor line-up with no. 2 and 3 station air compressors out of service;
- Unplanned maintenance on the 12 CAC concurrent with control room ventilation maintenance;
- TS 3.0.4.b risk assessment for mode ascension with one intermediate range neutron monitor out of service;
- Unit 3 gas turbine generator and 22 CAC out of service; and
- The Unit 2 control area ventilation maintenance window extension.

b. Findings

Introduction. A self-revealing Green NCV for failure to comply with 10 CFR 50, Appendix B, Criterion V, "Instruction, Procedures, and Drawings," was identified when operators discovered the 21 CAC in an inoperable condition. In accordance with post-maintenance testing procedures implemented for the 22 CAC, operators placed the 21 CAC in the pump down mode. When the test of the 22 CAC was aborted, operators did not return the 21 CAC to operable status in accordance with procedures. The 21 CAC was inoperable for approximately six hours.

Description. On May 1, 2007, at approximately 3:00 p.m., the 22 CAC was reported as ready for post-maintenance testing. In preparation for testing the 22 CAC, all three CACs for Unit 2 were placed in the pump-down mode. This allowed for adequate loading of the 22 CAC during the testing. Operators stationed a dedicated equipment operator to maintain the 21 and 23 CACs in a operable condition during the test. Operators stopped the test because the 22 CAC did not complete the pump-down cycle. In accordance with step 3.7 of the surveillance procedure, operators placed the 22 CAC key switch in off (lockout) and terminated the test as a failed surveillance test. PSEG procedure SH.OP-AP.ZZ-0102, "Use of Procedures," provided procedure termination guidance. The control room supervisor directed the equipment operator to place the 21 and 23 CACs in the run mode to restore the 21 and 23 CACs to operable status.

At approximately 9:00 p.m., the primary equipment operator noted that the 21 CAC was not running but should have been running based on chill water system outlet temperature and the chiller loading sequence. Maintenance performed troubleshooting and determined that the 21 CAC key switch was loose. This allowed the internal switch casing to rotate and indicate that the switch was in run without placing the actual switch in run. The equipment operator that manipulated the key switch after the 22 CAC post-maintenance test failure did not question why the 21 CAC chiller did not start after placing the key switch in the run position. Step 5.4 of the surveillance procedure, which was not performed, provided instructions to restore the chillers to a pretest position. This step required independent verification that required one operator to perform the restoration and a second operator to independently verify the restoration.

The inspectors determined that PSEG's inadequate configuration control was a performance deficiency that resulted in six hours of inoperability for the 21 CAC.

Analysis. This finding is more than minor because the performance deficiency is associated with the equipment performance attribute of the Mitigating Systems cornerstone, and affected the cornerstone objective to ensure availability and reliability 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 determined that the finding was of very low safety significance because the finding was not a design or qualification deficiency, did not represent a loss of a system safety function or safety function of a single train, and did not screen as potentially risk significant due to a seismic, flooding, or severe weather initiating event.

The finding has a cross-cutting aspect in the area of human performance because PSEG personnel did not use human error prevention techniques (H.4.a). Specifically, an operator did not identify an incorrect switch position because the operator did not verify the expected system response when placing the 21 CAC switch to run.

Enforcement. 10 CFR 50, Appendix B, Criterion V, "Instruction, 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, the instructions for restoration of the 21 CAC key switch to its as found status were not accomplished as prescribed by step 5.8.3 of PSEG procedure SH.OP-AP.ZZ-0102, "Use of Procedures." Because this finding is of very low safety significance and has been entered into the CAP as notifications 20322784 and 20322793, this violation is being treated as an NCV, consistent with section VI.A.1 of the NRC Enforcement Policy. **(NCV 05000311/2007003-03, 21 CAC Inoperable due to Operator Procedural Error)**

1R15 Operability Evaluations (71111.15)

a. Inspection Scope (6 samples)

The inspectors reviewed six operability determinations for degraded or non-conforming conditions associated with:

- 1A Emergency diesel generator following an unsuccessful start;
- 13 AFW pump following unsatisfactory full flow test;
- 23 CAC malfunction of load sequence number 1;
- 12 CC HX with high SW differential pressure;
- Unit 1 containment sump level channel 2 with unsatisfactory calibration; and
- Unit 1 charging pump, safety injection pump, and CC HXs during periods of heavy river detritus (grassing).

The inspectors reviewed the technical adequacy of the operability determinations to verify that conclusions were justified. The inspectors also walked down accessible equipment to corroborate the adequacy of PSEG's operability determinations. Additionally, the inspectors reviewed other PSEG identified safety-related equipment deficiencies during this report period and assessed the adequacy of their operability screenings. Notifications and documents reviewed are listed in the Attachment.

b. Findings

Introduction. The inspectors identified a Green NCV for failure to comply with 10 CFR 50, Appendix B, Criterion V, "Instruction, Procedures, and Drawings," when operators did not implement additional log readings for SW HXs as specified by plant procedures during extended periods of high river detritus from March through May of 2007. This required PSEG to take the 12 CC HX out of service for 45 hours to complete system flushes in May and June 2007.

Description. The lower Delaware River in the vicinity of Salem Nuclear Generating Station has a history of entraining large amounts of marsh grass and other debris (detritus) as the winter ends and the spring rains begin. Due to this condition, PSEG procedures required operators to monitor river detritus levels. On March 3, 2007, operators recorded detritus levels that exceeded the entry conditions for action level 1 of procedure SC.OP-SO.ZZ-0003, "Component Biofouling." Step 5.1.4.B required operators to initiate additional log readings for all in-service components listed on Attachment 3, “Heat Exchangers Affected by Biofouling.” In accordance with the procedure, the Operations Superintendent or Control Room Supervisor and the Engineering/89-13 Program Manager determined the frequency and scope of the additional log readings. Attachment 3 listed approximately 60 components, and identified ten as most susceptible to clogging because of small tube arrangements and piping geometry. The inspectors determined that on March 3, 2007, operators started additional logs for the specified circulating water components, but not for the in-service SW components listed in Attachment 3, such as the 12 CC HX.

Step 5.1.4.D of the component biofouling procedure required operators to evaluate the need for increased monitoring for safety-related HXs, based on NRC GL 89-13, and for balance of plant HXs, as listed in Attachment 3. On March 3, 2007, PSEG personnel determined that no additional monitoring for biofouling was necessary.

On March 22, 2007, river detritus levels exceeded the threshold for action level 2. This required operators to implement abnormal procedure SC.OP-AB.ZZ-0003, “Component Fouling.” The procedure required additional log taking and that additional biofouling monitoring be evaluated. Documented comments in the procedure indicated that on March 22, 2007, operators determined that the monitoring in effect at the time was adequate.

Step 3.6.8 of the component fouling procedure required the Engineering/89-13 Program Manager to establish periodic briefings with the shift manager or control room supervisor to discuss the status of SW HXs on a weekly basis. These weekly meetings provided an opportunity to discover that no additional logs were being taken on SW HXs.

On April 13, 2007, notification 20320108 indicated that the 12 charging pump LO cooler was biofouled, with a differential pressure of 52 psi that exceeded the limit of 45 psi. This component was listed as one of the most susceptible to biofouling, but no additional logs were in place for this component. The 12 charging pump was removed from service, and the SW side of the lube oil cooler was cleaned.

On April 22, 2007, detritus levels were the highest ever recorded at Salem, 329 kg per minute. This is eight times the threshold for entering the component biofouling procedure. Entry criteria for action level 2 were again met because three or more circulating water traveling screens were operating in high speed due to high river detritus. Operators still did not initiate additional log readings for the SW HXs listed in Attachment 3.

On April 29, 2007, a high differential pressure alarm was received on the 12 CC HX. On April 30, at 2133, the 12 CC HX was declared inoperable for biofouling testing. The biofouling monitoring was completed as unsatisfactory, and the 12 CC HX was maintained as inoperable, pending engineering analysis. Engineering analysis determined that the 12 CC HX was operable, even with the high differential pressure (DP) and low flow condition, for the existing river temperature.

On May 1, 2007, the inspectors reviewed the component fouling and component biofouling procedure requirements and implementation. The inspectors determined that additional log readings for SW HX were not initiated on these components upon entry into action level 1 of the procedure on March 3, or upon entry into action level 2 of the procedure on March 23. Additional logs for selected SW HX were initiated by PSEG personnel on May 1, following discussions with the inspectors.

Eleven high flow flushes of the A and B side of the 12 CC HX were conducted between May 1 and June 17 to restore full operability of the HX. These flushes accrued 45 hours of inoperability for the 12 CC HX. These flushes could have been avoided if the additional log readings on the 12 CC HX had been in place. The 12 CC HX is more susceptible to fouling than the 11 CC HX. The 12 CC HX is a plate fin HX and the 11 CC HX is a shell and tube type. The 12 CC HX could have been placed in standby before the differential pressure gauge pegged high at greater than 30 psid, and a control room alarm prompted action by PSEG personnel. The operability of other safety related equipment was verified through additional logs and tests conducted after identification of the log taking deficiency on May 1.

