April 3, 2006

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

SUBJECT: SALEM NUCLEAR GENERATING STATION - NRC INSPECTION REPORT 05000272/2006006 AND 05000311/2006006

Dear Mr. Levis:

On February 17, 2006, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at the Salem Nuclear Generating Station. The enclosed inspection report documents the inspection findings, which were discussed on February 17, 2006, with Mr. T. Joyce 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. In conducting the inspection, the team examined the adequacy of selected components and operator actions to mitigate postulated transients, initiating events, and design basis accidents. The inspection also reviewed PSEG's response to selected operating experience issues. The inspection involved field walkdowns, examination of selected procedures, calculations and records, and interviews with station personnel.

This report documents six NRC-identified findings, and one licensee-identified finding, all of which were of very low safety significance (Green). Five of the NRC-identified findings were determined to involve violations of NRC requirements. However, because of the very low safety significance of these findings and because they were entered into your corrective action program, the NRC is treating these findings as non-cited violations (NCVs) consistent with Section VI.A of the NRC Enforcement Policy. If you contest any NCV in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, D.C. 20555-0001, with copies to the Regional Administrator, Region I; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, D.C. 20555-0001; and the NRC Resident Inspectors at the Salem Nuclear Generating Station.

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

Sincerely,

/RA/

Lawrence T. Doerflein
Engineering Branch 2
Division of Reactor Safety

Docket Nos. 50-272, 50-311
License Nos. DPR-70, DPR-75

Enclosure: Inspection Report 05000272 and 05000311/2006006
w/Attachment: Supplemental Information

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U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket Nos.	50-272, 50-311
License Nos.	DPR-70, DPR-75
Report Nos.	05000272/2006006, 05000311/2006006
Licensee:	Public Service Enterprise Group Nuclear LLC
Facility:	Salem Nuclear Generating Station, Units 1 & 2
Location:	P.O. Box 236 Hancocks Bridge, NJ 08038
Dates:	January 9 - 13, 2006 (onsite); January 23 - 27, 2006 (onsite); February 6 - 10, 2006 (onsite); February 13 - 17, 2006 (onsite)
Inspectors:	F. Arner, Senior Reactor Engineer, Team Leader J. Josey, Reactor Engineer J. Kulp, Reactor Engineer J. Richmond, Reactor Engineer N. Sieller, Reactor Engineer/NSPDP C. Baron, NRC Contractor K. Sullivan, NRC Contractor
Approved By:	Lawrence T. Doerflein, Chief Engineering Branch 2

Enclosure

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SUMMARY OF FINDINGS

IR 05000272/2006006, 05000311/2006006; 01/09/2006 - 02/17/2006; Salem Nuclear Generating Station Units 1 and 2; Component Design Bases Inspection.

This inspection was conducted by a team of five NRC inspectors and two NRC contractors. Six findings of very low risk significance (Green) were identified, five of which were non-cited violations. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using IMC 0609, "Significance Determination Process" (SDP). Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Initiating Events

C Green. The team identified a finding of very low safety significance involving a non-cited violation of Technical Specification 6.8.1, Procedures, for an inadequate procedure to respond to a loss of component cooling water (CCW) event. The procedure was inadequate because it required operators to trip the reactor and immediately enter the emergency operating procedures (EOPs), but relied on an alarm response procedure to accomplish time critical and risk significant actions. The team identified that the execution of the alarm response procedure could be delayed during EOP implementation. As a consequence of relying on a lower tier procedure, the delayed actions significantly decreased margin with respect to reactor coolant pump (RCP) seal temperatures approaching operating limits during this postulated event.

This finding was more than minor because it was similar to Example 3.k in NRC Inspection Manual Chapter (IMC) 0612 Appendix E, Examples of Minor Issues. Specifically, PSEG's human reliability analysis associated with a loss of CCW event, assumed operators could complete required risk significant, time critical actions in less than one minute, when in fact, the actions could have nominally taken 14 minutes. As a result of this procedure deficiency, there was a significant reduction in the time margin assumed in PSEG's analysis to perform risk significant manual actions (i.e., isolate letdown flow and transfer charging pump suction). This finding affected the Initiating Events Cornerstone objective to limit the likelihood of events that challenge critical safety functions, because it was associated with the cornerstone's attribute for procedure quality. The finding was of very low safety significance because it screened to Green in Phase 1 of the significance determination process (SDP) documented in IMC 0609, Appendix A, Significance Determination of Reactor Inspection Findings for At-Power Situations. Specifically, while the finding directly affected the likelihood of an RCP seal failure because PSEG's previous procedures had little margin for operator error or delay, it appeared that operators could have isolated letdown prior to reaching excessive RCP seal temperatures. Additionally, there was no affect on mitigating systems. A contributing cause of this finding was related to the cross-cutting area of problem identification and resolution. (Section 1R21.2.2.2.4)

Cornerstone: Mitigating Systems

- Green. The team identified a finding of very low safety significance (Green) involving a non-cited violation of 10 CFR 50, Appendix B, Criterion XVI, Corrective Action. Specifically, the corrective actions for a degraded condition that impacted the existing design analysis for component cooling water flowrates to safety-related components under certain accident scenarios was inadequate. PSEG had failed to identify and evaluate the impact of a 700 gpm leak-by through a spent fuel pool heat exchanger valve which invalidated existing component cooling hydraulic model design analysis assumptions.

  The finding was more than minor because the condition affected the design control performance attribute of the mitigating system cornerstone objective to ensure the capability of systems that respond to initiating events. The team reviewed this finding using the Phase 1 SDP worksheet for mitigating systems and determined the finding was of very low safety significance (Green), because there was no loss of system safety function. (Section 1R21.2.2.1.7)

- Green. The team identified a finding of very low safety significance involving a non-cited violation of 10 CFR 50, Appendix B, Criterion III, Design Control. The team determined that analyses did not exist to verify the availability of the auxiliary feedwater (AFW) equipment and capability to operate during temperature conditions which would exist due to a postulated SBO event.

  The finding was more than minor because it affected the design control attribute associated with the mitigating systems cornerstone as related to the availability, reliability, and capability of the AFW system. The team reviewed this finding using the Phase 1 SDP worksheet for mitigating systems and determined the finding was of very low safety significance (Green), because it did not represent a loss of system safety function. (Section 1R21.2.2.1.8)

- Green. The team identified a finding of very low safety significance involving a non-cited violation of 10 CFR 50, Appendix B, Criterion III, Design Control. The technical basis of the AFW pump low suction pressure trip setpoint was not available, and the setpoint appeared to be inadequate to protect the pumps with respect to air entrainment under vortex conditions during a postulated extreme weather event which damages the AFW suction tank. This issue was applicable to all the AFW pumps for both units.

  The finding was more than minor because it affected the design control attribute associated with the mitigating systems cornerstone as related to the availability, reliability, and capability of the AFW system. The team reviewed this finding using the Phase 1 SDP worksheet for mitigating systems and determined the finding was of very low safety significance (Green), because it was a design deficiency confirmed not to result in loss of operability. Based on PSEG's evaluation and credit for operator actions to mitigate the condition, the deficiency would not have resulted in the AFW system becoming inoperable given the failure of the AFW suction tank due to an extreme weather event. (Section 1R21.2.2.1.8)

- Green. A self-revealing finding of very low safety significance (Green) was identified which was associated with the failure of the No. 11 Switchgear return exhaust fan breaker to close and start the fan in October 2005. Specifically, the failure occurred due to latch binding, caused by grease hardening, which was a result of the inadequate implementation of a station procedure which required the performance of preventive maintenance tasks on or before their suggested due dates.

  The finding was more than minor because the failure of the 11 switchgear return exhaust fan breaker affected the Mitigating Systems cornerstone objective of ensuring the availability, reliability and capability of systems that respond to initiating events to prevent undesirable consequences. In accordance with Inspection Manual Chapter 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," the inspectors conducted a Phase 1 Significance Determination Process screening. This screening determined that a Phase 2 evaluation was required, because the finding represented an actual loss of safety function of one non-Technical Specification Train of equipment designated as risk-significant per 10 CFR 50.65, for greater than 24 hours.

  A Phase 3 evaluation was performed instead of a Phase 2 evaluation because the risk informed notebook directed performance of a Phase 3 evaluation for issues involving the Switchgear ventilation system. A Phase 3 Risk Assessment determined this finding to be of very low safety significance (Green). While a performance deficiency was identified with regard to the failure to properly implement a station procedure for a preventive maintenance task, there were no violations identified during the review of this issue. (Section 1R21.2.2.1.13)

- Green. The team identified a finding of very low safety significance involving a non-cited violation of 10 CFR 50, Appendix B, Criterion III, Design Control. The Unit 2 design did not ensure that an internal auxiliary building flood, due to a postulated moderate energy line break, could not affect both residual heat removal (RHR) pump rooms as specified in Updated Final Safety Analysis Report (UFSAR) section 3.6.5.12.5. This issue did not apply to Salem Unit 1.

