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

February 9, 2010

Mr. Thomas P. 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 05000272/2009005 and 05000311/2009005

Dear Mr. Joyce:

On December 31, 2009, 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 8, 2010, with Mr. Fricker and other members of your staff.

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

The report documents two self-revealing findings of very low safety significance (Green). These findings were determined to involve violations of NRC requirements. However, because of the very low safety significance and because they are entered into your corrective action program (CAP), 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 NCVs in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001; with copies to the Regional Administrator, Region I; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the Salem Nuclear Generating Station. In addition, if you disagree with the characterization of any finding in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your disagreement, to the Regional Administrator, Region I, and the NRC Resident Inspector at Salem Nuclear Generating Station. The information you provide will be considered in accordance with Inspection Manual Chapter (IMC) 0305.

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

Sincerely,

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 05000272/2009005 and 05000311/2009005
w/Attachment: Supplemental Information

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Sincerely,
/RA/
Arthur L. Burritt, Chief
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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:	05000272/2009005 and 05000311/2009005
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, 2009 through December 31, 2009
Inspectors:	D. Schroeder, Senior Resident Inspector H. Balian, Resident Inspector E. Bonney, Reactor Engineer J. Furia, Senior Health Physicist T. O'Hara, Reactor Inspector M. Patel, Reactor Inspector S. Pindale, Senior Reactor Inspector P. Presby, Operations Engineer
Approved By:	Arthur L. Burritt, Chief Projects Branch 3 Division of Reactor Projects

Enclosure

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SUMMARY OF FINDINGS

IR 05000272/2009005, 05000311/2009005; 10/01/2009 - 12/31/2009; Salem Nuclear Generating Station Unit Nos. 1 and 2; Maintenance Effectiveness.

The report covered a three-month period of inspection by resident inspectors, and announced inspections by three reactor safety inspectors, a regional radiation specialist, and a regional operator licensing examiner. Two Green non-cited violations (NCVs) were identified. The significance of most findings is indicated by their color (Green, White, Yellow, or Red) using IMC 0609, "Significance Determination Process" (SDP) and the cross-cutting aspect of a finding is determined using IMC 0305, "Operating Reactor Assessment Program." 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.

Cornerstone: Mitigating Systems

- Green. A self-revealing NCV of technical specification (TS) 6.8.1.a, "Procedures and Programs," was identified because valve 22RH18 failed while in-service on October 17, 2009. This caused a degradation of shutdown core cooling on October 18, 2009. 22RH18 failed because PSEG did not use the correct procedure to complete scheduled maintenance on the valve. Corrective actions included repairing 22RH18 using the correct procedure and verifying the condition of the other three RH18 valves. This issue was placed in PSEG's corrective action program.

  The finding is more than minor because it is associated with the Mitigating Systems cornerstone attribute of equipment performance and adversely affected the cornerstone objective to ensure the reliability of systems that respond to initiating events to prevent undesirable consequences. Specifically, failure to correctly maintain 22RH18 reduced the reliability of the shutdown cooling system. Per IMC 0609.04, "Initial Screening and Characterization of Findings," the inspectors conducted a Phase 1 screen per IMC 0609, Appendix G, "Shutdown Operations SDP" and determined that the finding required a Phase 2 analysis because the plant did not meet the safety function guidelines for core heat removal. The senior reactor analyst (SRA) performed a Phase 2 analysis per IMC 0609, Appendix G, Attachment 2 and determined that the finding is of very low safety significance (Green). The finding is not greater than Green because the change in core damage frequency is substantially less than 1E-6. The inspectors did not identify a cross-cutting aspect associated with this finding because the procedure problems associated with this issue were not indicative of current performance, in that the procedure and work planning process improvements that corrected these problems were implemented in response to a notification written by the valve engineer in 2008 well before the self-revealing finding was identified. (Section 1R12.b.1)

- Green. A self-revealing NCV of TS 6.8.1, "Procedures and Programs," was identified because bolting between the valve body and actuator for 22SW356 broke causing the valve to partially close. This caused a degradation of shutdown core cooling by causing an unplanned reduction in SW flow through the only available CCHX. Valve 22SW356 failed because PSEG did not establish adequate maintenance procedures for valve

actuator installation. PSEG completed corrective actions to replace 22SW356 using high strength bolts, with loctite adhesive and at the correct torque to secure the valve to the actuator. This issue was placed in PSEG's corrective action program.

This finding is more than minor because it is associated with the equipment performance attribute of the Mitigating Systems cornerstone and it adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, use of an inadequate maintenance procedure for the manual valve operator installation on 22SW356 led to the bolting failure and partial closure of this manual butterfly valve. The inspectors evaluated the significance of this finding using IMC 0609, Appendix G, "Shutdown Operations SDP," Attachment 1, Checklist 3 and determined that a Phase 2 analysis was required because the valve failure increased the likelihood that a loss of decay heat removal will occur due to a failure of the system itself or support systems. The senior reactor analyst (SRA) performed a Phase 2 analysis per IMC 0609, Appendix G, Attachment 2 and determined that the finding was of very low safety significance (Green). The finding is not greater than Green because the change in core damage frequency is substantially less than 1E-6. This finding has a cross cutting aspect in the area of Human Performance because maintenance on 22SW356 was performed in 2002 with an inadequate procedure and work instructions [H.2(c)]. The procedure did not prescribe high strength bolts, loctite adhesive and correct torque, and, before the 22SW356 failure occurred, PSEG had not identified the errors and had planned to use the procedure and work instructions for the preventative maintenance valve replacement originally scheduled for October 2009. (Section 1R12.b.2)

REPORT DETAILS

Summary of Plant Status

Salem Nuclear Generating Station Unit No. 1 (Unit 1) began the period at full power. Unit 1 operated at or near full power for the duration of the inspection period.

Salem Nuclear Generating Station Unit No. 2 (Unit 2) began the period at full power. Operators shut down Unit 2 on October 13 to start the seventeenth refueling outage (RFO) (S2R17). Operators returned Unit 2 to service on November 11 and achieved full power on November 17. 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)

.1 Readiness for Seasonal Extreme Weather Conditions

a. Inspection Scope

The inspectors completed one seasonal extreme weather preparation inspection sample for the onset of cold weather. The inspectors reviewed cold weather preparations to verify PSEG adequately prepared equipment to operate reliably in extreme cold weather conditions. Specifically, the inspectors interviewed engineering and operations personnel, and walked down the service water intake structure, vital heat trace systems, and control area ventilation. The inspectors verified that design features used to maintain these systems functional during cold weather conditions were adequately maintained. The documents reviewed during this inspection are listed in the Attachment.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04 - 4 samples; 71111.04S – 1 sample)

.1 Partial Walkdown

a. Inspection Scope

The inspectors completed four partial system walk down inspection samples. The inspectors walked down the systems listed below 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 CAP to identify

and resolve equipment alignment problems that could cause initiating events or impact the capability of mitigating systems or barriers. Documents reviewed are listed in the Attachment.

- Protection of the 21 service water (SW) header on October 20 to ensure cooling to the operating train of residual heat removal (RHR) and operable emergency diesel generators (EDG) during RFO S2R17
- Unit 2 EDG fuel oil system on October 22 following maintenance on the 21 and 22 diesel fuel oil storage tanks
- Unit 2 spent fuel cooling system following full core offload during RFO S2R17
- 21 RHR loop while the 22 RHR loop was unavailable during RFO S2R17

b. Findings

No findings of significance were identified.

.2 Complete Walkdown

a. Inspection Scope

The inspectors conducted one complete walk down of the Unit 2 RHR system on December 2 through 4, 2009, when RHR was realigned from shutdown cooling to emergency core cooling after completion of the recent RFO. The inspectors independently verified the alignment and status of RHR pump and valve electrical power, labeling, hangers and supports, and associated support systems. The walk down also included evaluation of system piping and equipment to verify pipe hangers were in satisfactory condition, oil reservoir levels were normal, pump rooms and pipe chases were adequately ventilated, system parameters were within established ranges, and equipment deficiencies were appropriately identified. The inspectors interviewed engineering personnel and reviewed corrective action evaluations associated with the system to determine whether equipment alignment problems were identified and appropriately resolved. Documents reviewed are listed in the Attachment.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05Q - 4 samples)

.1 Fire Protection - Tours

a. Inspection Scope

The inspectors completed four quarterly fire protection inspection samples. The inspectors conducted tours of the areas listed below to assess the material condition and operational status of fire protection features. The inspectors verified that combustibles and ignition sources were controlled in accordance with PSEG's administrative procedures; fire detection and suppression equipment was available for use; that passive fire barriers were maintained in good material condition; and that compensatory measures for out-of-service (OOS), degraded, or inoperable fire protection equipment

were implemented in accordance with PSEG's fire plan. Documents reviewed are listed in the Attachment.

- Unit 1 containment
- Unit 2 outer penetration area
- Unit 1 and 2 electrical penetration area

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance (71111.07A - 2 samples)

a. Inspection Scope

The inspectors reviewed performance data and interviewed the NRC Generic Letter (GL) 89-13 program manager to verify that potential heat exchanger (HX) or heat sink deficiencies were identified and that PSEG adequately resolved heat sink performance problems. Specifically, the inspectors reviewed 21 component cooling water (CCW) HX and 2B emergency diesel generator (EDG) jacket water and lube oil cooler data. Inspectors evaluated trending data and verified that equipment would perform satisfactorily under design basis conditions. The method of performance monitoring was compared to the guidance provided in NRC GL 89-13, "Service Water System Problems Affecting Safety-Related Equipment," and Electric Power Research Institute (EPRI) NP 7552, "HX Performance Monitoring Guidelines."

The inspectors walked down the selected components and the SW intake structure to assess the general material condition. The inspectors also inspected the internal components of the 21 CCW HX and 2B EDG coolers, which were open for preventive maintenance, and observed the type and quantity of material present in the HXs. Documents reviewed are listed in the Attachment.

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection Activities (71111.08 - 1 sample)

a. Inspection Scope

The inspectors observed a selected sample of nondestructive examination (NDE) activities in process. Also, the inspectors reviewed the records of selected additional samples of completed NDE and repair/replacement activities. The sample selection was based on the inspection procedure objectives and risk priority of those components and systems where degradation would result in a significant increase in risk of core damage. The observations and documentation reviews were performed to verify the activities described were performed in accordance with the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code requirements.

The inspectors reviewed the PSEG Boric Acid Corrosion Control Program. The inspectors observed PSEG personnel performing boric acid walk down inspections, inside containment, and in other affected areas outside of containment, at the beginning of the Unit 2 RFO. The walk down inspections were thorough, well organized, and indications of boric acid leakage were recorded and evaluated in accordance with the PSEG program for documentation in the corrective action (notifications) process. Additionally, the inspectors reviewed a sample of notifications for correct evaluation and/or further engineering analysis and/or final resolution.