Component fouling procedures were not adequately implemented to ensure that the effects of biofouling on heat transfer surfaces were detected and mitigated during periods of high river detritus. The inspectors determined that this failure to adequately implement procedural guidance was a performance deficiency.

Analysis. This finding was greater than minor because the failure to ensure proper HX condition impacted the equipment performance attribute of the Mitigating Systems cornerstone and adversely affected the cornerstone objective of ensuring the availability, reliability, and capability 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 determined that the finding was of very low safety significance because the finding was not a design or qualification deficiency, did not represent a loss of a system safety function or safety function of a single train, and did not screen as potentially risk significant due to a seismic, flooding, or severe weather initiating event.

The finding has a cross-cutting aspect in the area of human performance because PSEG personnel did not follow plant procedures (H.4.b). Specifically, operators did not implement additional log readings for SW HXs as specified by plant procedures during extended periods of high river detritus from March through May of 2007.

Enforcement. Title 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," requires that procedures affecting quality shall be prescribed by documented instructions or procedures appropriate to the circumstances, and shall be accomplished in accordance with these procedures. Contrary to the above, PSEG did not implement step 3.6.2 of the Component Fouling procedure. Additional logs were not taken on HXs affected by fouling as listed in Appendix 3 of the component fouling procedure. Because this violation was of very low safety significance, and was entered into the PSEG CAP as notification 20323054, this violation is being treated as a NCV consistent with section VI.A.1 of the NRC enforcement policy. **(NCV 05000272&311/2007003-04, Failure to Implement Step 3.6.2 of the Component Fouling Procedure)**

1R19 Post-Maintenance Testing (71111.19)

a. Inspection Scope (7 samples)

The inspectors observed portions of and/or reviewed results of seven post-maintenance test activities for the following equipment:

- 1C diesel generator overspeed trip function test following cylinder head replacements and other scheduled maintenance activities during RFO S1R18;
- WO 30079469, 14 MS 167 actuator replacement during RFO S1R18;
- WO 30104572, 1SJ5 valve stem replacement during RFO S1R18;
- WO 60060385, 1C 125 Vdc battery replacement during RFO S1R18;
- WO 60066436, 1A 28 Vdc battery cell replacement during RFO S1R18;
- WO 60052925, 11 charging pump mechanical speed increaser replacement during RFO S1R18; and
- Unit 2, 21CS21 check valve test following corrective maintenance performed on 6/4/07.

The inspectors assessed whether: the effect of testing on the plant had been adequately addressed by control room and engineering personnel; testing was adequate for the maintenance performed; acceptance criteria were clear and adequately demonstrated operational readiness, consistent with design and licensing basis documentation; test instrumentation had current calibration, range, and accuracy for the application; tests were performed, as written, with applicable prerequisites satisfied; and equipment was returned to an operational status and ready to perform its safety function. Documents reviewed are listed in the Attachment.

b. Findings

No findings of significance were identified.

1R20 Refueling and Other Outage Activities (71111.20)

a. Inspection Scope (4 samples)

Unit 1 Refueling Outage. The inspectors reviewed the schedule and risk assessment documents associated with the Salem Unit 1 refueling outage to confirm that PSEG appropriately considered risk, industry experience, and previous site-specific problems in developing and implementing a plan that assured maintenance of defense-in-depth systems and barriers. Prior to the refueling outage the inspectors reviewed PSEG's outage risk assessment to identify risk significant equipment configurations and determine whether planned risk management actions were adequate. During the refueling outage the inspectors observed portions of the shutdown and cooldown processes and monitored PSEG controls over the outage activities listed below. The inspectors verified that cool down rates were within TS limitations.

The inspectors observed the Unit 1 RCS draining to the mid-loop condition on March 31, 2007. RCS inventory controls and contingency plans were reviewed by the inspectors to determine whether they met TS requirements and provided for adequate inventory control. The inspectors reviewed procedures and observed portions of activities in the control room when the unit was in reduced inventory modes of operation, including mid-loop operations. The inspectors verified that level and core temperature measurement instrumentation was installed and operational. Calculations that provide time-to-boil information were also reviewed for RCS reduced inventory conditions as well as the spent fuel pool during increased heat load conditions.

The inspectors also observed conditions within containment for indications of unidentified leakage and damaged equipment. The inspectors verified that PSEG managed the outage risk commensurate with the outage plan. The inspectors periodically observed refueling activities from the refueling bridge in containment and the spent fuel pool to verify refueling gates and seals were properly installed and determine whether foreign material exclusion boundaries were established around the reactor cavity. Core offload and reload activities were periodically observed from the control room and refueling bridge to verify whether operators adequately controlled fuel movements in accordance with procedures.

The inspectors verified that tagged equipment was properly controlled and equipment configured to safely support maintenance work. Specifically, the inspectors walked down SW system tagouts for isolating one SW header and hardening the remaining inservice SW header. Equipment work areas were periodically observed to determine whether foreign material exclusion boundaries were adequate. During control room tours, the inspectors verified that operators maintained adequate RCS level and temperature and that indications were within the expected range for the operating mode.

The inspectors determined whether offsite and onsite electrical power sources were maintained in accordance with TS requirements and consistent with the outage risk assessment. Periodic walkdowns of portions of the switchyard, onsite electrical buses and the EDGs were conducted during risk significant electrical configurations. The inspectors verified through routine plant status activities that the decay heat removal safety function was maintained with appropriate redundancy as required by TS and consistent with PSEG's outage risk assessment. During core offload conditions, the inspectors periodically determined whether the fuel pool cooling system was performing in accordance with applicable TS requirements and consistent with PSEG's risk assessment for the refueling outage.

Containment status and procedural controls were reviewed by the inspectors during fuel offload and reload activities to verify that TS requirements and procedure requirements were met for containment. Specifically, the inspectors verified that during fuel movement activities, personnel, materials and equipment were staged to close containment penetrations as specified in the licensing basis.

The inspectors conducted a thorough walk down of containment prior to reactor startup. Areas of containment where work was completed were inspected for evidence of leakage and to ensure debris that could block containment sumps was removed. Portions of mode changes and reactor startup were observed and reviewed for compliance with applicable procedures and TS.

The inspectors reviewed applicable documents associated with the Unit 1 refueling outage as listed in the Attachment.

Unit 1 Forced Outage - April 24, 2007. On April 24, 25, and 26, 2007, the inspectors reviewed the Unit 1 forced outage work scope associated with a manual reactor trip on April 24, 2007. The inspectors confirmed that PSEG appropriately considered shutdown plant risk and maintained defense in depth systems while Unit 1 remained in hot standby conditions. The inspectors walked down the equipment related to the cause of the trip, reviewed PSEG's post reactor trip review and root cause report, and observed portions of the reactor startup.

Unit 1 Forced Outage - April 30, 2007. On April 30 through May 3, 2007, the inspectors reviewed the Unit 1 forced outage work scope associated with a manual reactor trip on April 30, 2007. The inspectors confirmed that PSEG appropriately considered shutdown plant risk and maintained defense in depth systems while Unit 1 remained in hot standby conditions. The inspectors walked down the equipment related to the cause of the trip, reviewed PSEG's post reactor trip review and root cause report, and observed preparations for the reactor startup.

Unit 2 Forced Outage - May 24, 2007. On May 24 through June 2, 2007, the inspectors reviewed the Unit 2 forced outage work scope associated with an automatic reactor trip on May 24, 2007. The inspectors confirmed that PSEG appropriately considered shutdown plant risk and maintained defense-in-depth systems while Unit 2 remained in hot standby conditions. The inspectors walked down the equipment related to the cause of the trip, reviewed PSEG's post reactor trip review and root cause report, and observed portions of the reactor startup.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope (8 samples)

The inspectors observed portions of and/or reviewed results for eight surveillance tests to verify, as appropriate, whether the applicable system requirements for operability were adequately incorporated into the procedures and that test acceptance criteria were consistent with procedure requirements, the TS requirements, the Updated Final Safety Analysis Report (UFSAR), and ASME Section XI for pump and valve testing. Documents reviewed are listed in the Attachment. The following surveillance tests were inspected:

- S1.OP-ST.DG-0003, "1C Diesel Generator Surveillance Test;"
- S1.OP-ST.SSP-0002, "SEC Mode Ops Testing 1A Vital Bus;"
- SC.MD-ST.125-0006, "125 Volt Station Batteries 18 Month Service Test;"
- WO 50101877, 21 AFW Pump inservice testing;
- WO 50091190, 11 and 12 safety injection pump inservice full flow test;
- WO 50090995, 1A 28V Battery 18 month service test;
- WO 50091229, ECCS Throttle Valve verification; and
- WO 50090904, 11 and 12 Containment Spray Pump inservice full flow test.

