UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION I
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KING OF PRUSSIA, PA 19406-1415

February 9, 2009

Mr. Thomas Joyce
President and Chief Nuclear Officer
PSEG Nuclear LLC - N09
P.O. Box 236
Hancock's Bridge, NJ 08038

SUBJECT: SALEM NUCLEAR GENERATING STATION, UNIT NOS. 1 AND 2 - NRC INTEGRATED INSPECTION REPORT 05000272/2008005 and 05000311/2008005

Dear Mr. Joyce:

On December 31, 2008, 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 discussed on January 20, 2009, with Mr. Braun and other members of your staff.

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

The report documents two NRC-identified findings and three self-revealing findings of very low safety significance (Green). Four of these findings were determined to involve violations of NRC requirements. However, because of their very low safety significance and because they were entered into your corrective action program, the NRC is treating these findings as non-cited violations (NCVs) consistent with Section VI.A.1 of the NRC Enforcement Policy. If you contest any NCV in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001; with copies to the Regional Administrator, Region I; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the Salem 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

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Sincerely,

/RA/ Original Signed By:

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

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

Enclosure: Inspection Report 05000272/2008005 and 05000311/2008005
w/Attachment: Supplemental Information

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U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket Nos:	50-272, 50-311
License Nos:	DPR-70, DPR-75
Report No:	05000272/2008005 and 05000311/2008005
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:	October 1, 2008 through December 31, 2008
Inspectors:	D. Schroeder, Senior Resident Inspector H. Balian, Resident Inspector J. Schoppy, Senior Reactor Inspector J. Furia, Senior Health Physicist M. Modes, Senior Reactor Inspector S. Chaudhary, Reactor Engineer E. Huang, Reactor Inspector P. Presby, Operations Engineer E. Gray, Senior Reactor Engineer
Approved By:	Arthur L. Burritt, Chief Projects Branch 3 Division of Reactor Projects

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SUMMARY OF FINDINGS

IR 05000272/2008005, 05000311/2008005; 10/01/2008 - 12/31/2008; Salem Nuclear Generating Station Unit Nos. 1 and 2; Fire Protection; Maintenance Effectiveness; Maintenance Risk Assessment and Emergent Work Control; Post-Maintenance Testing; Refueling and Other Outage Activities.

The report covered a three-month period of inspection by resident and regional-specialist inspectors. Four Green non-cited violations (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. <u>NRC-Identified and Self-Revealing Findings</u>

Cornerstone: Mitigating Systems

- <u>Green</u>: The inspectors identified a non-cited violation (NCV) of Salem Operating License condition 2.C.5, that requires that PSEG implement all provisions of the Fire Protection Program as described in the Updated Final Safety Analysis Report (UFSAR). Specifically, PSEG strung nine temporary power cables through a combustible control zone without an engineering evaluation that assessed risk and established compensatory measures. PSEG corrective actions included: briefing all personnel involved with installation and removal of temporary power and light (TP&L) for S1R19; completing an immediate extent of condition review correcting the master work orders for staging TP&L by including steps for completing fire protection program requirements; and adding this issue to the scope of general employee training.

  This finding was more than minor because it was associated with the external factors attribute of the Mitigating Systems cornerstone and adversely affected the cornerstone objective to ensure the availability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the identified transient combustibles were located in a combustible control zone (CCZ) that was required to maintain cable separation between service water trains A and B and to limit challenges to physical separation afforded by steel floor hatches above and below the CCZ. Using IMC 0609, Appendix F, "Fire Protection Significance Determination Process," the inspectors determined the finding was of very low safety significance (Green). This finding has a cross-cutting aspect in the area of human performance because PSEG did not provide complete, accurate and up-to-date design documentation, procedures, and work packages [H.2(c)]. Specifically, WO 30156086 did not direct maintenance personnel to obtain a transient combustible permit (TCP) before staging combustible material in a CCZ. (Section 1R05)

- Green: The inspectors identified a self-revealing NCV of 10 CFR 50, Appendix B, Criterion III, Design Control, because the No. 22 component cooling water heat exchanger (CCWHX) service water (SW) outlet temperature control valve (22SW127) did not stroke open when the 22 CCWHX was placed in service following a high flow flush on November 18, 2008. Specifically, PSEG did not ensure that the design basis was correctly translated into valve set-up instructions for the 22SW127 valve. PSEG's corrective actions included mechanical adjustment to the valve's stroke, revising the valve's set-up instructions, and an extent of condition review.

  The finding was more than minor because it was associated with the design control 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. Specifically, the improper valve set-up instructions caused the 22SW127 to operate not as expected resulting in an unexpected rise in component cooling water (CCW) system temperatures after the 22CCWHX was placed in service on November 18, 2008. As a result operators declared the 22CCWHX inoperable and documented the condition in the corrective action program. In accordance with NRC IMC 0609 the inspectors determined the finding was of very low safety significance (Green) because it was a design deficiency that was confirmed not to result in a loss of CCW train operability. The finding has a cross-cutting aspect in the area of human performance, resources, because PSEG did not ensure that adequate resources were available to maintain complete, accurate and up-to-date design documentation, procedures, and work packages [H.2(c)]. Specifically, PSEG did not maintain the 22SW127 ICD card and valve set-up work order up-to-date in accordance with the valve's design basis documentation. (Section 1R12)

- Green: The inspectors identified a Green NCV of 10 CFR 50.65(a)(4) because PSEG did not did not implement prescribed risk management actions (RMA) while both Unit 2 pressurizer (PZR) power operated relief valves (PORV) were isolated. PSEG's corrective actions included adding the requirement for operators to record protected SSCs in the control room narrative log and training operators on the risk assessment process.

  This finding was more than minor because PSEG did not implement a prescribed significant compensatory measure for an identified yellow risk condition. Specifically, PSEG did not implement equipment risk awareness and control measures while both PZR PORVs were isolated, and conducted testing on a protected component without the required written authorization and supervision. The inspectors completed a Phase 1 screening of the finding per Appendix K of Inspection Manual Chapter (IMC) 0609, "Maintenance Risk Assessment and Risk Management Significance Determination Process." The inspector determined that the incremental core damage probability (ICDP), based on PSEG's risk analysis of the event, was 5.6E-8. Therefore, the inspectors determined the finding to be of very low safety significance (Green) because the ICDP for the event did not exceed 1.0E-6. The finding had a cross-cutting aspect in the area of human performance because PSEG did not define and effectively communicate expectations regarding procedural compliance and personnel did not follow procedures [H.4(b)]. Specifically, operators did not implement the RMAs specified by an approved risk assessment per PSEG work management and operations procedures. (Section 1R13)

- Green: The inspectors identified a self-revealing finding because PSEG did not use the corrective action process (CAP) to identify and correct a recurring issue with the calibration of a narrow range mid loop level transmitter. This extended the time that the reactor was placed in a reduced reactor coolant (RC) inventory condition during the S1R19 refueling outage, which unnecessarily increased shutdown plant risk. Corrective actions taken by PSEG included correction of the surveillance data sheet for the narrow range level indication for the 11 RC loop. PSEG also entered the issue into the corrective action program as notification 20390640.

  This finding was more than minor because it was associated with the design control attribute of the Mitigating Systems cornerstone and it affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, not correcting the calculation error resulted in the inaccurate calibration procedure for the 11 RC loop narrow range level indication. This unnecessarily extended the time that the plant was operated in a reduced reactor coolant inventory condition which increased shutdown plant risk. The inspectors evaluated the significance of this finding using IMC 0609, Appendix G, "Shutdown Operations SDP," Attachment 1, Checklist 6 and Figure 1. The inspectors determined that this finding was of very low safety significance (Green) because it did not require a quantitative assessment since two sources of level instrumentation remained available during the reduced inventory evolution. This finding had a cross-cutting aspect in the area of problem identification and resolution because PSEG did not identify the calculation error issue completely, accurately, and in a timely manner commensurate with the safety significance [P.1(a)]. Specifically, PSEG did not ensure that technician observations related to repeat calibration errors on the 11 RC loop level indicator, which were identified in 2007, were entered into the CAP. (Section 1R20)

- Green: A self-revealing NCV of 10 CFR 50, Appendix B, Criteria XI, "Test Control," was identified because all Unit 2 high steam flow protection channels were discovered inoperable on May 12, 2008. Specifically, following steam generator replacement on Unit 2, PSEG did not perform adequate post-modification acceptance testing and, as a result, did not maintain Technical Specification (TS) required steam flow instrumentation operable. PSEG entered this issue into the corrective action program and implemented corrective actions that included specifying testing requirements and acceptance criteria for the steam line instrumentation, enforcing procedure use standards and heightened managerial oversight of power ascension testing.

  The finding was more than minor because it was associated with the equipment performance attribute of the Mitigating Systems cornerstone and because it affected the cornerstone objective of ensuring the availability, reliability and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, all channels of the Unit 2 engineered safety feature actuation system (ESFAS) high steam flow protective function were not correctly calibrated after completion of steam generator replacement. As a result, operators declared the affected ESFAS channels inoperable and shutdown the plant in accordance with TS requirements. Per Inspection Manual Chapter (IMC) 0609.04, “Initial Screening and Characterization of Findings,” the inspectors conducted a Phase 1 screen and determined the finding to be of very low safety significance (Green) because the performance deficiency was a qualification deficiency confirmed to result in loss of operability that did not result in an actual loss of safety function and did not screen as potentially risk significant due to external initiating events. This finding had a cross-cutting aspect in the area of human performance because PSEG did not provide complete, accurate and up-to-date design documentation, procedures, and work packages [H.2(c)]. Specifically, PSEG did not specify adequate testing requirements and acceptance criteria for steam flow instrumentation in the design change package 80083522, Supplement 12 as required by PSEG design change implementation procedure guidance. (Section 4OA5)

B. <u>Licensee Identified Violations</u>

None

REPORT DETAILS

Summary of Plant Status

Salem Nuclear Generating Station Unit 1 (Unit 1) began the period at full power. Operators shut down Unit 1 on October 14 to start the nineteenth refueling outage (S1R19). Operators returned Unit 1 to service on November 13 and achieved full power on November 18. On December 7, operators lowered Unit 1 to 83% power in response to circulating water system degradation. Operators returned Unit 1 to full power on December 8. On December 15, operations reduced power to 83% because a brush fire posed a risk to an offsite transmission line. Operators returned Unit 1 to full power on December 16. On December 22, operators lowered Unit 1 to 92% power in response to circulating water system degradation and returned Unit 1 to full power the same day. Unit 1 operated at or near full power for the remainder of the inspection period.

Salem Nuclear Generating Station Unit 2 (Unit 2) began the period at full power. On October 16, operators lowered Unit 2 to 65% power to support planned transmission grid maintenance and returned to full power on October 19. On December 15, operations reduced power to 83% because an off-site fire posed a risk to an off-site transmission line. Operators returned Unit 2 to full power on December 16. Unit 2 operated at or near full 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 - 1 sample)

a. Inspection Scope

The inspectors completed one seasonal weather preparation inspection sample for the onset of cold weather. The inspectors reviewed adverse weather preparation procedures and compensatory measures to verify that PSEG adequately protected and prepared risk-significant systems to operate reliably in extreme cold weather conditions. The inspectors interviewed engineering and operations personnel, walked down risk-significant systems, and evaluated the readiness of associated control room instrumentation to independently assess PSEG's preparations. Specifically, the inspectors walked down the service water (SW) intake structure, outdoor areas within the protected area, emergency diesel generators (EDGs), refueling water and auxiliary feedwater storage tank areas, SW pipe tunnel, gas turbine generator, and the station blackout (SBO) air compressor. In addition, the inspectors reviewed the technical specifications (TS), UFSAR, and PSEG procedures to ensure that PSEG operated and maintained the systems and components as required. The documents reviewed during this inspection are listed in Attachment A.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04 - 5 samples)

Partial Walkdown

a. Inspection Scope

The inspectors completed five partial system walkdown inspection samples. The inspectors walked down the 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 increase plant 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 properly utilized its corrective action program to identify and resolve equipment alignment problems that could cause initiating events or impact the capability of mitigating systems or barriers. Documents reviewed for this inspection are listed in Attachment A. The inspectors walked down the systems listed below:

- Unit 1 1A vital instrument bus inverter following maintenance on the 1A vital instrument bus;
- Unit 2 containment fan coil unit (CFCU) SW cooling alignment following failure of 22SW72 and subsequent removal of the 22 CFCU from service;
- Unit 1 4 kVac and 460 Vac distribution systems alignment following SSPS testing and during modifications to the offsite transmission grid;
- Unit 1, 1B and 1C EDG during planned unavailability of the 1A EDG; and
- Unit 1, SW to the EDGs during planned unavailability of one SW header.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05Q - 6 samples)

Fire Protection - Tours

a. Inspection Scope

The inspectors completed six fire protection quarterly inspection samples. The inspectors performed walkdowns 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 Attachment A. The inspectors evaluated the fire protection areas listed below:

- Unit 1, service water intake bay 3;
- Unit 1, containment;

- Unit 1 and 2 EDG and fuel oil day tank rooms; and
- Unit 1 and 2 EDG fuel oil storage tank and fuel oil transfer pump rooms.

b. Findings

Introduction: The inspectors identified a NCV of Salem Operating License condition 2.C.5, that requires PSEG implement all provisions of the Fire Protection Program as described in the UFSAR. Specifically, PSEG strung nine temporary power cables through a CCZ without an engineering evaluation that assessed risk and established compensatory measures. This finding was determined to be of very low safety significance (Green).

Description: PSEG procedure FP-AA-011 “Control of Transient Combustible Material” governs the handling and limits the use of ordinary combustible materials, and combustible and flammable liquids and gases. An important part of this control program was the designation of transient CCZs. A CCZ was defined as an area in the plant in which transient combustible material is prohibited when not constantly attended or approved by a TCP. CCZ-8 was established to provide separation between service water cable trains A and B and to limit challenges to physical separation afforded by steel floor hatches above and below CCZ-8.

On September 11, 2008, inspectors identified nine temporary electrical cables staged for the fall Unit 1 refuel outage. The cables were strung in the overhead, and passed through CCZ-8. Further inspection revealed that an engineering evaluation to determine the risk and appropriate compensatory measures did not exist for the transient combustibles located in this CCZ. The inspectors notified the control room operator of this apparent deficiency, and a notification was written. PSEG subsequently issued a TCP on September 12 for the cables.