The inspectors observed the performance of two in-process ultrasonic testing (UT) activities and reviewed documentation and examination reports for an additional 22 NDE activities. These observations and reviews covered UT, visual testing (VT), penetrant testing (PT) and magnetic particle testing (MT) NDE processes. PSEG did not perform any radiographic testing (RT) during this outage. The inspectors reviewed inspection data sheets and documentation for these activities to verify the effectiveness of the examiner, process, and equipment in identifying degradation of risk significant systems, structures, and components (SSCs) and to evaluate the activities for compliance with the requirements of ASME Code, Section XI.

The inspectors reviewed records of seven repair/replacement activities on reactor coolant system (RCS) pressure boundary components. These reviews included documentation of some limited welding activities. These repair/replacement activities had been conducted in accordance with the ASME Code during the present, S2R17 outage, and during previous outages.

The inspectors reviewed the Unit 2 steam generator (SG) eddy current testing (ECT) tube examinations, and applicable procedures for monitoring degradation of steam generator tubes to verify that the steam generator examination activities were performed in accordance with the rules and regulations of the steam generator examination program, Unit 2 steam generator examination guidelines, NRC GLs, Code of Federal Regulations 10 CFR 50, Technical Specifications (TSs) for Unit 2, Nuclear Energy Institute (NEI) 97-06, EPRI PWR SG examination guidelines, and the ASME Boiler and Pressure Vessel Code Sections V and XI. The review also included the Unit 2 SG degradation assessment and SG Cycle 18 operational assessment.

The inspectors also observed the ECT of the Unit 2 SGs. This outage was the first RFO after replacement of the SGs in 2008. The observations included data collection, data analysis and reporting of SG tube inspections. Additionally, the inspectors reviewed the inspection results of the ECT and the results of the visual inspections of the secondary side of the SGs conducted during this outage.

PSEG identified wear degradation to the tubing in the four SGs at Unit 2. The majority of these wear indications were attributed to anti-vibration bar (AVB) wear in the u-bend regions of the four SGs. After conducting the appropriate analyses and evaluations, a total of ten tubes were plugged. Nine of the plugged tubes were due to AVB wear and one tube was due to support plate wear.

b. Findings

No findings of significance were identified.

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

.1 Requalification Activities Review by Resident Staff

a. Inspection Scope

The inspectors completed one quarterly licensed operator requalification program inspection sample. Specifically, the inspectors observed two simulator training scenarios on December 7. The first scenario involved a fire affecting operation of safety-related equipment, an electrical ground that requires a main turbine runback, and a small break loss-of- coolant accident (LOCA) complicated by various component malfunctions. The second scenario involved a fire in containment, a fuel failure leading to high reactor coolant activity and a reactor coolant leak that progressed to a LOCA complicated by a loss of offsite power and the 2C 4kV vital buss that eventually required alignment for cold leg recirculation.

The inspectors reviewed operator actions to implement the abnormal and emergency operating procedures. The inspectors examined the operators' ability to perform actions associated with high-risk activities, the Emergency Plan, previous lessons learned items, and the correct use and implementation of procedures. The inspectors observed and verified that the deficiencies were adequately identified, discussed, and entered into the CAP, as appropriate. Documents reviewed are listed in the Attachment.

b. Findings

No findings of significance were identified.

.2 Biennial Review by Regional Specialist

a. Inspection Scope

On December 16, 2009, a region-based inspector conducted an in-office review of results of the licensee-administered annual operating tests. Results from the 2008 comprehensive written exams were not included in this review because those exams were reviewed during an on-site visit in the third quarter of 2009. The inspection assessed whether pass rates were consistent with the guidance of NRC IMC 0609, Appendix I, "Operator Requalification Human Performance 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 3.2%); and
- Overall pass rate among individuals for all portions of the exam was greater than or equal to 75%. (Overall pass rate was 96.8%).

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12 - 3 samples)

a. Inspection Scope

The inspectors completed three quarterly maintenance effectiveness inspection samples. The inspectors reviewed performance monitoring and maintenance effectiveness issues for three SSCs. 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 met. The inspectors reviewed applicable work orders, corrective action notifications, and preventive maintenance tasks. The documents reviewed are listed in the Attachment. The inspectors evaluated the SSCs listed below:

- Pressurizer relief line check valve, 2PR25, RCS, pressurizer overpressure protection (POPS), safety injection (SJ) systems pressure relief line check valve;
- RHR valve 22RH18, 22 RHR HX flow control valve; and
- SW valve 22SW356, 22 CCW HX SW outlet isolation valve.

b. Findings

.1 Salem Unit 2 Degradation of Shutdown Cooling Caused by Failure of 22RH18

Introduction: A self-revealing Green NCV of TS 6.8.1.a, "Procedures and Programs," was identified because valve 22RH18 failed while in-service on October 17, 2009. This caused a degradation of shutdown core cooling on October 18, 2009. PSEG determined that the cause of the valve failure was that PSEG did not adequately plan and perform maintenance on RHR valve 22RH18. Specifically, in March 2008, PSEG did not complete scheduled maintenance on 22RH18 in accordance with the appropriate site procedure.

Description: The RHR system is used to provide core cooling in operational modes 4, 5 and 6. The system is comprised of two trains that can be cross-connected, with one heat exchanger in each train, 21 and 22 RHR HXs. 22RH18 is an air operated butterfly valve located downstream of the 22 RHR HX. 22RH18 is used in conjunction with the RHR HX bypass valve 2RH20 to control RHR flow and cooling through in-service HXs. On October 18, 2009, Unit 2 was in Mode 6 (refueling), the reactor refueling cavity water level was 126.7 feet (22.7 feet above the reactor vessel flange) and reactor coolant temperature was 106° Fahrenheit.

On October 18, both trains of RHR were operating cross-connected such that both the 21 and 22 RHR HXs were providing decay heat removal (DHR) for the reactor core. The 21 RHR pump was stopped at 1:10 AM to facilitate draining of the refueling cavity. This

removed the 21 RHR HX from service so that only the 22 RHR HX was providing DHR for the reactor core. After stopping the 21 RHR pump, operators observed that the position indication for valve 22RH18 changed to the closed position while demand signal for valve position remained at 74% open and that total RHR flow rate lowered from 2,567 gpm to 903 gpm. In response to these indications the operators attempted to open 22RH18 from the control room but were unsuccessful. Operators then opened 21RH18 and restarted the 21 RHR pump to raise RHR flow rate and also raised refueling cavity water level to 127.6 feet (23.6 feet above the reactor vessel flange). Water level was raised to greater than 23 feet because the Unit 2 TSs only required one operable train of RHR in Mode 6 if reactor cavity water level was greater than 23 feet above the reactor vessel flange. During this incident reactor coolant temperature rose approximately 5°F. PSEG repaired 22RH18 and successfully returned the 22 loop of RHR to service prior to lowering cavity level below 127.0 feet.

PSEG completed a past operability evaluation and determined that 22RH18 most likely became inoperable on October 17 at 11:41 PM. At that time the valve was closed and then stuck at approximately 20% open when it was reopened. This was not evident to the control room operators at that time due to the impact of the RHR system configuration on RHR system indications in the control room when the RHR loops are cross-connected. The PSEG apparent cause evaluation concluded that, the reason the failure became evident when the 21 RHR pump was secured was that securing the 21 RHR pump caused a small flow perturbation that caused the 22RH18 valve disc to move in a way that caused the closed indicator to energize in the control room.

PSEG determined through its ACE that an incorrect maintenance procedure was used during the previous RFO in the spring of 2008. PSEG conducts internal valve refurbishments for the RH18 valves on a 12-year periodicity. The 22RH18 was scheduled for this refurbishment in March 2008. However, the work order incorrectly directed maintenance technicians to use a general butterfly valve procedure that only requires a visual inspection of the assembled internals rather than SC.MD-PM.ZZ-0205, "Disassembly, Inspection and Reassembly of Fisher Butterfly Valve Mark#'s A-52, A-53, A-57, AA-83, BA-77, BA156 and BA-159." SC.MD-PM.ZZ-0205 requires disassembly of the internals for a more rigorous inspection and refurbishment of worn or degraded parts. This procedure was selected because the automated process that PSEG used to identify the procedure to use for the valve refurbishment assigned the wrong procedure and because the correct procedure did not include 22RH18 in its defined scope. The inspectors determined that these errors were corrected by PSEG in the first half of 2009 in response to a notification written by the valve engineer in 2008, well before the self-revealing finding was identified and therefore no corrective actions were necessary to correct these issues in response to this finding.

Following this incident, PSEG disassembled the valve and found that the 22RH18 shaft and shaft bushings were worn. This allowed the stem to shift, thereby causing the disk to contact the valve body. PSEG determined that these degraded components would have been identified if the correct procedure was used to complete the internal valve inspection in March 2008. Immediate corrective actions included repairing 22RH18 using the correct procedure.

PSEG performed an extent of condition review on the three remaining RH18 valves. PSEG is planning to refurbish all three valves during the next RFOs for each unit. Work

orders for two of the three remaining valves refer to the correct procedure. The third work order has not been written. PSEG is completing a root cause evaluation to determine what work practices caused the incorrect work order for 22RH18 among other issues.

Analysis: The inspectors determined that not performing an adequate 12-year internal inspection in accordance with SC.MD-PM.ZZ-0205 in March 2008, which caused PSEG to miss the opportunity to replace the worn shaft and shaft bushings that ultimately caused 22RH18 to fail on October 17, 2009, was a performance deficiency. The performance deficiency was more than minor because it was associated with the Mitigating Systems cornerstone attribute of equipment performance and adversely affected the cornerstone objective to ensure the reliability of systems that respond to initiating events to prevent undesirable consequences. Specifically, failure to correctly maintain 22RH18 reduced the reliability of the shutdown cooling system.

Per IMC 0609.04, "Initial Screening and Characterization of Findings," the inspectors conducted a Phase 1 screen per IMC 0609, Appendix G, "Shutdown Operations SDP." The inspectors used Checklist 3 of Attachment 1 and determined that the finding required a Phase 2 analysis because the plant did not meet the safety function guidelines for core heat removal. Specifically, the likelihood of a loss of shutdown cooling increased because both trains of RHR were not operable.

The Phase 2 assessment was conduct by a Region I SRA utilizing using IMC 0609, Appendix G, "Shutdown Operations SDP," Worksheet 9 for a Loss of RHR in POS 2. The following assumptions and input were incorporated into the analysis:

1. The Plant Operating State was 2 (POS 2), Time Window Late (TWL).
2. The repositioned 22RH18 valve reduced flow from approximately 2500 gpm to 900 gpm. Although some degree of DHR was present, the analysis will conservatively assume all flow was terminated.
3. The time to boil (TTB) at the beginning of the event exceeded 5 hours.
4. The RWST contained 24,000 gallons of water.
5. Both trains of safety injection and charging were available for injection.
6. Gravity Feed was not available.
7. Make-up to the RWST was available from the boric acid storage tanks and the CVCS holdup tanks.
8. The time to restore level to greater than 23 ft above the flange was approximately 20 minutes.