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope (2 samples)

The inspectors reviewed two temporary modifications. The inspectors assessed whether PSEG followed its administrative process for implementing the modifications, NC.DE-AP.ZZ-0030, "Control of Temporary Modifications," and verified that each temporary modification did not adversely impact the operation and performance of the associated structure, system, or component. The inspectors verified that the modifications did not affect the operators' response to abnormal or emergency conditions. The following temporary modifications were inspected:

- 24 containment fan coil unit, blank installed on one section of the SW HX; and
- No. 1 service air compressor temporary SW piping installation.

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

1EP6 Drill Evaluation (71114.06)

a. Inspection Scope (1 sample)

The inspectors observed one EP drill from the technical support center on June 20, 2006. The inspectors evaluated drill performance relative to developing event classifications and implementation of notifications. The inspectors reviewed the Salem Event Classification Guides and Emergency Plans. The inspectors referenced Nuclear Energy Institute 99-02, "Regulatory Assessment PI Guideline," Revision 4, and verified that PSEG correctly counted this drill's contribution to the NRC PI for drill and exercise performance.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2OS1 Access Control to Radiologically Significant Areas (71121.01)

a. Inspection Scope (9 Samples)

Based on PSEG's schedule of work activities, the inspectors selected three jobs being performed in radiation areas, airborne radioactivity areas, or high radiation areas (<1 R/hr) for observation (containment scaffold; permanent shielding; and, fibre reduction). The inspectors reviewed radiological job requirements (radiation work permits (RWP) requirements and work procedure requirements). The inspectors observed job performance with respect to these requirements. The inspectors determined that radiological conditions in the work area were adequately communicated to workers through briefings and postings.

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

During job performance observations, the inspectors verified the adequacy of radiological controls, such as: required surveys (including system breach radiation, contamination, and airborne surveys), radiation protection job coverage (including audio and visual surveillance for remote job coverage), and contamination controls.

For high radiation work areas with significant dose rate gradients (factor of 5 or more), the inspectors reviewed the application of dosimetry to effectively monitor exposure to personnel. The inspectors verified that PSEG controls were adequate.

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

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

During job performance observations, the inspectors observed radiation protection technician performance with respect to radiation protection work requirements. The inspectors determined that they were aware of the radiological conditions in their workplace and the RWP controls/limits, and that their performance was consistent with their training and qualifications with respect to the radiological hazards and work activities.

b. <u>Findings</u>

No findings of significance were identified.

2OS2 <u>ALARA Planning and Controls</u> (71121.02)

a. <u>Inspection Scope (13 Samples)</u>

The inspectors obtained from PSEG a list of work activities ranked by actual/estimated exposure that were in progress and selected 3 work activities of highest exposure significance (containment scaffold; permanent shielding; and, fibre reduction).

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

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

Based on scheduled work activities and associated exposure estimates, the inspectors selected 3 work activities in radiation areas, airborne radioactivity areas, or high radiation areas for observation. The inspectors evaluated PSEG's use of ALARA controls for these work activities by performing the following: evaluated PSEG's use of engineering controls to achieve dose reductions; procedures and controls consistent with PSEG's ALARA reviews; sufficient shielding of radiation sources provided for; and, dose expended to install/remove the shielding exceed the dose reduction benefits afforded by the shielding.

The inspectors observed radiation worker and radiation protection technician performance during work activities being performed in radiation areas, airborne radioactivity areas, or high radiation areas. The inspectors determined that workers demonstrated the ALARA philosophy in practice and there were no procedure compliance issues. Also, the inspectors observed radiation worker performance to determine whether the training/skill level was sufficient with respect to the radiological hazards and the work involved.

The inspectors evaluated the interface between operations, radiation protection, maintenance, maintenance planning, scheduling and engineering groups for interface problems or missing elements.

The inspectors reviewed the integration of ALARA requirements into work procedures and RWP documents.

The inspectors compared the person-hour estimates provided by maintenance planning and other groups to the radiation protection group with the actual work activity time requirements and evaluated the accuracy of these time estimates.

The inspectors determined that workers were utilizing the low dose waiting areas and were effective in maintaining their doses ALARA.

The inspectors determined that workers received appropriate on-the-job supervision to ensure ALARA requirements were met. The inspectors determined that the first-line job supervisor ensured the work activity was conducted in a dose efficient manner.

The inspectors reviewed exposures of individuals from selected work groups. The inspectors evaluated any significant exposure variations which may exist among workers and determined whether these significant exposure variations were the result of worker job skill differences or whether certain workers received higher doses because of poor ALARA work practices.

The inspectors attended a station ALARA committee meeting on April 9, 2007. The subject of the meeting was to discuss dose goals and minimization for emergent work on the 1CV4 valve.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator (PI) Verification (71151)

a. Inspection Scope (6 samples)

Cornerstone: Initiating Events

- Unplanned Scrams per 7000 Critical Hours
- Scrams with Loss of Normal Heat Removal
- Unplanned Power Changes per 7000 Critical Hours

For Unit 1 and 2, 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 uplanned power changes greater than 20 percent that had occurred during the previous four quarters, first quarter 2006 through first quarter 2007. 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 the PI data collection, evaluation, and distribution.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

.1 Review of Items Entered into the CAP

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 all items entered into

PSEG's CAP. This was accomplished by reviewing the description of each new notification and attending daily management review committee meetings. Documents reviewed are listed in the Attachment.

b. Findings

No findings of significance were identified.

.2 Semi-Annual Review to Identify Trends

a. Inspection Scope (1 sample)

As required by Inspection Procedure 71152, "Identification and Resolution of Problems," the inspectors performed a review of PSEG's CAP and associated documents to identify trends that could indicate the existence of a more significant safety issue. The inspectors' review was focused on repetitive equipment and corrective maintenance issues, but also considered the results of daily inspector CAP item screening discussed in Section 4OA2.1. The review also included issues documented in system health reports, corrective maintenance WOs, component status reports, site monthly meeting reports and maintenance rule assessments. The inspectors' review nominally considered the six-month period of December 1, 2006, through May 31, 2007, although some examples expanded beyond those dates when the scope of the trend warranted. The inspectors compared and contrasted their results with the results contained in PSEG's latest integrated quarterly assessment report. Corrective actions associated with a sample of the issues identified in PSEG's trend report were reviewed for adequacy. The inspectors also evaluated the trend report specified in SPP-3.1, "Corrective Action Program." Documents reviewed are listed in the Attachment.

b. Assessment and Observations

No findings of significance were identified. The inspectors noted a trend of low level issues entered into the CAP related to the service air compressors. These compressors were replaced through the design change process over the last twelve months, and have experienced problems related to the design and installation of these compressors. The inspectors determined PSEG is aware of these areas identified through this trend review and is appropriately addressing these issues.

.3 Annual Sample: Human Performance, Procedure Use and Adherence

a. Inspection Scope (1 sample)

The inspectors reviewed PSEG's actions at Salem station taken to improve procedure use and adherence at the station. This sample evaluates PSEG's scope of efforts and progress in the area of procedure compliance.

b. Findings and Observations

No findings of significance were identified.

PSEG conducted a common cause analysis (CCA) for procedure use and adherence issues documented in November 2006. This CCA concluded that most of the issues found were related to a failure to meet requirements of administrative procedures. Examples provided were foreign material exclusion, housekeeping, and temporary power and light. The problems identified were believed to be of minor significance. More recent causes identified for gaps in procedure use and adherence are poor decision making, ineffective communications, inconsistent place keeping, and proper use of category I and II procedures. This has led to a heightened focus on accountability. PSEG believes that the expectations for proper use of procedures is known, but compliance is not adequate because expectations are not reinforced through consistent accountability of individuals.

Two corrective actions implemented to improve procedure compliance are the manager in the field (MIF) program and the fundamental management system (FMS). The MIF program reinforces expectations and heightens accountability in a real time environment. This program is a useful tool to provide feedback to craft workers and first line supervisors. An example of an issue identified through this program is inconsistent marking of “not applicable” steps of maintenance procedures. The expectation is for the first line supervisor to perform this task prior to the performance of the particular maintenance procedure. This expectation has been performed inconsistently. The FMS is a computer software program to enable managers to increase accountability of personnel through documentation of positive and negative behaviors observed. Proper use of this program has recently been implemented. FMS will enable supervisors to detect and correct problem behavior trends more easily than the previous observation documentation system.