PSEG completed a work group evaluation (WGE) and determined that inadequate planning and work control caused this violation. PSEG procedures that governed control of transient combustible material, management and control of temporary power, and work management and maintenance planning all alerted work planners that a TCP was required when staging TP&L in a CCZ. Specifically, procedure MA-AA-716-010, “Maintenance Planning Process,” required that TCPs necessary to complete work be identified by maintenance planning; procedure SA-AA-129-2118, “Management and Control of Temporary Power,” required that combustible loading be evaluated; and FP-AA-011, “Control of Transient Combustible Material,” required a TCP for transient combustibles staged in a CCZ. PSEG also found that maintenance personnel responsible for installing TP&L did not understand that the CCZ included the entire space between the floor and ceiling enveloped by the horizontal boundaries of the CCZ. TP&L was staged throughout Unit 1 under work order (WO) 30156086. This WO was a repetitive maintenance task to stage TP&L at standardized locations to support refueling outage activities. Each location was identified by a separate step under the WO and included both safety and non-safety related structures. WO 30156086 did not include direction to obtain a TCP before placing TP&L in a CCZ. The WO only identified the locations where TP&L was to be staged. As a result, maintenance personnel working under WO 30156086 did not obtain a TCP as required by FP-AA-011.

The inspectors reviewed PSEG's cause analysis and determined that PSEG did not adhere to the procedural requirements of the fire protection program with respect to the control of transient combustibles. As a result, transient combustibles were staged in a combustible control zone established to protect train separation without the support of an engineering analysis. The inspectors determined that this was a performance deficiency because PSEG procedure FP-AA-011 "Control of Transient Combustible Material," stated that transient combustible material was prohibited in a CCZ when not constantly attended or approved by a TCP.

PSEG corrective actions included: briefing all personnel involved with installation and removal of TP&L for S1R19; completing an immediate extent of condition review correcting the master work orders for staging TP&L by including steps for completing fire protection program requirements; and adding this incident to the scope of general employee training.

Analysis: This finding was more than minor because it was associated with the external factors attribute of the Mitigating Systems cornerstone and adversely affected the cornerstone objective to ensure the availability of systems that respond to initiating events to prevent undesirable consequences. Specifically, the identified transient combustibles were located in a CCZ that was required to maintain separation between service water cable trains A and B and to limit challenges to physical separation afforded by steel floor hatches above and below the CCZ. Using IMC 0609, Appendix F, "Fire Protection Significance Determination Process," the inspectors determined that this issue involved the finding category, "Fire Prevention and Administrative Controls." Referencing IMC 0609, Appendix F, Attachment 2, "Degradation Rating Guidance Specific to Various Fire Protection Program Elements," the inspectors assigned a low degradation rating to the issues involving the failure to comply with PSEG's transient combustible program. The inspectors' conclusions were based on the fact that none of the items found in the combustible free zone could be considered transient combustibles of significance, as described in IMC 0609, Appendix F, Attachment 2. This attachment defined transient combustibles of significance as low flash point liquids (below 200 degrees F) and self-igniting combustibles (oily rags). Because this item was assigned a "low degradation" rating this issue was of very low safety significance (Green) in accordance with IMC 0609, Appendix F, Task 1.3.1.

This finding had a cross-cutting aspect in the area of human performance because PSEG did not provide complete, accurate and up-to-date design documentation, procedures, and work packages [H.2(c)]. Specifically, WO 30156086 did not direct maintenance personnel to obtain a TCP before staging combustible material in a CCZ.

Enforcement: License condition 2.C.5 requires that PSEG Nuclear implement and maintain in effect all provisions of the Fire Protection Program as described in the UFSAR. Section 9.5.1.1.2 of the UFSAR, Use of Combustible Materials, states that "Administrative controls are established to minimize the quantity of combustibles in areas designated as combustible control zones." PSEG Nuclear procedure FP-AA-011, "Control of Transient Combustible Material," defined a transient CCZ as an area in the plant in which transient combustible material was prohibited when not constantly attended, or permitted by an approved TCP. Contrary to the above, on September 11, 2008, the NRC identified that transient combustible materials were stored in a CCZ unattended and without an approved TCP. Specifically, nine cables with an estimated heat content of 480,000 BTU were located in CCZ-8. CCZ-8 existed to maintain cable separation between service water trains A and B. PSEG's corrective action for this issue included issuing a TCP for the temporary cables located in CCZ-8 and to perform an extent of condition review for transient combustibles stored in all CCZs. Because this issue was of very low safety significance and has been entered into PSEG's corrective action program as notification 20383239, this violation is being treated as a NCV, consistent with Section VI.A, of the NRC Enforcement Policy. **(NCV 05000272/2008004-01, Improper Control of Transient Combustible Material)**

1R07 Heat Sink Performance (71111.07A - 1 sample)

a. Inspection Scope

The inspectors completed one heat sink performance inspection sample. Specifically, the inspectors reviewed performance data and interviewed the program manager responsible for implementation of PSEG's NRC Generic Letter (GL) 89-13 program to verify that potential heat exchanger (HX) or heat sink deficiencies were identified and resolved. The inspectors reviewed 12A component cooling water (CCW) HX data. The inspectors evaluated trending data and verified that the equipment would perform satisfactorily under design basis conditions. PSEG's performance monitoring was compared to NRC GL 89-13, "Service Water System Problems Affecting Safety-Related Equipment," and EPRI NP 7552, "Heat Exchanger Performance Monitoring Guidelines," to verify conformance with these guidance documents.

The inspectors walked down the 12 CCW heat exchanger during disassembly to assess the general material condition of the selected HX and the associated SW system components. The inspectors also observed replacement of the internal plates to verify correct configuration. Documents reviewed are listed in Attachment A.

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection (71111.08 - 1 sample)

a. Inspection Scope

A sample of visual inspection (VT) included the areas of the containment inner boundary at the containment liner to containment floor intersection. The basis for not doing other ASME Section XI, Subsection IWE containment liner to containment penetration examinations during the 1R19 outage was reviewed. Documentation of VT, including photographs of the reactor pressure vessel (RPV) lower head penetration examinations, was also reviewed. This included documentation that supported completion of the inspection requirements for painted penetrations that required bare metal inspections at the penetration to lower head intersection. In resolving the issue, PSEG determined that the paint only bridged a portion of the penetration-to-head intersection and it was removed by the examiner for the VT.

As part of the TI-172 inspection scope, the inspectors evaluated the application of computer-based phased array ultrasonic testing (UT) and manual phased array UT to the pre- and post-mechanical stress improvement (MSIP) conditions for the four hot leg (HL) and four cold leg (CL) reactor vessel nozzle-to-safe-end welds made with alloy 82/182. The procedures for both computer-based phased array UT and manual phased array UT were reviewed and the data, including visual presentations from both methods, were examined. The records of an indication in HL weld #14 that were made by the computer-based phased array UT and manual phased array UT, pre and post MSIP, were compared for equivalency and to the stress improvement qualification report.

Activities inspected during S1R19 included observations of UT calibration and data review for component testing that was in-progress using manual UT technique. This included UT of safety injection system piping.

For component replacement work, the inspectors observed the installation and reviewed the work orders for modifications to the SW system. The work packages included the requirements for welding and related quality verifications. Preparations for radiographic testing (RT) and the RT procedure of two 10" diameter circumferential SW pipe welds were also reviewed. The inspectors reviewed welding parameters and observed SW pipe replacement welds for comparison to the ASME Code fabrication requirements. The sensitivity of the radiographic technique and the applicable parts of the RT procedure were discussed with the responsible radiographer.

The replacement of reactor coolant system (RCS) system thermowells to eliminate the dissimilar 82/182 weld material in these components was observed.

Because the Unit 1 upper RPV head with control rod drive mechanism (CRDM) penetrations was recently replaced, no detailed examination of these welds was conducted during S1R19, however no degradation of the CRDMs or the upper head was observed.

In the area of boric acid corrosion control activities, the inspector confirmed the extent of plant boric acid walk downs completed during the plant shutdown process and noted that identified problem areas were documented in condition reports for evaluation and resolution. The inspectors followed-up on boric acid evaluations and observed corrective actions in the plant, including an RCS vent valve replacement.

Steam generator (SG) tube inspection results from S1R18 provided a basis to not do eddy current of SG tubes during S1R19. The inspectors reviewed the SG tube assessment for S1R18 and the documented review of the acceptability of SG operation until S1R20.

In the area of flow accelerated corrosion, the inspectors reviewed the program scope and completed field observations in-progress piping and component replacements. The inspectors also verified the measurement process with an NDE technician.

The task work orders and test data for several UT and VT identified indications were reviewed and confirmed to be evaluated by PSEG as part of the inservice inspection process.

There were no previous ASME Section XI NDE indications from previous outages that required follow-up inspection during S1R19.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification Program (71111.11Q - 1 sample)

.1 Requalification Activities Review by Resident Staff.

a. Inspection Scope

The inspectors completed one quarterly licensed operator requalification program inspection sample on November 18. Specifically, the inspectors observed an annual operating examination administered to a single crew. The scenario involved a spent fuel pool high level caused by valve leakage, loss of cooling to an operating emergency diesel generator, and a leak in the turbine area cooling (TAC) system that forced operators to commence a rapid shutdown. Documents reviewed are listed in Attachment A.

b. Findings

No findings of significance were identified.

.2 Biennial Review by Regional Staff.

a. Inspection Scope

On November 25, 2008, a region-based inspector conducted an in-office review of results of the PSEG-administered annual operating tests and comprehensive written exams for 2008. The inspection assessed whether pass rates were consistent with the guidance of NRC Manual Chapter 0609, Appendix I, "Operator Requalification Human Performance Significance Determination Process (SDP)." The inspector verified that:

- Crew failure rate was less than 20%. (Crew failure rate was 0%)
- Individual failure rate on the dynamic simulator test was less than or equal to 20%. (Individual failure rate was 0%)
- Individual failure rate on the walk-through test was less than or equal to 20%. (Individual failure rate was 3%)
- Individual failure rate on the comprehensive written exam was less than or equal to 20%. (Individual failure rate was 0%)
- Overall pass rate among individuals for all portions of the exam was greater than or equal to 75%. (Overall pass rate was 97%)

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12Q - 2 samples)

a. Inspection Scope

The inspectors completed two quarterly maintenance effectiveness inspection samples. The inspectors reviewed performance monitoring and maintenance effectiveness issues for two components. The inspectors reviewed PSEG's process for monitoring equipment performance and assessing preventive maintenance effectiveness. The inspectors verified that systems and 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 being met. The inspectors reviewed applicable work orders, corrective action notifications (NOTFs), and preventive maintenance tasks. Documents reviewed are listed in Attachment A. The inspectors evaluated the components listed below:

- 22 CCWHX SW outlet temperature control valve (22SW127); and
- 2C 125 VDC vital battery.

b. Findings

Introduction: The inspectors identified a self-revealing NCV of 10 CFR 50, Appendix B, Criterion III, Design Control, because the No. 22 CCWHX SW outlet temperature control valve (22SW127) did not stroke open when the 22 CCWHX was placed in service following a high flow flush on November 18, 2008. Specifically, PSEG failed to ensure that the design basis was correctly translated into valve set-up instructions for the 22SW127 valve. This finding was determined to be of very low safety significance (Green).

Description: The 22 CCWHX configuration included a SW flow control valve upstream (22SW122) and downstream (22SW127) of the heat exchanger. In November 1994, design change package (DCP) 2EC-3252 replaced the CCWHX flow and temperature controllers for these valves with a single pneumatic cascade type control system. When the CCWHX was out of service both valves were shut. The 22SW127 valve has a safety function to open to provide sufficient SW flow during a loss-of-coolant-accident (LOCA). Due to the differential pressure across the valves, the control system was designed so that the SW outlet control valve (22SW127) started to open before the SW inlet control valve (22SW122). Once opened, the 22SW127 modulates to control CCW temperature.

On October 29, 2008, Unit 2 operators noted a rising CCW temperature after placing the No. 22 CCWHX in service to support a CCW pump test. Equipment operators reported that the 22SW127 valve remained closed vice stroking open immediately. Operators also noted that the 22SW127 valve subsequently opened and then throttled to control temperature. Operators declared the 22CCWHX inoperable and initiated corrective action NOTF 20389212. PSEG lubricated the valve, replaced the valve needle bearing, shortened the valve's stroke and declared the valve operable. The emergent condition resulted in approximately 27.5 hours of unavailability due to troubleshooting and corrective maintenance.

On November 18, 2008, equipment operators reported that the 22SW127 remained closed vice stroking open immediately when the 22CCWHX was placed in service following a high flow flush. Operators again declared the 22CCWHX inoperable and initiated corrective action NOTF 20391910. The emergent condition resulted in approximately 30 hours of unavailability due to troubleshooting and corrective maintenance.

During troubleshooting after the November 18 failure, engineering identified that the instrument calibration data (ICD) card that technicians used to setup 22SW127 did not contain the valve stroke length specified by the 1994 design change, DCP 2EC-3252. This caused technicians to set-up the valve incorrectly in April 2008, which resulted in the valve to not stroking open as expected in October and November 2008. PSEG's immediate corrective actions included revising the ICD card to correct the valve stroke length and adjusting the valve shaft spline to lightly seat and short stroke the valve in accordance with DCP 2EC-3252. Following these adjustments the valve was tested satisfactorily.

During a more detailed review of causes for this issue, engineering identified several other design documentation discrepancies that may have also contributed to 22SW127's unexpected performance. In response to these issues engineering initiated corrective action NOTF 20392246. The identified discrepancies included:

(1) Contrary to DCP 2EC-3252, the ICD card listed actuator air supply pressure as 85 psig vice 90 psig. This reduced the unseating torque applied to the valve by the valve actuator.

(2) Contrary to DCP 2EC-3252, the ICD card listed the positioner pressure setting as 4-15 psig vice 4-16 psig. The higher pressure was necessary to account for the 10% tolerance on the 22SW122 positioner setting. The higher pressure band for the 22SW127 positioner ensured that 22SW127 started to open before 22SW122. This reduced the differential pressure that 22SW127 was exposed to when it was opened. A lower positioner pressure may have prevented 22SW127 from opening before 22SW122 which would increase the differential pressure across 22SW127 during an open stroke.

(3) System design calculations assumed the maximum SW pressure was 130 psig, but the SW operating procedure allowed system pressures as high as 150 psig. This increased the system pressure that 22SW127 was exposed to during an open stroke.

Engineering evaluated the No. 22 CCWHX for past operability given these design discrepancies. Engineering determined that the 22SW127 remained operable but its design margin was reduced to 2 percent.

The inspectors reviewed engineering's past operability determination and determined that it was acceptable. However, the inspectors also identified that in addition to the design documentation inaccuracies identified by engineering, the Inservice Testing (IST) Program Basis data sheet for 22SW127 contained misleading information. Specifically, the IST data sheet stated that 22SW127 was normally open and not subject to travel to the closed position. This information was contrary to actual system operation because, as stated above, the 22SW127 valve on the standby CCWHX was normally closed. The inspectors noted that the misleading IST information was a problem because engineering and operations used this information to support several engineering evaluations and operability determinations associated with the 22SW127 valves. Engineering initiated NOTF 20395102 to evaluate IST testing requirements for the 22SW127 valves and to correct the IST program data sheet information.