Based on the available control room indications and time to complete recovery actions, an estimated initiating event likelihood (IEL) of 4 was determined utilizing IMC 0609, Appendix G, "Shutdown Operations SDP," Table 4 – Initiating Event Likelihoods (IELs). Given the above assumption and plant conditions the following mitigation credit was assessed:

1. Decay heat removal (DHR) recovery before RCS boiling (RHR-S) was assigned a credit of 3 due to the TTB being greater than 1 hr.
2. The ability to inject into the RCS before core damage (FEED) was assigned a credit of 4, due to both safety injection and charging being available and capable of injection.

3. The ability to recover DHR before RWST depletion (DHR-R) was assigned a credit of 2 due to the estimated time to RWST depletion being greater than 10 hrs.
4. The ability to provide borated water makeup before core damage (RWSTMU) was assigned a credit of 2. This was based on the estimate time available to restore the RWST inventory before core damage which exceeded 13 hrs.

Applying the above mitigation credit resulted in a change in core damage frequency being substantially less than 1E-6, therefore the finding is GREEN.

The inspectors did not identify a cross-cutting aspect associated with this finding because the performance deficiency was not indicative of current performance. Specifically as described above, at the time the Spring 2008 outage work was planned, the automated process used to assign procedures to work orders was incorrect and the procedure that should have been used to perform the valve refurbishment did not specify that it should have been used for the work. However, the inspectors review determined that both of these issues were corrected prior to the October 18, 2009, self-revealing finding. As discussed above both issues were corrected in response to a notification written by the valve engineer in 2008, and were therefore not indicative of PSEG performance in work planning at the time of the finding.

Enforcement: TS 6.8.1.a requires establishment, implementation and maintenance of written procedures recommended in Appendix A of Regulatory Guide (RG) 1.33, Revision 2, February 1978. RG 1.33, Appendix A, Section 9 requires that maintenance affecting the performance of safety-related equipment be properly preplanned and performed per written procedures, documented instructions or drawings appropriate to the circumstances. Contrary to the above, in March 2008, PSEG completed a scheduled internal inspection of 22RH18 with an inadequate procedure. Consequently, degradation of internal components was not identified or corrected and 22RH18 failed in service on October 17, 2009, resulting in a degradation of shutdown cooling on October 18, 2009. Immediate corrective actions included repairing 22RH18 using the correct procedure and verifying the condition of the other three RH18 valves. Because this finding is of very low safety significance and has been entered into the CAP in Notification 20437473, this violation is being treated as a NCV, consistent with Section VI.A of the NRC Enforcement Policy: **NCV 05000311/2009005-01, Salem Unit 2 Degradation of Shutdown Cooling Caused by Failure of 22RH18**

.2 Inadequate Maintenance of the 22 CCHX SW Outlet Butterfly Valve

Introduction: A self-revealing Green NCV of TS 6.8.1, "Procedures and Programs," was identified because bolting between the valve body and actuator for the 22 CCHX SW isolation valve broke causing the valve to partially close. This resulted in an unplanned reduction in SW flow through the only available CCHX while the unit was in cold shutdown conditions for a planned RFO. The inspectors determined that the cause of the failure was that PSEG did not establish adequate maintenance procedures for valve actuator installation.

Description: The CCW system provides cooling water to the RHR system to remove decay heat from the reactor core during cold shutdown. The system includes two redundant trains with one HX per train, 21 (train A) and 22 (train B) CCHXs, that transfer heat from the CCW system to the SW system. Each CCHX is designed to remove one-

half of the heat load occurring at 20 hours after plant shutdown. Each HX is also capable of removing one-half of the maximum heat removal load occurring when the RHR system is first placed in operation during a plant cool down operation.

Unit 2 was shutdown at 7:57 PM on October 13, 2009. At 6:00 AM on October 17, 2009, Unit 2 was in cold shutdown with the water level at the reactor pressure vessel flange and time to boil was at seventeen minutes. The 22 CCHX (train B) was in service for DHR. The 21 CCHX (train A) was unavailable for separate maintenance activities while train A mode ops testing was conducted and vital bus A components were cycled in and out of service. During the mode ops test, the reactor operator noted RHR inlet temperature increasing more than expected. The operator checked 22 CCHX temperature and observed that it had risen from 70 F to 85 F and SW header pressure increased approximately 10 psig. After RCS temperature rose from 118 F to 125 F, operators took action to increase reactor coolant flow through the RHR HXs and stabilized temperature at approximately 125 F. The control room dispatched an equipment operator to the 22 CCHX room and discovered that the actuator for the manual outlet butterfly valve had moved in the closed direction approximately 60 degrees, which lowered SW flow through the 22 CCHX from 9500 gallons per minute (gpm) to 3200 gpm. This reduced the DHR capability of the 22 CCHX and the reliability of the 22 CCW train. In response to the issue PSEG expedited the completion of maintenance on the 21 CCHX and restored it to service within two hours, which restored full heat removal capability.

PSEG determined through its causal investigation that the 22 CCHX manual outlet butterfly valve had partially closed because the four bolts that mounted the valve actuator assembly to the valve body had broken and, as a result, the actuator assembly had rotated relative to the valve body partially closing the valve. Analysis of the broken bolts showed that they had loosened over time and were then subjected to cyclic lateral forces until the bolts failed in service.

Maintenance records showed that the valve operator was installed in April of 2002, using the PSEG procedure for Pratt Model MDT-4 Manual Valve Operator Disassembly, Inspection, and Reassembly. PSEG determined that the 38 foot pound torque value specified in this procedure was less than the 55 foot pound value recommended in the Pratt valve operator vendor manual, loctite was not used during bolt installation as specified in the body of the procedure and the broken bolts were carbon steel not high strength as specified in the bill of material for this valve. These were the main causes specified by PSEG for the valve actuator bolt failure.

PSEG completed corrective actions to properly replace the 22 CCHX manual outlet butterfly valve and actuator. The replacement twenty inch valve was installed and the actuator was mounted using high strength bolts and loctite with a specified bolting torque of 55 foot pounds. The inspectors determined that PSEG performed an appropriate extent of condition review that led to the replacement of actuator bolts with high strength bolts for three similar valves on Unit 2 SW. Two similar valves were identified on Unit 1 SW, and the bolts on these valves have been scheduled for replacement.

Analysis: In April 2002, PSEG used an inadequate maintenance procedure for installation of a valve actuator on valve 22 SW 356, which ultimately caused the valve to fail and reduced SW cooling flow through the only available CCHX while the plant was in

cold shutdown on October 17, 2009. This was a performance deficiency. This performance deficiency was more than minor because it was associated with the equipment performance attribute of the Mitigating Systems cornerstone and it adversely affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Specifically, use of an inadequate maintenance procedure for the manual valve operator installation on the 22 SW 356 valve led to the bolting failure and inadvertent partial closure of this manual butterfly valve. The inspectors evaluated the significance of this finding using IMC 0609, Appendix G, "Shutdown Operations SDP," Attachment 1, Checklist 3. The inspectors determined that a Phase 2 analysis was required because the valve failure increased the likelihood that a loss of DHR will occur due to a failure of the system itself or support systems.

The Phase 2 assessment was conduct by a Region I SRA utilizing using IMC 0609, Appendix G, "Shutdown Operations SDP," Worksheet 9 for a Loss of RHR in POS 2. The following assumptions and input were incorporated into the analysis:

- The Plant Operating State was 2 (POS 2), Time Window Early;
- The repositioned SW valve would not shut further than observed due to the locking mechanism on the valve;
- Initial Rx temperature at the time of the event was assumed to be 120°F, which was at the upper end of the operating band of 110°F -120°F;
- The observed heat up rate (HUR) when the valve repositioned was 10°F/45mins (0.22F/min);
- Feed and bleed was available; and
- Gravity Feed was available.

Based on the initial temperature and the observed HUR, the observed time to boil (TTB) was approximately seven hours. Core uncovery, after boiling commenced was estimated to be at approximately 157 minutes. Given these conditions the following mitigation credit was assessed:

- DHR recovery before RCS boiling (RHR-S) was assigned a credit of 3 due to the TTB being greater than 1 hr.;
- The ability to inject into the RCS before core damage (FEED) was assigned a credit of 4, due to the 22 CCP being in-service and capable of injection;
- The ability to recover DHR before RWST depletion (DHR-R) was assigned a credit of 2 due to the estimated time to RWST depletion being greater than 10 hrs.; and
- The ability to provide borated water makeup before core damage (RWSTMU) was assigned a credit of 2. This was based on the estimate time available to restore the RWST inventory before core damage which exceeded 13 hrs.

Applying the above mitigation credit resulted in a change in core damage frequency being substantially less than 1E-6, therefore, the finding is GREEN.

The inspectors determined that this finding had a cross cutting aspect in the area of Human Performance because PSEG did not ensure that complete, accurate, and up to date procedures and work packages were available for performance of maintenance. [H.2.(c)] Specifically, maintenance on the 22 CCHX outlet manual isolation valve, which included installation of a new manual valve operator, was performed in 2002 with a

procedure and a work order that were, as described above, inadequate for the task. Specifically, the procedure did not prescribe high strength bolts and correct torque, and, before the 22SW356 failure occurred, PSEG had not identified the errors and had planned to use the procedure and work instructions for the preventative maintenance valve replacement originally scheduled for October 2009.

Enforcement: TS 6.8.1a, "Procedures and Programs," requires establishment, implementation, and maintenance of written procedures recommended in Appendix A of RG 1.33, Revision 2, February 1978. Item 9.a of RG 1.33, Appendix A, recommends procedures for maintenance that can affect the performance of safety-related equipment and that such maintenance be properly preplanned and performed in accordance with written procedures, documented instructions, or drawings appropriate to the circumstances. Contrary to the above, in July 2002, PSEG completed modifications to 22SW356 using an inadequate procedure. Consequently, on October 17, 2009, the valve broke causing it to partially close and resulting in an unplanned reduction in SW flow through the only available CCHX that was supporting decay heat removal from the core while in cold shutdown. PSEG completed immediate corrective actions to replace 22SW356 using high strength bolts, with loctite adhesive and at the correct torque to secure the valve to the actuator. Because this issue is of very low safety significance and has been entered into PSEG's CAP as notification 20436351, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: **NCV 05000311/2009005-02, Inadequate Maintenance of the 22 CCHX SW Outlet Butterfly Valve.**

1R13 Maintenance Risk Assessments and Emergent Work Control (71111.13 - 5 samples)

a. Inspection Scope

The inspectors completed five maintenance risk assessment and emergent work control inspection samples. The inspectors reviewed the maintenance activities listed below 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 OOS workstation) to gain insights into the risk associated with these plant configurations. The inspectors reviewed notifications documenting problems associated with risk assessments and emergent work evaluations. Documents reviewed are listed in the Attachment.