.4 Annual Sample: 2CV52 Centrifugal Charging Pump Discharge Check Valve Back-leakage

a. Inspection Scope (1 sample)

The inspectors reviewed PSEG’s corrective actions associated with Notification 20216326 that were taken to address the human performance and untimely corrective actions pertaining to NCV 05000311/2005003-04, Unavailability of 22 Charging Pump due to Discharge Check Valve Leakage. This issue is related to the 2CV52, Unit 2 centrifugal charging pump check valve, back-leakage that was identified in May 2005, after the discovery of back-leakage on the 1CV52 discharge check valve in June 2004.

In response to the back-leakage identified on 1CV52 in June of 2004, PSEG generated Order 80082188, which included actions to implement preventative maintenance (PM) on 2CV52, as well as other susceptible check valves. The PM called for opening and inspecting the valves on a 72 month interval. Prior to that PM being implemented on 2CV52, back-leakage was identified that impacted margin for the charging system. The back leakage through 2CV52 was five gallons per minute and the 21 charging pump had a total of six gallons per minute margin in injection flow before it was inoperable. This performance deficiency was documented in NCV 05000311/2005003-04. PSEG’s actions taken to address the check valve back-leakage were reviewed. The inspectors reviewed surveillance and system operating procedures, WOs, and system health reports in order to gain insight on the maintenance history and overall health of the system. The charging system engineer and valve engineer were interviewed. The inspectors also evaluated PSEG's actions against the requirements of the CAP.

b. Findings and Observations

No findings of significance were identified.

As a result of the back-leakage identified on the charging pump discharge check valves, PSEG implemented an adverse condition monitoring and contingency plan for the valves, to ensure safety margins were preserved. Since implementation of the adverse condition monitoring and contingency plan, no instances of system inoperability were noted as a result of check valve back leakage through the 2CV52 valve. PSEG appropriately considered the extent of condition of the valves. Additionally, PSEG has planned and implemented maintenance on that type of Velan swing check valve in order to reduce back-leakage through the check valves and to improve system performance. The maintenance for 2CV52 is to be done under order 30130352.

4OA3 Event Followup (71153)

.1 (Closed) LER 05000272/2007001-00, Engineered Safety Feature (ESF) Actuation of AFW Pumps in Mode 3 (1 sample)

On March 27,2007, at approximately 8:30 p.m., Unit 1 was in Mode 3 following a planned manual reactor trip to begin a scheduled refueling outage. Operators established initial RCS cooldown using the steam dumps for heat removal and the 11, 12, and 13 AFW pumps for steam generator make-up. Steam generator levels were being maintained lower than normal due to planned full flow testing. The 12 and 14 steam generators reached the low steam generator setpoint trip, resulting in a valid ESF actuation (i.e, start signal to the AFW pumps); however, all AFW pumps were already inservice. The actuation signal also generated a reactor trip signal; however, the plant was already in a shutdown condition with the reactor trip breakers open. The lowest level during this transient occurred in 13 steam generator and was 11.3 percent narrow range level. Steam generator water level was restored to a normal value and the RCS cooldown recommenced. There were no equipment failures that contributed to this event.

The cause of this event was attributed to the failure of the operating crew to establish clear termination criteria for stopping the cooldown based on low steam generator levels and the lack of clear termination criteria guidance in the procedure for maintaining steam generator levels during a cooldown. This failure to comply with 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings", constitutes a violation of minor significance that is not subject to enforcement action in accordance with Section IV of the NRC's enforcement policy. PSEG documented the issue in notification 20318068. This LER is closed.

.2 (Closed) LER 05000311/2007001-00, Inoperability of the Chilled Water System (21 and 22 Chillers Inoperable) (1 sample)

At 8:13 p.m. on April 25, 2007, the 22 chiller was declared inoperable due to emergent maintenance. At 9:30 p.m. on May 1, 2007, 21 chiller was declared inoperable because it failed to start with the initiating conditions present. However, further investigation revealed that 21 chiller had been inoperable since 1500 hours on May 1. Therefore, the applicable actions of TS were not performed within the four hour allowable time. The cause for 21 chiller inoperability was due to a human performance error. That issue was discussed in section 1R13 of this report. This LER was reviewed by inspectors, and with the exception of the human performance issue discussed in this inspection report, no findings of significance were identified. This LER is closed.

.3 Unit 2 Automatic Reactor Trip

a. Inspection Scope (1 sample)

The inspectors responded to an automatic reactor trip that occurred on May 24, 2007. The inspectors observed control room operators establish and maintain stable hot-standby conditions. The inspectors walked down all control board indications for abnormalities, walked down the AFW system, and later interviewed operators for additional insights on equipment performance.

The inspectors discussed the reactor trip with PSEG's investigation team, managers, and engineers. The inspectors reviewed the initial investigation report and post-reactor trip report, and observed the plant operations review committee on restart issues.

PSEG's initial investigation determined that the low steam generator levels were caused by a rupture of the upper sight glass on the 24 demineralizer vessel (DMV), which allowed the escape of a large amount of condensate, and reduced steam generator feed pump suction pressure below the trip set point. This site glass had been improperly installed in 2002. Extent of condition review resulted in the replacement of all twelve Unit 2 DMV sight glasses prior to the Unit 2 restart, and the replacement of Unit 1 DMV sight glasses as the vessels were removed from service for bed regeneration.

b. Findings

Introduction. A self-revealing Green finding for improper maintenance on a demineralizer sight glass was identified when the sight glass catastrophically failed and initiated a condensate system transient that resulted in a reactor trip. Contrary to vendor recommendations that each sight glass be installed and torqued in place only one time, maintenance technicians had re-installed the sight glass on the demineralizer following vessel maintenance.

Description. Unit 2 automatically tripped on low steam generator water level at 2:32 a.m. on May 24, 2007. The upper sight glass on the 24 DMV ruptured and caused a significant condensate system leak. The steam generator feed pumps tripped sequentially on low suction pressure due to the loss of pressure caused by the condensate system leak. This caused steam generator levels to lower to the lo-lo setpoint and caused a reactor trip and auxiliary feed pumps to start. The reactor shutdown and auxiliary feed pumps started and restored steam generator water levels to normal.

The inspectors reviewed the maintenance performed on the 24 DMV upper sight glass and determined that maintenance technicians reinstalled the site glass they removed for scheduled maintenance and torqued the installation bolts to 150 foot pounds. Vendor guidance specified that a sight glass should not be reinstalled once removed, and that the maximum torque for the sight glass installation bolts was 50 foot pounds. The failure mechanism identified by the PSEG cause analysis after the reactor trip was consistent with the stresses caused by reinstalling a sight glass after removal and over-torqueing the installation bolts. PSEG did not locate the vendor documents for the DMV sight glass onsite following the trip, and PSEG had not incorporated this guidance into the plant maintenance procedures.

Following an extent of condition review, all sight glasses on Unit 2 were replaced prior to Unit 2 startup. Sight glasses on the Unit 1 DMVs were scheduled to be replaced when the vessels were removed from service for regeneration.

The inspectors determined that the PSEG procedure for maintenance conducted on the DMV sight glass was inadequate because PSEG did not incorporate appropriate vendor guidance regarding reinstallation and torque requirements for the sight glasses into plant procedures. This constituted a performance deficiency and resulted in the March 24, 2007, Unit 2 reactor trip.

Analysis. The finding is greater than minor because it is associated with the equipment performance attribute of the Initiating Events cornerstone, and because it affects the cornerstone objective of limiting the likelihood of those events that upset plant stability and challenge critical safety functions during power operations. The inspectors conducted a Phase 1 SDP screening of the finding in accordance with IMC 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," and determined that the finding was of very low safety significance because the condition did not contribute to both the likelihood of a reactor trip and the unavailability of mitigating systems equipment.

The inspectors determined that the finding had a cross-cutting aspect in the area of human performance because PSEG did not ensure that complete, accurate, and up to date design documentation, procedures, and work packages were available (H.2.c). Specifically, vendor documentation for the DMV sight glass was not available on site, and as a result, PSEG did not incorporate appropriate vendor guidance regarding reinstallation and torque requirements for the sight glasses into plant procedures.

Enforcement. Enforcement action does not apply because the performance deficiency did not involve a violation of a regulatory requirement. **(FIN 05000311/2007003-05, Salem Unit 2 Automatic Reactor Trip)**

4OA5 Other Activities

.1 (Closed) Unresolved Item (URI) 05000272&311/2005002-03, Ground Water Intrusion to the Auxiliary Building and Containment Building Seismic Gap

a. Inspection Scope

The inspectors reviewed an issue related to the potential long term impacts on concrete and reinforcing bar in the auxiliary building and containment building seismic gap areas due to boric acid in ground water. This issue also included review of the transfer canal and the reactor vessel cavity concrete structure. This issue is related to URI 05000272/2003006-02, NRC to Review Results of Unit 1 Spent Fuel Pool Structural Integrity Analysis. URI 05000272/2003006-02 was closed in inspection report 05000272&311/2007002, based on inspector review of the spent fuel pool integrity analysis, and inspection of visible areas of the concrete structure. The spent fuel pool analysis bounds the limit of concrete degradation which could affect concrete structures in containment and the auxiliary building. The inspectors reviewed results of the most recent visual inspections of concrete in the containment. This review, coupled with the spent fuel pool integrity analysis provides assurance that these structures will not be adversely impacted by degradation from boron exposure for the life of the plant.

b. Findings

No findings of significance were identified.