The inspectors determined PSEG did not adequately implement design control measures to ensure that 22SW127 valve set-up instructions were correctly translated into maintenance procedures when the design was revised in 1994. In addition, in September 2007 engineering reviewed and approved calculation S-C-SW-NDC-2140 regarding 22SW127 valve performance capability, but also did not identify inaccurate assumptions regarding SW pump discharge header pressure and 22SW127 valve position or the inaccurate set-up instructions for 22SW127. The inadequate design control in 1994 and 2007 resulted in the incorrect 22SW127 set-up which caused an unexpected rise in CCW system temperatures after the 22 CCWHX was placed in service on October 29, and November 18, 2008.

<u>Analysis</u>: This finding was more than minor because it was associated with the design control 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. Specifically, the improper valve set-up instructions caused the 22SW127 to not operate as expected resulting in an unexpected rise in CCW system temperatures after the 22CCWHX was placed in service on November 18, 2008. As a result operators declared the 22CCWHX inoperable and documented the condition in the corrective action program. In accordance with NRC IMC 0609, Attachment 4, Phase 1- Initial Screening and Characterization of Findings, a Phase 1 SDP screening was performed and determined the finding was of very low safety significance (Green) because it was a design deficiency that was confirmed not to result in a loss of CCW train operability.

The finding had a cross-cutting aspect in the area of human performance, resources, because PSEG did not ensure that adequate resources were available to maintain complete, accurate and up-to-date design documentation, procedures, and work packages [H.2(c)]. Specifically, PSEG did not maintain the 22SW127 ICD card and valve set-up work order up-to-date in accordance with the valve's design basis documentation.

<u>Enforcement</u>: 10 CFR 50 Appendix B, Criterion III, Design Control, requires, in part, that design control measures be established and implemented to assure that applicable regulatory requirements and the design basis for structures, systems, and components are correctly translated into specifications, drawings, procedures, and instructions. Contrary to the above, from approximately November 1994 until November 18, 2008, PSEG did not ensure that applicable design requirements were correctly translated into specifications, drawings procedures or instructions. Specifically engineering did not ensure that the 22SW127 valve set-up instructions specified in the design documentation were correctly translated into valve-setup documentation for maintenance. This adversely affected the CCWHXs ability to adequately maintain its temperature control function. Because this issue is of very low safety significance, and it

was entered into the corrective action program (NOTF 20392246), this violation is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy. **(NCV 05000311/2008005-02, Inadequate Design Control for No. 22 CCWHX SW Outlet Temperature Control Valve)**

1R13 Maintenance Risk Assessments and Emergent Work Control (71111.13 - 6 samples)

a. Inspection Scope

The inspectors completed six maintenance risk assessments and emergent work control inspection samples. The inspectors reviewed the selected maintenance activities to verify that the appropriate risk assessments were performed as specified 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. PSEG's risk management actions were reviewed during shift turnover meetings, control room tours, and plant walk downs. 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. The inspectors reviewed NOTFs documenting problems associated with risk assessments and emergent work evaluations. Documents reviewed are listed in Attachment A. The inspectors assessed the plant configurations listed below:

- Planned unavailability of the 22 diesel fuel oil transfer pump concurrent with closure of PZR PORV block valve 2PR6 and emergent maintenance on the 21 stator water cooling water pump on October 7;
- Planned unavailability of the 5038 500 kV offsite transmission line concurrent with unavailability of the 11 service water header and the 1C 125 VDC buss during a refueling outage on October 15;
- Simultaneous, planned unavailability of the 11 and 12 chiller during a refueling outage concurrent with unavailability of the 1A EDG and the Unit 1 control room emergency air conditioning system on October 24;
- Unit 2 contingency preparations to repower the overhead annunciator system while one of two redundant (auctioneered) power supplies was failed on November 5;
- Unit 1 preparations to prevent internal flooding during removal of 12SW79 to support internal pipe inspections on October 23; and
- Unit 2 concurrent blocking of both PZR PORVs for troubleshooting on November 17.

b. Findings

Introduction: The inspectors identified a Green NCV of 10 CFR 50.65(a)(4) because PSEG did not implement prescribed RMA while both Unit 2 PZR PORVs were isolated. This finding was determined to be of very low safety significance (Green).

Description: PSEG procedures "On-line Work Management Process" and "On-line Risk Assessment" govern the on-line work management process. The procedures defined on-line risk levels as green, yellow, orange and red in order of increasing risk. For yellow risk conditions both procedures required increased awareness and control by protecting structures, systems and components (SSC) that would unacceptably increase risk if made unavailable. The procedures defined protection as using barriers such as ropes or signs to prevent inadvertent work on risk-important SSCs for the given plant configuration.

On November 17, 2008, the inspectors identified that PSEG did not implement prescribed RMAs for a planned yellow on-line risk condition. PSEG had previously assessed the Unit 2 on-line risk condition between November 14 and November 17, 2008, as yellow because both PZR PORVs (2PR1 and 2PR2) were isolated on November 14, 2008. The PORVs were isolated per an approved troubleshooting plan that was written to address an increasing trend in unidentified RCS leakage. In accordance with the online risk assessment procedure requirements for yellow risk conditions, PSEG specified RMAs that required operators to protect the following SSCs: station switchyard, auxiliary feedwater pumps, steam generator atmospheric dump valves, PZR spray, and the station blackout (SBO) air compressor. PSEG work management and operations department procedures specified that work on protected SSCs required written authorization from the shift manager and continuous supervision. On November 15, 2008, contrary to these procedure requirements, PSEG conducted periodic testing of the SBO air compressor, but did not obtain written authorization from the shift manager for the work or provide continuous supervision of the work.

PSEG completed a work group evaluation (WGE) for this issue and identified several corrective actions that included a requirement to record protected SSCs in the control room narrative log and training the operators on the risk assessment process.

The inspectors determined that not implementing risk management actions for the identified yellow risk condition was a performance deficiency because the cause was within PSEG's ability to foresee and correct. Specifically, PSEG procedures governing on-line work management required implementation of RMAs prescribed by the results of the risk assessment.

Analysis: This finding was more than minor because PSEG did not implement a prescribed significant compensatory measure for an identified yellow risk condition. Specifically, PSEG did not implement equipment risk awareness and control measures while both PZR PORVs were isolated and conducted testing on a protected component without the required written authorization and supervision. The inspectors completed a Phase 1 screening of the finding per Appendix K of Inspection Manual Chapter (IMC) 0609, "Maintenance Risk Assessment and Risk Management Significance Determination Process." The inspectors determined that the incremental core damage probability (ICDP), based on PSEG's risk analysis of the event was 5.6E-8 based on a 72-hour risk exposure while both PZR PORVs were isolated. In accordance with IMC 0609 Appendix K the inspectors determined the finding to be of very low safety significance (Green) because the ICDP for the event did not exceed 1.0E-6.

This finding had a cross-cutting aspect in the area of human performance because PSEG did not define and effectively communicate expectations regarding procedural compliance and personnel did not follow procedures [H.4(b)]. Specifically, operators did not implement the RMAs specified by an approved risk assessment per PSEG work management and operations procedures.

Enforcement: 10 CFR 50.65 (a)(4), “Requirements for monitoring the effectiveness of maintenance at nuclear power plants,” requires in part, that PSEG assess and manage risk of proposed maintenance activities before performing such maintenance. PSEG procedure WC-AA-101, “On-line Work Management Process,” implements the requirements set forth in 10 CFR 50.65 (a)(4) during power operation. OP-AA-101-112-1002, “On-line Risk Assessment,” defines the requirements of station personnel to assess and manage risk-significant activities at the station and requires increased awareness and control of SSCs that would cause unacceptably high on-line risk if the SSC became unavailable during the proposed maintenance. Contrary to the above, between November 14 and 17, 2008, PSEG did not implement prescribed risk management actions. Specifically, the station switchyard, auxiliary feedwater pumps, steam generator atmospheric dump valves, PZR spray and the station blackout air compressor were not protected as prescribed by a risk assessment. Additionally, on November 15, 2008, PSEG completed testing on the station blackout air compressor without taking the actions required by PSEG procedures for protected SSCs. PSEG’s corrective action included initiating a requirement to record protected SSCs in the control room narrative log and training the operators on the risk assessment process. Because this issue was of very low safety significance and has been entered into PSEG’s corrective action program as NOTF 20391880, this violation is being treated as a NCV, consistent with Section VI.A, of the NRC Enforcement Policy. **(NCV 05000311/2008005-03, Inadequate Implementation of Risk Management Actions Associated with Planned Maintenance on the Unit 2 Pressurizer PORVs).**

1R15 Operability Evaluations (71111.15 - 6 samples)

a. Inspection Scope

The inspectors completed six operability evaluation inspection samples. The inspectors reviewed the operability determinations for the degraded or non-conforming conditions listed below:

- Potential binding of Unit 1 containment spray (CS) system motor operated valve 1CS14 during (MOV) diagnostic testing;
- Unit 1 and 2 modifications to the transmission grid that supplies power to the offsite electrical power sources during S1R19;
- Missed surveillance functional testing for Unit 1 PZR safety relief valves 1PR3 and 1PR4 position indication;
- Seat leakage past Unit 2, component cooling water system service water outlet valve 22SW127;
- Degraded operation of Unit 1 CFCU service water accumulator outlet valve 12SW534; and
- Inaccurate Unit 1 cold calibrated PZR level instrument during drain down from solid to mid-loop conditions for S1R19.

The inspectors reviewed the technical adequacy of the operability determinations to ensure the conclusions were justified. The inspectors also walked down accessible equipment to corroborate the adequacy of PSEG’s operability determinations. The inspectors also reviewed other PSEG identified safety-related equipment deficiencies during this report period and assessed the adequacy of their operability screenings. Documents reviewed are listed in Attachment A.

b. Findings

No findings of significance were identified.

1R18 Plant Modifications (71111.18 – 2 samples)

.1 Temporary Modification

a. Inspection Scope

The inspectors completed one plant modifications inspection sample. The inspectors reviewed a temporary modification developed and implemented as a contingency to repower the overhead annunciator system should one of two redundant (auctioneered) power supplies fail while the second power supply was out of service. This temporary modification consisted of an external power supply that could be rapidly placed in service should the remaining internal power supply fail. The inspectors reviewed power supply requirements to ensure compatibility. The inspectors observed technician training that included simulated activities to place the external power supply in service. Finally, the Inspectors reviewed the 10 CFR 50.59 screening against the system design basis documentation, and verified that the modifications did not affect system functionality.

b. Findings

No findings of significance were identified.

.2 Permanent Modification

a. Inspection Scope

The inspectors completed one plant modifications inspection sample. The inspectors reviewed a permanent modification to Unit 1 CFCU service water flow control under design change package (DCP) 80092249. This review included system walk downs, interviews with plant engineers, and functional comparison of the new control scheme to the UFSAR description. The inspectors also reviewed design adequacy of the modification, preparation, staging, and implementation of the modification, and post-modification testing. This modification replaced a system that varied service water flow for normal and accident conditions with a simplified scheme that provided a fixed resistance service water flow to the CFCUs under normal and accident conditions. This modification simplified the SW system and eliminated numerous components and instruments that had active safety functions. This modification was made following approval of License Change Request S06-10. Each of the five CFCUs located in the Unit 1 containment were included in this permanent modification. This modification was performed during S1R19. Documents reviewed are listed in Attachment A.

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing (71111.19 - 7 samples)

a. Inspection Scope

The inspectors completed seven post-maintenance testing inspection samples. The inspectors observed portions of and/or reviewed the results of the post-maintenance test activities. The inspectors verified that the effect of testing on the plant was adequately addressed by control room and engineering personnel; testing was adequate for the maintenance performed; acceptance criteria were clear, demonstrated operational readiness and were consistent with design and licensing basis documentation; test instrumentation was calibrated, and the appropriate 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 Attachment A. The inspectors evaluated the post-maintenance tests for the following maintenance items listed below:

- Work order (WO) 30153423, repair of the 1N32 source range neutron detector;
- WO 60045498, repacking of residual heat removal (RHR) valve 1SJ69;
- WO 30132037, repacking of main steam isolation valve 12MS167;
- WO 30132501, reinstallation of service water (SW) valve 14SW5;
- WO 30106016, reassembly of component cooling water (CCW) heat exchanger 12A;
- WO 60079160, repair of leak from CS valve 12CS46; and
- WO 50117367, refueling outage overhaul of 1A EDG.

b. Findings

No findings of significance were identified.

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

a. Inspection Scope

Unit 1 Refueling Outage (S1R19). The inspectors observed or reviewed the following refueling outage activities to verify that operability requirements were met and that risk, industry experience, and previous site specific problems were considered. Documents reviewed for this inspection are listed in Attachment A.

The inspectors reviewed the schedule and risk assessment documents associated with S1R19 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 S1R19 the inspectors reviewed PSEG's outage risk assessment to identify risk significant equipment configurations and determine whether planned risk management actions were adequate. During S1R19 the inspectors verified that PSEG managed the outage risk commensurate with the outage plan.

The inspectors observed portions of the shutdown and cool down processes and monitored PSEG controls over the outage activities. The inspectors also verified that cool down rates were within TS limitations. Following an inadvertent over-draining of water from the RCS, the inspectors increased monitoring and inspection of activities that affected reactor coolant inventory during the remainder of S1R19.

At the start of S1R19, the inspectors inspected containment for evidence of previously unidentified reactor coolant leakage. Throughout S1R19, the inspectors routinely inspected containment for indications of unidentified leakage, damaged equipment, foreign material control, radiation worker work practices and fire prevention.

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, tags hung to support work on components cooled by the 12 SW header were verified to comply with procedural requirements for hardening of the 11 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 verified that offsite and onsite electrical power sources were maintained in accordance with TS requirements and consistent with the outage risk assessment. Periodic walk downs of portions of the onsite electrical buses and the EDGs were conducted during risk significant electrical configurations. The inspectors assessed offsite grid modifications for operability impact.

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.

The inspectors observed the Unit 1 RCS draining on October 17 and November 3, 2008. 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. 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.

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. The condition of equipment used for fire detection, prevention and suppression were inspected for operability and functionality. Portions of mode changes and reactor startup were observed and reviewed for compliance with applicable procedures and TS.

b. Findings

Introduction: The inspectors identified a self-revealing finding because PSEG did not use the CAP to identify and correct a recurring issue with the calibration of a narrow range mid loop level transmitter. This extended the time that the reactor was placed in a reduced RC inventory condition during S1R19, which unnecessarily increased shutdown plant risk. This finding was determined to be of very low safety significance (Green).