  The finding was more than minor because it affected the mitigating systems cornerstone as related to the availability, reliability, and capability of the RHR system. The team reviewed this finding using the Phase 1 SDP worksheet for mitigating systems and determined the finding was of very low safety significance (Green), because it was a design deficiency confirmed not to result in loss of operability. The performance deficiency had a PI&R cross-cutting aspect. (Section 1R21.3)

B. Licensee-identified Violations

None.

REPORT DETAILS

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R21 Component Design Bases Inspection (IP 71111.21)

.1 Inspection Sample Selection Process

The team selected risk significant components and operator actions for review using information contained in the Salem Probabilistic Risk Assessment (PRA) and the U.S. Nuclear Regulatory Commission's (NRC's) Standardized Plant Analysis Risk (SPAR) model. Additionally, the Salem Significance Determination Process (SDP) Phase 2 Notebook, revision 2, was referenced in the selection of potential components for review. In general, this included components and operator actions that had a risk achievement worth (RAW) factor greater than two. The components selected were located within both safety related and non-safety related systems, and included a variety of components such as turbines, pumps, fans, generators, transformers and valves. The components selected involved 11 different plant systems and are discussed in section 1R21.2.

An initial list of 50 components was created based on risk considerations. A margin assessment was then performed to narrow this down to 17 components for a detailed design review. This design margin assessment considered original design issues, margin reductions due to modifications, or margin reductions identified as a result of material condition/equipment reliability issues. These included items such as failed performance test results, significant corrective action history, repeated maintenance, maintenance rule (a)1 status, operability reviews for degraded conditions, NRC resident inspector input of equipment problems, system health reports and industry operating experience. Consideration was also given to the uniqueness and complexity of the design and the available defense-in-depth margins. An overall summary of the reviews performed and the specific inspection findings identified are included in the following sections of the report.

.2 Results of Detailed Reviews

.2.1 Detailed Component Design Reviews

.2.1.1 No. 11 Service Water Pump

a. Inspection Scope

The team selected the No. 11 Service Water Pump as a representative sample of the service water pumps installed in either unit. The team conducted a walkdown of the pump, a detailed walkdown of the service water pumphouse with the service water maintenance engineer, and a review of design documents, calculations, in-service testing criteria and results, vendor manuals, maintenance history and notification reports.

b. Findings

No findings of significance were identified.

.2.1.2 No. 16 Service Water Traveling Screen

a. Inspection Scope

The team selected the No. 16 Service Water Traveling Screen as a representative sample of the service water traveling screens. Each service water pump has an associated traveling screen to prevent clogging of the pump with debris originating from the ultimate heat sink. The failure of a traveling screen causes the associated service water pump to be inoperable and the possibility of common mode failure exists that would affect the operability of the service water system. The team conducted a walkdown of the No. 16 service water traveling screen with the service water maintenance engineer, and performed a review of vendor manuals, maintenance history and notification reports.

b. Findings

No findings of significance were identified.

.2.1.3 No. 21 Service Water Strainer

a. Inspection Scope

The team selected the No. 21 Service Water Strainer as a representative sample of the service water strainers. Each service water pump discharges cooling water into a strainer to remove small impurities prior to being sent through the service water system, providing cooling to various safety related and non-safety related components. The failure of a service water strainer causes the associated service water pump to be inoperable. The team conducted a walkdown of the No. 21 service water strainer, had detailed discussions of maintenance issues with the maintenance engineer, and performed a review of vendor manuals, maintenance history, design changes and notification reports. The effects of the modification to the strainer media mesh size and blowdown setpoints were evaluated for both strainer and service water system cooler performance.

b. Findings

No findings of significance were identified.

.2.1.4 No. 2C Emergency Diesel Generator Service Water Cooling Inlet Valve (23 SW39)

a. Inspection Scope

The 23SW39 valve was selected as a representative sample of the installed emergency diesel generator (EDG) service water inlet valves. The team conducted a walkdown of the valve and associated piping, held interviews with the valve system engineer, and performed a review of vendor manuals, design changes, apparent cause investigations, engineering evaluations, maintenance history and notification reports associated with the valve.

b. Findings

No findings of significance were identified.

.2.1.5 Service Water Inlet Valve to No. 11 Component Cooling Heat Exhanger (11SW122)

a. Inspection Scope

The team evaluated the 11SW122 valve for adequacy of design and its ability to perform as required during normal and accident conditions. The team reviewed piping and instrument diagrams (P&IDs), thrust calculations, control system diagrams and vendor manuals. The team reviewed the maintenance and functional history of the valve by sampling notifications, work orders, system health reports, design change packages, and In-Service Test (IST) results. The team interviewed Instrument and Control (I&C) technicians, operators, and system engineers to gain an understanding of recent maintenance issues and the overall reliability of the valve.

b. Findings

No findings of significance were identified.

.2.1.6 Unit 2 Feedwater Regulating Valve (23BF19)

a. Inspection Scope

The feedwater regulating valve was selected for a detailed review due to its contribution to total plant risk as a transient initiator. The feedwater regulating valve has a safety function of shutting upon a safety injection signal to isolate the feedwater system. Valve 23BF19 was selected as a representative sample of the installed valves based upon maintenance history. The team conducted a walkdown of 23BF19, interviewed the valve system engineer, and performed a review of vendor manuals, design calculations, root cause investigations, control air system standards, engineering evaluations, maintenance history and notification reports.

b. Findings

No findings of significance were identified.

.2.1.7 No. 12 Component Cooling Water Heat Exchanger (12CCHX)

a. Inspection Scope

The team evaluated the No. 12 component cooling water heat exchanger (CCHX) design, maintenance history, and current condition to assess whether it was capable of removing sufficient heat from the component cooling water (CCW) system during normal and accident conditions. To evaluate the adequacy of design, the team reviewed the CCHX vendor manual, CCW and service water (SW) thermal-hydraulic calculations, and CCW and SW operating procedures. To assess the effectiveness of preventive and corrective maintenance and to evaluate the current condition of the No. 12 CCHX, the team reviewed notifications, work orders, system health reports, maintenance procedures, engineering evaluations, and fouling data trends. The team also interviewed the CCW and SW system engineers, design engineers, and the Generic Letter 89-13 program engineer.

b. Findings

Introduction: The team identified a finding of very low safety significance (Green) involving a non-cited violation of 10 CFR 50, Appendix B, Criterion XVI, Corrective Action. Specifically, the corrective actions for a degraded condition that impacted the existing design analysis for component cooling water flowrates to safety-related components under certain accident scenarios was inadequate.

Discussion: The team identified that PSEG did not thoroughly evaluate a degraded condition involving valve 1CC37, a throttle valve for CCW flow to the spent fuel pool heat exchanger (SFPHX). Notification 20171399, written on February 6, 2003, identified that the 1CC37 valve leaked by approximately 700 gallons per minute (gpm) when closed. PSEG failed to recognize that this degraded condition had the potential to impact the capability of the CCW system to provide its assumed minimum safety-related flowrates during certain accident conditions. Specifically, following an accident with a loss-of-offsite power and a single failure of an emergency diesel generator or SW pump, the Salem emergency operating procedure EOP-LOCA-1 instructed operators to close 1CC37 to isolate CCW flow to the SFPHXs. The component cooling water system alignment at this point would be one CCW pump, one CCHX, one residual heat removal heat exchanger (RHRHX), 2 trains of ECCS pump seal coolers, and miscellaneous auxiliary loads. In this alignment, the required CCW flow rates would approach the maximum that the pump can deliver. The team identified that, because the hydraulic analysis did not account for any leak-by, the degraded 1CC37 valve had the potential to increase total CCW flow, decrease CCW pressure, and invalidate the minimum expected flow rates to safety related loads.

During the inspection, PSEG's initial calculations determined that the leak-by through valve 1CC37 would have resulted in CCW flowrate to the RHR heat exchanger being 2.5% below the minimum flowrate assumed in the hydraulic analysis. Subsequent calculations, based on actual pump performance from recent IST data, rather than minimum acceptable pump performance typically used in these analyses, determined that sufficient flow could be delivered to the safety loads with the degraded leak-by condition. Since the minimum flow rates would have been met given the actual pump performance over the duration of the leak-by condition, PSEG concluded that there was no loss of safety function. The team concurred with this conclusion. However, the team determined that the impact on the existing model had not been recognized by PSEG, and existing CCW pump in-service test performance minimum acceptance criteria would not have ensured that the minimum flow rates to safety-related components would have been attained.