.2 Temporary Instruction (TI) 2515/166 - Pressurized Water Reactor Containment Sump Blockage

a. Inspection Scope

The inspectors performed an inspection of modifications to the Unit 1 containment sump in accordance with TI 2515/166. The TI was developed to support the NRC review of licensee activities in response to NRC GL 2004-02, “Potential Impact of Debris Blockage on Emergency Sump Recirculation at Pressurized Water Reactors.” Specifically, the inspectors reviewed implementation of the modifications and procedure changes to verify they were consistent with the actions committed to in the GL response. The inspectors reviewed a sample of the licensing and design documents to verify that they were either updated or in the process of being updated to reflect the modifications. A sample of design specifications, testing and surveillance procedures, and calculations were reviewed to verify that they were updated to reflect the modifications and the new requirements for the containment sumps and debris generation sources. The inspectors observed construction activities and performed a walkdown of the strainer to verify it was installed in accordance with the approved design change package. Additionally, the inspectors walked down the steam generator blowdown piping in containment where CalSil insulation, that could be dislodged during a loss-of-coolant accident, was replaced by reflective metal insulation. Finally, the inspectors walked down areas for potential choke-points that could prevent water from reaching the recirculation sump during a design basis accident.

b. Evaluation of Inspection Requirements

The TI requested the Inspectors to evaluate and answer the following questions:

1. Did the licensee implement the plant modifications and procedure changes committed to in their GL 2004-02 response?

The inspectors verified that actions implemented by PSEG, as described in response to GL 2004-02, were complete as related to the installation of the sump screen, removal of insulation, and evaluation of potential debris sources inside containment. The inspectors found that procedures to programmatically control potential debris generation sources were updated. The inspectors noted that the PSEG had not competed evaluations related to the potential for clogging of downstream component due to debris bypass, long term downstream effects, or the effects of chemical precipitants on the strainer head loss at the time of the inspection.

2. Has the licensee updated its licensing basis to reflect the corrective actions taken in response to GL 2004-02?

   The inspectors verified that changes to the facility or procedures, as described in the UFSAR, that were identified in PSEG's GL 2004-02 response, were reviewed and documented in accordance with 10 CFR 50.59. Finally, the inspectors verified that PSEG intends to update the Unit 1 licensing bases to reflect the final modification and associated procedure changes taken in response to GL 2004-02.

The TI will remain open for review of the actions specified in the GL response that have not been completed. Specifically, PSEG had not completed their downstream effects analysis or chemical precipitant analysis. The results of these analyses have the potential to impact the final size of the strainer, the licensing basis and programmatic procedures. Therefore, the inspection will be considered incomplete until the results are reviewed. PSEG plans to evaluate the strainer for adequacy once the test results for head loss are known.

c. Findings

No findings of significance were identified.

4OA6 Meetings, Including Exit

On July 6, 2007, the inspectors presented the inspection results to Mr. G. Gellrich. None of the information reviewed by the inspectors was considered proprietary.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee personnel:

B. Braun, Site Vice President
G. Gellrich, Plant Manager
T. Joyce, Sr. Vice President Operations - Salem & Hope Creek
C. Fricker, Vice President - Operations Support
R. Gary, Radiation Protection Manager
T. Neufang, Radiological Engineering Manager
R. Diaz, Project Manager
T. Oliveri, PSEG Engineering
H. Berrick, PSEG Licensing
P. Durant, PSEG ISI
W. Sheets, PSEG ISI
H. Malikowski, PSEG Engineering
J. Cirlli, PSEG Engineering
W. Wikoff, PSEG Engineering
B. Montgomery, PSEG FAC Engineer
P. Fabian, PSEG, Steam Generator Engineer
D. McCollum, Principal Nuclear Engineer
S. Bowers, Salem Charging System Engineer
K. Weigel, Supervisor, Systems Engineering
M. Cardile, Fire Protection Supervisor
M. McCabe, Regulatory Assurance Technical Specialist
C. Banner, Emergency Preparedness Supervisor

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000311/2007003-01	NOV	Failure to obtain code relief for incomplete inspections of Class 1 and Class 2 welds during the second ISI interval within the required time period. (Section 1R08)

Opened/Closed

05000311/2007003-02	NCV	Failure to Inspect Tubing on the 22 CAC (Section 1R12)
05000311/2007003-03	NCV	21 CAC Inoperable due to Operator Procedural Error (Section 1R13)
05000272&311/2007003-04	NCV	Failure to implement step 3.6.2 of the Component Fouling Procedure (Section 1R15)

05000311/2007003-05	FIN	Salem Unit 2 Automatic Reactor Trip (Section 4OA3.3)
05000272/2007001-00	LER	ESF Actuation of AFW Pumps in Mode 3 (Section 4OA3.1)
05000311/2007001-00	LER	Inoperability of the Chilled Water System (21 and 22 Chillers Inoperable) (Section 4OA3.2)

Closed

05000272&311/2005002-03	URI	Ground Water Intrusion to the Auxiliary Building and Containment Building Seismic Gap (Section 4OA5.1)

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 1R01: Adverse Weather Protection

Procedures
S1.OP-SO.CC-0002, 11 & 12 CC HX Operation, Rev. 25
S1.OP-PM.CC-0012, 12 CC HX High Flow Flush and Alignment, Rev. 17
SC.OP-AB.ZZ-0001, Adverse Environmental Conditions, Rev. 10
S1.OP-AR.ZZ-0011, 12 CCHX Alarm & Flow, Rev. 41
SC.OP-PT.ZZ-0002, Station Preparations for Seasonal Conditions, Rev. 11
SH.OP-DG-0011, Station Seasonal Readiness Guide, Rev. 5
Specification No. S-C-SA-MDS-0441, Station Air Compressors, 02/09/2007
Station Air System Health Report, 1st Quarter 2007
WC-AA-107, Seasonal Readiness, Rev. 3

Notifications

20272148	20281787	20283958	20284885	20323794	20324805
20325714	20325715	20325716			

Orders

30137351	60062651	70045063	70049239	70054394	70066491
70067604	80088650				

Calculations
S-1-CC-MDC-1817, CC System Thermal-Hydraulic Analysis - U1,
Rev. 4A

Other Documents
2006 Summer Readiness Critique
ACM -7-022, CC HX Monitoring Plan, 05/18/2007
List of Potential NOED T.S. for Salem Unit 1 and 2, 2007 Summer Readiness
Management Overview CROD Status, May 10, 2007
NER NC-07-012 Red Action Plan

Operability Determination 05-004, Salem Units 1 & 2 Auxiliary Building Ventilation, 03/01/2005
Operability Determination 05-015 (CROD 70049239), Elevated Service Water Temperatures, 08/03/2005
PSEG letter dated May 15, 2007 from Bill Levis to Carl Fricker, re: 2007 Salem Summer Seasonal Readiness Affirmation
SER OTDM No. 07-016, SW \ Salem Unit 1 12A HX High D/P, 05/10/2007

Section 1R04: Equipment Alignment

Procedures
SC.CH-AD.CC-0411, CC System Dechromation, Rev. 7
S1.OP-SO.CC-0001, CC System Operation, Rev. 16
S1.OP-SO.CC-0001(Q), CC System Operation, Rev. 16
S1.OP-ST.4KV-0002(Q), Electrical Power Systems AC Distribution, Rev. 21
S1.OP-SO.RHR-0001(Q), Initiating RHR, Rev. 26

Section 1R05: Fire Protection

Procedures
Salem - Unit 1, (Unit 2) Pre-Fire Plan FRS-II-421, 4160V Switchgear Rooms & Battery Rooms, Rev. 5
Salem - Unit 1, (Unit 2) Pre-Fire Plan FRS-II-435, Diesel Fuel Oil Storage Area, Rev. 5
SC.FP-AP.ZZ-0003, Actions for Inoperable Fire Protection - Salem Station, Rev. 11
Pre-Fire Plan FRS-II-453, U1 & U2 Auxiliary Building Ventilation Units, Elevation: 122' - 0"
Pre-Fire Plan FRS-II-911, U1 & U2 Service Water Intake Structure, Elevations: 92' & 112'
SC.FP-AP.ZZ-0003, Actions for Inoperable Fire Protection - Salem Station, Rev. 11
Salem - Unit 1, (Unit 2) Pre-Fire Plan FRS-II-452, Control Room Area Rev. 5
SC.FP-AP.ZZ-0003, Actions for Inoperable Fire Protection - Salem Station, Rev. 11
SC.FP-PM.ZZ-0038, Annual Fire Extinguisher Inspection , Rev. 7