Description: PSEG's program for shutdown risk management was defined by PSEG procedure, OU-AA-103, "Shutdown Safety Management Program." This procedure defined the key safety functions during shutdown as decay heat removal, inventory control, power availability, reactivity control, and containment. The safety function, inventory control, was defined as measures established to ensure that irradiated fuel remained covered with coolant to maintain heat transfer and shielding requirements. From a risk perspective the greater the RCS inventory, the greater the decay heat removal capability and therefore the lower the shutdown risk. OU-AA-103 defined outage risk status using the colors green, yellow, orange and red, with green being lowest risk and red being highest risk. Due to increased shutdown risk, contingency plans were required to enter an orange risk condition and the outage plan was designed to avoid entries into red risk conditions. PSEG's shutdown safety management program also required that planned entries into orange risk conditions should be minimized and that contingency plans should include actions to minimize time in this condition.

On November 3, 2008, Salem Unit 1 plant operators reduced reactor coolant inventory and entered an orange risk condition to perform preparations for planned mid loop operations. PSEG calibrated two narrow range and one wide range level indicators using PSEG procedure S1.IC-CC.RHR-0002, "RC Level Indication for Midloop Operation." After completion of these calibrations, when the RC level was reduced and narrow range indication came on scale, the narrow range level indication for 11 RC loop was compared to the other indications (channel check). Operators determined that the channel check with the other two instruments was unsatisfactory. After initial troubleshooting to resolve the channel check discrepancy was unsuccessful, operators exited the reduced inventory condition by raising reactor coolant level. In response to this issue, PSEG prepared a technical evaluation (70091282) to allow technicians to make minor adjustments to the transmitter and noted that the cause of the indication error was a difference between calculated and actual transmitter elevation. In accordance with this evaluation, technicians then adjusted the 11 RC narrow range transmitter to lower its indicated level so it matched the level indication of the other two level instruments.

PSEG's investigation for this issue identified that in 2001 the narrow range midloop level transmitter for the 11 RC loop was relocated using the design change process. The calculation for the reference height used for this level transmitter relocation included a three inch level error. With no adjustments to the calibration procedure to account for this error, this caused the 11 RC narrow range level indication to be calibrated to read approximately three inches high. PSEG determined that this level discrepancy was identified during previous refueling outages, and that following the discovery of the level discrepancy during these outages, technicians adjusted the 11 RC narrow range transmitter to match the level indication on the other two level indications.

PSEG identified that this correction was applied during both the 2005 and 2007 refueling outages. Technicians documented the adjustments made in 2005 in a corrective action program NOTF, 20256705. However, no action was taken to address the calibration discrepancy and the NOTF was closed to trending. The 2007 adjustments were not documented in the corrective action program. However, PSEG identified that the technician who completed the adjustments documented in the calibration work order (WO 30132137) that the issue may be related to an incorrect elevation survey for the level transmitters. Again, following the 2007 outage, no action was taken to address the discrepancy. As a result, when the discrepancy was identified again in 2008, the time that the plant was operated in reduced inventory operations was extended by approximately 3.5 hours.

The inspectors determined that not correcting the calculation error that resulted in an inaccurate calibration procedure for the 11 RC loop narrow range level indication was a performance deficiency. PSEG procedure, "Issue Identification and Screening Process," LS-AA-120, required that unexpected conditions found during surveillance testing where preliminary troubleshooting did not resolve the issue be entered into the CAP. However the unexpected transmitter adjustments made by the PSEG technician during the 2007 refueling outage were not entered into the CAP. Corrective actions taken by PSEG to address this performance deficiency included correction of the surveillance data sheet for the narrow range level indication for the 11 RC loop. The issue was also entered into the corrective action program as NOTF 20390640.

<u>Analysis</u>: This finding was more than minor because it was associated with the design control attribute of the Mitigating Systems cornerstone and it affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, not correcting the calculation error resulted in the inaccurate calibration procedure for the 11 RC loop narrow range level indication. This unnecessarily extended the time that the plant was operated in a reduced reactor coolant inventory condition which increased shutdown

plant risk. The inspectors evaluated the significance of this finding using IMC 0609, Appendix G, "Shutdown Operations SDP," Attachment 1, Checklist 6 and Figure 1. The inspectors determined that this finding was of very low safety significance (Green) because it did not require a quantitative assessment since two sources of level instrumentation remained available during the reduced inventory evolution.

The inspectors determined that this finding had a cross cutting aspect in the area of problem identification and resolution because PSEG did not identify the calculation error issue completely, accurately, and in a timely manner commensurate with the safety significance [P.1(a)]. Specifically, PSEG did not ensure that technician observations related to repeat calibration errors on the 11 RC loop level indicator, which were identified in 2007, were entered into the CAP.

Enforcement: Enforcement action does not apply because the performance deficiency did not involve a violation of a regulatory requirement. **(FIN 05000272/2008005-04, Inadequate Identification of Midloop Level Calibration Error)**

1R22 Surveillance Testing (71111.22 - 8 samples)

a. Inspection Scope

The inspectors completed eight surveillance testing inspection samples. The inspectors observed portions of and/or reviewed results for the 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 UFSAR, and ASME Section XI for pump and valve testing. Documents reviewed are listed in Attachment A. The inspectors evaluated the surveillance tests listed below:

- S1.OP-LR.FP-0001, "Type C Leak Rate Test 1FP147 and 1FP148;"
- S1.OP-ST.SJ-0006, "In-service Testing Safety Injection Valves Mode 6;"
- S1.OP-ST.SJ-0015, "Intermediate Head Hot Leg Throttling Valve Flow Balance Verification;"
- S1.OP-ST.DG-0013, "1B Diesel Generator Endurance Run;"
- S1.OP-LR.CS-0001, "Type C Leak Rate Test 11CS2, 11CS10 and 11CS48;"
- S1.IC-ST.SSP-0009, "Solid State Protection System Train B Functional Test;"
- S1.OP-ST.AF-0007, "In-service Testing, Auxiliary Feedwater Valves, Mode 3;" and
- S2.OP-ST.RC-0008, "Reactor Coolant System Water Inventory Balance"

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

1EP6 Drill Evaluation (71114.06 - 1 sample)

a. Inspection Scope

The inspectors completed one drill evaluation inspection sample. On November 20, the inspectors observed a drill from the control room simulator during an evaluated annual licensed operator requalification training scenario. The inspectors evaluated operator performance relative to developing event classifications and notifications. The inspectors reviewed the Salem Event Classification Guides. The inspectors referenced Nuclear Energy Institute 99-02, "Regulatory Assessment PI Guideline," Revision 5, and verified that PSEG correctly counted the evaluated scenario'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 - 4 samples)

a. Inspection Scope

The inspectors reviewed radiation work permits for airborne radioactivity areas with the potential for individual worker internal exposures of >50 mrem committed effective dose equivalent (20 DAC-hrs). For these selected airborne radioactive material areas, the inspectors verified barrier integrity and engineering controls performance (e.g., HEPA ventilation system operation).

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.

The inspectors discussed with the Radiation Protection Manager high dose rate-high radiation area, and very high radiation area controls and procedures. The inspectors focused on any procedural changes since the last inspection. The inspectors verified that any changes to licensee procedures did not substantially reduce the effectiveness and level of worker protection.

The inspectors discussed with health physics supervisors the controls in place for special areas that have the potential to become very high radiation areas during certain plant operations. The inspectors verified that these plant operations required communication with the health physics group beforehand, to allow properly posting and control of radiation hazards.

The inspectors verified adequate posting and locking of all entrances to high dose rate-high radiation areas, and very high radiation areas.

The inspector evaluated PSEG performance in each of these areas against the requirements contained in 10 CFR 20, and Unit 2 TS 6.12.

b. Findings

No findings of significance were identified.

2OS2 ALARA Planning and Controls (71121.02 - 6 samples)

a. Inspection Scope

The inspectors obtained from PSEG a list of work activities ranked by actual/estimated exposure that were in progress during the S1R19 and selected the two work activities of highest exposure significance. The activities selected were core offload and reactor coolant pump 11 motor replacement.

The inspectors reviewed the ALARA work activity evaluations, exposure estimates, and exposure mitigation requirements. The inspectors verified that PSEG had established procedures, engineering and work controls, based on sound radiation protection principles, to achieve occupational exposures that were ALARA. The inspectors also verified that PSEG grouped radiological work into work activities based on historical precedence, industry norms, and/or special circumstances.

The inspectors compared the results achieved (dose rate reductions, person-rem used) with the intended dose established in PSEG's ALARA planning for the selected work activities. The inspectors reviewed the causes for any inconsistencies between intended and actual work activity doses.

The inspectors reviewed PSEG's method for adjusting exposure estimates, or re-planning work, when unexpected changes in scope or emergent work were encountered. The inspectors verified that adjustments to estimated exposures (intended dose) were based on sound radiation protection and ALARA principles or were adjusted to account for inadequate work controls.

For the selected work activities the inspectors evaluated PSEG's use of engineering controls to achieve dose reductions.

The inspectors evaluated PSEG performance in each of these areas against the requirements contained in 10 CFR 20.1101.

b. Findings

No findings of significance were identified.

2OS3 Radiation Monitoring Instrumentation and Protective Equipment (71121.03 - 1 sample)

a. Inspection Scope

The inspectors reviewed PSEG self-assessments, audits, and Licensee Event Reports and focused on radiological incidents that involved personnel contamination monitor alarms due to personnel internal exposures. For internal exposures >50 mrem committed effective dose equivalent, the inspectors verified that affected personnel were properly monitored utilizing calibrated equipment and that the data was analyzed and internal exposures properly assessed in accordance with PSEG procedures. The inspectors also verified that identified problems were entered into the corrective action program for resolution.

The inspector evaluated PSEG performance against the requirements contained in 10 CFR 20.1501, 10 CFR 20.1703 and 10 CFR 20.1704.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator (PI) Verification (71151 - 4 samples)

a. Inspection Scope

The inspectors reviewed PSEG submittals covering the period between the fourth quarter 2007 and the third quarter 2008 for the Unit 1 and Unit 2 Mitigating Systems cornerstone performance indicators listed below . To verify the accuracy of the PI data reported during this period the data was compared to the PI definition and guidance contained in Nuclear Energy Institute (NEI) 99-02, “Regulatory Assessment Indicator Guideline,” Revision 5.

Cornerstone: Mitigating Systems

- Unit 1 and Unit 2 High Pressure Safety Injection Mitigating Systems Performance Index (MSPI)
- Unit 1 and Unit 2 Emergency AC Power System MSPI

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152 - 3 samples)

.1 Review of Items Entered into the Corrective Action Program

a. Inspection Scope

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 corrective action program. This was accomplished by reviewing the description of each new NOTF and attending daily management review committee meetings. Documents reviewed are listed in Attachment A.

b. Findings

No findings of significance were identified.

.2 Semi-Annual Trend Review: Corrective Actions Related to the Safety Conscious Work Environment

a. Inspection Scope

As required by Inspection Procedure 71152, “Identification and Resolution of Problems,” the inspectors performed a review of PSEG’s corrective action program (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 included issues documented in corrective maintenance work orders, site monthly meeting reports and maintenance rule assessments. The review also included NOTFs submitted to the CAP anonymously to evaluate the reasons for anonymous submissions. Open NOTFs older than five years were evaluated to determine whether resolution of issues important to safety were inappropriately delayed. The inspectors’ review nominally considered the six-month period of June 1, 2008, through November 30, 2008, 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.

In 2004 through 2006, PSEG undertook a number of actions and commitments to improve the safety conscious work environment (SCWE) at the Salem and Hope Creek Generating Stations. The NRC reviewed the status of these actions during two team inspections, in August/September 2005 and June 2006. The inspection report for the second inspection (Inspection Report 05000272;311/2006012 and 05000354/2006011, dated July 31, 2006) documented that the improvements to the SCWE were substantial and sustainable. PSEG’s commitments in this area included performing periodic cultural surveys through 2008. PSEG completed its last committed survey in July and August 2008, and documented this in a letter to NRC Region I, dated December 2, 2008. The inspectors performed a problem identification and resolution semi-annual trend inspection to review the results of this cultural survey and to evaluate PSEG’s corrective action plans to address work environment related issues revealed by the survey. The inspectors reviewed the cultural survey report, examined PSEG’s action plans for specific work groups, and discussed the information with staff and management personnel at both Salem and Hope Creek Generating Stations.

b. Assessment and Observations

No findings of significance were identified. The inspectors noted that the cultural survey report provided detailed information for PSEG management to assess the work environment and culture in the various individual work groups. Overall, the survey indicated that the site-wide work environment ratings remained generally steady from the last cultural survey performed in 2006. The results for individual work groups varied, with some showing improvement and others indicating some decline. With respect to all organizations, including those showing some decline, the inspectors identified no significant concerns in the area of SCWE. The survey indicated that personnel remain willing to raise safety concerns without fear of retaliation.

The inspectors observed that PSEG developed a site-wide Action Plan to communicate and address the results of the survey. Both Salem and Hope Creek drafted action plans, called "Work Environment Improvement Excellence Plans," for each major work group. The Excellence Plans considered the specific survey results for the affected work group and included various communications, meetings, and discussions to address perceptions revealed in the survey. In the case of groups identified as having low ratings in certain areas of the survey, supervisors and staff members were scheduled to participate in specific activities aimed at addressing these areas.

The inspectors concluded that PSEG's Action Plan and work group Excellence Plans appropriately addressed the results of the 2008 cultural survey. These plans provided specific actions to maintain a focus on improvements in the work environment.

.3 Annual Sample: Vibration Analysis

a. Inspection Scope

This inspection focused on Salem's problem identification, evaluation, and resolution of vibration monitoring alarms.

The inspectors reviewed PSEG's associated program documents and a series of corrective action reports. The inspectors also interviewed plant personnel; reviewed vibration analysis reports, procedures, and related industry operating experience. In addition, the inspectors reviewed the Salem TS and Updated Final Safety Analysis Report to assess the potential adverse impact of vibration alarms on RCS components. Documents reviewed are listed in Attachment A.

b. Findings and Observations

No findings of significance were identified. The inspectors noted that program managers documented their basis for concluding that the alarms received for exceeding the OM Code prescribed thresholds were not related to vibration induced damage or indicative of component degradation. The inspectors concluded that the vibration alarm set points at Salem were established based on the simplified vibration analysis approach prescribed by the 1987 Edition of the OM Code to which Salem was committed. These setpoints were set lower than more current versions of the OM code based on the limited vibration analysis technology available at the time the 1987 edition of the code was issued. Using more sophisticated equipment to analyze the vibration that caused the alarms at Salem, PSEG determined that the more frequent alarms were not indicative of equipment degradation. A more current version of the OM code, that credits more sophisticated vibration analysis equipment, would allow PSEG to raise the set point for the vibration alarms and, therefore, reduce the number of alarms. As such, as corrective action for this issue PSEG plans to implement a more up-to-date edition of the OM Code.

.4 Annual Sample: Procedure Quality

a. Inspection Scope

The inspectors reviewed the actions taken to improve procedure quality at Salem. The sample evaluated PSEG's scope of efforts and progress in addressing procedure quality for the period of January 2008 through December 2008.

b. Findings and Observations

No findings of significance were identified.