- Unit 1 and 2 planned unavailability of Unit 2 control room emergency air conditioning system (CREACS) to support planned maintenance on the 2C 125 Vdc electrical buss during a RFO on October 13.
- Unit 2 unplanned inoperability of the 22 RHR train following failure of 22 CCW HX SW outlet valve 22SW356 on October 17.
- Unit 2 unplanned inoperability for the 22 RHR train following failure of RHR flow control valve 22RH18 on October 18.
- Unit 2 response to emergent failure of the spent fuel manipulator crane with a spent fuel bundle grappled and fully raised on October 19.
- Unit 2 planned entry into Mode 6 with the 23 chiller unavailable on October 29.

b. Findings

No findings of significance were identified.

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 degraded or non-conforming conditions associated with:

- Operability of Unit 2 electrical penetration 2-5 following inadvertent energizing of the penetration conductor from an alternate power supply while Unit 2 was in mode 1;
- Operability of Unit 2 electrical systems during mid-loop conditions with the 2C 125 Vdc battery disconnected and the 2C EDG unavailable;
- Operability of the 2C 125 Vdc electrical system with degradation of the 2C 125 Vdc battery;
- Operability of the 22 train of RHR after binding of flow control valve 22RH18 when less than 20% open;
- Operability of Unit 2 containment after discovery of corrosion of containment liner test channels; and
- Operability of Unit 2 safety injection following repair of high head safety injection manual isolation valve 24 SJ388.

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. Additionally, the inspectors 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 the Attachment.

b. Findings

No findings of significance were identified.

1R18 Plant Modifications (71111.18 – 2 samples)

.1 Permanent Modifications

a. Inspection Scope

The inspectors completed one plant modification inspection sample. The inspectors reviewed a permanent modification to replace Unit 2 pressurizer heater electrical distribution panels. The original configuration was obsolete and routinely caused overheating of the circuit breakers and electrical connections. The new design uses currently available standard components to ensure replacements are readily available, has improved pressurizer heater reliability and has enhanced electrical containment penetration over-current protection. The inspectors' review verified that the design bases, licensing bases, and performance capability of the system were not degraded by

the modification. The inspectors verified the new configuration was accurately reflected in the design documentation, and the post-modification testing was adequate to ensure the SSCs would function properly. The inspectors also interviewed plant staff and reviewed issues that had been entered into the CAP to assess whether PSEG was effective at identifying and resolving problems associated with permanent plant modifications. The 10 CFR 50.59 screen associated with this permanent plant modification was also reviewed. Documents reviewed for this inspection are listed in the Attachment.

b. Findings

No findings of significance were identified.

.2 Temporary Modifications

a. Inspection Scope

The inspectors completed one plant modification inspection sample. The inspectors reviewed a temporary modification on Unit 2 to plug and cap a flux thimble thermocouple assembly to stop reactor coolant leakage. This modification was accomplished during mode ascension at the end of the RFO. The inspectors ensured that TS requirements for operability of the in core flux mapping instrumentation were met and that RCS barrier integrity was maintained. The inspectors verified that the design bases, licensing bases, and performance capability of the affected systems were not degraded by the temporary modification. The inspectors verified the new configuration was accurately reflected in the design documentation, and that the post-modification testing was adequate to ensure the affected systems would remain functional. The 10 CFR 50.59 screen associated with this temporary modification was also reviewed Documents reviewed for this inspection are listed in the Attachment.

b. Findings

No findings of significance were identified.

1R19 Post-Maintenance Testing (71111.19 - 4 samples)

a. Inspection Scope

The inspectors completed four post-maintenance testing inspection samples. The inspectors observed portions of and/or reviewed the post maintenance testing results for the maintenance activities listed below. 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 the Attachment.

- Work order (WO) 60083248, planned corrective maintenance on the 21 CCW pump

- WO 60086317, emergent corrective maintenance on the over-temperature delta-temperature (OTΔT) input to the reactor protection system
- WO 30167509, 2B EDG overhaul
- WOs 60085147 and 60083538, planned modifications to the 12 chiller

b. Findings

No findings of significance were identified.

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

a. Inspection Scope

Unit 2 RFO (S2R17). The inspectors observed or reviewed the following RFO 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 the Attachment.

The inspectors reviewed the schedule and risk assessment documents associated with S2R17 to confirm that PSEG appropriately considered risk, operating experience, and site specific problems in developing and implementing a plan that assured maintenance of defense-in-depth systems and barriers. Prior to S2R17, the inspectors reviewed PSEG's outage risk assessment to identify risk significant equipment configurations and determine whether planned risk management actions were adequate. During S2R17, the inspectors verified that PSEG managed the outage risk commensurate with the outage plan.

The inspectors observed portions of the shut down and cool down processes and monitored PSEG controls over the outage activities. The inspectors also verified that cool down rates were within TS limitations. The inspectors responded to the plant following two separate problems with shutdown cooling valves experienced while the plant was in cold shut down. These issues are discussed in detail in Section 1R12 above.

At the start of S2R17, the inspectors inspected containment for evidence of previously unidentified reactor coolant leakage. Throughout S2R17, 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 (SFP) to verify refueling gates and seals were properly installed and to verify that 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 that 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 22 SW header were verified to comply with procedural requirements protection of the 21 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 verified through routine plant status activities that the DHR safety function was maintained with the appropriate redundancy as required by TS and consistent with PSEG's outage risk assessment. During core offload conditions, the inspectors periodically verified that the fuel pool cooling system was performing in accordance with the applicable TS requirements and consistent with PSEG's risk assessment for the RFO.

The inspectors observed the Unit 2 RCS draining to a reduced inventory condition on November 2, 2009. RCS inventory controls and contingency plans were reviewed by the inspectors to verify that 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 were installed and operational. Calculations that provided time to boil information were also reviewed for RCS reduced inventory conditions as well as the SFP 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 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 sump pumps were 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

No findings of significance were identified.

1R22 Surveillance Testing (71111.22 – 8 samples)

a. Inspection Scope

The inspectors completed eight surveillance testing inspection samples. The inspectors witnessed performance of and/or reviewed test data for the risk-significant STs listed below to assess whether the SSCs tested satisfied technical specification (TS), UFSAR, and procedure requirements. The inspectors verified that test acceptance criteria were clear, demonstrated operational readiness and were consistent with design documentation; that test instrumentation had current calibrations and the range and accuracy for the application; and that tests were performed, as written, with applicable prerequisites satisfied. Upon ST completion, the inspectors verified that equipment was returned to the status specified to perform its safety function. Documents reviewed are listed in the Attachment.

- S2.IC-ST.RHR-014, RHR Interlock and Alarm Verification;
- S2.OP-LR.FP-0001, Type C Leak Rate Test 2FP147 and 2FP148;
- S2.OP-ST.SSP-0007, Engineered Safety Feature Containment Isolation – Phase 'A';
- S2.IC-ST.SSP-0008, Solid State Protection System Train A Functional Test;
- S1.OP-ST.RC-0004, RCS Water Inventory Balance;
- SC.RE-ST.ZZ-0013, Initial Criticality and Testing;
- S2.OP-ST.SSP-0003, SEC Mode Ops Testing 2B Vital Bus; and
- S1.OP-ST.SW-0001, Inservice Testing – 11 Service Water Pump.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2OS1 Access Control to Radiologically Significant Areas (71121.01 - 5 samples)

a. Inspection Scope

Based on PSEG's schedule of work activities, the inspectors selected three jobs performed in radiation areas, airborne radioactivity areas, or high radiation areas (<1 R/hr) for observation (steam generator inspection, RCP 22 motor replacement, and reactor head grinding). The inspectors observed work that was estimated to result in the highest collective doses, involved diving activities in or around spent fuel or highly activated material, or that involved potentially changing or deteriorating radiological conditions. The inspectors reviewed all radiological job requirements, including radiation work permit requirements and work procedure requirements. The inspectors observed job performance with respect to these requirements and verified that radiological conditions in the work area were adequately communicated to workers through briefings and postings.

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

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

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

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

The inspectors evaluated PSEG performance against the requirements contained in 10 CFR 20.1601, Plant TS 6.11 and 6.12, and Updated Final Safety Analysis Report (UFSAR) Chapter 12.

b. Findings

No findings of significance were identified.

2OS2 As Low As Reasonably Achievable (ALARA) Planning and Controls (71121.02 - 2 samples)

a. Inspection Scope

The inspectors observed radiation worker and radiation protection (RP) technician performance during work activities performed in radiation areas, airborne radioactivity areas, or high radiation areas. The inspectors concentrated on work activities that presented the greatest radiological risk to workers and verified that workers demonstrated the ALARA philosophy and that there were no procedure compliance issues. The inspectors also observed radiation worker performance to verify that the training/skill level was sufficient for the radiological hazards and the work involved.

The inspectors verified that workers were utilizing the low dose waiting areas and were effective in maintaining their doses ALARA. The inspectors also verified that workers received appropriate on-the-job supervision to ensure the ALARA requirements were met and that the first-line job supervisor ensured the work activity was conducted in a dose efficient manner.

The inspectors evaluated PSEG performance against the requirements contained in 10 CFR 20.1101 and UFSAR Section 12.4.

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 the plant UFSAR to identify applicable radiation monitors associated with transient high and very high radiation areas, including those used in remote emergency assessment.

The inspectors evaluated licensee performance against the requirements contained in 10 CFR 20.1501, 10 CFR 20.1703,10 CFR 20.1704, ANSI N323-1978, ANSI N323A-1997 and ANSI N42.17A-2004.

b. Findings

No findings of significance were identified.

Cornerstone: Public Radiation Safety

2PS2 Radioactive Material Processing and Transportation (71122.02 - 6 samples)

a. Inspection Scope

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

The inspectors reviewed surveys of the liquid and solid radioactive waste processing systems to verify and assess that the current system configuration and operation agree with the descriptions contained in the FSAR and in the Process Control Program. The inspectors reviewed the status of any radioactive waste process equipment that was not operational and/or was abandoned in place. The inspectors reviewed PSEG's administrative and physical controls to ensure that the equipment did not contribute to an unmonitored release path and/or affect operating systems or be a source of unnecessary personnel exposure.

The inspectors reviewed the adequacy of any changes made to the radioactive waste processing systems since the last inspection. The inspectors verified that the changes were reviewed and documented in accordance with 10 CFR 50.59, as appropriate. The inspectors reviewed the impact, if any, of radiation doses to members of the public. The inspectors reviewed current processes for transferring radioactive waste resin and sludge discharges into shipping/disposal containers to verify that appropriate waste stream mixing and/or sampling procedures, and methodology for waste concentration averaging provide representative samples of the waste product for the purposes of waste classification as specified in 10 CFR 61.55 for waste disposal.

The inspectors reviewed the radio-chemical sample analysis results for each of PSEG's radioactive waste streams. The inspectors reviewed PSEG's use of scaling factors and calculations used to account for difficult-to-measure radionuclides. The inspectors verified that PSEG's program assured compliance with 10 CFR 61.55 and 10 CFR 61.56

as required by Appendix G of 10 CFR Part 20. The inspectors reviewed PSEG's program to ensure that the waste stream composition data accounted for changing operational parameters and remained valid between the annual or biennial sample analysis update.