Notifications
20221470 20277361 20325754 20325858

Orders
60067842

Other Documents
Salem and Hope Creek Fire Impairment Log Book, dated 5/31/07
Salem U/1 & U/2 Non-RCA Hourly Fire Watch Log, dated 6/1/07

Section 1R06: Flood Protection Measures

Procedures
NC.OP-DG.ZZ-0002, Severe Weather Guide, Rev. 6
SC.FP-SV.FBR-0026(Q), Flood and Fire Barrier Penetration Seal Inspection, Rev. 3
SC.OP-AB.ZZ-0001(Q), Adverse Environmental Conditions, Rev. 10

Notifications
20321430

Other Documents
Salem Individual Plant Examination for External Events, Section 5, High Winds, Floods and Other External Events
Technical Specifications 3/4.7.5, Flood Protection
Updated Final Safety Analysis Report, Figure 2.4-2, Yard Drainage System
Updated Final Safety Analysis Report, Figure 2.4-3, Service Water Intake
Updated Final Safety Analysis Report, Section 2.4, Hydrologic Engineering
Updated Final Safety Analysis Report, Section 3.4, Water Level (Flood) Design

Section 1R07: Heat Sink Performance

Procedures
S1.OP-PT.SW-0016(Q), 11 CC Heat Exchanger Heat Transfer Performance Data Collection, Rev. 16

Section 1R08: Inservice Inspection Activities

Procedures
ER-AA-335-018, Revision 4; Detailed, General VT-1, VT-1C, VT-3 and VT-3C Visual Examination of ASME Class MC and CC Containment Surfaces and Components

NDE Examination Reports (Data Sheets)
R18-EVT1-001, 009801, 31-RCN-1120-IRS
R18-EVT1-001, 009901, 29-RCN-1120-IRS
R18-EVT1-001, 010801, 29-RCN-1120-IRS
R18-EVT1-001, 010801, 29-RCN-1110-IRS
R18-EVT1-001, 010701, 31-RCN-1110-IRS
UT-07-028, 003700, 1-RPV-LIG 19 Thru 36,
UT-07-042, 006850, 1-PZR-21
UT-07-045, 006850, 1-PZR-21
UT-07-043, 006850, 1-PZR-21
UT-07-044, 006850, 1-PZR-21
UT-07-041, 022100, 2-CV-1175-36
UT-07-040, 022100, 2-CV-1175-36
UT-07-029, 035900, 4-PS-1111-17
UT-07-030, 036300, 4-PS-1111-21
UT-07-033, 203401, 11-STG-21
UT-07-032, 203401, 11-STG-21
UT-07-034, 203401, 11-STG-21
UT-07-011, 219150, 4-AF-2111-6
UT-07-012, 219150, 4-AF-2111-6
UT-07-010, 220583, 8-CS-2115-2
UT-07-010, 220583, 8-CS-2115-2
UT-07-009, 220718, 6-CV-2112-10
UT-07-004, 105400, 8-SJ-1162-9
PT-07-007, 098000, 10-SJ-1131-5PS
PT-07-002, 220757, 6-CV-2111-14R1
VT-07-214, 932100, IVVI-202

VT-07-215, 932150, IVVI-203
VT-07-216, 932200, IVVI-204
VT-07-237, 033501, 4-PS-1131-29
MT-07-001, 277900, 12 MS 167 VS-1
MT-07-008, 277900, 12 MS 167 VS-1
RT-60063997-0140, S1-SGF-22-16-1-10-8
RT-60063997-0140, S1-SGF-22-16-1-8-16
RT-60063997-0140, S1-SGF-22-16-1-16-25
RT-60063997-0140, S1-SGF-22-16-1-25-34
RT-60063997-0140, S1-SGF-22-16-1-34-0

<u>Subsection IWE Data Sheets</u>
882800, 882900, 823000, 823500, 823600, 823700
824000, 828200, 828600, 828700, 828800, 828900
824100, 824200, 824300, 824400, 824500, 824600
825100, 829000, 825200, 825300, 825400, 825500
825600, 825800, 825900, 826000, 826100, 826200
826300, 826400, 826600, 826700, 826800, 826900
827600, 827700, 827800, 827900, 821100

<u>Repair-Replacement Work Order</u>
60061783, Notif. 20318020, Valve SIRC-13RC15
60063997, Valve SICN-12BF19
60059073, S1SJ-1SJ214
60055945, S1SW-11SW23

<u>Drawings/Isometrics</u>
Westinghouse dwg 5D64861, Rev 2; Guide Tube Support Pin Nut
Westinghouse dwg 5D64863, Rev 3; Guide Tube Support Pin Crimp Cap Locking
Westinghouse dwg 5D64973, Rev 3; Special Guide Tube .750-10UN-R Sch. Cap Screw
Westinghouse dwg 5D64860, Rev 5; Guide Tube Cap Screw Tandem Locking Device
Westinghouse dwg 5D64864, Rev 2; Guide Tube Support Pin Nut Assembly
Westinghouse dwg 10016D26, Rev 0; Salem Unit 1CW316SS Guide Tube Support Pin
Westinghouse dwg 10024E63, Sht 1 of 3 Rev 0; Salem Unit 1CW316SS Guide Tube General Assembly Support Pin Replacement Salem Unit 1
Westinghouse dwg 10024E63, Sht 3 of 3 Rev 0; Salem Unit 1CW316SS Guide Tube General Assembly Support Pin Replacement Salem Unit 1
Westinghouse dwg 10024E63, Sht 2 of 3 Rev 0; Salem Unit 1CW316SS Guide Tube General Assembly Support Pin Replacement Salem Unit 1

<u>Calculations/Evaluations</u>
Engineering Evaluation No. S-1-RC-MME-1992, Revision 0, 3/19/07; Steam Generator Degradation Assessment, Salem Unit 1 Refueling Outage 18 (1R18), March/April 2007

<u>Equivalency Evaluation</u>
80088106, ECP for Split Pin Replacement 1R18, Unit 2

<u>Self-Assessments</u>
80084848, Check In Self Assessment Report for Salem SG Program for S1R18 outage
80087812, Check In Self Assessment for NRC ISI Inspection Activities, 3/28/07
Focused Self Assessment Boric Acid Corrosion Management and Alloy 600 Program Implementation Performance, 3/28/05
80063759, Engineering Programs 2004 1st Quarter Self Assessments, 3/17/04

Miscellaneous Documents

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PSEG ltr. LR-N07-0039, 2/27/07, Salem Generating Station, Unit 2, Facility operating License Nos. DPR-70, NRC Docket No. 50-311, Response to request for additional information #2 On LCR- S06-01 Request For Change To Technical Specifications To Add Steam Generator Tube Integrity Program

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NRC ltr. Salem Nuclear Generating Station, Unit No. 1 - Relief From ASME Code Requirements Related To The Salem Inservice inspection Program Relief Requests S1-RR-BO1 and S1-RR-CO1 (TAC NO.MB3811)

PSEG ltr. LR-N07-0071, 3/26/07, WITHDRAWAL OF INSERVICE INSPECTION PROGRAM RELIEF REQUESTS S2-I2-RR-B01 AND S2-I2-RR-C01

PSEG ltr. NLR-N94227, 12/28/94, Inservice Inspection Program Salem Generating Station, Unit 2, NRC Docket No. 50-311

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NRC ltr. Dated 10/23/95; Evaluation of The Second Ten-Year Interval Inspection Program Plan And Associated Requests For Relief For Salem Generating Station, Unit No. 2 (TAC NO. M83316

PSEG ltr. NLR-N92135, 9/28/92, Inservice Inspection - Long Term Plan Final Relief Requests - First interval Salem Generating Station, Unit 2, NRC Docket No. 50-311

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20318020	20317980	20317763	20317746	20317745	20317071
20317046	20316502	20315202	20316189	20315346	20316495
20303139	20303314	20303341	20304121	20304941	20307441
20307657	20309679	20309819	20312712	20295855	20296281
20263645	20313930	20300313	20300653	20300654	20300655
20300656	20300657	20299707	20300090	20298612	20300309
20302238	20301207	20282171	20263674	20263671	20319291
20263672	20241091	20241050	20256572	20065319	20187086
20256760	20312281	20268549	20321043*	20311248	20312614
20318156	20318179	20318157	20318317	20318481	20008368
20116971	20156492				

* Indicates this was generated as a result of this inspection.