Analysis: The performance deficiency associated with this finding was that PSEG had failed to properly identify and evaluate the impact of the 700 gpm leak-by through valve 1CC37 to the existing design analysis for CCW flowrates to safety-related components under certain accident scenarios.

The finding was more than minor because the condition invalidated the assumptions in the existing design analyses which affected the design control performance attribute of the mitigating system cornerstone objective to ensure the capability of systems that respond to initiating events. The team reviewed this finding using the Phase 1 SDP worksheet for mitigating systems and determined the finding was of very low safety significance (Green), because there was no loss of system safety function. PSEG demonstrated that there was available margin in the current CCW pump performance to overcome the 1CC37 leak-by.

Enforcement: Failure to properly identify and evaluate the impact of the 700 gpm leak-by through valve CC37 on the ability of the CCW system to deliver sufficient flow post-loss of coolant accident, was a violation of 10 CFR Part 50, Appendix B, Criterion XVI, Corrective Actions, which requires, in part, that measures be established to assure conditions adverse to quality are promptly identified and corrected. Contrary to the above, a degraded plant condition had invalidated the existing CCW hydraulic analyses assumptions and this had not been fully identified, evaluated and corrected. Because this issue was of very low safety significance, and it was entered into the corrective action program (Notification 20271904), this violation is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy.
(NCV 05000272/2006006-01, Degraded Component Cooling Water Valve Impact on CCW Hydraulic Analyses)

.2.1.8 No. 13 Turbine Driven Auxiliary Feedwater (AFW) Pump and Turbine

a. Inspection Scope

The team reviewed the design of the No. 13 Turbine Driven Auxiliary Feedwater Pump. This review included the system flow and net positive suction head (NPSH) calculations related to the pump operation under various transient and accident conditions. The team also reviewed the recent results of pump tests and various notifications, as well as system health reports and other available documentation. The team reviewed the station blackout (SBO) report regarding the performance of this pump in the event of a loss of all AC power, and interviewed various personnel regarding the operation of this pump under the most limiting conditions.

b. Findings

Turbine Driven AFW Pump Enclosure Temperature During an SBO Event

Introduction: The team identified a finding of very low safety significance (Green) involving a non-cited violation of 10 CFR 50, Appendix B, Criterion III, Design Control. The team determined that analyses did not exist to verify the availability of the AFW equipment and capability to operate during temperature conditions which would exist due to a postulated station blackout (SBO) event. This issue was applicable to both units.

Description: The Turbine Driven Auxiliary Feedwater pump was installed in a small enclosure to protect other equipment from the effects of a high energy line break event. This enclosure contained the AFW pump, the turbine driver, associated equipment and three of the four control valves associated with this pump. The temperature of this enclosure would normally be controlled by a ventilation system. However, in the event of a postulated SBO event, this ventilation would not function and the temperature would increase. This pump would perform a critical function during an SBO event.

The team noted that Table 7-2 in the plant SBO report indicated that the temperature in the area could exceed 250 degrees Fahrenheit (EF) with the enclosure door closed. The team questioned the acceptability of this value with regard to equipment operation and personnel access to the area. PSEG determined that they did not have an analysis available to address this scenario and demonstrate acceptability given the postulated conditions. PSEG initiated notification 20271973 on February 15, 2006, to address the issue.

In response to this concern, PSEG completed a preliminary evaluation during the inspection. The evaluation determined that the enclosure temperature could peak at approximately 180EF if the door was opened in 30 minutes and 190EF if the door was opened in 60 minutes. In both cases the enclosure temperature would then fall to less than 150EF for the duration of the SBO event. PSEG also performed a preliminary evaluation of the equipment in the area and concluded that it could perform its required function under these temperature conditions. The team noted that plant procedures instructed the operators to open the door within 30 minutes.

Analysis: The team determined this issue was a performance deficiency since analyses did not exist to verify the availability of the auxiliary feedwater equipment and capability to operate the system during temperature conditions which would exist due to a postulated SBO event. The finding was greater than minor because it affected the design control attribute associated with the mitigating systems cornerstone as related to the availability, reliability, and capability of the AFW system. The team reviewed this finding using the Phase 1 SDP worksheet for mitigating systems and determined the finding was of very low safety significance (Green), because it did not represent a loss of system safety function.

Enforcement: 10 CFR 50 Appendix B, Criterion III, Design Control, requires, in part, that design control measures provide for verifying or checking the adequacy of design. Contrary to the above, PSEG did not have a supporting analysis to verify that the TDAFW Pump and its associated equipment would have been capable of performing the required function during an SBO event. Because this issue was of very low safety significance, and it was entered into the corrective action program (Notification 20271973), this violation is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy. **(NCV 05000272, 311/2006006-02, Lack Of Supporting Analyses For TDAFW Operation Under SBO condition)**

AFW Pump Suction Pressure Trip Setpoint

Introduction: The team identified a finding of very low safety significance (Green) involving a non-cited violation of 10 CFR 50, Appendix B, Criterion III, Design Control. The technical basis of the AFW pump low suction pressure trip setpoint was not available, and the setpoint appeared to be inadequate to protect the pumps with respect to air entrainment under vortex conditions during a postulated extreme weather event which damages the AFW suction tank. This issue was applicable to all the AFW pumps for both units.

Description: The AFW pump design included a suction pressure switch to trip each of the pumps in the event of a loss of suction pressure. This design was intended to prevent damage to the pumps in the event of a tornado missile damaging the AFW Storage Tank. These pressure switches were normally defeated, and were only armed in the event of an extreme weather warning. The team noted that the setpoint of the switches was approximately 4 psig, and that it appeared that the pumps would not trip until the AFW storage tank was empty. As a result the team was concerned that air could be entrained in the AFW flow prior to tripping the pumps, and potentially damage the pumps.

In response to this issue, PSEG initiated notification 20272356 on February 17, 2006. This notification stated that the basis for these setpoints (S1/2AF-1PD6780, PD-6781, and PD-6782) should be reconstituted and revised, as required. The notification also determined that this issue was not an operability concern because the operators would be expected to trip the pumps before the tank was exhausted. The notification also recommended operator training to reinforce the manual isolation of the pumps upon reaching the low-low AFW storage tank level.

Analysis: The team determined this issue was a performance deficiency since analyses did not exist to support the AFW pump low suction pressure trip setpoint and the current setpoint could challenge the safety-related AFW system during a postulated extreme weather event. The finding was greater than minor because it affected the design control attribute associated with the mitigating systems cornerstone as related to the availability, reliability, and capability of the AFW system. The team reviewed this finding using the Phase 1 SDP worksheet for mitigating systems and determined the finding was of very low safety significance (Green), because it was a design deficiency confirmed not to result in loss of operability. Based on PSEG's evaluation and credit for operator actions to mitigate the condition, the deficiency would not have resulted in the AFW system becoming inoperable due to an extreme weather event.

Enforcement: 10 CFR 50 Appendix B, Criterion III, Design Control, requires, in part, that design control measures be established and implemented to assure that applicable regulatory requirements and the design basis for structures, systems, and components are correctly translated into specifications, drawings, procedures, and instructions. Contrary to the above, an analysis was not available to verify that the AFW Pump low suction pressure trip setpoint was correctly specified to protect the pumps given an extreme weather event with damage to the AFW tank. Because this issue was of very low safety significance, and it was entered into the corrective action program (Notification 20272356), this violation is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy. **(NCV 05000272, 311/2006006-03, Inadequate Supporting Analyses For Auxiliary Feedwater Pump Low Suction Trip Setpoint)**

.2.1.9 Nos. 21 and 22 Motor Driven Auxiliary Feedwater Pumps

a. Inspection Scope

The team reviewed the design of the Nos. 21 and 22 Motor Driven Auxiliary Feedwater Pumps. This review included the system flow and NPSH calculations related to the pump operation under various transient and accident conditions. The team also reviewed the recent results of pump tests and various notifications, as well as system health reports. The team reviewed additional calculations related to the capacity and setpoints of the Auxiliary Feedwater Storage Tank.

b. Findings

The AFW Pump Low Suction Pressure Trip Setpoint finding discussed above was also applicable to the Motor Driven Auxiliary Feedwater Pumps. No other findings of significance were identified.

.2.1.10 Gas Turbine Generator (GTG)

a. Inspection Scope

The team reviewed the mechanical, control, and instrumentation design and operating procedures for the GTG, to assess operating performance during a postulated SBO event. This review included normal GTG operating procedures, loss of AC power abnormal procedures, and emergency operating procedures (EOPs), as well as formal design and operating assumptions, calculations, engineering analysis, and system boundary conditions. The team also reviewed routine performance tests, system health reports, and notifications on the GTG for the prior 2 years to evaluate the GTG reliability.

b. Findings

One licensee identified finding concerning the time assumed available to start and align the GTG is described in section 1R21.2.2.2.1 of this report.