PSEG completed a root cause analysis for the Salem procedure compliance issues identified at the 2007 mid-cycle assessment. PSEG determined that one contributing cause for the problems with procedure compliance was procedure adequacy. Specifically, in many cases, procedures were vague or lacked sufficient detail. Personnel were not recognizing substandard procedures and were accepting poor procedures instead of correcting them. In addition the transition to Exelon administrative procedures contributed to confusing and duplicate guidance.

PSEG corrective actions to address the concerns with procedure adequacy were included as part of the site-wide human performance improvement plan that was initiated to mitigate the substantive cross-cutting issue in procedure compliance. The actions included reviewing procedures to identify those that were inadequate and allocating additional resources to improve the progress with which the procedure change backlog was worked down. As a priority, the plan required PSEG to complete a detailed review of all procedures needed to implement the spring 2008 Salem outage before the outage started.

The inspectors assessed the status of PSEG's corrective action plan as of the fourth quarter of 2008 and determined that PSEG had made substantial progress with its improvement plan. The inspectors noted, however, that the station had made limited progress in addressing the backlog of procedures that required revision, particularly in the operations and maintenance departments. The procedure review effort, including outage preparations, had resulted in a significant increase in the number of procedures that needed to be revised and significantly increased the procedure change backlog. The inspectors determined that this increase occurred even though the station placed additional emphasis on working down the backlog and actually completed ten percent more procedure revisions in 2008 than in 2007. The inspectors also determined that the increase in the backlog was not a concern at this time because PSEG's plan for working down the backlog appropriately prioritized procedure revisions to ensure that the most important revisions were processed first. A review of the 2008 findings with procedure adequacy cross-cutting aspects determined that none of the findings were related to procedure changes identified in the backlog that had not been completed. PSEG was also making plans to further increase the number of staff allocated to the procedure revision effort.

To assess effectiveness of PSEGs procedure reviews the inspectors compared the results of the root cause evaluation that PSEG performed in 2007 to the findings with procedure adequacy cross-cutting aspects that were identified in 2008. PSEG's procedure reviews were focused on identifying inadequate procedures and adding sufficient detail where necessary. However, while significant progress was made in completing the directed procedure reviews, seven findings with procedure adequacy aspects were identified in 2008. In addition a review of the details of these findings determined that the documentation and procedures were inadequate because they did not include applicable regulatory requirements, design basis information or lessons learned from available operating experience. The inspectors also determined that in some cases the procedures that resulted in the findings had been reviewed in accordance with PSEGs human performance improvement program, and in other cases the procedures had been developed after the procedure adequacy issues were identified. Based on these results, PSEG plans to perform a common cause analysis to identify the causes for the continuing theme in procedure and documentation adequacy.

4OA3 Event Followup (71153 - 4 samples)

.1 Resident Inspector Event Response

a. Inspection Scope

On December 12, 2008, the Salem circulating water (CW) plant operator discovered five electrical breakers on a CW lighting panel out of position, open vice closed, but not in the tripped condition. Operations initiated a prompt investigation and corrective action NOTF 20394822 to evaluate the loss of status control. The inspectors responded to the control room to directly observe PSEG's response. The inspectors independently walked down the CW and SW intake structures, vital switchgear rooms, EDGs, and other safety-related equipment to assess configuration control and extent of condition. Documents reviewed are listed in Attachment A.

b. Findings

No findings of significance were identified.

.2 Resident Inspector Event Response

a. Inspection Scope

On the evening of October 14, 2008, Unit 1 was shut down and a plant cooldown was commenced for the 1R19 refuel outage. On the afternoon of October 15, the reactor was in Mode 5 with an RCS temperature of 140 F and the PZR vented to the PRT. At 3:43 PM plant operators commenced lowering PZR level from a solid condition to a target level of 10 to 15 percent, by creating a letdown to charging flow mismatch of 100 to 125 gallons per minute. The PZR cold calibration level was used as the means of determining PZR level during the draining evolution. At 5:26 PM, plant operators observed the PZR level had stopped lowering at 80 percent indicated level. At 5:35 PM, Reactor Vessel Level Indicating System began to indicate less than 100 percent level.

The operating crew immediately stopped the drain down and raised charging flow to increase PZR level. Subsequently, the PZR level cold calibration level indication was found to be inaccurate due to voiding in the reference leg. Review of other indications in the control room indicated that more water was drained from the RCS than the total volume of the PZR. This unintended loss of reactor coolant was evaluated and determined to meet the criteria for a special inspection in accordance with IMC 0309. The results of the special inspection were documented in NRC IR 05000272/2008009. Following the PZR drain down event, the inspectors observed subsequent RCS draining activities and verified that plant operators used adequate controls to verify RCS inventory during these activities.

b. Findings

No findings of significance were identified.

.3 (Closed) LER 05000272/2008001-00, Inadvertent Start of an Emergency Diesel Generator During Testing

On November 5, 2008, Salem Unit 1 experienced a valid engineered safeguards feature (ESF) signal to start the 1A EDG. Unit 1 was in cold shutdown (Mode 5) and surveillance testing of the 11 CFCU load shed feature de-energized the 1A vital bus. This actuated the blackout mode of the 1A safeguards equipment controller and started the 1A EDG. PSEG determined that a human performance error caused the event because an error was made while developing the test plan and was not identified or corrected during subsequent reviews. There were no complications associated with the ESF actuation. With the plant shut down and cooled down and the 1B and 1C EDGs and vital buses operable, the 1A EDG and vital bus were not required to be operable. Additionally, because the 1A EDG auto-started when the 1A vital bus de-energized, the inspectors determined that the loss of the normal supply to the 1A vital bus was a minor impact on the safety of the plant. PSEG instituted an extent of condition review to identify similar test plan errors and found no additional errors. PSEG also plans to revise mode operations surveillance test procedures to include alternate test methodologies in the event a component is not available or fails to properly actuate during testing. The failure to comply with TS 6.8.1, "Procedures and Programs," constituted a violation of minor significance not subject to enforcement action in accordance with the NRC's Enforcement Policy. The inspectors reviewed this LER and identified no additional findings of significance or violations of NRC requirements. PSEG documented the cause and corrective actions for this event in technical evaluation 70091327. This LER is closed.

.4 (Closed) LER 05000311/2008003-00 and 01, TS 3.0.3 Shutdown Due to All Steam Flow Channels Being Inoperable

During the sixteenth refueling outage for Unit 2, all four steam generators and the high pressure turbine were replaced. PSEG developed a post-modification acceptance test procedure to validate predicted plant parameters following the outage. During startup, following the outage, power ascension testing was not implemented as planned and, as a result, operators did not recognize that all Unit 2 high steam flow protection channels were inoperable until the plant reached 84% power on May 12, 2008. Operators ultimately identified the condition because the steam flow rate measurement used for protection and indication was outside of acceptable limits. Operators immediately conducted a plant shutdown in accordance with TS 3.0.3. The inspectors completed a review of this LER and identified one finding of very low safety significance. The details for this finding are discussed in Section 4OA5 of this report. This LER is closed. Documents reviewed are listed in Attachment A.

4OA5 Other Activities

.1 Quarterly Resident Inspector Observations of Security Personnel and Activities

a. Inspection Scope

During the inspection period the inspectors conducted observations of security force personnel and activities to ensure that the activities were consistent with PSEG security procedures and regulatory requirements related to nuclear plant security. These observations took place during both normal and off-normal plant working hours. These observations did not constitute an additional inspection sample. Rather, they were considered an integral part of the inspectors' normal plant status reviews and inspection activities.

b. Findings

No findings of significance were identified.

.2 (Closed) Unresolved Item 05000272&311/2007002-01, Potential Vulnerabilities to Internal Flooding

a. Inspection Scope

In March 2007, the inspectors identified several potential vulnerabilities to internal flooding at Salem Units 1 and 2 (see NRC Inspection Report 05000272&311/2007002 Section 1R06). The inspectors treated these issues as an unresolved item (URI) pending completion of a technical evaluation by PSEG. Since March 2007, the inspectors had closed three of the five original concerns related to PSEG's design and licensing bases for internal flooding (see NRC Inspection Reports 05000272&311/2007005 Section 1R06 and 5000272&311/2008002 Section 4OA2.2).

During this inspection period, inspectors independently assessed PSEG's technical evaluation of the remaining open issues; the drain system condition and adequacy (PSEG evaluation 70077852), the internal flooding design reconciliation analysis (PSEG evaluation 70068045), and the residual heat removal (RHR) pump room drain cross-connect vulnerability (PSEG evaluation 70066205-320). Specifically, the inspectors evaluated whether PSEG implemented appropriate measures or provided an adequate evaluation of the existing plant design to ensure or demonstrate that the capability of safety-related equipment would not be affected by internal flooding from non-safety-related and non-seismic-qualified water sources. The inspectors reviewed PSEG's internal flooding design reconciliation analysis and drain inspection activities (including as-found videos, cleaning, and preventive maintenance). The inspectors also walked down the vital switchgear rooms, EDG rooms, and other safety-related areas in the auxiliary building to assess operational readiness of drains and flood barriers to protect safety-related structures, systems, and components from internal flooding. Documents reviewed are listed in Attachment A.

b. Findings

No findings of significance were identified. This URI is closed.

.3 Implementation of Temporary Instruction (TI) 2515/176, EDG TS Surveillance Requirements Regarding Endurance and Margin Testing

a. Inspection Scope

The objective of TI 2515/176, “Emergency Diesel Generator Technical Specification Surveillance Requirements Regarding Endurance and Margin Testing,” was to gather information to assess the adequacy of nuclear power plant EDG endurance and margin testing as prescribed in plant-specific TS. The inspectors reviewed EDG ratings, design basis event load calculations, surveillance testing requirements, and EDG vendor specifications and gathered information in accordance with TI 2515/176.

The inspector assessment and information gathered while completing this TI was discussed with PSEG personnel. This information was forwarded on to the Office of Nuclear Reactor Regulation for further review and evaluation.

b. Findings

No findings of significance were identified.

.4 (Closed) Unresolved Item 05000311/2008003-04, Salem Unit 2 Steam Flow – Feed Flow Mismatch

a. Inspection Scope

During the sixteenth refueling outage of Unit 2, all four steam generators and the high pressure turbine were replaced. These replacements resulted in changes to various plant parameters, including main steam flow rate and pressure. PSEG developed a post-modification acceptance test procedure to validate predicted parameters, including main steam flow rates. During startup, power ascension testing was not implemented as planned and as a result operators did not recognize that all Unit 2 high steam flow protection channels were inoperable until the plant reached 84% power. Operators ultimately identified the condition because the steam flow rate measurement used for protection and indication was outside of acceptable limits, and conducted a plant shutdown in accordance with TS 3.0.3.

PSEG completed a root cause evaluation and determined that weak administrative controls and supervision led to an incomplete post-modification test plan. The root cause evaluation also identified multiple contributing causes. To complete inspection of this issue the inspectors reviewed the root cause evaluation and other design control practices associated with the steam generator replacement project. Documents reviewed are listed in Attachment A.

b. Findings

Introduction: A self-revealing non-cited violation of 10 CFR 50, Appendix B, Criteria XI, "Test Control," was identified because all Unit 2 high steam flow protection channels were discovered inoperable on May 12, 2008. Specifically, following steam generator replacement on Unit 2, PSEG did not perform adequate post-modification acceptance testing and, as a result, did not maintain TS required steam flow instrumentation operable. This finding was determined to be of very low safety significance (Green).

Description: The ESFAS system monitored various plant parameters using installed plant instrumentation in several plant systems to determine when emergency system actuation was required. For example to mitigate the consequences of a steam line break, the system monitored steam flow. The system was designed to respond to a large increase in steam flow caused by a steam line break by automatically actuating emergency systems. To perform this function ESFAS relied on accurate steam flow measurement.

On May 12, 2008, operators at Salem Unit 2 identified that all steam flow channel indications were 10 to 14 percent lower than actual flow when the plant was operating at 84% of rated power. Operators determined that all high steam flow ESFAS actuation channels were inoperable and shutdown the plant in accordance with TS requirements.

During S2R16 all four steam generators and the high pressure turbine rotor were replaced per DCP 80083522. These modifications changed the physical properties of the steam exiting the steam generators during normal plant operation and, as a result, affected the accuracy of the steam flow instrumentation. Supplement 12 to the DCP that specified the required post-modification acceptance testing (PMAT) for the design change, identified this impact and included main steam flow instrument calibration as part of the PMAT. To support the main steam flow instrumentation calibration, Engineering revised calculation SC-CN-007-02, "Salem Unit 2 Steam Flow Computerized Scaling." This calculation was performed to calculate main steam flow transmitter output voltages using predicted operating parameters for the steam generators. This revision to SC-CN-007-02 stated that because steam flow from the new steam generators could not be predicted to the required precision the steam flow transmitters should be calibrated so that the indicated steam flow rate matched feedwater flow rate during power ascension.

PSEG's cause analysis for this event determined that, contrary to the requirements of design change implementation procedures, this information was not incorporated into the PMAT requirements defined in supplement 12 to DCP 80083522. As a result, the steam flow instrumentation was not calibrated as needed. Consequently, contrary to TS 3.3.2, "Engineered Safety Feature Actuation System Instrumentation," Unit 2 operated with all high steam flow ESFAS features inoperable from May 8 to 12, 2008. After the event Westinghouse analyzed the potentially affected postulated steam line break scenarios at PSEG's request. Westinghouse determined that, based on the magnitude of the error between steam flow and feed flow, the high steam flow ESFAS safety function was not lost during the event.

The inspectors reviewed the event and PSEG's cause analysis and determined that PSEG did not perform adequate post-modification testing for the Unit 2 steam generator replacement project. Specifically, PSEG did not calibrate steam flow transmitters as required to maintain the instruments operable and as a result, Unit 2 operated with all high steam flow ESFAS features inoperable from May 8 to 12, 2008. The inspectors determined that this was a performance deficiency because PSEG calculation SC-CN-007-02, which was revised to support the instrument calibration, identified the need to calibrate steam flow to match feed flow during the power ascension.

PSEG entered this issue into the corrective action program and implemented corrective actions that included specifying testing requirements and acceptance criteria for the steam line instrumentation, enforcing procedure use standards and heightened managerial oversight of power ascension testing.

<u>Analysis</u>: This finding was more than minor because it was associated with the equipment performance attribute of the Mitigating Systems cornerstone and because it affected the cornerstone objective of ensuring the availability, reliability and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, all channels of the Unit 2 ESFAS high steam flow protective function were not correctly calibrated after completion of steam generator replacement. As a result, operators declared the affected ESFAS channels inoperable and shutdown the plant in accordance with TS requirements. Per Inspection Manual Chapter (IMC) 0609.04, "Initial Screening and Characterization of Findings," the inspectors conducted a Phase 1 screen and determined the finding to be of very low safety significance (Green) because the performance deficiency was a qualification deficiency confirmed to result in loss of operability that did not result in an actual loss of safety function and did not screen as potentially risk significant due to external initiating events.