Section 1R11: Licensed Operator Requalification Program

Other Documents

TQ-AA-106-0204, Simulator Training Scenario, Rev. 1

Section 1R12: Maintenance Effectiveness

Procedures
ER-AA-310-1001, Maintenance Rule - Scoping, Rev. 3
S1.OP-DL.ZZ-0005, Secondary Plant Log, Rev. 35
SC.ER-DG.ZZ-0002, System Function Level Maintenance Rule Scoping vs. Risk Reference, Rev. 2
SC.OP-AR.SA-0001, Station Air Compressors Control and Alarm Panel, Rev. 13
SC.OP-SO.SA-0001, Station Air System Operation, Rev. 40
SH.ER-DG.ZZ-0001, Preventable and Repeat Preventable System Functional Failure Determination, Rev. 3

Drawings
211319, Station Air Compressors and Control Air Dryers

Notifications

20313354	20316792	20321770	20327748	20323876

Orders

30130122	60056762	60069701	60069122	60068569	70059905
70067564	80083925				

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Station Air System - 1st quarter 2007

Other Documents
80075675, “10CFR50.59 Screening - Replacement of Salem’s Station Air Compressors”
UFSAR, Section 9.3.1, Compressed Air System

Section 1R13: Maintenance Risk Assessments and Emergent Work Control

Procedures
ER-AA-600-1042, On-Line Risk Management, Rev. 4
S1.OP-SO.CAV-0001, Control Area Ventilation Operation, Rev. 31
S2.OP-ST.CH-0004(Q), Chilled Water System - Chillers, Rev. 15
SC.OP-PM.SA-0001, Removal of Station Air Compressors from Service for Maintenance, Rev. 1
SC.OP-SO.500-0005, Salem Switchyard Key Interlock Scheme, Rev. 9
SC.OP-SO.13-0001, 13KV Breaker Operation, Rev. 10
SC.OP-SO.SA-0002, Temporary Station Air Compressor Operation, Rev. 16
SH.OP-AP.ZZ-0015, Safety Tagging Operations, Rev. 20
SH.OP-AB.ZZ-0027, On-Line Risk Assessment, Rev. 13
WC-AA-101, On-Line Work Control Process, Rev. 13
S1.OP-SO.CH-0001(Q), Chilled Water System Operation, Rev. 22

Notifications
20327319

Orders
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Other Documents
SA-304B-07-002, Risk Assessment for U1 Mode Ascension with two CACs out of service, Rev. 0
SGS U1 & U2 PRA Risk Evaluation Form for 04/22/2007 - 04/28/2007
SGS U1 & U2 PRA Risk Evaluation Form for 05/13/2007 - 05/19/2007
Tagging Request 00011388, 02/27/2007
Technical Specifications section 3.0.4.b
Work Clearance Document No. 4195989, 02/27/2007

Section 1R15: Operability Evaluations

Procedures
S1.IC-CC.WD-0013(Q), 1LT-939 Containment Sump Level Channel II, Rev. 9
S1.OP-AR.ZZ-0011(Q), CCW System CCW HX Outlet, Rev. 41
S1.OP-PM.CC-0012(Q), 12 CC Heat Exchanger High Flow Flush and Alignment, Rev. 17
S1.OP-SO-CC.-0002(Q), 11 and 12 CC Heat Exchanger Operation, Rev. 25
SC.OP-SO-ZZ-0003 (Q), Component Biofouling, Rev. 1
SC.OP-AB.ZZ-0003(Q), Component Fouling, Rev. 10
SH.OP-AP.ZZ-0008(Q), Troubleshooting/Evolution Plan, Rev. 3
1-EOP-TRIP-1, Reactor Trip or Safety Injection, Rev. 26
1-EOP-CFST-1, Critical Safety Function Status Trees, Rev. 22

Notifications

20321795	20322100	20322128	20322176	20320747	20322835
20326623	20326489	20322417	20320108	20323741	20323054

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Other Documents
CROD Evaluation 07-012, NUCR 70068847, Operability Determination, 04/25/2007
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Calculation SC-WD001-01, Salem Unit 1 & 2 Containment Sump Level Alarm & Indicator, Rev. 2
Technical Specifications 3/4.3.3.7, Accident Monitoring Instrumentation
Updated Final Safety Analysis Report, Section 7.5, Safety Related Display Instrumentation
U.S. NRC Regulatory Guide 1.97, Criteria for Accident Monitoring Instrumentation for Nuclear Power Plants, Rev. 4
U.S. NRC Regulatory Guide 1.97, Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environs Conditions During and Following an Accident, Rev. 3
1LT-939 Containment Sump Level Channel II (70068505)
Technical Evaluation 80091981-10, 13 AFW Pump Full Flow Test Unsat
GL 89-13, Service Water System Problems Affecting Safety-Related Equipment
S-C-SW-MDC-1500, Biofouling Monitoring and Trending Calculation

Section 1R19: Post-Maintenance Testing

Procedures
S1.OP-PT.DG-0018, 2C Diesel Generator Engine Lube Oil Header Low Pressure Trip and Overspeed Trip Functional Test, Rev. 3
SC.MD-ST.125-0003(Q), Quarterly Inspection and Preventive Maintenance of Units 1, 2 & 3 125 Volt Station Batteries, Rev. 22
SC.MD-CM.125-0004(Q), 125V Battery Terminal Post Resistance Measurements, Rev. 6
SC.MD-CM.28D-0005(Q), 28Vdc Vital Battery Cell Replacement, Rev. 3
S1.OP-ST.CVC-0003(Q), Inservice Testing - 11 Charging Pump, Rev. 17
S1.RA-ST.CVC-0003(Q), Inservice Testing 11 Charging Pump Acceptance Criteria, Rev. 8
VTD 301137, Instructions for Installing, Operating and Maintaining Pacific Pumps, 4/1/91
S2.OP-ST.CS-0001(Q), Inservice Testing - 21 Containment Spray Pump, Rev. 18

Drawings
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Section 1R20: Refueling and Outage Activities

Procedures
SC.OP-DG.ZZ-0101, Salem Post-Trip Data Collection Guidelines, Rev. 8
S1.OP-IO.ZZ-0003(Q), Hot Standby to Minimum Load, Rev. 19
S1.OP-SO.RC-0005(Q), Draining The Reactor Coolant System to ≥ 101 Foot Elevation, Rev. 28
S1-OP-SO.RC-0006(Q), Draining The Reactor Coolant System ,101Foot Elevation With Fuel in The Vessel, Rev. 20
SH.OP-AP.ZZ-0084(Q), Attachment 2, IPTE Briefing- S1C19 Startup and LPPT

Other Documents
Contingency Plan For Loss of All Unit 1 Service Water

Section 1R22: Surveillance Testing

Procedures
S1.OP-ST.SSP-0002, SEC Mode Ops Testing 1A Vital Bus, Rev. 19
S1.OP-ST.DG-0003, 1C Diesel Generator Surveillance Test, Rev. 42
SC.MD-ST.125-0006, 125 Volt Station Batteries 18 Month Service Test Using BCT-2000 with Windows Software and Associated Surveillance Testing
S2.OP-ST.AF-0001(Q), Inservice Testing - 21 AFW Pump, Rev. 15
SC.MD-ST.28D-0003(Q), Quarterly Inspection and Preventative Maintenance of 28V Vital Batteries, Rev. 12
SC.MD-ST.28D-0006(Q), 28 Volt Station Batteries 18 Month Service Test Using BCT-2000 with Windows Software and Associated Surveillance Testing, Rev. 1
S1.OP-ST.CS-0005(Q), Inservice Testing Containment Spray Pump Full Flow Test and Containment Spray Check Valves, Rev. 15
S1.RA-ST.CS-0005(Q), Inservice Testing Containment Spray Pump Full Flow Test and Containment Spray Check Valves Acceptance Criteria, Rev. 4
S1.OP-ST.SJ-0012(Q), Emergency Core Cooling - ECCS Throttle Valves, Rev. 6

Section 1R23: Temporary Plant Modifications

Procedures
SC.OP-SO.SA-0009(Z), Temporary Cooling to #1 Station Air Compressor, Rev. 0

Other Documents
CC-SH-112-1001, Installation of Blind Flanges on # 4 Cooler Coil For 24 CFCU, Rev. 0
TMP 1ST-06-016, Alternate SW Flow Path to the #1 SAC

Section 1EP6: Drill Evaluation

Notifications
20327577 20327594

Other Documents
Emergency Plan Drill Scenario Overview for 6/20/07
Salem Onsite Drill (S07-03)
TSC Drill Critique (S07-03)
Salem Event Classification Guide, Rev. 69
Artificial Island Emergency Plan, Rev. 59