.2.1.11 Unit 2 Power Operated Relief Valve (PORV) Isolation Valves (2PR6,2PR7)

a. Inspection Scope

The team reviewed the design of valves 2PR6 and 2PR7 which were the Unit 2 isolation valves associated with the reactor coolant system power operated relief valves. These valves were normally maintained in an open position during plant operation, but may be closed as required. These valves had a function to open or close in response to a transient or accident. The review included valve calculations, summaries of inservice testing results, emergency operating procedures, and various notifications.

b. Findings

No findings of significance were identified

.2.1.12 No. 11 Safety Injection Containment Sump Suction Valve (11SJ44)

a. Inspection Scope

The team reviewed the design of the containment sump isolation valve 11SJ44. This was one of the Unit 1 isolation valves between the containment sump and the Residual Heat Removal (RHR) pump suction. This valve had a function to open during the recirculation phase of a loss-of-coolant accident (LOCA) event. The review included valve calculations, summaries of inservice testing results, emergency operating procedures, and various notifications related to the valve.

b. Findings

No findings of significance were identified.

.2.1.13 No. 11 Switchgear Exhaust Fan

a. Inspection Scope

The No. 11 switchgear exhaust fan was chosen as a representative sample of the switchgear ventilation fans installed in either unit, primarily due to the failure of the fan breaker to function in October of 2005 due to latch binding from grease hardening. The team conducted a walkdown of the fan and its associated breaker. The team also performed a walkdown of the switchgear rooms served by the fan. The team performed interviews with the system engineer and conducted reviews of design documents, calculations, operating procedures, maintenance procedures, maintenance history, notifications and orders.

b. Findings

Introduction: A self-revealing finding of very low safety significance (Green) was identified which was associated with the failure of the No. 11 Switchgear return exhaust fan breaker to close and start the fan in October 2005. Specifically, the failure occurred due to latch binding, caused by grease hardening, which was a result of the inadequate implementation of a station procedure which required the performance of preventive maintenance tasks on or before their suggested due dates.

Description: In February of 2003, PSEG implemented a preventive maintenance (PM) optimization task to revise their low voltage breaker maintenance program using a preventive maintenance change request (PMCR). The purpose of the PMCR was to adjust the inspection periodicity of their breakers to more closely model the industry standard. During implementation of the PMCR, PSEG discovered that a condition existed in their computer-based maintenance tracking program which had resulted in the failure to properly activate the maintenance plan on a portion of their low voltage breakers. As a result of this, PSEG used order CR 70049387 to revise/reset these breaker overhaul due dates based on the last documented PM performance dates.

However, in the case of the No. 11 switchgear return exhaust fan, the last documented PM which was performed in 2001, had been a simple timing check of the breaker. It did not involve an inspection or overhaul of the breaker which was the requirement of the station PM at that time. This was contrary to station procedure NC.WM-AP.ZZ-0003, Regular Maintenance Process, which allowed the due date to be reset if the work that was performed fulfilled the intent of the PM for the component.

On October 14, 2005, while operations personnel were performing procedure S1.OP-SO.PC-0001, Switchgear and Penetration Areas Ventilation Operation, the No. 11 switchgear return exhaust fan breaker failed to close when the control room switch was placed in the auto position. PSEG's evaluation and followup inspection identified the breaker had hardened grease, the magnetic latch for the solid-state trip device was binding intermittently, and the shunt trip device was binding intermittently. PSEG's apparent cause evaluation identified that the failure of the breaker to close was due to latch binding which was a result of grease hardening. This condition was directly attributed to the failure to perform preventive maintenance on the No. 11 switchgear return exhaust fan breaker for a period of ten years.

PSEG also performed an extent of condition review to determine how many other low voltage safety-related breakers were past their PM frequency. As a result of this review, PSEG identified 20 additional breakers. Using industry experience on grease hardening, manufacturer guidance, and recent maintenance records, PSEG determined that only 2 of the 20 breakers identified were beyond 10 years without the PM being performed and were susceptible to grease hardening. PSEG performed a technical evaluation of these breakers, and performed cycling of these breakers, to ensure that there was no grease hardening. PSEG also scheduled all 20 of the breakers for PM performance.

The team noted that PSEG had no formal surveillance program or requirement that directed the No. 11 switchgear return exhaust fan to be swapped with the backup fan (No. 12 exhaust fan). Therefore, from a risk determination perspective, the team considered that the fan could have been exposed to this condition for approximately one year, consistent with the last time the fan was documented as being operated.

Analysis: The team determined that the inadequate implementation of administrative procedure NC.WM-AP.ZZ-0003, Regular Maintenance Process, with respect to performing PM tasks on or before their due dates was a performance deficiency. The inappropriate extension of the No. 11 switchgear exhaust fan breaker PM task resulted in PSEG not identifying a hardened grease condition and resulted in the failure of the No. 11 switchgear return exhaust fan breaker to close on October 14, 2005.

The issue was more than minor because the failure of the No. 11 switchgear return exhaust fan breaker affected the Mitigating Systems cornerstone objective of ensuring the availability, reliability and capability of systems that respond to initiating events to prevent undesirable consequences. In accordance with Inspection Manual Chapter 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power Situations," the inspectors conducted a Phase 1 Significance Determination Process screening. This screening determined that a Phase 2 evaluation was required, because the finding represented an actual loss of safety function of one non-Technical Specification Train of equipment designated as risk-significant per 10 CFR 50.65, for greater than 24 hours.

The NRC Senior Reactor Analyst (SRA) performed a Phase 3 evaluation and determined that the issue was of very low safety significance. The need to complete a Phase 3 analysis was directed by the Phase 2 Salem risk-informed notebook for issues involving the Switchgear ventilation system. The Phase 3 evaluation was completed using the Salem SPAR model Revision 3.22, with the following assumptions: (1) the condition existed for a year, (2) the time to take corrective actions following a loss of switchgear ventilation was greater than 30 minutes, and could be as much as 2 hours, (3) a computer point alarm exists for temperature in the switchgear rooms which would alert operators of a potential common loss of the exhaust fans, (4) the failure of this fan was recoverable 99% of the time as evidenced by the operators ability to recover the fan following the October 2005 breaker failure to close by racking the breaker out and in, (5) obvious compensatory measures to open doors to alleviate temperature concerns would have been successful 95% of the time, and (6) the operator would trip the running reactor coolant pumps (RCPs) locally at their power source 90% of the time, if the areas cooled by switchgear cooling were not recovered or alternate cooling established, resulting in a loss of RCP seal cooling and inability to trip running RCPs from the control room due to loss of DC control power.

The estimated increase in core damage frequency was in the range of 1 in 12,500,000 years of reactor operation (high E-8). The actual significance of this type of event could be much lower than calculated, because of the conservative assumption that AC and DC power supplies would fail at the same time as room temperatures reach an equipment specification temperature of approximately 110EF. The dominant core damage sequence was a transient with successful reactor shutdown and AFW operation, and closure of any PORVs that opened; switchgear cooling subsequently fails due to failure of the running exhaust fan and failure of the No. 11 fan to start or be recovered by operator action; and operator action to open doors is unsuccessful. The subsequently assumed loss of all DC and AC power would lead to a loss of RCP seal cooling (loss of power to the charging and CCW pumps). The operators are assumed to have successfully secured the running RCPs locally. Core damage occurs after an RCP seal failure, because high pressure coolant injection is not available due to the loss of DC and AC power.

Enforcement: While a performance deficiency was identified with regard to the failure to properly implement a station procedure for a preventive maintenance task, there were no violations identified during the review of this issue. PSEG had initiated order 70050897 to address the concern. **(FIN 05000272/2006006-04, Failure of No. 11 SWGR Exhaust Fan Due To Lack Of PM Performance)**

.2.1.14 Class 1E Station Battery (2BTRY2BDC)

a. Inspection Scope

The team reviewed the station battery calculations to verify that the battery sizing would satisfy the requirements at the loads and that the minimum possible voltage was taken into account. Specifically, the evaluation focused on verifying that the battery and battery chargers were adequately sized to supply the design duty cycle of the 125 Vdc system for both the loss-of-offsite power/loss-of-coolant accident (LOOP/LOCA) and SBO loading scenarios, and that adequate voltage would remain available for the individual load devices required to operate during a four-hour SBO coping duration. In addition, a walkdown was performed to visually inspect the physical/material condition of the battery and battery chargers, and confirm that the battery room temperatures were within specified design temperature ranges. During the walkdown, the team also visually inspected Station Battery 2BTRY2BDC for signs of degradation such as excessive terminal corrosion and electrolyte leaks. The battery chargers were observed to be energized with acceptable indicated voltage and current.