This finding had a cross-cutting aspect in the area of human performance because PSEG did not provide complete, accurate and up-to-date design documentation, procedures, and work packages [H.2(c)]. Specifically, PSEG did not specify adequate testing requirements and acceptance criteria for steam flow instrumentation in the DCP 80083522 Supplement 12 as required by PSEG design change implementation procedure guidance.

<u>Enforcement</u>: 10 CFR 50, Appendix B, Criteria XI, "Test Control" requires in part that a test program be established to assure that all testing required to demonstrate that structures, systems and components will perform satisfactorily is identified and performed. Contrary to the above, between May 8 and 12, 2008, PSEG did not perform testing required to demonstrate that structures, systems and components affected by plant modifications performed satisfactorily. Specifically, following steam generator replacement on Unit 2, PSEG did not perform adequate post-modification acceptance testing to demonstrate that main steam flow instrumentation was operable. As a result, between May 8 and 12, 2008, PSEG operated Unit 2 with all high steam flow ESFAS features inoperable. Because this finding is of very low safety significance and has been entered into the corrective action program in NOTF 20369574, this violation is being treated as a NCV, consistent with Section VI.A of the NRC Enforcement Policy. **(NCV 05000311/2008005-05, ESFSAS High Steam Flow Protection Channels Inoperable)**

.5 Inspection Results for TI 2515/172, RCS Dissimilar Metal Butt Welds

a. Inspection Scope

The Temporary Instruction, TI-2515/172 provides for confirmation that owners of pressurized-water reactors (PWRs) implemented the industry guidelines of the Materials Reliability Program (MRP) -139 regarding nondestructive examination and evaluation of certain dissimilar metal welds in RCS piping and components containing Alloy 600/82/182. The TI requires documentation of the answers to specific questions in an inspection report. The questions and responses for mechanical stress improvement (MSIP) at Unit 1 are included in Attachment B. The answers for other portions of TI-2515/172 for Unit 1 and 2 were provided in NRC IR 05000272&311/2008004.

Unit 1 and 2 have MRP-139 applicable Alloy 600/82/182 RCS welds in the RCS hot and cold leg pipe to vessel nozzle connections. For Unit 1 these eight welds were examined volumetrically by ultrasonic testing (UT) from the outside surface visually during the S1R19 both prior to and after MSIP. One pre-MSIP indication identified in weld #14HL was mitigated by MSIP and post-MSIP examined by UT.

b. Findings

No findings of significance were identified

4OA6 Meetings, Including Exit

On January 20, 2009, the inspectors presented the inspection results to Mr. Braun. PSEG acknowledged that none of the information presented during the exit was proprietary.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee personnel:

H. Berrick, Regulatory Affairs
A. Garcia, System Engineer – SW
R. Gary, Radiation Protection Manager
G. Gellrich, Plant Manager
T. Giles, ISI Program Owner
B. Gustems, RCS MSIP and RCS Thermowell Project Manager
M. Gwirtz, Director Operations
A. Johnson, Design Engineer
J. Keenon, Licensing Manager
D. Kolasinski, System Engineer
E. Maloney, ISI/IST Corp Program Engineer
D. McCollum, Component Maintenance Organization
R. Montgomery, Principal Engineer (FAC – EC Program)
R. Moore, Electrical Systems Manager
T. Oliveri, NDE Project Manager
N. Ortiz, Design Engineer
D. Poulin, Alloy 600 Program Engineer
T. Roberts, Materials Engineering Supervisor
W. Sheets, ISI, NDE Examiner
N. Siniaho, WesDyne UT NDE Analyst
F. Szanyi, IST Manager
E. Villar, Licensing Engineer

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened/Closed

05000272/2008005-01	NCV	Improper Control of Transient Combustible Material (Section 1R05)
05000311/2008005-02	NCV	Inadequate Design Control for No. 22 CCWHX SW Outlet Temperature Control Valve (Section 1R12)
05000311/2008005-03	NCV	Inadequate Implementation of Risk Management Actions Associated with Planned Maintenance on the Unit 2 Pressurizer PORVs (Section 1R13)
05000272/2008005-04	FIN	Inadequate Identification of Midloop Level Calibration Error (Section 1R20)

05000272/2008001-00	LER	Inadvertent Start of an Emergency Diesel Generator During Testing (Section 4OA3.3)
05000311/2008003-00 and 01	LER	TS 3.0.3 Shutdown Due to All Steam Flow Channels Being Inoperable (Sections 4OA3.4 & 4OA5.4)
05000311/2008005-05	NCV	ESFSAS High Steam Flow Protection Channels Inoperable (Section 4OA5.4)

Closed

05000272&311/2007002-01	URI	Potential Vulnerabilities to Internal Flooding (Section 4OA5.2)
05000311/2008003-04	URI	Salem Unit 2 Steam Flow – Feed Flow Mismatch (Sections 4OA3.4 & 4OA5.4)

LIST OF DOCUMENTS REVIEWED

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

Section 1R01: Adverse Weather Protection

Notifications
20385499 20390794 20392049 20392559 20394271

Operating Experience
NRC Information Notice 96-36, Degradation of Cooling Water Systems Due to Icing, dated 6/12/96
NRC Information Notice 98-02, Nuclear Power Plant Cold Weather Problems and Protective Measures, dated 1/21/98

Other Documents
SC.MD-GP.ZZ-0001, Station Preparations for Winter - Mechanical, dated 9/22/08
SC.OP-PT.ZZ-0002, Station Preparations for Seasonal Conditions, dated 10/22/08
Winter Readiness 0800 Phone Call, dated 11/28/09

Procedures
OP-SH-108-111-1001, Severe Weather and Natural Disaster Guidelines, Revision 0
SC.MD-GP.ZZ-0001, Station preparations for Winter - Mechanical, Revision 6
SC.OP-AB.ZZ-0001, Adverse Environmental Conditions, Revision 12
SC.OP-PT.ZZ-0002, Station Preparations for Seasonal Conditions, Revision 11
WC-AA-107, Seasonal Readiness, Revision 8

Work Orders

30160540 30160694

Section 1R04: Equipment Alignment

Procedures
S1.OP-SO.115-0011, 1A Vital Instrument Bus UPS System Operation, Rev. 13
S2.OP-SO.SW-0007, Containment Fan Coil Unit Outage, Rev. 10
S1.OP-ST.4KV-0002, Electrical Power Systems AC Distribution, Rev. 21

Drawings
205342

Notifications
20386073 20387327

Orders
70090704

Other Documents
Tagging Work List 4231612, dated October 8, 2008

Section 1R05: Fire Protection

Procedures
FRS-II-611, Salem Unit 1, (Unit 2) Pre-fire Plan, Reactor Containment Elevations: 78', 100' & 130'
FRS-II-911, Salem Unit 1 (Unit 2) – Pre-fire Plan, Service Water Intake Structure Elevations: 92' & 112'
Salem - Unit 1, (Unit 2) - Pre-Fire Plan FRS-II-435 Diesel Fuel Oil Storage Area Elevation 84' - 0", Revision 5
Salem - Unit 1, (Unit 2) - Pre-Fire Plan FRS-II-445 Diesel Generator Area Elevations 100' and 122', Revision 11
SC.FP-AP.ZZ-0003, Actions for Inoperable Fire Protection - Salem Station, Rev. 13

Notifications
20388343 20389129 20399743 20393967

Other Documents
Salem and Hope Creek Fire Impairment Log Book, dated 11/21/08

Section 1R07: Heat Sink Performance

Procedures
S1.OP-PT.SW-0017, 12 Component Cooling Heat Exchanger Heat Transfer Performance Data Collection, Rev. 15

Notifications
20388473 20388786 20388503 20389656 20386816 20386817
Orders

30130700

Section 1R08: Inservice Inspection

Procedures
WDI-PJF-1303981-EPP-001, Rev 0. UT Examination Plan for RPV DM welds from the OD
WesDyne WCAL-014, Rev 0. Phased Array UT Linearity
54-ISI-836-12, UT of Austenitic Piping Welds
54-ISI-112-12, UT for Thickness Measurements

Drawings
CE fabrication drawings and notes E-233-045 and WC-3266-045-1, dated 7/19/1966
E 233-056-6, lower RPV head penetrations
Salem U1 and U2 Reactor Containment Plan – Bottom Liner

Condition Reports (Notifications)
Boric Acid - List of Notifications for 10/01/08 to 10/20/2008, including 20386064, 6070, 6769, and 20387160
20387460 (WO 60079160),, 20386769 (WO 60079312)
20389274 (Material type not on UT test Record)
20389211 (UT machine calibration sticker out of date but N/A)
20387700, 20367910, 20356242, 20388575 (70090669)

Steam Generator Reports / Assessments
Steam Generator Degradation Assessment for Outage 18 (1R18) dated 3/19/2007, Engineering Evaluation No. S-1-RC-MEE-1992, Rev 0
Steam Generator Degradation and Operational Assessment Validation, Order 70087436, Dated September 2008
Salem Unit 1 SG Operational Assessment at 1R18 for Cycles 19 and 20, Dated 10/1/2008, document Identifier 51-9052270-001

Other
MRP-139.
ASME Section XI
ASME Section XI, Sub-Section IWE
UT Summary No. 101600 for 10-SJ-1121-20 pipe to Elbow UT using cal block 4640.
UT Summary No. 101100 for 10-SJ-1121-16 pipe to tee UT using cal block 4640.
VT-2 Record dated 10/16/08 and photographs for the lower RPV head penetrations
Work Order 30132184 – Inspection of lower RPV head penetrations
Work Order 60073830 – Salem Unit 1, MSIP for HL and CL piping to RPV Nozzles
VTD 901389, Rev 1. Analytical Verification of MSIP for RPV CL, Salem U1
VTD 901388, Rev 1. Analytical Verification of MSIP for RPV HL, Salem U1
WCAP-8167-P, Rev 2. Structural Analysis of RCS Support System for Salem U1.

Section 1R11: Licensed Operator Requalification Program

Procedures

S2.OP-AB.LOAD-0001, Rapid Load Reduction, Rev. 17
S2.OP-SO.SF-0001, Fill and Transfer of the Spent Fuel Pool, Rev. 17
2-EOP-TRIP-1, Reactor Trip or Safety Injection, Rev. 27
2-EOP-TRIP-2, Reactor Trip Response, Rev. 27

Section 1R12: Maintenance Effectiveness

Calculations
S-1-SW-MDC-0893, MOV Capability Assessment for 11SW22-MRTY, Revision 0
S-2-SW-MDC-1304, Control Air Characterization of Valves SW-122 and SW-127, Revision 0
S-2-SW-MDC-1305, Existing Control of Valves SW-122 and SW-127, Revision 0
S-C-SW-MDC-1323, Equal Signal Pressure/Control of Valves SW122 and SW127, Revision 0
S-C-SW-NDC-2140, SVCE WTR COMPNT CLG HT EXCHG OUT V-BALL, Revision 0

Completed Surveillances
SC.MD-ST.125-0003, Quarterly Inspection and Preventive Maintenance of Units 1, 2 & 3 125 Volt Station Batteries, dated 7/15/08 and 10/15/08
SC.MD-ST.125-0005, Annual Inspection and Surveillance of Unit 1 & 2 125 Volt Vital Batteries, dated 10/16/07 and 10/3/08
SC.MD-ST.125-0006, 125 Volt Station Batteries 18 Month Service Test Using BCT-2000 With Windows Software and Associated Surveillance Testing, dated 4/1/08
S2.OP-ST.125-0001, Electrical Power Systems 125 VDC Distribution, dated 11/9/08, 11/16/08, and 11/23/08

Drawings
205342 SH 1, 3, & 4, No. 2 Unit Service Water Nuclear Area, Revision 74, 73, & 59

Evaluations

70008683	70071784	70075949	70081897	70083607	70085342
70091135	70091813	70091919	70092114		

Notifications

20197527	20202417	20236362	20302073	20308487	20310737
20313748	20314440	20330012	20332185	20333719	20341931
20343366	20344371	20350235	20353542	20359895	20361069
20361516	20361555	20363673	20364085	20364627	20367008
20369323	20379276	20386840	20387801	20388546	20389212
20389385	20390426	20391538	20391557	20391601	20391382
20392246	20392302	20392643	20393438	20393669	20393712
20393775	20393795	20394546			

Operating Experience
NRC Information Notice 84-83, Various Battery Problems, dated 11/19/84
NRC Information Notice 88-24, Failures of Air-Operated Valves Affecting Safety-Related Systems, dated 5/13/88
NRC Information Notice 89-17, Contamination and Degradation of Safety-Related Battery Cells, dated 2/22/89
NRC Information Notice 95-21, Unexpected Degradation of Lead Storage Batteries, dated 4/20/95

Other Documents
IEEE Std 450, IEEE Recommended Practice for Maintenance, Testing, and Replacement of Vented Lead-Acid Batteries for Station Applications, dated 4/3/03
IEEE Std 484, IEEE Recommended Practice for Installation Design and Installation of Vented Lead-Acid Batteries for Station Applications, dated 2/12/03
Monitoring of River Water Temperature for 22CCHX Adverse Condition Monitoring and Contingency Plan, dated 11/19/08
NRC Regulatory Guide 1.128, Installation Design and Installation of Large Lead Storage Batteries for Nuclear Power Plants, Revision 1
NRC Regulatory Guide 1.129, Maintenance, Testing, and Replacement of Large Lead Storage Batteries for Nuclear Power Plants, Revision 1
PSEG Nuclear 10CFR 50.65 (a)(1) Goals, dated 11/13/08
Risk-Informed Inspection Notebook for Salem Generating Station, Revision 2.1a
S1125-125VDC SHIP System Report, 3rd Qtr 2008
S2125-125VDC SHIP System Report, 3rd Qtr 2008
S2 2C 125v DC (A Feed) Charger Unavailability (Cumulative) Trend, 7/1/07 – 11/1/08
S2 2C 125v DC Battery Unavailability (Cumulative) Trend, 7/1/07 – 11/1/08
S2SW122-AO, Air Operated Valve Report, dated 12/4/08
S2SW127-AO, Air Operated Valve Report, dated 12/4/08
S2SW-Service Water SHIP System Report, 2nd Qtr 2008
Salem Inservice Testing Program Basis Data Sheets – Valves (Table 9-2B) Unit 2, dated 5/16/97
Salem Top Ten Equipment Issues, dated 9/24/08
Salem Maintenance Rule/EPIX Programs Report, 3rd Qtr 2008
Salem MOV Program Report, 3rd Qtr 2008