The inspectors observed shipment packaging, surveying, labeling, marking, placarding, vehicle checks, emergency instructions, disposal manifest, shipping papers provided to the driver, and licensee verification of shipment readiness. The inspectors verified that the requirements of all applicable transport cask Certificate of Compliance had been met. The inspectors conducted direct observation of PSEG shipment 09-123. The inspectors verified that the receiving licensee was authorized to receive the shipment packages. The inspectors observed radiation workers during the conduct of radioactive waste processing and radioactive material shipment preparation activities. The inspectors verified that the shippers were knowledgeable of the shipping regulations and whether shipping personnel demonstrated adequate skills to accomplish the package preparation requirements for public transport with respect to NRC Bulletin 79-19 and 49 CFR Part 172 Subpart H. The inspectors also verified that PSEG's training program provided training to personnel responsible for the conduct of radioactive waste processing and radioactive material shipment preparation activities.

The inspectors sampled non-excepted package shipment records. The inspectors reviewed these records for compliance with NRC and Department of Transportation requirements.

The inspectors reviewed the PSEG licensee event reports (LERs), Special Reports, audits, State agency reports, and self assessments related to the radioactive material and transportation programs performed since the last inspection. The inspectors also verified that identified problems were entered into the CAP for resolution. The inspectors reviewed corrective action reports written against the radioactive material and shipping programs since the previous inspection.

The inspectors interviewed staff and reviewed documents to verify that PSEG conducted the following activities in an effective and timely manner commensurate with their importance to safety and risk: problem identification, characterization, and tracking; disposition of operability/reportability issues; evaluation of safety significance/risk and priority for resolution; identification of repetitive problems; identification of contributing causes; identification and implementation of effective corrective actions; resolution of NCVs tracked in the corrective action system; and implementation/consideration of risk significant operational experience feedback.

For repetitive or significant individual deficiencies, in radioactive material processing and transportation the inspectors also verified that PSEG's self-assessment activities were also identifying and addressing those deficiencies.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator (PI) Verification (71151 - 6 samples)

a. Inspection Scope

Cornerstone: Mitigating Systems

The inspectors reviewed PSEG information from the fourth quarter 2008 to the third quarter 2009 for the Salem Unit 1 and 2 performance indicators (PIs) listed below: To verify the accuracy of the PI data reported during that period, PI definitions and guidance contained in NEI 99-02, "Regulatory Assessment Indicator Guideline," Revision 5, was used to verify the basis in reporting each data element.

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

The inspectors reviewed the consolidated data entry MSPI derivation reports for the unavailability and unreliability indexes (UAI and URI) for the monitored systems; the monitored component demands and demand failure data for the monitored systems; and the train and system unavailability data for the monitored systems. The inspectors verified the accuracy of the data by comparing it to corrective action program records, control room operators' logs, maintenance rule performance and scope reports, system performance/health reports, the equipment/operability issues database, the site operating history database, key performance indicator summary records, operating data reports and the MSPI basis document.

Cornerstone: Occupational Radiation Safety

- Occupational Exposure Control Effectiveness

The inspectors reviewed a listing of PSEG action reports for the period January 1, 2009 through December 7, 2009, for issues related to the occupational radiation safety PI, that measures non-conformances with high radiation areas greater than 1R/hr and unplanned personnel exposures greater than 100 mrem total effective dose equivalent (TEDE), 5 rem skin dose equivalent (SDE), 1.5 rem lens dose equivalent (LDE), or 100 mrem to the unborn child. The inspectors' review of the data for this period confirmed that no PI events had occurred during the assessment period.

Cornerstone: Public Radiation Safety

- RETS/ODCM Radiological Effluents Occurrences

The inspectors reviewed a listing of PSEG action reports for the period January 1, 2009 through December 7, 2009, for issues related to the public radiation safety performance indicator (PI) that measures radiological effluent release occurrences per site that exceed 1.5 mrem/qtr whole body or 5 mrem/qtr organ dose for liquid effluents; or 5 mrads/qtr gamma air dose, 10 mrads/qtr beta air dose; or 7.5 mrems/qtr organ doses from I-131, I-133, H-3 and particulates for gaseous effluents The inspectors' review of

the data for this period confirmed that no PI events had occurred during the assessment period.

b. Findings

No findings of significance were identified.

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

.1 Review of Items Entered into the CAP

a. Inspection Scope

As required by IP 71152, "Identification and Resolution of Problems," and in order to help identify repetitive equipment failures or specific human performance issues for follow-up, the inspectors performed a daily screening of all items entered into PSEG's CAP. This was accomplished by reviewing the description of each new notification and attending daily management review committee meetings. Documents reviewed are listed in the Attachment.

b. Findings

No findings of significance were identified.

.2 Semi-Annual Review to Identify Trends

a. Inspection Scope

As required by IP 71152, "Identification and Resolution of Problems," the inspectors performed a review of PSEG's CAP and associated documents to identify trends that could indicate the existence of a more significant safety issue. The inspectors' review was focused on repetitive equipment and corrective maintenance issues, but also considered the results of daily inspector CAP item screening discussed in Section 4OA2.1. The review included issues documented in system health reports, corrective maintenance WOs, component status reports, site monthly meeting reports and maintenance rule assessments. The inspectors' review nominally considered the six-month period of June 1, 2009 through November 30, 2009, although some examples expanded beyond those dates when the scope of the trend warranted. The inspectors compared and contrasted their results with the results contained in PSEG's latest integrated quarterly assessment report. Corrective actions associated with a sample of the issues identified in PSEG's trend report were reviewed for adequacy. The inspectors also evaluated the trend report specified in SPP-3.1, CAP. Specific documents reviewed are listed in the Attachment.

b. Assessment and Observations

No findings of significance were identified.
The inspectors noted a trend of low level issues entered into the CAP related to equipment reliability. There were several radiation detection monitor emergent repairs, and emergent repairs required for the control area chillers. The inspectors also noted deficiencies with the scope, planning, and implementation of long term equipment

preventive maintenance. Some of the preventive maintenance deficiencies have been corrected through implementation of a performance centered maintenance plan. The inspectors determined PSEG is aware of these issues identified through this trend review and is appropriately addressing these issues.

.3 Annual Sample: Unit 1 RHR System Potential Water Hammer

a. Inspection Scope

This inspection focused on PSEG's identification, evaluation, and corrective actions associated with indications that a gas void existed in the RHR system, which has resulted in pressure surges during Unit 1 RHR pump starts. Specifically, station personnel had reported hearing a loud bang upon starting either of the two RHR pumps at Unit 1.

The inspectors reviewed PSEG's technical evaluations and corrective action reports, and interviewed engineering and operations personnel to assess the condition of the RHR system. The inspectors reviewed emergency core cooling system (ECCS) drawings, operating and test procedures, and test results to evaluate the potential leakage sources that could have resulted in gas accumulation in the ECCS. The inspectors also toured portions of the safety injection and RHR systems, and witnessed an RHR pump test to supplement the documentation review in assessing the condition of the RHR system. The inspectors reviewed PSEG's planned and completed corrective actions to evaluate the effectiveness of their issue investigation. Documents reviewed are listed in the Attachment.

b. Findings and Observations

No findings of significance were identified.

The inspectors noted that PSEG first identified that a pressure surge occurred during an RHR pump start on April 1, 2009, at which time PSEG initiated an investigation into the potential water hammer. Engineers and operators evaluated system parameters and system performance; however, no obvious cause was identified. Subsequently, detailed troubleshooting plans were executed and a systematic monitoring plan was implemented (which included UT). Based upon reviews of system operating parameters, data analysis, and local RHR pump observation, PSEG concluded that a gas void existed in the RHR system. However, UT of specific accessible areas of RHR piping did not identify the presence of a void. PSEG's monitoring plan, which measures and calculates void volume, has estimated that the void size has been between 2 - 3 cubic feet. PSEG suspects the location of the void to be in a stagnant portion of the RHR system, located downstream of the two (parallel) RHR pumps. As this section of piping is not accessible during power operations, PSEG plans to perform UT of this piping during the next RFO (April 2010). PSEG is also considering the installation of high point vents on this piping if it is confirmed that this is the location of the void.

PSEG also measures and trends peak RHR system pressure during pump starts, which has been between 400 - 470 psig, to further monitor RHR system performance. The inspectors determined that these values do not compromise RHR pump operability as this range is within the operating pressure band of the system (relief valve setpoint is

600 psig). Further, RHR system peak pressure was subsequently measured for a Unit 2 RHR pump start for comparison purposes, and was found to be 430 psig. There were no indications or concerns with gas voids at Unit 2.

Regarding extent-of-condition, the inspectors confirmed that PSEG has considered potential impact to Unit 2, which was in a RFO during this inspection. PSEG assessed similar piping at Unit 2 during the outage, which included performing UT of the suspect pipe section (normally inaccessible at power). No voids were identified at Unit 2, and similar water hammer or voiding concerns have not been observed during Unit 2 RHR pump starts.

The inspectors observed the performance of a Unit 1 RHR pump test on October 9, 2009. A noise was heard upon starting the pump, similar in magnitude to that of a check valve closing. However, the noise resembled a short duration rumbling sound, which would be representative of the presence of a void in the system. During that test, the system manager observed associated RHR system piping and reported slight movement, similar in magnitude of prior Unit 1 RHR pump starts (since the void was first reported). The pipe movement was considered acceptable, and not a challenge to pipe or system integrity.

Based upon review of the monitoring plan data, pump test results, and associated technical evaluations, PSEG verified that the void that existed in the RHR system does not adversely impact RHR system operability. The calculated void size of between 2 – 3 cubic feet is less than the limit established for water hammer by PSEG (5 cubic feet), which is based on vendor and industry guidance. In addition, the results of the monitoring plan and physical system inspections provided additional assurance that the RHR system operability had not been compromised.

The inspectors concluded that PSEG's actions were appropriate and provided reasonable assurance of Unit 1 RHR system operability. However, while the RHR system remained operable, the full extent and details associated with the void formation are necessary in order to correct this instance and prevent additional challenges. The NRC will be performing an inspection of PSEG's response to NRC GL 2008-01, "Managing Gas Accumulation in Emergency Core Cooling, DHR, and Containment Spray Systems," in August 2010. The details and final resolution associated with the Unit 1 gas void issue will be considered as part of that inspection.

.4 Annual Sample: Human Performance, Procedure and Document Quality

a. Inspection Scope

On March 4, 2009, the NRC identified a substantive cross-cutting issue in the area of human performance with a cross-cutting aspect of procedure and document quality. PSEG's subsequent causal evaluations, as of June 2009, identified that personnel did not consistently develop and revise procedures in a way that ensured the adequacy of procedure and document quality. As a result, inadequate procedures were sometimes used in the performance of engineering, operations, and maintenance activities. This substantive cross-cutting issue was maintained open in the mid cycle assessment letter because PSEG did not meet the criteria for clearing the substantive cross-cutting issue since many of the corrective actions identified in the causal evaluations to address procedure adequacy were still in progress at the end of the mid cycle assessment period.