The team reviewed battery surveillance test results to verify that applicable test acceptance criteria and test frequency requirements specified in TS for the batteries were met.

b. Findings

No findings of significance were identified.

.2.1.15 4160 Volt Alternating Current (Vac) Safety Bus (1SWGR1AD)

a. Inspection Scope

The team reviewed calculations and drawings to determine if the loading of 4160V Vital Bus 1SWGR1AD was within equipment ratings. The team reviewed the adequacy and appropriateness of design assumptions and calculations related to motor starting and loading voltages to determine if the voltages across motor terminals, under worst-case motor starting and loading conditions, would remain above the minimum acceptable values. On a sample basis, the team reviewed maintenance and test procedures and acceptance criteria to verify that 4160Vac Vital Bus 1SWGR1AD was capable of supplying the minimum voltage necessary to ensure proper operation of connected equipment during normal and accident conditions. The team reviewed the adequacy of the short circuit ratings of the switchgear and circuit breakers, and the adequacy of protective device coordination provided for a selected sample of equipment.

The team reviewed calculations, drawings, and procedures to determine whether undervoltage relay setpoints, load shed schemes, and load sequencing, were adequate to assure availability of vital loads within the times assumed in Section 8.3.1.2 of the Updated Final Safety Analyses Report (UFSAR). The team conducted a walkdown of 4160Vac Vital Buses to determine if their material condition and operating environment were consistent with the design basis, and to verify that system alignments were consistent with the design basis.

b. Findings

No findings of significance were identified.

.2.1.16 Emergency Diesel Generator (EDG) (1DAE4-GEN1BD)

a. Inspection Scope

The team focused on the electrical capabilities of the EDG as existing calculations reflected a low margin for future growth. The evaluation of EDG 1DAE4-GEN1BD focused on its ability to power safety-related loads during design basis events (e.g., LOOP, LOOP/LOCA) and the adequacy of protective relay settings. Specifically, the team reviewed load flow analysis and voltage drop calculations to verify that adequate voltage was provided to the safety-related loads during worst-case loading conditions, the 4160Vac coordination analysis to ensure that the protective devices were adequately rated, and the sequential starting of loads to determine if EDG 1DAE4-GEN1BD had sufficient capability to accelerate the loads within the time periods specified in Section 8.3.1.2 and 8.3.1.5 of the UFSAR. The team reviewed the emergency diesel generator surveillance test results to verify that the EDG tested condition under LOOP and LOOP/LOCA test conditions verified compliance with requirements for actual conditions of loading that would be present under a design basis event that there was assurance against overlapping of loading steps, and that there was assurance of operability between test periods.

The team reviewed calculations and elementary drawings to determine if the diesel generator protective relaying was designed as described in UFSAR Section 8.3.1.5, and tested in accordance with the requirements of TS 4.8.1.1.2.

The team verified that all nonessential automatic diesel generator trips (other than engine overspeed, lube oil pressure low, 4 KV bus differential and generator differential), would be bypassed upon loss of voltage on the vital bus concurrent with a safety injection actuation signal and that the bypass function was tested at least once every 18 months as required by TS 4.8.1.1.2.d.6.c.

b. Findings

No findings of significance were identified.

.2.1.17 Normal Offsite Power Supply 500 kV Station Power Transformer (3STAPWRXFR)

a. Inspection Scope

The team reviewed the Configuration Baseline Document (CBD) for the 13 and 500kVac switchyard power systems to determine the margin between the allowable ranges of off-site voltages and the values of voltage acceptable for operation. The team reviewed calculations, drawings, maintenance procedures, and vendor data to determine whether transformers that supply power from offsite to safety-related 4160Vac buses were adequately designed and maintained. The team reviewed load flow calculations to determine whether loading of Station Power Transformer 3STAPWRXFR was within its design ratings (i.e., verification that the transformer was adequately sized). The team also reviewed the design of protective relaying schemes to determine adequacy of protection provided for the transformer.

b. Findings

No findings of significance were identified.

.2.2 Review of Low Margin Operator Actions

The team performed a margin assessment and detailed review of a sample of risk significant, time critical operator actions. These actions were selected from PRA rankings of Human Action Importance based on RAW and Birnbaum values.

The team reviewed risk significant, time critical operator actions associated with low margin issues. Low margin issues were typically characterized as having one or more of the following attributes:

- Low margin between the time required and the time available to perform the actions.
- Complexity of the required actions.
- Reliability or redundancy of the components associated with the actions.
- Procedure or training deficiencies that increase the likelihood of an operator error.

.2.2.1 <u>Gas Turbine Generator Alignment & Start during a Station Blackout</u>

a. <u>Inspection Scope</u>

The team selected the manual operator actions to align, start, and load the gas turbine generator (GTG) during a dual unit loss of off-site power (LOOP) with a station blackout (SBO) on one unit. These manual operator actions were identified in Salem's probabilistic risk analysis (PRA) as high risk significant based on the risk importance to prevent a reactor coolant pump (RCP) seal failure and to provide AC power to accident mitigation equipment. The team selected this sample because these risk significant, time critical manual actions were complex, and appeared to have low margin between the time required and the time available to perform the actions.

The team interviewed licensed and non-licensed operators, and reviewed operator training, to evaluate the time required to perform the manual actions. The team performed field and main control room walkdowns, to independently identify operator task complexity. The team evaluated the available time margins to perform the operator actions to verify the reasonableness of PSEG's operating and risk assumptions. Specific documents reviewed are listed in the attachment to this report.

b. <u>Findings</u>

<u>Introduction</u>: The team determined that a licensee-identified finding relative to GTG capability was of very low safety significance through a significance determination process (SDP) Phase 3 analysis. The issue was associated with an inadequate PRA evaluation of risk significant operator actions. Specifically, operators could not align, start, and load the GTG during an SBO event, in sufficient time to prevent a postulated RCP seal failure, as previously assumed in PSEG's PRA. This issue was determined not to involve a violation of regulatory requirements. The NRC determined that this licensee-identified finding warranted documentation because weaknesses in PRA risk models can impact the implementation of the revised oversight process (ROP). PRA models are important tools in the determination of the significance of plant performance deficiencies.

<u>Description</u>: PSEG relied on manual operator actions to start and align the GTG to prevent RCP seal damage by providing seal injection to cool the seals during an SBO event. Salem's PRA, as documented in the human reliability analysis (HRA) notebook, credited manual operator actions to align, start, and load the GTG to recover AC power within 30 minutes. Based on recovering AC power within 30 minutes, PSEG assumed that operators could restart RCP seal injection flow, and thus significantly reduce the likelihood of a seal failure. PSEG also assumed that recovery of AC power within 4 hours, from either the GTG or an off-site source, would significantly reduce the likelihood of core damage if an RCP seal failure did occur. Salem EOP-LOPA-1, Loss of All AC Power, OP-AB-LOOP-0001, Loss of Off-Site Power, and OP-SO-JET-0002, Dead Bus Operation - Station Blackout, directed operator response for an SBO event.

In December 2005, a PSEG self assessment identified that the GTG could not be started and aligned to supply power to the safety buses in 30 minutes, and might take 4 hours to start and align during an SBO. Based on operator interviews, the team noted that time estimates for the manual actions varied from 1 to 6 hours. The team was concerned that, as of February 2006, PSEG had not initiated effective action to perform an interim or near term evaluation of the consequence of a significant delay in starting the GTG, and had not placed any compensatory actions into effect to mitigate the consequences of an RCP seal failure during an SBO.

In response to the teams' concerns, the team observed PSEG perform tabletop and walk-through exercises, using one licensed operator and one non-licensed operator, to demonstrate their ability to align, start, and load the GTG under simulated SBO conditions. Overall, PSEG successfully demonstrated that they could implement existing procedures and energize vital electrical buses with the GTG in about 2 hours. The 2-hour time-line relied on daylight good weather, and an early decision by operations, during EOP execution, to allocate operator resources to start the GTG without any appreciable delays. Some of the estimated times used in the tabletops were obtained from simulator training experience for similar tasks. PSEG engineering, including human reliability engineers, also observed the demonstration, and subsequently determined that a 2.8 hour task time was appropriate to allow sufficient margin to account for unexpected conditions or delays. The team considered PSEG's estimate of 2 to 3 hours to be reasonable.