Procedures
ER-AA-310-1004, Maintenance Rule - Performance Monitoring, Revision 7
ER-SA-310-1009, System Function Level Maintenance Rule Scoping VS. Risk Reference, Revision 0
SC.MD-CM-125-0005, 125 VDC Vital Battery Cell Replacement, Revision 7
SC.MD-ST.ZZ-0003, Inspection and Preventive Maintenance of Units 1, 2 and 3 Batteries, Revision 26
S2.OP-SO.125-0003, 2C 125 VDC Battery Charger Operation, Revision 7
S2.OP-SO.125-0004, 125 VDC Ground Detection, Revision 13
S2.OP-SO.125-0007, 2C 125VDC Bus Operation, Revision 17
S2.OP-SO.SW-0005, Service Water System Operation, Revision 40
S2.OP-ST.125-0001, Electrical Power Systems 125 VDC Distribution, Revision 10

Work Orders

30088408	30095382	30125523	30144599	60048372	60005774
60062785	60067815	60072826	60075767	60075983	60079321
60079350	60079475	60079792			

Section 1R13: Maintenance Risk Assessments and Emergent Work Control

Procedures
SC.IC-CM.ANN-0001, Beta Annunciator Emergency Crash Cart Connections, Rev. 0

SC.IC-TI.ANN-0001, Overhead Annunciator: RCW Computer Usage, Rev. 5
SC.OM-AP.ZZ-0001, Shutdown Safety Management Program – Salem Annex, Rev. 2
S1.OP-AB.ZZ-0002, Flooding, Rev. 3
WC-AA-101, On-line Work Management Process, Rev. 16
OP-AA-101-112-1002, On-line Risk Assessment, Rev. 3
SC.OP-PT.CA-0001, SBO Diesel Control Air Compressor Test, Rev. 12

Drawings

232977	222759	222577	205242	205309	205212
205226	205227	205239	205201		

Notifications

20379549	20377878	20387719	20391880	20386962

Orders

80086351	70088052	50091470	30171190

Other Documents
SGS Unit 2 PRA Risk Evaluation Form, work week 841 (October 5 to 11), Rev. 0
SGS Unit 2 PRA Risk Evaluation Form, work week 842 (October 12 to 18), Rev. 0
Salem Unit 1 Shutdown Risk Status Sheet for October 15, 2008 (day shift)
Salem Unit 1 Shutdown Risk Status Sheet for October 24, 2008 (day shift)
SA-RM-2008-04, Erin Engineering Risk Management Document, Evaluation of Risk Significance of 11/14/2008 Missed Risk Management Actions
SGS Unit 2 PRA Risk Evaluation Form, work week 846 (November 9 to 15, 2008), Rev. 1
SGS Unit 2 PRA Risk Evaluation Form, work week 847 (November 16 to 22, 2008), Rev. 0

Section 1R15: Operability Evaluations

Procedures
SC.MD-DC.RC-0003, Calibration of Pressurizer Safety Relief Valve Indicating Switches, Rev. 5
S1.OP-ST.SW-0016, In-service Testing Service Water Accumulator Discharge Valves, Rev. 4
S1.RA-ST.SW-0016, In-service Testing Service Water Accumulator Discharge Valves Acceptance Criteria, Rev. 7

Drawings

601701	203063	203002	205242	223129605392	233613

Notifications

20388060	20383190	20391638	20392108	20389212	20395702
20389212	20391910	20372253	20390118	20390183	20393475
20393512	20394073	20394085			

Orders

30104126	70090975	70089625	80094384	60079719	80024770
50117132	70091135				

Other Documents
PSEG Nuclear MOV Program MOV Test Data for WO 30104126

Electronic mail correspondence between PSEG and PJM re: power ratings of off-site transformers relied on to support Salem electric power supply
PSEG Analysis of Transmission Project Impact (Artificial Island MW losses)
PSEG Electric Delivery Projects and Construction, 5038 Loop into New Freedom, C.90801 PJM RTEP Project SPS Modifications Requirements
ES-8.003, 500/13.8 kV Transformer Sizing Calculation, Rev. 1
A-5-500-EEE-1686, Artificial Island Operating Guides and Documentation, Rev. 8
SA-RM-2008-04, Erin Engineering Risk Management Document, Risk Assessment of Missed Surveillance – Pressurizer Safety Valve Positioin Indication, Rev. 1

Section 1R18: Plant Modifications

Procedures
SC.IC-CM.ANN-0001, Beta Annunciator Emergency Crash Cart Connections, Rev. 0
SC.IC-TI.ANN-0001, Overhead Annunciator: RCW Computer Usage, Rev. 5
S1.OP-AR.ZZ-0003, Overhead Annunciators Window C, Rev. 14

Drawings
232977 222759 222577

Notifications
20379549 20377878

Orders
80086351 70088052

Other Documents
CFCU Simplification - Fixed Resistance Control Scheme, Rev. 1
CC-AA-112-1001, Provide Temporary Feed to LTG Panel S1LTS-T11D, Rev. 1
Calculation S-C-SW-MDC-0475, Revision 4

Section 1R19: Post-Maintenance Testing

Procedures
SC.IC-CC.NIS-0012, N32 Source Range, Rev. 6
SC.MD-CM.MS-0001, Repacking of Main Steam Stop Valves, Rev. 5
S1.OP-ST.SW-0004, Inservice Testing – 14 Service Water Pump, Rev. 31
S1.OP-LR.CS-0002, Type C Leak Rate Test 12CS2, 12CS10, and 12CS48, Rev. 0
S1.OP-ST.DG-0001, 1A Diesel Generator Surveillance Test, Rev. 40

Notifications
20391169 20387460 20388385 20388616 20388265 20387327
20388533 20388488

Orders
30153423 60045498 30151585 30132037 60079152 30106016
60079160 70091044 50117367

Section 1R20: Refueling and Outage Activities

Procedures
S1.OP-IO.ZZ-0003, Hot Standby to Minimum Load, Rev. 23
S1.OP-IO.ZZ-0004, Power Operation, Rev. 51
S1.OP-IO-ZZ-0005, Minimum Load to Hot Standby, Rev. 18
S1.OP-IO.ZZ-0006, Hot Standby to Cold Shutdown, Rev. 30
S1.OP-IO.ZZ-0008, Maintaining Hot Standby, Rev. 13
S1.OP-IO.ZZ-0010, Spent Fuel Pool Manipulations, Rev. 16
S1.OP-SO.RC-0002, Vacuum Refill of the RCS, Rev. 18
S1.OP-SO.RC-0003, Filling and Venting the Reactor Coolant System, Rev. 27
S1.OP-SO.RC-0005, Draining the Reactor Coolant System to ≥ 101 Foot Elevation, Rev. 32
S1.OP-SO.RC-0006, Draining the Reactor Coolant System < 101FT Elevation with Fuel in the Vessel, Rev. 24
SC.RE-RA.ZZ-0001, Estimated Critical Position, Rev. 7
S1.OP-ST.SJ-0010, ECCS - Containment Inspection for Mode 4, dated 11/11/08
S1.IC-SC.RHR-0002, RC Level Indication for Midloop Operation, Rev. 19
S1.OP-SO.RC-0005, Draining the Reactor Coolant System to ≥ 101 Foot Elevation, Rev. 31

Drawings

205303	233025

Notifications

20386821	20387821	20388137	20387580	20389149	20390139
20390165	20390160	20390171	20390173	20393512	20388354
20391395	20387983	20386749	20386831	20387749	20388201
20388315	20387962	20388042	20390139	20390160	20390171
20390173	20391395	20393930	20185110	20390640	20389812
20256705	20257168				

Orders

30132137	70091127	70091050	70091282

Other Documents
OP-SA-108-114-1001, Post-Trip Data Collection Guidelines - Salem, Rev. 1
VTD 172572, RLV Instrument System Capillary Schematic, Rev. 0
LS-AA-125, Corrective Action Program Procedure, Rev. 12
LS-AA-120, Functional Area Threshold guidance, Rev. 8
SC-RC013-01, Unit 1 and 2 Midloop Narrow and Wide Range Level, Rev. 3
S1.IC-SC.RHR-0002, 1LT-16273 RC Hot Leg #11 Narrow Range Level Data Sheets, dated 10/15/08, 10/16/08, and 10/27/08

Section 1R22: Surveillance Testing

Procedures
S1.OP-LR.FP-0001, Type C Leak Rate Test 1FP147 and 1FP148

S1.OP-ST.SJ-0006, In-service Testing Safety Injection Valves Mode 6, Rev. 10
S1.OP-ST.AF-0007, Inservice Testing Auxiliary Feedwater Valves Mode 3, Rev. 18
S1.OP-ST.SJ-0015, Intermediate Head Hot Leg Throttling Valve Flow Balance Verification, Rev. 16
S1.OP-ST.DG-0013, 1B Diesel Generator Endurance Run, Rev. 16
LRT-VOL4-ATT.2, Summarized Listing of Administrative and IST Limits Type "C" - Air Tested Valves, Revision 3
S1.IC-ST.SSP-0009, Solid State Protection System Train B Functional Test, dated 12/9/08
S1.OP-LR.MP-0001, Type B Mechanical Penetration Leak Rate Testing, Revision 0
S1.OP-LR.CS-0001, Type C Leak Rate Test 11CS2, 11CS10 and 11CS48, dated 10/25/08 and 10/30/08
S2.OP-ST.RC-0008, Reactor Coolant System Water Inventory Balance, Revision 29, completed 11/3/08 0532
S2.OP-ST.RC-0008, Reactor Coolant System Water Inventory Balance, Revision 29, completed 11/4/08 0148

Notifications
20385771 20390171 20393364 20394207 20394459 20394460
20394481 20395102

Operating Experience
NRC Information Notice 2005-25: Inadvertent Reactor Trip and Partial Safety Injection Actuation Due to Tin Whisker, dated 8/25/05

Orders
20104167 50103939 70085807 50102798

Other Documents
ACM 08-017, Monitor RCS Leakage When PORV S2RC-2PR1 is Isolated with Block Valve S2RC-2PR6 in the Open Position
S-C-ESE-0017, Containment Piping Penetration Seals No. 1 and 2 Units Salem Nuclear Generating Station, Revision 0
S-C-R700-MSE-253, Leakage Rate Test Requirements For Containment Mechanical Piping Penetrations Salem Nuclear Generating Station, Revision 0
S-C-RC-MEE-1067, Nonconservative Reactor Coolant System Leakage Calculation

Section 1EP6: Drill Evaluation

Procedures
NC.EP-EP.ZZ-0102, Emergency Coordinator Response, Revision 14

Notifications
20390569

Other Documents
Salem Event Classification Guides
SGS EAL/RAL Technical Basis, Salem Generating Station Emergency Action Level/Reporting Action Level Technical Basis Document, Revision 8

ESG-088, Stuck Rod, SGTR Examination Scenario Guide, Revision 0
S08-U1, Emergency Preparedness Unannounced Drill Critique Report, October 2, 2008

Section 4OA1: Performance Indicator Verification

Other Documents
Unit 1 log search for Diesel Generator entries, 10/1/07 through 9/30/08
Unit 2 log search for Diesel Generator entries, 10/1/07 through 9/30/08
Unit 1 log search for charging system entries, 10/1/07 through 9/30/08
Unit 2 log search for charging system entries, 10/1/07 through 9/30/08

Section 4OA2: Identification and Resolution of Problems

Procedures
MA-AA-716-230, Predictive Maintenance Program, Revision 4
MA-AA-716-230-1002, Vibration Analysis/Acceptance Guideline, Revision 1
ER-AA-321, Administrative Requirements For Inservice Testing, Revision 9
MA-AA-716-040, Rev. 5; Control of Portable Measurement and Test Equipment Program
LS-AA-126-1006, Rev. 1; Attachment 1, Benchmarking report
SY-AA-103-518, Rev. 12; Attachment 2, Out-processing Check List
NO-AA-1013, Rev. 7; Attachment E, NOS Problem Development Work Sheet, 09/17/2007
LS-AA-120, Issue Identification and Screening Process, Rev. 8
LS-AA-125, Corrective Action Program (CAP) Procedure, Rev. 12
SH.RA-AP.ZZ-0106, ASME Class 1, 2 and 3 Pressure Relief Device Assurance Activities, Rev 0
EI-SH-100-1003, Executive Protocol Group, Rev. 2
AD-AA-101, Processing of Procedures and T&RMs, Rev. 17
AD-AA-101-1001, Writers' Guide for Nuclear Policies and Descriptions, Rev. 4
AD-AA-101-1002, Writer's Guide and Process Guide for Procedures and T&RMs, Rev. 10
AD-AA-101-1003, Implementing Procedure Writers Guide, Rev. 0
AD-AA-101-1004, Requesting Changes to PSEG Procedures and T&RMs, Rev. 1
AD-AA-101-1005, Procedure Revision Priority Coding and Expectations, Rev. 0
AD-SH-9910, AD Platform Transition to Independence Rules, Rev. 7
HU-AA-1081, Fundamentals Tool Kit, Rev. 4

Condition Reports

20363042	20361025	20349723	20339378	20339487	20382700
20384903	20341000	20340242	20339787	20339758	20396511

Notifications

2036649	20368667	20371765	20372210	20373173	20375737
20376332	20378019	20382436	20383853	20354692	20357170
20394390	20384564	20392108	20392145	20392546	20396353
20391888	20392502	20310242	20376504	20369175	20335119
20354688					

Orders

70073823	70080030	70065206	70085238	70087518	70079816

Other Documents

NOSA-SLM/HPC-07-11; M&TE Increased frequency Audit 03/05/2007
NOSA-SLM-08-03; Salem Maintenance Functional Area Audit Report, 02/13/2008
Nuclear Over Sight Elevation Notice, Salem M&TE Issues
Nuclear Over Sight Escalation Notice, Salam 1 & 2, 10/03/2008
Salem Chemistry Department Work Environment Improvement Excellence Plan
Salem 12-Hour Shift Work Environment Improvement Excellence Plan
Salem Maintenance Planning & Support Work Environment Improvement Excellence Plan
Salem Electrical Department Work Environment Improvement Excellence Plan
Salem Instrumentation & Controls Work Environment Improvement Excellence Plan
Salem Engineering Programs Work Environment Improvement Excellence Plan
PSEG Employee Concerns Program Work Environment Improvement Excellence Plan
Salem Generating Station 2nd Quarter SRUM Meeting Agenda, dtd August 28, 2088
Salem Generating Station 2nd Quarter SRUM Meeting Minutes, dtd August 28, 2008
LR-N08-0255, PSEG letter to NRC dated December 2, 2008, re: Updated Status of Safety Conscious Work Environment Commitments
PSEG 2008 Comprehensive Cultural Assessment Results Report (Synergy Survey)
PSEG 2009 Procedure Quality, Use, and Adherence Excellence Plan
Salem 2009 Procedure Quality, Use, and Adherence Excellence Plan