The inspectors reviewed the actions PSEG had taken to improve procedure and document quality at the station. This sample evaluated PSEG's scope of efforts and progress in the area of procedure and document quality for the period of July 2009 through December 2009. The inspectors review focused on the comprehensiveness of PSEG's corrective actions and the review and revision risk significant procedures, including those that were used in the Unit 2 fall refueling outage. The inspectors verified completion of the most significant identified corrective actions and reviewed the effectiveness of the site's improvement program by reviewing procedure revision backlogs and internal PSEG performance indicators such as trends in the number of procedure use and adherence related events.

b. Findings and Observations

A root cause evaluation on implementing procedure quality completed by PSEG in May 2009, identified that PSEG management had failed to enforce administrative processes, specifically with regard to rigorous reviews, validation and incorporation of operating experience to ensure implementing procedure quality. To address this cause, station procedures were revised to provide more explicit procedure review requirements. Specifically, the Station Qualified Reviewer's (SQR) Guide level of use was changed to require the procedure to be referenced during SQR reviews. An SQR check list was added with required sign-offs to ensure accountability for key steps including ensuring that procedure changes were subjected to the appropriate level of review. Further, examples were added to reinforce when a review by an organization independent of the procedure owners department would be required for implementing procedure changes. All personnel qualified as an SQR were trained on the changes and to reinforce expectations with regard to the use of the SQR checklist. SQR continuing training was re-instated to require biennial requalification of all SQRs. In addition, the Implementing Procedures Writers Guide was revised to modify the cover sheet for implementing procedures to include documentation of existing operating experience that was incorporated change.

PSEG identified several key contributing causes during the RCA and other causal evaluations. The most important contributing causes included a lack of PSEG staff familiarity with reference level procedures for administrative processes. For example the engineering department identified that one of the contributing causes for the negative trend in human performance related issues associated with calculations, drawing and design changes, which was identified in 2008, was unfamiliarity with the administrative procedures that control those processes. Corrective actions to address these issues included departmental training for the staff, creation of a administrative procedure guide for common engineering tasks, and thorough review of these procedures to improve their quality and ease of use.

PSEG also found that there was a lack of focus related to continuous procedure and work order improvements. For example, work order feedback was often inconsistent and did not provide sufficient detail to allow effective improvements to be made and, with respect to procedures, PSEG had not used industry "best practices," published by NEI and proven to make procedures clearer and easier to use, to improve implementing procedure quality.

To address these contributing causes, PSEG implemented a range of corrective actions focused on including improving familiarity and knowledge of administrative procedures and raising standards for procedure compliance and quality. Specific corrective actions included, conducting training needs analyses, updating procedures and conducting staff evaluations and dynamic learning activities. In addition, a site wide communication from the leadership team was used to start the improvement initiatives and the "procedure in-hand day" and "procedure of the week" programs were used to maintain an emphasis on the improvement efforts throughout the assessment period.

Standards were reinforced through the use of a manager in the field, designated for each working day, to ensure that the standards and expectations of the leadership team were implemented in the field. To increase personal accountability, identified deficiencies were documented in the corrective action process or the fundamentals management system (FMS). These feedback processes provided the basis for the continuous improvement efforts in the procedure area at the station. PSEG also implemented post-job briefings in an attempt to more fully and accurately capture feedback from job performance so necessary improvements to work orders and implementing procedures could be made.

The inspectors determined that appropriate corrective actions were identified to address procedure adequacy and that all of the actions required to correct the problem have been completed. As stated above the administrative process for writing and modifying station procedures was revised to improve the quality of station procedures and management expectations regarding procedure quality were reinforced throughout the assessment period. The process for incorporating operating experience into procedures was improved by requiring operating experience reviews for all implementing procedure revisions. Corrective actions for incorporating industry "best practices" into implementing procedures have also been initiated. And to ensure that procedure quality continues to improve at both Salem and Hope Creek a procedure working group consisting of personnel from both Salem and Hope Creek was formed to monitor site wide procedure quality issues through trending and individual procedure reviews.

Procedure revision backlogs are tracked for the operations, maintenance, chemistry, radiation protection, and engineering departments. PSEG manages the backlogs through the prioritization of the revision requests. PSEG established backlog goals at the beginning of 2009, and as of the end of 2009, all major departments had met those goals, but this did not result in a steady decline in the total backlog of procedure revisions. The lack of progress in reducing the backlog was caused by a significant increase in the number of revisions requested due to the site wide communications and training regarding expectations for procedure quality. PSEG has maintained its focus on completing requested procedure revisions in a timely manner and as a result the backlog has not grown to an unmanageable level.

As part of the fall 2009 outage preparation and execution, PSEG personnel identified risk significant procedures that would be used during the outage. There were 121 risk significant evolutions identified as either a high risk evolution or heightened level of awareness required. Pre-job briefs were assigned as part of the outage preparation. Development of these pre-job briefs and review of these outage procedures led to the revision of 29 risk significant procedures. During the outage, inspectors attended some of the pre-job briefings prior to critical evolutions and found that the briefings were

informative and thorough. Technicians and plant operators actively participated in the briefings to ensure that they understood the procedures being discussed.

There were no significant human performance events during the outage and the inspectors' review of risk significant activities identified only a few minor issues and one finding of significance with cross cutting aspects in procedure or documentation adequacy. The finding was identified when a service water isolation valve broke causing an unplanned reduction in decay heat removal capacity because the valve actuator installation procedure was not adequate. The procedure was not adequate because the correct torque for the valve's actuator to body bolts was not specified. The procedure was an old procedure and the problem was not identified during outage preparations because it was not included in the scope of the 121 high risk activity reviews completed before the outage. A review of events documented in the corrective action program on a quarterly basis with an assigned significant level of 1 through 3 also confirmed a downward trend in this area in 2009, from a maximum of 6 in the fourth quarter of 2008 to 1 in the fourth quarter of 2009.

4OA3 Event Follow-up (71153 - 1 sample)

.1 (Closed) LER 05000311/2009002-00, 22 Component Cooling HX Inoperable for Greater Than Allowed Outage Time

On October 17, 2009, while Unit 2 was in cold shutdown, the 22 (CCHX) SW outlet valve, 22SW356, failed from full open to a partially open position while the 21 CCHX was out of service for planned maintenance. As a result, Unit 2 shutdown core cooling was reduced. Operators responded by securing 22SW356 to prevent further closure and raised RHR flow to restore core cooling. Operators subsequently returned the 21 CCHX to service. As part of their causal investigation, PSEG determined that since valve 22SW356 gear box mounting bolts failed after operation at high service water flow conditions during the outage, a similar failure could have occurred during post-LOCA conditions. Since the 22 CCHX was not able to perform its design basis post-LOCA heat removal function during the past operating cycle, the 22 CCHX was inoperable for greater than the allowed outage time of TS 3.7.3. The inspectors reviewed this event and identified performance deficiencies as documented in NCV 05000311/2009005-02. The NCV and its enforcement aspects are documented in Section 1R12 above. This LER is closed.

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 quarterly resident inspector observations of security force personnel and activities did not constitute any additional inspection samples. Rather, they were considered an integral part of the inspectors' normal plant status review and inspection activities.

b. Findings

No findings of significance were identified.

.2 Reactor Coolant System Dissimilar Metal Butt Welds (TI 2515/172)

a. Inspection Scope

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 NDE and evaluation of certain dissimilar metal welds in the RCS containing nickel based alloys 600/82/182.

Unit 2 has dissimilar metal welds in the eight RCS piping to reactor vessel nozzle safe end welds. Prior to the October 2009, S2R17 RFO, the affected welds had not been inspected with a performance demonstration initiative (PDI) qualified UT process.

During S2R17, in preparation for mitigating stress application to all eight RCS nozzles, PSEG conducted manual PDI qualified UT examinations on all RCS nozzles. These inspections resulted in no recordable indications in all eight nozzles.

PSEG successfully applied the mitigating stress to all four hot leg nozzles during S2R17. After completion of the mechanical stress improvement process (MSIP), PSEG completed an automated phased array, PDI qualified, ultrasonic examination on each hot leg nozzle. The hot leg nozzles in RCS loops 22 and 23 had no recordable indications during this UT examination. The hot leg nozzles in RCS loops 21 and 24 had one minor cladding indication in each nozzle. PSEG dispositioned these indications as acceptable "as-is" for further operation.

PSEG was not able to complete the MSIP on the four cold leg nozzles due to equipment interferences discovered during S2R17. PSEG has successfully completed a manual PDI qualified UT on each of the four cold leg nozzles. PSEG will continue to inspect the Unit 2 cold leg nozzles at the frequency required by MRP-139. PSEG intends to perform the MSIP on the four cold leg nozzles during a future RFO.

The inspectors reviewed all procedures, including procedure qualification records, used during the MSIP application and the pre- and post-MSIP UT testing. Additionally, the inspectors observed the application of the process in containment and observed the evaluation of engineering data resulting from the MSIP application and the UT testing.

This TI requires documentation of specific questions in an inspection report. The questions and responses for MSIP for the IR 05000311/2009005, section 4OA5, are included in this report as Attachment B.

b. Findings

No findings of significance were identified.

.3 (Closed) Unresolved Item (URI) 05000272; 311/2008007-004, Vital Bus Degraded Voltage Licensing Bases

During the 2008 component design bases inspection (CDBI), the NRC-identified an URI related to thermal overload (TOL) relay protection of motor operated valves (MOVs) during a postulated design basis event concurrent with degraded 4 kV vital buses. The CDBI team noted that the safety-related MOV TOL relays were not bypassed on an accident condition for Unit 1 or Unit 2. The team was concerned that if a postulated sustained undervoltage condition were to occur, where the 4 kV vital bus voltages remained below the degraded voltage set point of 94.6% but higher than the loss-of-voltage set point of 70% for the duration of the degraded voltage time delay of 13 seconds, the safety-related MOVs could go into stall condition where their associated TOL relays could trip. The TOLs can only be reset from the affected motor control centers to restart the safety-related MOVs. At the time of the CDBI inspection, it was not clear if the above scenario was within Salem's licensing basis. Subsequent to the CDBI inspection, PSEG determined that the postulated scenario causing 4 kV vital buses to stay at a voltage less than 94.6% and greater than 70% until the second level undervoltage protection scheme relays time out in 13 seconds, was a scenario to be considered in Salem's licensing basis.

PSEG conducted an initial assessment and determined that the existing thermal overload heaters (TOLH) were selected without considering the above described scenario, and may interfere with the successful completion of low margin MOV safety functions. As a result, PSEG developed an engineering evaluation, calculations and design change packages to replace the existing TOLH with an adequately sized TOLH for the associated MOVs, to ensure that the TOLH did not trip under a stall condition during the postulated 13 seconds degraded voltage condition. PSEG developed a replacement plan for the TOLH that consisted of replacing 90% of the TOLH for Unit 1 and 2 during their RFOs, and replacing the remaining TOLHs online. The inspectors reviewed PSEG's engineering evaluation, calculations, design change packages, and post-modification testing for both units to ensure that the replacement TOLs were selected such that they would not trip during the degraded voltage condition described above and did not change the valve design functions. PSEG completed the replacement modification for Unit 2 TOLH during the recent RFO and have plans to complete the Unit 1 replacement during the upcoming RFO in the spring 2010. The inspectors also verified that the MOV cables were adequately protected, and that proper short circuit protection and breaker coordination protection were also maintained.