Several industry standards provide guidance on the technical adequacy of plant PRA results, including verifying or validating risk significant assumptions:

- NRC Regulatory Guide 1.200, An Approach for Determining the Technical Adequacy of PRA Results for Risk-informed Activities
- NRC Standard Review Plan Chapter 19.1, Determining the Technical Adequacy of PRA Results for Risk-Informed Activities
- ASME RA-S-2002, Standard for PRA for Nuclear Plant Applications
- NEI 2000-02, PRA Peer Review Process Guidance
- NEI Revision to NUMARC 93-01 Section 11, Assessment of Risk from Maintenance Activities

Although the above standards are not regulatory requirements, they are widely used. Salem procedure SH-SE-PS-ZZ-0001, Programmatic Standard for Nuclear Risk Assessment, controlled the maintenance, review, and revision to the Salem PRA reports, models, software, and analyses. SH-SE-PS-ZZ-0001 required that PRA related analysis be based on current industry practices or appropriate regulatory guidelines. In addition, it required a review and an update of the PRA model every other refueling cycle (i.e., approximately once every 3 years).

The ASME PRA standard required, in part, a review of human actions whose failure contributed to significant core damage frequency (CDF) sequences. In addition, the ASME standard also required that a defined and consistent assessment process be used for review of human failure events (e.g., operator error), and take into account written procedure instructions, task complexity, and the time available and time required to perform the task. In addition, the NEI standard for PRA peer review required, in part, that dominant operator actions be reviewed by the operating staff, and their impact be included in the HRA evaluation. The team concluded that an adequate review of operator actions would reasonably identify whether the time required to perform risk significant actions greatly exceeded the time assumed in a PRA model.

The Salem PRA model assumed that AC power from the GTG would be available in sufficient time to reestablish RCP seal injection flow prior to a postulated seal failure in 30 minutes. PSEG performed a peer review and peer certification of the Salem PRA in December 2001. Neither the peer review, nor subsequent self assessments identified significant issues with operator action assumptions until December 2005. In December 2005, in preparation for this inspection, PSEG self identified that the GTG might take 4 hours to start during an SBO. The team concluded that previous assessments of Salem's PRA, including the peer review, had not adequately implemented industry standards for review of these risk significant manual operator actions. As a result of prior inadequate assessments, PSEG had under-predicted the probability of core damage during a postulated SBO event. Specifically, the Salem PRA assumed that the GTG could be used to prevent an RCP seal failure, when in fact, the GTG would not be available until several hours after a seal failure was predicted to occur.

Analysis: The performance deficiency was that the Salem PRA did not reflect a reasonable representation of the current plant design, with respect to the GTG. In this case, because of inadequate review and periodic updating of manual operator actions the PRA incorrectly assumed, in the event of a station blackout (SBO - loss of offsite power with the failure of the onsite emergency diesel generators) that the GTG could be started and aligned to supply power in sufficient time to prevent a loss of seal cooling to the reactor coolant pumps (RCP). In fact, the GTG would not be available until several hours following an SBO. As a consequence of the performance deficiency, PSEG under-predicted the probability of core damage during a postulated SBO event because the actions to prevent a loss of RCP seal cooling could not be completed within the available time (e.g., a significant reduction in margin), which increased the probability of RCP seal failures.

This issue was more than minor because it was similar to Example 3.k in NRC Inspection Manual Chapter (IMC) 0612 Appendix E, Examples of Minor Issues. Specifically, the Salem PRA, assumed operators could complete risk significant, time critical actions within 30 minutes to support safe shutdown of the plant during an SBO event. In fact, the actions could take several hours to complete.

This finding affected the Initiating Events Cornerstone objective to limit the likelihood of events that challenge critical safety functions, because it was associated with the cornerstone's attribute for equipment availability. The finding was evaluated in accordance with IMC 0609, Appendix A, Significance Determination of Reactor Inspection Findings for At-Power Situations, using a Phase 1, Phase 2, and Phase 3 significance determination process (SDP) analysis. The Phase 1 screening determined that a Phase 2 assessment was required because the finding affected the initiating events cornerstone loss-of-coolant accident initiator of the Phase 1 worksheet. This finding directly affected the initiating event cornerstone because, due to a reduction in the availability of the GTG, an RCP seal failure became more likely, which affected a primary system loss-of-coolant accident (LOCA) initiator and affected the mitigating systems cornerstone because, without the GTG as a support system (i.e., AC power), mitigating systems would not be able to perform their safety function.

The SRA determined that Revision 2 to the Phase 2 notebook for Salem was not relevant to the actual situation, because it did not credit the success of the GTG as a method to prevent a loss of RCP seal cooling following an SBO. Also the notebook reflects only low temperature RCP seals when some RCPs had high temperature (HT) seals and some had low temperature (LT) seals (mixed seal packages).

The SRA conducted a Phase 3 analysis, using the Salem SPAR model Revision 3.22, and determined that the issue was of very low safety significance. The analysis made the following assumptions:

- The duration of the condition was one year, from the end of the inspection on February 17, 2006. Over that time;
  - Unit 1 was considered to have all HT seals for 2 months since the November 2005 outage and one LT seal for 9 months, with an approximately one month Fall 2006 outage.
  - Unit 2 was considered to have three HT seals and one LT seal for 10 months and two HT and two LT for 1 month, with an approximately one month Spring 2006 outage.

- The GTG had been in the SPAR model with a six percent chance of failure, as if it was an EDG (i.e., the GTG was assumed to prevent an SBO and seal problems if it functioned). In reality the GTG could have only been used after about 3 hours. A 5% chance of failure at 4 hours was appropriate.

The assumed times to core uncovery due to RCP seal failure following an SBO with the loss of seal cooling were important. The times used in the original SPAR model were based on core uncovery estimates made by the Idaho National Laboratory (INL). The pumps seal manufacturer and ERIN Engineering presented data that indicated potentially longer time periods prior to core uncovery. The NRC Office of Nuclear Regulator Research (RES) completed independent thermo-hydraulic calculations, which in some cases validated the industry information and in others validated the INL information. The SRA used a composite time to core uncovery using a “Best Estimate” case from the NRC RES validated information.

In completing this analysis the SRA noted two additional operator actions that could not be validated, which tended to increase the chance of core damage given an SBO. Credit for these potential success paths was removed from the SPAR model.

Specifically:

- The positive displacement charging pump from the uneffected unit could not be used as a seal injection source in sufficient time to prevent a loss of RCP seal cooling or a thermal shock situation on the seals.
- The closure of the turbine building service water supply valve to ensure adequate SW flow to a running EDG, in the event of a failure of the B EDG to start and the failure of any other EDG, could not be verified as possible prior to potential overheating of the running EDG.

Two annual changes in core damage frequency (ΔCDF), one assuming four HT seal (ΔCDF_{4HT}) and the other four LT seals (ΔCDF_{4LT}), were calculated using the assumptions above and the best estimate RCP seal leakage times to core uncovery. The ΔCDF resulted from the increased chance of core damage, if the GTG was assumed to only be credited at the 4-hour point, vice the incorrect assumption that the GTG could have restored power to prevent a loss of seal cooling.

The analysis estimated the increase in core damage frequency, for each unit to be in the range of one core damage accident in 1,250,000 years of reactor operation (high E-7 range). In both cases the dominating core damage sequence was an SBO, the failure of the GTG to supply power early, and the failure of the TDAFW pump; leading to steam generator dryout, with an inability to restore offsite power or an EDG within 2 hours.

This result was developed for each unit, to address the mixed seal situation and the associated times involved. The SRA approximated an annual ΔCDF for three HT and one LT combination (ΔCDF_{3HT1LT}) by taking 0.75 of ΔCDF_{4HT} and adding 0.25 of ΔCDF_{4LT}. The annual ΔCDF for two HT and one LT combination (ΔCDF_{2HT2LT}) was estimated by taking 0.5 of ΔCDF_{4HT} and adding 0.5 of ΔCDF_{4LT}. The assumptions for the number of months that each plant operated with the specific mixed seals were then used to estimate the total ΔCDF for each Unit, as follows:

ΔCDF Unit 1:
2 months/12 months/yr *(ΔCDF_{4HT}) + 9 months/12 months/yr * (ΔCDF_{3HT1LT})

ΔCDF Unit 2:
10 months/12 months/yr *(ΔCDF_{3HT1LT}) + 1 month/12 months/yr* (ΔCDF_{2HT2LT})

The core damage frequency due to the loss-of-offsite power caused by external events such as fires, floods and seismic conditions was not impacted by the GTG finding, because in these events the GTG would be unable to supply power to the safety-related switchgear. This is because the GTG power is transferred in place of one of the site power sources, and if damage to the onsite switchyard or switchgear were postulated by an external event, the pathway to the safety buses is assumed to have been damaged.