Section 2OS2: ALARA Planning and Controls

Notifications
70067940 70068044

Other Documents
Work-in-Progress Reviews: Fibre Reduction (RWP # 1, Task # 613, ALARA Plan # 67))
Install Permanent Shielding (RWP #6, ALARA Plan #85)

Section 4OA2: Identification and Resolution of Problems

Procedures
LS-AA-120, Issue Identification and Screening Process, Rev. 6
LS-AA-125, CAP Procedure, Rev. 11
NC.CA-DG.ZZ-0103, Adverse Condition Monitoring and Contingency Planning, Rev. 1
S2.OP-SO.CVC-0002(Q), Charging Pump Operation, Rev. 34
S2.OP-ST.SJ-0016(Q), High Head Cold Leg Throttling Valve Flow Balance Verification, Rev. 26
S2.OP-ST.RC-0007(Q), Seal Injection Flow, Rev. 6
S2.OP-ST.CVC-0005(Q), Inservice Testing- 13 Charging Pump, Rev. 16
S2.OP-ST.CVC-0005(Q), Inservice Testing- 23 Charging Pump, Rev. 17

Drawings
78501

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20321795	20321796	20321835	20321868	20193098	20193182
20193456	20196151	20238417	20238511	20238570	20245421
20245708	20246326	20264675	20270268	20277685	20277740
20278825					

Orders

30130348	30130351	30130352	60046082	60054536	60055838
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Other Documents
ACM 05-008, Charging Pump Check Valve Back Leakage

Section 4OA3: Event Followup

Procedures
S1.OP-AB.CW-0001, Circulating Water System Malfunction, Rev. 26
S1.OP-AB.LOAD-0001, Rapid Load Reduction, Rev. 11
S1.OP-AB.SW-0001, Loss of Service Water Header Pressure, Rev. 15
S1.OP-IO.ZZ-0003, Hot Standby to Minimum Load, Rev. 19
S1.OP-IO.ZZ-0103, Hot Standby to Minimum Load Administrative Requirements, Rev. 3
S1.OP-SO.CW-0001, Circulating Water System Operation, Rev. 29
S2.OP-AB.CN-0001, Main Feedwater/Condensate System Abnormality, Rev. 19
S2.OP-AB.PZR-0001, Pressurizer Pressure Malfunction, Rev. 15
S2.OP-AB.RAD-0001, Abnormal Radiation, Rev. 25
S2.OP-IO.ZZ-0004, Power Operation, Rev. 58
SC.MD-PM.CW-0003, Service Water Auto Strainer Adjustment, Inspection, Repair and Replacement, Rev. 26
SC.OP-AB.ZZ-0003, Component Fouling, Rev. 10
SC.OP-SO.ZZ-0003, Component Biofouling, Rev. 1
SC.OP-DG.ZZ-0101, Post Reactor Trip/ECCS Actuation Review, Rev. 8
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SC.OP-DG.ZZ-0101, Post Reactor

Notifications

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Other Documents
Jacoby-Tarbox Sight Flow Indicators and Sight Windows: Installation, Operation and Maintenance Instructions, 12/28/1998
Trip/ECCS Actuation Review - Automatic Trip on Low-Low SG Level, 05/24/2007
Palo Verde LER 050005302006005-01, Manual Reactor Trip Due to Loss of Main Feedwater
LS-AA-115, Operating Experience Procedure, Rev. 10

Section 4OA5: Other Activities

Procedures
S1.OP-PT.CAN-0001, Containment Walkdown, Rev. 15
S1.OP-ST.CAN-0007, Refueling Operations - Containment Closure, Rev. 18
S1.OP-ST.SJ-0010, ECCS - Containment Inspection for Mode 4, Rev. 5
S1.OP-ST.SJ-0011, Emergency Core Cooling ECCS Subsystems - Containment Sump Modes 5-6, Rev. 5

<u>Drawings</u>
103.133.454.500, Recirculating Strainer Unit 1
103.133.471.500, Module 15 Packets
103.133.472.500, Module 10 Packets
606090 A, 80080787R0 S87R2, Sh. 1, No. 1 - Reactor Containment Gates at Bioshield Access, Revised per FCR 60066108-0480
606090 A, 80080787R0 S88R3, Sh. 2, No. 1 - Reactor Containment Gates at Bioshield Access, Revised per FCR 60066108-0480
606090 A, 80080787R0 S96R2, Sh. 2, No. 1 - Reactor Containment Gates at Bioshiled Access, Revised per FCR 60066108-0480
PSEG Nuclear Dwg. 241211 A 1552-5, Auxiliary Building and Reactor Cont. Area Wire Mesh Gate Schedule

<u>Notifications</u>
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<u>Orders</u>
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<u>Calculations</u>
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S-C-CAN-MDC-2061, Minimum Containment Flood Level, Rev. 0
S-2-CAN-MDC-2076, Calculation for Latent Debris (Dust & Lint) Determination for Salem Unit 2 Containment for Resolution of Generic Safety Issue (GSI) 191, Rev. 0IR0
S-C-RHR-MDC-1711, Available NPSH at RHR Pump in Recirc. Mode, Rev. 3A
S-C-RHR-MDC-2039, Debris Generation due to LOCA within Containment for Resolution of GSI-191, Rev. 0IR1
S-C-RHR-MDC-2056, Post-LOCA Debris Transport to Containment Sump for Resolution of GSI-191, Rev. 0IR0
Q.003.84772, Containment Sump Strainer Replacement: Salem MFT Chemical Test Specification, Rev. 6

<u>Other Documents</u>
80080787, Salem 1 Containment Sump Upgrades, Rev. 0, dated 01/23/2007
80090886, GSI-191 Insulation Debris Reduction, Rev. 0, dated 02/27/2007
CC-AA-309-1001, Analysis No. 6S0-1703, Unit #1 & #2 Reactor Containment Equipment Access Platforms and Barriers, Rev. 2A
Document 2004-03483, Report No. 11050-259, Walkdown Report for Evaluating Debris Sources Inside Salem Unit 1 Containment for Resolution of GSI-191, Rev. 0
Engineering Evaluation No. S-C-CAN-MEE-1986, Input to Procurement Specification S-C-CAN-MDS-0445, Rev. 0
LR-N05-0103, PSEG Letter: 90-Day Response to GL 2004-02 "Potential Impact of Debris Blockage on Emergency Recirculation During Design Basis Accidents at Pressurized-Water Reactors," dated March 4, 2005
LR-N05-0401, PSEG Letter: Response to GL 2004-02 "Potential Impact of Debris Blockage on Emergency Recirculation During Design Basis Accidents at Pressurized-Water Reactors," dated September 1, 2005
LR-N06-0253, PSEG Letter: Updated Response to GL 2004-02 and Request for Extension for Insulation Replacement, dated June 7, 2006
LR-N07-0022, PSEG Letter: Clarification to GL 2004-002 Response, dated February 2, 2007
NC.CC-AP.ZZ-0081, Acceptance Walkdown Closeout

PSEG Nuclear Salem Units 1&2, GSI 191 Preliminary Evaluation for Allowable Head Loss for Sump Screen, 12/21/2006
SCN 06-043, UFSAR Change Notice, Rev. 0
SCN 06-044, UFSAR Change Notice, Rev. 0
USNRC Memorandum: GL 2004-02 "Potential Impact of Debris Blockage on Emergency Recirculation During Design Basis Accidents at Pressurized Water Reactors," Extension Request Approval for Salem, Unit 2, dated July 7, 2006
USNRC Letter: Salem Nuclear Generating Station, Unit No. 2 - Approval of GL 2004-02 Extension Request, dated August 11, 2006

LIST OF ACRONYMS

ADAMS	Agency-wide Documents Access and Management System
AFW	Auxiliary Feedwater
ALARA	As Low As is Reasonably Achievable
ASME	American Society of Mechanical Engineers
CAC	Control Area Chiller
CAP	Corrective Action Program
CC	Component Cooling
CCA	Common Cause Analysis
CCW	Component Cooling Water
CFR	Code of Federal Regulations
DMV	Demineralizer Vessel
DP	Differential pressure
ESF	Engineered Safety Feature
GL	Generic Letter
GSI	Generic Safety Issue
HX	Heat Exchanger
IMC	Inspection Manual Chapter
ISI	Inservice Inspection
LER	Licensee Event Report
NCV	Non-cited Violation
NDE	Non-Destructive Examination
NRC	Nuclear Regulatory Commission
PARS	Publicly Available Records
PI	Performance Indicator
PM	Preventative Maintenance
PSEG	Public Service Enterprise Group Nuclear LLC
RCS	Reactor Coolant System
RHR	Residual Heat Removal
RWP	Radiation Work Permit
SDP	Significance Determination Process
SPT	Station Power Transformer
SW	Service Water
TI	Temporary Instruction
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
UT	Ultrasonic Testing
WO	Work Order