PSEG had generated a Notification (20379520) when the URI was opened and initiated a compensatory action to maintain a common unit standing order that required Operations to enter TS 3.0.3 instead of TS 3.8.1.1 Action D when two of the required independent AC circuits were declared inoperable as a result of a degraded voltage condition. PSEG plans to maintain the standing order until the TOLH replacement has been completed. The inspectors reviewed PSEG's compensatory actions in the standing order, as well as PSEG's online monitoring tools that were in place to analyze and periodically verify the condition of the transmission system to determine the availability and adequacy of offsite power. The inspectors found the compensatory actions to be adequate. The state estimator online monitoring tool provides plant operations with post-trip switchyard voltages for anticipated and postulated accident occurrences to ensure availability and adequacy of offsite power.

The inspectors reviewed PSEG's corrective actions responding to the URI, the licensing basis information regarding the postulated scenario of degraded 4kV vital bus for 13

seconds, and the previously issued NCV associated with TOLs from the 2008 CDBI inspection, and concluded that no additional findings of significance were identified and no violation of NRC requirements occurred. This unresolved item is closed.

4OA6 Meetings, Including Exit

The inspectors presented the inspection results to Mr. C. Fricker and other members of PSEG management at the conclusion of the inspection on January 8, 2010. The inspectors asked PSEG whether any materials examined during the inspection were proprietary. No proprietary information was identified.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee personnel:

C. Fricker	Salem Site Vice President
H. Berrick	Regulatory Affairs
S. Bowers	RHR System Engineer
E. Eilola	Plant Manager
A. Garcia	System Engineer
R. Gary	Radiation Protection Manager
G. Gauding	Operations Training Exam Developer
D. Johnson	MOV Program Engineer
W. Kittle	ISI Program Engineer
N. Ortiz	Senior Engineer
G. Pahwa	89-13 Program Engineer
R. Settle	Project Manager
M. Straubmuller	Operations Training Manager
R. Villar	Salem Licensing

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened/Closed

05000311/2009005-01	NCV	Salem Unit 2 Degradation of Shutdown Cooling Caused by Failure of 22RH18 (Section 1R12.b.1)
05000311/2009005-02	NCV	Inadequate Maintenance of the 22 CCHX SW Outlet Butterfly Valve (Section 1R12.b.2)

Closed

05000311/2009-002-00	LER	Title 22 Component Cooling HX Inoperable for Greater Than Allowed Outage time (Section 4OA3.1)
05000272; 311/2008007-004	URI	Vital Bus Degraded Voltage Licensing Bases (Section 4OA5.3)

LIST OF DOCUMENTS REVIEWED

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

Section 1R01: Adverse Weather Protection

Procedures
SC.MD-GP.ZZ-0001, Station Preparations for Winter – Mechanical, Revision 6
SC.MD-GP.ZZ-0178, Station Preparation for Winter – Electrical, Revision 16
SC.OP-PT.ZZ-0002, Station Preparations for Seasonal Conditions, Revision 11
SH.FP-TI.FP-0001, Freeze Prevention and Winter Readiness of Fire Protection Systems, Revision 4
WC-AA-107, Seasonal Readiness, Revision 7

Drawing
240342 240347 240347 240348 240433

Notifications
20440776 20443993 20445878

Orders
30171544

Other Documents
VPPO-2009-019, 2009 Salem Winter/Grassing Seasonal Readiness Affirmation
Plant System Readiness Review – Heat Trace
Plant System Readiness Review – Service Water Intake Structure
Plant System Readiness Review – Control Area Ventilation

Section 1R04: Equipment Alignment

Procedures
S2.OP-AB.SF-0001, Loss of SFP Cooling, Revision 7
S2.OP-SO.FO-0001, Emergency Diesel Fuel Oil System Operation, Revision 12
S2.OP-SO.RHR-0002, Terminating RHR, Revision 19
S2.OP-SO.SW-0003, 22 Nuclear Service Water Header Outage, Revision 22

Drawings
205249 205332 205333 205342 211306 211307

Other Documents
Segmented Reactor Cavity Seal Design Analysis, NES Project No. 3496
Tagging Work List 4238916, October 19, 2009 at 19:48
Tagging Work List 4263755, December 3, 2009 at 10:24
Tagging Work List 4263757, December 3, 2009 at 10:23
Tagging Work List 4263775, December 3, 2009 at 10:23

Section 1R05: Fire Protection

Procedures

FRS-II-511, Salem – Unit 1 (Unit 2) Pre-fire Plan, Electrical Penetration Area, Elevation: 78'-0," Revision 5

FRS-II-611, Salem – Unit 1 (Unit 2) Pre-fire Plan, Reactor Containment Elevations 78', 100' & 130'

FRS-II-914, Salem – Unit 1 (Unit 2) Pre-fire Plan, Outer Penetration Area, Revision 2

Section 1R07: Heat Sink Performance

Procedures

ER-AA-340, GL 89-13 Program Implementing Procedure, Revision 4

ER-AA-340-1001, GL 89-13 Program Implementation Instructional Guide, Revision 6

ER-AA-340-1003, GL 89-13 Program PIs, Revision 2

S2.OP-PM.SW-0001, Flush of EDG SW Supply Header, Revision 1

S2.OP-PT.SW-0006, SW Fouling Monitoring Diesel Generators, Revision 10

S2.OP-PT.SW-0027, 22 Component Cooling HX Heat Transfer Performance Data Collection, Revision 12

SC.MD-PM.CC-0002, Component Cooling HXs #11, 21, and 22 Internal Inspection, Revision 13

SC.MD-PM.DG-0017, Diesel Generator Lube Oil and Jacket Water Cooler Internal Inspection, Revision 4

SC.OP-PM.CC-0002, Cleaning of Component Cooling HXs, Revision 0

SC.OP-PM.CC-0022, 22 Component Cooling HX High Flow Flush and Alignment, Revision 16

Drawings

205342

Notifications

20438445 20438538 20438538

Orders

30123350 70095726 80096598 80099960

Other Documents

CM-SC-1990-591, Commitment Change Evaluation of GL 89-13 Program for Testing Heat Transfer Capability

ECT Results of 2B EDG Jacket Water Cooler Tube Bundle Performed by Maplewood Testing Services, October 27, 2009

ECT Results of 2B EDG Lube Oil Cooler Tube Bundle Performed by Maplewood Testing Services, October 27, 2009

GL 89-13 Program, Program Health Report, Third Quarter of Calendar Year 2009

S-C-SW-MDC-1500, Biofouling Monitoring and Trending Calculation

Section 1R08: Inservice Inspection Activities

Notifications:

20236613	20364957	20372630
20352806	20367476	20372681
20352822	20369258	20372682
20354300	20369641	20373890

20374296	20434664	20434833
20377390	20434665	20434836
20378993	20434666	20434837
20379846	20434668	20434838
20384104	20434670	20434839
20384884	20434671	20434841
20385458	20434672	20434842
20386879	20434673	20434844
20389147	20434674	20434846
20389616	20434675	20434848
20395324	20434679	20434852
20401542	20434680	20434854
20404057	20434681	20434855
20404524	20434682	20434856
20409943	20434683	20434915
20413147	20434684	20435588
20416549	20434739	20437408
20416549	20434740	20437550
20416605	20434741	20437846
20426886	20434742	20437939
20431403	20434745	20438026
20434545	20434769	20438943
20434547	20434828	20439384
20434658	20434831	
20434660	20434832	

Section XI Repair/Replacement Samples:
30040060 – 1LT102 Boric Acid Storage Tank (BAST) LEVEL SENSOR CAL
30069874 – 2RC40/Perform PM, Internal Inspection
30123027 – 2PR2 Valve Internals Refurbishment
60064624 – Boron Leak At 2SJ195
60069565 – Replace PS1 Stem/Bellows Assembly
60069566 – Replace 2PS3 Stem/Bellows Assembly
60078285 – 21 CL Linear Indication (3/4 inch) Repair Plan

Non-Code Repair
AREVA NP 03-9123233, Revision 000, 10/13/09; Salem Unit 2 RVCH Flange Repair Procedure (Removal of RVCH Metal Interfering with Stud Elongation Tool.)

Drawings:
Chicago Bridge & Iron Company drawing 68-3246-1, Revision 5, General Plan, Containment Building, Liners Salem Generating Station, 2/27/69
Chicago Bridge & Iron Company drawing 68-3246-20, Revision 5, Test Channels 1st Stage, Unit No. 2, 90 degrees to 270 degrees, 3/17/69
Chicago Bridge & Iron Company drawing 68-3246-19, Revision 4, Test Channels 1st Stage, Unit No. 2, 270 degrees to 90 degrees, 3/17/69
Chicago Bridge & Iron Company drawing 68-3246-55, Revision 3, Shell Stretchout Test Channels from AZ 90 degrees to 270 degrees, Unit 2, 10/18/69
Chicago Bridge & Iron Company drawing 68-3246-57, Revision 1, Shell Stretchout Test Channels Shop Details & Billing, Units 1 & 2, 11/18/69
Chicago Bridge & Iron Company drawing 68-3246-58, Revision 10, Roof Test Channels Unit 1 &

2, 6/13/70
Chicago Bridge & Iron Company drawing 68-3246-68, Revision 1, Orientation of Roof Test Channels Unit 1 & 2, 1/26/73
Chicago Bridge & Iron Company drawing 68-3246-68, Revision 3, Shell Stretchout Test Channels from AZ 270 degrees to 90 degrees, Unit 2, 11/18/69
Chicago Bridge & Iron Company drawing 68-3246-59, Revision 5, Roof Test Channels, Shop Details, Units 1 & 2, 12/1/69
Chicago Bridge & Iron Company drawing 68-3246-10, Revision 6, Bottom Test Channels Unit 2, 2/18/69
Chicago Bridge & Iron Company drawing 68-3246-11, Revision 5, Knuckle Plate, Units 1 & 2, 1/9/69

Design Changes
Design Change No. 80096081, Revision 1, RPV Hot and Cold Legs MSIP Implementation – Salem Unit 2, 7/21/09
Salem Change No. 1E-A-1044, 12/3/09; Steam Generator/RCP Supports – Update Keeper Plate Details

Vendor Nonconformance Reports
4422-NCR-001, Salem U2 Weld Number 29-RC-1240-1, 10/26/09