Further, this finding did not affect the mitigation of steam generator tube rupture initiating events, so there was no increase in the frequency of a large early radiological release (LERF).

Enforcement: While a performance deficiency was identified with regard to a failure to perform an adequate assessment of operator actions within the PRA analysis, in accordance with existing industry standards, this was not considered to constitute a violation of any regulatory requirements. The GTG was not part of Salem's licensing bases, not covered by Technical Specification requirements, and not credited in Salem's SBO analysis. PSEG entered this self identified finding into their corrective action program as notification 20271537.

.2.2.2 Diesel Driven Air Compressor Start During a Loss of Control Air

a. Inspection Scope

The team selected the manual operator actions to start and align the diesel driven air compressor during a loss of control air pressure. These manual operator actions were identified in Salem's PRA as high risk significant based on the risk importance to provide control air to various risk significant components. The team selected this sample because:

- The allowed time of 30 to 60 minutes to complete the task, during a station blackout, did not appear to be balanced with the risk significance of the task.
- The air compressor's performance test was less rigorous than the expected usage during an actual emergency.
- The allowed time was, in part, based on an undocumented assumption that the opposite unit's emergency air compressors were highly reliable.
- The redundant air header automatic transfer panels appeared to have a higher failure rate than expected.

The team reviewed EOP and abnormal procedures used to diagnose control air problems and the operating procedures for the diesel driven air compressor, to evaluate time margins associated with this task. The team also reviewed design and operating assumptions, calculations, engineering analysis, maintenance procedures, routine performance tests, system health reports, and notifications on the control air system for the prior 2 years. The Salem PRA notebooks for the control air system and human reliability analysis (HRA), were reviewed to identify areas of lower margin. In addition, the team performed field walkdowns and interviewed maintenance technicians, engineers, and plant equipment operators to independently identify reliability issues associated with the control air system or the diesel driven air compressor. The team evaluated system design diversity and redundancy, material condition, and maintenance effectiveness to assess the reasonableness of PSEG's mitigation strategy for a loss of control air. Specific documents reviewed are listed in the attachment to this report.

b. Findings

No findings of significance were identified.

.2.2.3 Cold Leg Recirculation during a Large Break LOCA

a. Inspection Scope

The team selected the manual operator actions to establish cold leg recirculation during a large break loss-of-coolant accident (LOCA). Specifically, the actions reviewed were to transfer the emergency core cooling system (ECCS) pump suctions from the refueling water storage tank (RWST) to the containment sump. For Unit 2, the transfer was semi-automatic and required fewer manual actions. For Unit 1, these actions included:

- Identification of low RWST level
- Secure RHR pumps
- Open component cooling water valves to RHR heat exchanger
- Transfer RHR pump suction from RWST to containment sump
- Remove valve interlocks
- Stop one containment spray pump and positive displacement charging pump
- Start RHR pumps
- Open safety injection and charging pump suction valves from RHR
- Close safety injection and charging pump suction valves from RWST

These manual operator actions were identified in Salem's PRA as high risk significant based on the risk importance to establish cold leg recirculation prior to core damage, and the likelihood of an operator error associated with performing a task under moderate stress and in a short period of time. In this scenario, containment spray pumps would be operating, and there is a shorter time period to complete the actions before the RWST would be empty. The team selected this sample because these risk significant, time critical manual actions were complex, and appeared to have low margin between the time required and the time available to perform the actions.

The team reviewed the mechanical, control, and instrumentation design for selected portions of the ECCS components, to assess system performance, and design and operating limits, during the transfer from injection phase to recirculation phase for a large break LOCA. This review included the safety injection system configuration baseline document (design basis document), emergency operating procedure (EOP) setpoint document, EOP basis documents, RWST draindown and cold leg recirculation analysis, design and operating assumptions, calculations, engineering analysis, system boundary conditions, and hydraulic models. The team evaluated the available process margins, based on control logic and component interlocks, valve stroke times, fluid flow rates, and tank and sump capacities. The team performed limited independent calculations and analyses in several areas, to verify the reasonableness of the design and operating values. The independent checks included verification of pump net positive suction head (NPSH) and the time available, at expected ECCS flow rates, between the RWST low level alarm point and the low-low level point for completion of the transfer function.

In addition, the team reviewed the Salem PRA notebooks for the safety injection system and human reliability analysis (HRA). The team interviewed licensed operators and reviewed EOPs, licensed operator training lesson plans, and simulator training scenario plans, to evaluate the time required to perform the manual actions. In addition, the team performed main control room walkdowns, to independently identify operator task complexity. The team compared the available time against the time required to perform the manual actions to verify whether the implemented operator actions would be consistent with design, licensing, and PRA assumptions. Specific documents reviewed are listed in the attachment to this report.

b. Findings

No findings of significance were identified.

.2.2.4 Operator Response for Loss of Component Cooling Water (CCW)

a. Inspection Scope

The team selected the manual operator actions for a total loss of CCW. Specifically, the actions reviewed were to isolate reactor letdown flow to the volume control tank (VCT) and transfer charging pump suction from the VCT to the refueling water storage tank (RWST) following a loss of CCW. These manual operator actions were identified in Salem's PRA as high risk significant based on the risk importance of reactor coolant pump (RCP) seal integrity and the likelihood of an operator error associated with performing a task under high stress and in a short period of time. The team selected this sample because these risk significant, time critical manual actions were not clearly proceduralized, and appeared to have low margin between the time required and the time available to perform the actions.

The team reviewed the mechanical, control, and instrumentation design for selected portions of the CCW, the chemical and volume control system (CVCS), and the RCP seal systems, to assess component performance, and design and operating limits during a loss of CCW event. This review included the configuration baseline documents (design basis document), and operating assumptions, calculations, engineering analysis, system boundary conditions, and hydraulic models. The team evaluated the available process margins, based on fluid flow rates, temperatures, and heat transfer capacities, and performed limited independent calculations and analyses in several areas, to verify the reasonableness of the design and operating values. The independent checks included charging pump NPSH and the time available for manual operator action to transfer the suction source from the VCT to the RWST.

In addition, the team reviewed the Salem PRA notebooks for CCW, CVCS, and human reliability analysis. The team interviewed licensed operators and reviewed normal, abnormal, and emergency operating procedures (EOPs), to evaluate the time required to perform the manual actions. The team compared the available time against the time required to perform the manual actions to verify whether the implemented operator actions would be consistent with design, licensing, and PRA assumptions. Specific documents reviewed are listed in the attachment to this report.

b. Findings

Introduction: The team identified a finding of very low safety significance involving a non-cited violation of Technical Specification 6.8.1, Procedures, for an inadequate procedure to respond to a postulated loss of CCW event. The procedure was inadequate because it required operators to trip the reactor and immediately enter the EOPs, but relied on an alarm response procedure to accomplish time critical and risk significant actions. The team identified that the execution of the alarm response procedure could be delayed during EOP implementation. As a consequence of relying on a lower tier procedure, the delayed actions significantly decreased margin with respect to RCP seal temperatures approaching operating limits during this postulated event.

Description: During a postulated loss of CCW, cooling to the RCP thermal barrier would be lost, leaving RCP seal injection flow as the only cooling source to the RCP seals. If seal injection were terminated, then all RCP seal cooling would be lost which could result in increased seal leakage and potential seal damage. PSEG estimated that seal leakage could increase from 3 gpm to approximately 21 gpm for each RCP, if CCW and seal injection were both lost. If subsequent seal damage did occur, then leakage could significantly increase to a postulated value of 480 gpm per pump. In addition, due to seal thermal shock concerns, if seal injection flow was stopped for greater than 13 minutes, then Salem operating procedures prohibit immediately restarting seal injection flow.

During a loss of CCW, PSEG relied on manual operator actions to maintain RCP seal injection for seal cooling to prevent seal damage. Salem's PRA, documented in the HRA Notebook, credited manual operator actions to isolate letdown and transfer charging pump suction to the RWST after a loss of CCW. The HRA Notebook also stated that the tasks were performed without a procedure, from memory, and took less than 1 minute to perform.

Salem operating procedure OP-AB-CC-0001, Component Cooling Abnormality, directed operator response for a loss of CCW. For a total loss of CCW, OP-AB-CC-0001 Continuous Action Statement required operators to trip the reactor, trip all RCPs, and immediately enter EOP-TRIP-1. PSEG expected operators to manually isolate letdown flow, but relied on a VCT low level interlock to automatically transfer charging pump suction from the VCT to the RWST. For letdown isolation, PSEG relied on an alarm response procedure for the letdown heat exchanger high temperature annunciator to direct the operator to isolate letdown flow. The team determined that operators would not typically review or execute individual alarm response procedures until after EOP actions, followed by abnormal procedure actions, had reasonably stabilized the plant following a reactor trip. This was a reasonable assumption for procedure usage, based on operator interviews, and as observed in actual simulator scenarios.