Section 4OA3: Event Followup

Procedures
OP-AA-106-1001, Event Response Guidelines, Revision 8
SY-AA-101-108, Response to Suspicious Activity and Events Maliciously Directed at Plant Safety or Security, Revision 6
S1.OP-IO-.ZZ-0006, Hot Standby to Cold Shutdown, Rev. 29
S1.OP-TM.ZZ-0002, Tank Capacity Data, Rev. 7

Notifications
20394822 20386987 20386928 20386949

Evaluations
70090500

Other Documents
Root Cause Investigation Report, Salem Unit 1 Unintended Reduction in Reactor Coolant System Inventory, dated 11/25/08
NRC Information Notice 97-83, Recent Events Involving Reactor Coolant System Inventory Control During Shutdown, dated 12/5/97

Section 4OA5: Other Activities

Procedures
S2.OP-ST.DG-0001, 1A Diesel Generator Surveillance Test, Rev. 40
S2.OP-ST.DG-0002, 1B Diesel Generator Surveillance Test, Rev. 41
S2.OP-ST.DG-0003, 1C Diesel Generator Surveillance Test, Rev. 42
S2.OP-ST.DG-0012, 2A DG endurance run, Rev. 24
S2.OP-ST.DG-0013, 2B DG endurance run, Rev. 24
S2.OP-ST.DG-0014, 2C DG endurance run, Rev 23

S2.OP-ST.SSP-0001, Manual Safety Injection, Rev. 30
S2.OP-ST.SSP-0002, SEC Mode Ops Testing 2A Vital Bus, Rev. 30
S2.OP-ST.SSP-0003, SEC Mode Ops Testing 2B Vital Bus, Rev. 35
S2.OP-ST.SSP-0004, SEC Mode Ops Testing 2C Vital Bus, Rev. 32
HU-AA-1211, Briefings – Pre-job, Heightened Level of Awareness, Infrequent Plant Activity and Post-job Briefings
HU-AA-104-101, Procedure Use and Adherence, Rev. 3
OP-AA-108-110, Evaluation of Special Tests or Evolutions, Rev. 0
S2.PI-SP.ZZ-0001, Power Ascension Test for HP Turbine and Stm Gen Replacement, Revs. 4, 6, 8 -11
SC.RE-RA.ZZ-0004, Statepoint Data Collection, Rev. 19
SC.SE-DG.ZZ-0002, Statepoint Data Processing for I&C Procedures, Rev. 1
S2.RE-Ra.ZZ-0011, Tables, Revision 245
S2.OP-DL.ZZ-0003, Control Room Readings – Modes 1-4, Rev. 1
S2.OP-DL.ZZ-0003, Control Room Readings – Modes 1-4, Rev. 2
S2.OP-AR.ZZ-0006, Overhead Annunciators Window F, Rev. 13
S2.OP-AR.ZZ-0007, Overhead Annunciators Window G, Rev. 43
SC.DE-TS.ZZ-1904, Instrument Setpoint Calculations, Rev. 1

Completed Surveillance Procedures:
S1.OP-ST.DG-0012, 1A DG endurance run 9/14/05, Rev. 16
S1.OP-ST.DG-0012, 1A DG endurance run 2/26/07, Rev. 17
S1.OP-ST.DG-0012, 1A DG endurance run 9/30/08, Rev. 17
S1.OP-ST.DG-0013, 1B DG endurance run 9/21/05, Rev. 15
S1.OP-ST.DG-0013, 1B DG endurance run 2/8/07, Rev. 16
S1.OP-ST.DG-0013, 1B DG endurance run 10/8/08, Rev. 16
S1.OP-ST.DG-0014, 1C DG endurance run 2/17/05, Rev. 13
S1.OP-ST.DG-0014, 1C DG endurance run 8/30/05, Rev. 14
S1.OP-ST.DG-0014, 1C DG endurance run 5/9/06, Rev. 14
S1.OP-ST.DG-0014, 1C DG endurance run 11/14/07, Rev. 15
S2.OP-ST.DG-0012, 2A DG endurance run 11/29/07, Rev. 24
S2.OP-ST.DG-0012, 2A DG endurance run 5/26/06, Rev. 23
S2.OP-ST.DG-0012, 2A DG endurance run 1/4/05, Re 22
S2.OP-ST.DG-0013, 2B DG endurance run 12/3/07, Rev. 24
S2.OP-ST.DG-0013, 2B DG endurance run 4/10/06, Rev. 23
S2.OP-ST.DG-0013, 2B DG endurance run 2/9/05, Rev. 22
S2.OP-ST.DG-0014, 2C DG endurance run 12/14/07, Rev. 23
S2.OP-ST.DG-0014, 2C DG endurance run 7/7/06, Rev. 22
S2.OP-ST.DG-0014, 2C DG endurance run 1/21/05, Rev. 21

Drawings
205326 SH 1, No. 2 Unit Floor Drains - Contaminated, Rev. 29

Evaluations

70035516	70068045	70066205	70077852	80033288	70022345
70024517	70025735	70025735	70026741	70026741	70026758
70026758	70026964	70026964	70050150	70050150	80083522
70085368	70085441	70085314	70085358	70085444	

Notifications

20362696	20376438	20393610	20394420	20395591*	20395598*
20395777*	20395930*	20396063*	20373585	20369267	20369574
20372502	20369724	20352829	20369574	20369686	20369881
20369779	20370764	20371567	20372115		

Operating Experience

NRC Information Notice 83-44, Supplement 1: Potential Damage to Redundant Safety Equipment as a Result of Backflow Through the Equipment and Floor Drain System, dated 8/30/90

NRC Information Notice 2005-11: Internal Flooding/Spray-Down of Safety-Related Equipment Due to Unsealed Equipment Hatch Floor and/or Blocked Floor Drains, dated 5/6/05

Other Documents

S-C-ZZ-SDC-1203, Moderate Energy Analysis (Reconstitution), Rev. 3
ES-9.002, Salem Generating Station Units 1 & 2 Emergency Diesel Loading, Rev. 5
ES-15.009, Essential Controls Inverter Load Study for Salem Units 1&2, Rev. 6
Technical Specifications
UFSAR section 8.3 Rev. 23
MI-17236A, ALCO vendor manual, 1973
MA-AA-716-210-1001, EDG preventive maintenance program plan. dated 2/13/07
Safety Evaluation related to amendment nos. 218 and 200
Lesson Plan NOS05SEC000-06, 1/3/07
Letter from G. Baranek to M. Ochs, ALCO power letter concerning preventive maintenance recommendations for the emergency diesel generators, dated 6/26/84
SC-CN007-01, Salem Unit 1, 2 Steam Generator S.I. Initiate, Steam Flow Ind & Rec, Rev. 1
SC-CN007-02. Salem Unit 2 Steam Flow Computerized Scaling, Rev. 5B
SC-CN007-02. Salem Unit 2 Steam Flow Computerized Scaling, Rev. 5 Final
SC-MS002-01, Turbine Inlet Pressure Scaling/Uncertainty Calculation, Rev. 11
SC-RCP001-04, Overpower ΔT / Overtemperature ΔT Uncertainty Calculation, Rev. 1
Prompt Investigation U2 Steam Flow/Feed Flow Mismatch
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PSE-08-48, Westinghouse Letter to PSEG re: Transmittal of Information for Salem Unit 2 Increased High Steam Flow Setpoint – Impact on Steamline Break Mass/Energy Release Analyses, dated May 23, 2008, Rev. 2
SDE-07-0005, PSEG Internal Memo re: NUCP 80083522 Salem 2 Steam Generators Replacement/Key Parameters Values for Scaling/Uncertainty Calculations, dated May 1, 2007
Complex Troubleshooting Procedure for Salem Unit 2 Steam Flow/Feed Flow Mismatch
OpEval 08-030, Salem Unit 1 Steam Flow/Feed Flow Mismatch, Rev. 0
NOS05ADFWCS-07, Operations Training Lesson Plan for Advanced Digital Feedwater Control System
VTD 320367, PSEG Salem Units 1&2 – ADFCS Stm Flow, Stm Press, FW Header Press, Rev. 3
VTD 328295, Salem Unit 2 RSG – OSG-RSG Comparison, Rev. 1
DE-CB.RCP-0038, Design Basis Documentation for Reactor Protection System, Rev. 2

WCAP-16444-NP, Salem Unit 2 Replacement Steam Generator Program NSSS Licensing Report, Rev. 1

Work Orders
30098149 30102535 30157430 30161766 60076192 60077205
60079267

LIST OF ACRONYMS

ASME	American Society of Mechanical Engineers
CAP	Corrective Action Process
CCW	Component Cooling Water
CCWHX	Component Cooling Water Heat Exchanger
CCZ	Combustible Control Zone
CFCU	Containment Fan Coil Unit
CFR	Code of Federal Regulations
CL	Cold Leg
CS	Containment Spray
CW	Circulating Water
DCP	Design Change
ECR	Engineering Change Request
EDG	Emergency Diesel Generator
ESF	Engineered Safequards Feature
ESFAS	Engineered Safety Feature Actuation System
GL	Generic Letter
HL	Hot Leg
HX	Heat Exchanger
ICDP	Incremental Core Damage Probability
IMC	Inspection Manual Chapter
ISI	In-service Inspection
MOV	Motor Operated Valve
MRP	Materials Reliability Program
MSIP	Mechanical Stress Improvement Process
NCV	Non-cited Violation
NDE	Non-Destructive Examination
NOTF	Notification
NRC	Nuclear Regulatory Commission
PARS	Publicly Available Records
PI	Performance Indicator
PMAT	Post Modification Acceptance Testing
PORV	Power Operated Relief Valves
PSEG	Public Service Enterprise Group Nuclear LLC
PZR	Pressurizer
RCS	Reactor Coolant System
RFO	Refuel Outage
RHR	Residual Heat Removal
RMA	Risk Management Actions

RPV	Reactor Pressure Vessel
RT	Radiographic Test
SBO	Station Blackout
SCWE	Safety Conscious Work Environment
SDP	Significance Determination Process
SG	Steam Generator
SIT	Special Inspection Team
SSC	Structures Systems and Components
SW	Service Water
TAC	Turbine Area Cooling
TCP	Transient Combustible Permit
TI	Temporary Instruction
TP&L	Temporary Power and Light
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
UT	Ultrasonic Testing
VT	Visual Inspection
WGE	Work Group Evaluation
WO	Work Order

TI 172 MSIP Documentation Questions Salem Units 1

Introduction:

The Temporary Instruction, TI 2515/172 provides for confirmation that owners of pressurized-water reactors (PWRs) have implemented the industry guidelines of the Materials Reliability Program (MRP) -139 regarding nondestructive examination and evaluation of certain dissimilar metal welds in RCSs containing nickel based Alloys 600/82/182. The TI requires documentation of specific questions in an inspection report. The questions and responses for MSIP for the IR 05000272/2008005 section 4OA5 are included in this Attachment "B".

In summary the Salem Units 1 and 2 have MRP-139 applicable Alloy 600/82/182 RCS welds in the four hot and four cold leg piping to reactor pressure vessel nozzle connections for each plant. For Unit 1 during the U1-RFO 19 in October 2008, these eight welds were examined by ultrasonic testing (UT) from the outside surface, then rendered less susceptible to cracking by the mechanical stress improvement process (MSIP) and then UT inspected after the MSIP process was completed. An indication of internal surface initiated cracking in the vicinity of the weld deposit to the hot leg (HL) nozzle #14 was identified and sized. No other indication of cracking was found on any of the other HL or cold leg (CL) nozzle to safe end welds. The identified crack in #14 weld was found able to be mitigated by MSIP.

For MRP-139 MSIP inspections:

d. For each mechanical stress improvement used by the licensee during the Salem Unit 1 RFO 19 outage, was the activity performed in accordance with a documented qualification report for stress improvement processes and in accordance with demonstrated procedures? Specifically:

Qd1. Are the nozzle, weld, safe end, and pipe configurations, as applicable, consistent with the configuration addressed in the stress improvement (SI) qualification report?

A. The applicable information with reference to nozzle, weld, safe end, and pipe configurations was confirmed via field walk downs (contour & thicknesses data) and official transmittal between Westinghouse (Original NSS supplier and designer) and PSE&G Salem Design Engineering. The revision levels of various design basis drawings maintained by Westinghouse and PSE&G were licensee verified (Ref. S-TODI-2007-0006 Dated 12/03/07).

Qd2. Does the SI qualification report address the location radial loading is applied, the applied load, and the effect that plastic deformation of the pipe configuration may have on the ability to conduct volumetric examinations?

A. The applicable information with reference to nozzle, weld, safe end, and pipe configurations was confirmed via field walkdowns (contour & thicknesses data) and official transmittal between Westinghouse (Original NSS supplier and designer) and PSE&G Salem Design Engineering.

Qd3. Do the licensee's inspection procedure records document that a volumetric examination per the ASME Code, Section XI, Appendix VIII was performed prior to and after the application of the SI?

A. MSIP NDE volumetric examinations were performed before and after the application of MSIP. Based on this inspection, a flaw in 14 hot leg DM weld was found that was characterized as an inside surface connected circumferential flaw. The subject flaw through-wall dimension was noted to be on the order of 24% and the length to be 2.06". This exceeded the ASME Section XI, IWB-3514-2 allowable values but was within acceptable range of the flaw handbook (Westinghouse Document WCAP-15657 Rev 1 contained in PSEG VTD# 901391). It was also acceptable to perform stress improvement (MSIP) on weld 14HL in accordance with MRP-139, Section 3.2.2 guidance. Portions of the UT examinations pre and post-MSIP were inspected by NRC as part of the refuel outage NDE inspection.

Qd4. Does the SI qualification report address limiting flaw sizes that may be found during pre-SI and post-SI inspections and that any flaws identified during the volumetric examination are to be within the limiting flaw sizes established by the SI qualification report.

A. The limiting flaw size (or MSIP permissible flaw size) is consistent with NUREG 0313 and MRP-139 guidance in section 3.2.2. This limitation is noted to be 10% of the circumference & 30% of the wall thickness for application of stress improvement. As-found details of 14 hot leg flaw are noted to be about 2.3% (<10%) of circumference and 24% (<30%) of the wall thickness, thus within acceptable range of flaw size that can be stress improved per MRP-139 guidance.

Qd5. Performed such that deficiencies were identified, dispositioned, and resolved?

A. All RCS cold & hot leg nozzles DM welds were stress improved by MSIP implementation during Salem Unit 1 refueling outage 1R19. The as- found flaw on 14 hot leg has been mitigated by MSIP process to arrest any future propagation.

Note: The responses to questions Qd1 through Qd5 are based on preliminary review of information from the implementing work order field data collected during 1R19. Westinghouse will issue a final formal report upon completion of the MSIP project activities for Salem Unit 1 that will integrate Salem Unit 1 MSIP information.

Reference:
CAP Notification 20388575 (70090669), ASME Code Section XI Flaw Evaluation [i.e., 14 HL]