Program Documents
PSEG Nuclear Salem Units 1 & 2, Alloy 600 Management Plan, Long Term Plan (LTP), Revision 2, Integrated Strategic Plan For Long Term Protection from Primary Water Stress Corrosion Cracking (PWSCC), 10/15/09
Procedures
ER - AP - 335 - 1012, Revision 3, Bare Metal Visual Examination of PWR Vessel Penetrations and Nozzle Safe Ends
SH.RA - AP.ZZ - 8805(Q) - Revision 4, 8/31/06; Boric Acid Corrosion Management Program
ER - AP - 331, Revision 3, Boric Acid Corrosion Control (BACC) Program
ER - AP - 331 - 1001, Revision 2, BACC Inspection Locations, Implementation And inspection Guidelines
ER - AP - 331 - 1002, Revision 3, BACC Program Identification, Screening, and Evaluation
ER - AP - 331 - 1003, Revision 1, RCS Leakage Monitoring And Action Plan
ER - AP - 331 - 1004, Revision 2, BACC Program Training And Qualification
LS - AA - 125, Revision 12; CAP Procedure
LS - AA - 120, Revision 8; Issue Identification And Screening Process
SH.RA-IS.ZZ-0005(Q)-Revision 6; VT-2 Visual Examination Of Nuclear Class 1, 2 and 3 Systems
SH.RA-IS.ZZ-0150(Q) – Revision 8, 10/19/04; Nuclear Class 1, 2, 3 and MC Component Support Visual Examination
Wesdyne WDI-STD-1005, Revision 2, 11/16/06; Manual or Multi-Channel Automated Ultrasonic Instrument Linearity Procedure
Areva NP, Inc., Engineering Information Record 51-9118973-000; Qualified Eddy Current Examination Techniques for Salem Unit 2 Areva 61/19T Steam Generators, 10/15/09
AREVA NP 03-9123233, Revision 000, 10/13/09; Salem Unit 2 RVCH Flange Repair
WDI-TJ-1032, Revision 0, 9/23/08; Generic Procedure for Acquiring Material Thickness, Contours and Circumference Measurements for Similar and Dissimilar Metal Welds
WDI-TJ-1042, Revision 0, 9/24/09; Demonstration Report/Technical Basis Document: Ultrasonic Examination of Reactor Pressure Vessel Nozzle to Safe End Welds from the OD Surface Using IntraPhase Phased Array UT Technology

PDI Program qualification #636 for WesDyne International
WDI-STD-1025; Revision 1; Addenda 0, 9/29/09
WDI-STD-1025; Revision 1; Generic Procedure for Ultrasonic Examination of Nozzle to Safe-End and Piping Dissimilar Metal Welds Using the InterPhase Phased Array Imaging System
Westinghouse Nuclear Services Procedure PNJ-ISI-254, Revision 2, 1/24/02; Remote Inservice Ultrasonic Examination of the Reactor Vessel At Salem Unit 2
Nu Vision Engineering Procedure: Analytical Verification Of MSIP For RV Hot Leg Nozzle To Safe End Weld, Salem Unit 1 & 2, October 2007
Nu Vision Engineering Procedure: Field Service Procedure Mechanical SI Process (MSIP) Outlet (Hot Leg) Nozzle, PSEG Nuclear LLC, Salem, March 2009
Nu Vision Engineering Procedure: Field Service Procedure Mechanical SI Process (MSIP) Inlet (Cold Leg) Nozzle, PSEG Nuclear LLC, Salem, March 2009
Wesdyne WDI-STD-1048, Revision 0, 9/21/09; Salem Unit 2 Reactor Vessel Nozzle Mechanical SI Process – NDE Activities

<u>NDE Examination Reports & Data Sheets</u>
051400, 6-PR-1204-3, UT-09-017
010100, 2-PZR-LONG A, UT-09-028
064300, 4-PS-1231-32, UT-09-025
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20435462	20441593	20436157
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20436451	20441988	20437058
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Orders
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Notifications

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20437316		20439735	20070410
20437491		20439738	20435078
20437973		20439493	20438320
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Notifications

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Notifications

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S2.OP-IO.ZZ-0004, Power Operation, Revision 67
S2.OP-IO.ZZ-0005, Minimum Load to Hot Standby, Revision 20
S2.OP-IO.ZZ-0006, Hot Standby to Cold Shutdown, Revision 38
S2.OP-IO.ZZ-0007, Cold Shutdown to Refueling, Revision 14
S2.OP-IO.ZZ-0008, Maintaining Hot Standby, Revision 13
S2.OP-IO.ZZ-0009, Defueled to Refueling, Revision 27
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S2.OP-SO.RHR-0001, Initiating RHR, Revision 24
S2.OP-SO.SF-0009, Refueling Operations, Revision 14
S2.OP-ST.CAN-0007, Refueling Operations – Containment Closure, Revision 24
SC.MD-PM.RC-0008, Steam Generator and Reactor Coolant Pump Support Pin Inspection, Revision 1
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Orders

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Procedures
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Orders

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Section 2OS1: Access Control to Radiologically Significant Areas

Procedures
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Procedures
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Procedures
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Drawings
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Notifications

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ES-18.0006(Q), Selection of TOL Heater Elements Unit 1 & 2 Safety-Related MOVs, Revision 2

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SC.MD-PT.230-0001(Q), Thermal Overload Relay Overcurrent Trip Testing, Revision 6

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ES-18.0006(Q), Selection of TOL Heater Elements Unit 1 & 2 Safety-Related MOVs, Revision 2

LIST OF ACRONYMS

ACE	Apparent Cause Evaluation
ADAMS	Agencywide Documents Access and Management System
ALARA	As Low As Reasonably Achievable
ASME	American Society of Mechanical Engineers
AVB	Anti-vibration Bar
CAP	Corrective Action Program
CCW	Component Cooling Water
CCHX	Component Cooling Water Heat Exchanger
CDBI	Component Design Bases Inspection
CFR	Code of Federal Regulations
CR	Condition Report
DHR	Decay Heat Removal
DOT	Department of Transportation
ECCS	Emergency Core Cooling System
ECT	Eddy Current Testing
EDG	Emergency Diesel Generator
EPRI	Electric Power Research institute
EQ	Environmental Qualification
ER	Engineering Request
GEH	GE - Hitachi
GL	Generic Letter
HUR	Heat Up Rate
HX	Heat Exchanger
IMC	Inspection Manual Chapter
IP	Inspection Procedure
IR	NRC Inspection Report
IVVI	In Vessel Visual Inspection
LER	Licensee Event Report
LOCA	Loss of Coolant Accident
MOVs	Motor Operated Valves
MRP	Materials Reliability Program
MSIP	Mechanical Stress Improvement Process
MSPI	Mitigating Systems Performance Index
MT	Magnetic Particle Testing
NCV	Non-cited Violation
NDE	Nondestructive Examination
NEI	Nuclear Energy Institute
NRC	Nuclear Regulatory Commission
OE	Operating Experience
OOS	Out-of-Service
PARS	Publicly Available Records
PDI	Performance Demonstration Initiative
PI&R	Problem Identification and Resolution
PPL	Pennsylvania Power & Light Susquehanna
PQR	Procedure Qualification Record (Welding Procedures)
PSEG	Public Service Enterprise Group Nuclear LLC
PT	Dye Penetrant Testing
PWR	Pressurized Water Reactors
PWSCC	Primary Water Stress Corrosion Cracking

RCS	Reactor Coolant System
RG	Regulatory Guide
RHR	Residual Heat Removal
RFO	Refueling Outage
RSG	Replacement Steam Generator
RT	Radiographic Test (Radiography)
SDP	Significance Determination Process
SE	Safety Evaluation
SFP	Spent Fuel Pool
SG	Steam Generator
SI	Stress Improvement
SJ	Safety Injection
SSC	Structure, System, and Component
SW	Service Water
S2R17	Salem Unit 2, Seventeenth Refueling Outage
TOLH	Thermal Overload Heaters
TOL	Thermal Overload
TS	Technical Specifications
TTB	Time to Boil
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
UT	Ultrasonic Test
VT	Visual Examination
WO	Work Order
WPS	Weld Procedure Specification

TI 172 MSIP Documentation Questions Salem Unit 2

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 the RCS containing nickel based Alloys 600/82/182. This TI requires documentation of specific questions in an inspection report. The questions and responses for MSIP for the IR 05000311/2009005 section 4OA5 are included in this Attachment B.

In summary 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 2 during the S2R17 in October 2009, the four hot leg nozzle welds were examined with a manual, PDI-qualified, ultrasonic test (UT) from the outside surface. These pre-MSIP inspections had no reportable indications. PSEG then rendered the hot leg nozzles less susceptible to cracking by application of the mechanical stress improvement (MSIP) process and subsequently UT inspected the hot leg nozzles after the MSIP process with an automated phased array, PDI qualified UT methodology. One cladding indication in the Loop 24 hot leg nozzle and one cladding indication in the Loop 21 hot leg nozzle were reported. Each of these indications was completely contained within the cladding. No other indication of cracking was found on any of the other hot leg nozzle to safe end welds.

PSEG intended to perform the MSIP process on the cold leg nozzles during the S2R17 outage, as well; however, equipment interferences with the cold leg nozzles prevented installation of the MSIP press and compression rings in an acceptable arrangement for performing the compression of the cold leg nozzles. PSEG did perform a manual, PDI-qualified, ultrasonic test (UT) from the outside surface of each cold leg nozzle. No indications were identified in the cold leg nozzles during these inspections.

TI 2515/172 requires the following questions to be answered for MRP-139 MSIP inspections:

Question 1: For each mechanical stress improvement used by the licensee during the Unit 2 S2R17 outage, was the activity performed in accordance with a documented qualification report for stress improvement processes and in accordance with demonstrated procedures?

Response Question 1: The MSIP conducted on the hot leg nozzles was conducted in accordance with a documented qualification report for stress improvement processes and in accordance with demonstrated procedures.

Question d.1: Are the nozzle, weld, safe end, and pipe configurations, as applicable, consistent with the configuration addressed in the stress improvement (SI) qualification report?

Response – Question d.1: The applicable information with reference to all hot and cold leg 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 bases drawings maintained by Westinghouse and PSE&G were licensee verified (S-TODI-2007-0006 Dated 12/03/07).

Question d.2.: 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?

Response Question d.2: 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.

Question d.3.: 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 MSIP?

Response: Question d.3.: MSIP NDE volumetric examinations were performed before and after the application of MSIP on the hot leg nozzles only. Based on these inspections no flaws of concern were identified in the hot leg nozzles after the application of MSIP. The records of the hot leg pre and post-MSIP UT examinations were inspected by NRC as part of the refuel outage NDE inspection under Inspection Procedure 71111.08.

Question d.4.: 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 examinations are to be within the limiting flaw sizes established by the SI qualification report?

Response: Question d.4.: 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 (SI). No flaws were identified in the hot leg nozzles. Thus SI was applied and met the acceptable range of flaw size that can be stress improved per MRP-139 guidance.

Question d.5.: Was the MSIP performed such that deficiencies were identified, dispositioned, and resolved?

Response Question d.5.: The Unit 2 RCS hot leg nozzle DM welds were stress improved by MSIP implementation during Unit 2 refueling outage S2R17. The inspector reviewed selected notification reports issued by PSEG during the application of the process. This review demonstrated that PSEG and their subcontractors were identifying deficiencies and effectively dispositioning or resolving the causes of those deficiencies.