The team identified that a total loss of CCW would result in a significant and rapid temperature rise in the VCT due to the loss of letdown heat exchanger cooling. Without operator actions, the team estimated that within 10 to 15 minutes the VCT temperature could exceed the RCP seal temperature operating limit of 225 EF. In addition, prior to an automatic transfer of charging pump suction on VCT low level, it appeared that pump cavitation could occur due to a loss of NPSH. Following the reactor trip, the team questioned whether operators would respond to a letdown high temperature annunciator in sufficient time to prevent the VCT from exceeding 225EF.

During the inspection, PSEG performed a preliminary engineering review which indicated that the VCT would reach 225EF within 5 to 6 minutes after a loss of CCW (calculation S-C-CVC-MDC-2104 revision 0). As an immediate corrective action to this issue, PSEG revised OP-AB-0001 to require operators to isolate letdown and transfer charging pump suction to the RWST, concurrent with entry into EOP-TRIP-1, for a total loss of CCW.

Subsequently, PSEG performed a detailed engineering analysis (S-C-CVC-MDC-2104 revision 1) which determined that operators had at least 16.5 minutes to isolate letdown and transfer charging pump suction prior to the VCT reaching 225 EF. In addition, PSEG performed simulator scenarios to evaluate operator response times. Observed simulator response times were nominally 14 minutes to isolate letdown after a loss of CCW. Based on the more detailed analysis and the observed operator performance during a simulated loss of CCW, PSEG concluded that operators would likely have isolated letdown flow prior to reaching RCP seal temperatures that would have required isolating seal cooling flow and prior to challenging the NPSH for a charging pump.

The team reviewed PSEG’s evaluations and determined that although PSEG's previous procedures had little margin for operator error or delay, it appeared that operators could have isolated letdown prior to reaching excessive VCT temperatures. However, because of the low operational time margin and uncertainties involved, the team concluded that Salem's loss of CCW abnormal procedure was not adequate to ensure continued RCP seal cooling.

The team noted that PSEG had recently evaluated this same concern in notification 20077381. In July 2005, PSEG had concluded that the alarm response procedure, for letdown high temperature, was adequate to ensure letdown isolation, during EOP execution following a reactor trip from a loss of CCW. PSEG also had determined that a VCT low level auto transfer for the pump suction was adequate. The team determined that PSEG's previous evaluation of this issue lacked sufficient technical rigor to identify that VCT heat-up was a primary factor. In addition, PSEG did not appear to recognize that operator response to annunciators would be delayed during EOP execution, immediately following a reactor trip.

<u>Analysis</u>: The abnormal procedure for a loss of CCW was inadequate, in that it did not specify the action to isolate the letdown cooling flow from the RCS to the VCT and did not specify the switching of the charging pump suction to the RWST. The team determined this procedure issue was a performance deficiency because relying on a lower tier annunciator response procedure instead of actions delineated within the abnormal procedure for loss of CCW increased the potential for a loss of RCP seal cooling and resulting seal failure. This issue was more than minor because it was

similar to Example 3.k in NRC Inspection Manual Chapter (IMC) 0612 Appendix E, Examples of Minor Issues. Specifically, PSEG's human reliability analysis associated with a loss of CCW event, assumed operators could complete required risk significant, time critical actions in less than a minute, when in fact, the actions could have nominally taken 14 minutes. As a result of this procedure deficiency, there was a significant reduction in the time margin assumed in PSEG's analysis, to perform risk significant manual actions (i.e., isolate letdown flow and transfer charging pump suction).

This finding affected the Initiating Events Cornerstone objective to limit the likelihood of events that challenge critical safety functions, because it was associated with the cornerstone's attribute for procedure quality. The finding was of very low safety significance because it screened to Green in Phase 1 of the significance determination process (SDP) documented in IMC 0609, Appendix A, Significance Determination of Reactor Inspection Findings for At-Power Situations. PSEG completed engineering calculations and human reliability analysis needed to demonstrate the ability to isolate the letdown flow prior to potential RCP seal damage and charging pump loss of NPSH. Specifically, while the finding directly affected the likelihood of an RCP seal failure because PSEG's previous procedures had little margin for operator error or delay, it appeared that operators could have isolated letdown prior to reaching excessive RCP seal temperatures. Additionally, there was no affect on mitigating systems.

A contributing cause of this finding was related to the cross-cutting area of problem identification & resolution (PI&R), because PSEG previously reviewed this issue (notification 80077381) and did not identify that a delay in isolating letdown flow to the VCT could result in a loss of RCP seal injection or charging pump cavitation.

<u>Enforcement</u>: Technical Specification 6.8.1, Procedures, required, in part, that written procedures be established, implemented, and maintained for the activities specified in Regulatory Guide (RG) 1.33, revision 2, Appendix A. Item 6(l) of Appendix A required procedures for combating emergencies and significant events, including loss of component cooling system. Procedure OP-AB-CC-0001, Component Cooling Abnormality, directed operator actions for combating a loss of CCW.

Contrary to the above, from initial plant operation until February 10, 2006, PSEG had not established or maintained an adequate procedure for combating a loss of CCW. Procedure OP-AB-CC-0001 was not adequate because, for a total loss of CCW, it required the operators to trip the reactor and RCPs, and immediately enter EOP-TRIP-1. Procedure OP-AB-CC-0001 did not direct operators to isolate letdown flow. Instead, PSEG relied on an alarm response procedure to accomplish this time critical operator action. However, execution of the alarm response procedure could be delayed during implementation of the EOPs. As a consequence of relying on a lower tier procedure, the delayed actions significantly decreased the time margin to ensure that RCP seal temperatures would not exceed operating limits. PSEG entered this finding into their corrective action program as notification 70052807. As an immediate corrective action, PSEG revised the affected procedures to correct the deficiency. Because this issue was of very low safety significance, and it was entered into the corrective action

program, this violation is being treated as an NCV consistent with Section VI.A.1 of the NRC Enforcement Policy.
(NCV 05000272,311/2006006-05, Inadequate Procedure for Loss of Component Cooling Water)

.3 Review of Industry Operating Experience and Generic Issues

a. Inspection Scope

The team reviewed selected operating experience issues that had occurred at domestic and foreign nuclear facilities for applicability at Salem. The team performed an independent applicability review and issues that appeared to be applicable to Salem were selected for a detailed review. The issues that received a detailed review by the team included:

- NRC Information Notice (IN) 2005-30, Auxiliary Building Internal Flooding

  The team reviewed the potential of flooding within the auxiliary building due to the failure of moderate energy (relatively low pressure and temperature) piping. The Unit 2 licensing basis, UFSAR section 3.6.5.12.5, addressed the requirement that an internal flood does not affect both of the RHR pump areas. Unit 1 did not have this licensing basis requirement. The team reviewed notifications and technical evaluations related to this issue, performed walkdowns of the RHR pump area, and conducted interviews with various plant personnel. The RHR issue was a followup to an Unresolved Item, 05000272&311, documented in IR 2005002.

- NRC Information Notice (IN) 90-45, Turbine Driven Auxiliary Feedwater Pump Overspeed

  The team reviewed the potential consequences of the turbine driven auxiliary feedwater pump operating at higher speeds due to the loss of control air or a malfunction of the turbine driver. The areas reviewed included potential AFW system over-pressure, excess flow to the steam generators, and increased NPSH requirements. PSEG performed various evaluations during the inspection to address each of these issues.

- NRC Information Notice (IN) 88-23, Potential For Gas Binding of High Pressure Safety Injection Pumps During a Design Bases Accident

  The team reviewed a condition where gas was discovered and vented from the Unit 1 charging safety injection pump common suction vent valve during the performance of a surveillance test. The team reviewed notification 20262737 associated with the issue to evaluate the apparent cause determination and the corrective actions implemented.

- <u>NRC Information Notice (IN) 2002-12, Submerged Safety-related Electrical Cables</u>

  The team reviewed the applicability and disposition of electrical cable degradation concerns described in NRC Information Notice (IN) 2002-12, Submerged Safety-related Electrical Cables, March 21, 2002. The basis of IN 2002-12, was a concern that a potential common mode failure of underground cables could affect the operability of accident mitigation systems. This issue was selected for detailed review because degradation of an underground current transformer cable was identified as an initiator of the July 29, 2003, 500kV Failure/Bus Transfer Event (Ref: Root Cause Analysis Report No. 70032799).

b. <u>Findings</u>

<u>Flood Barrier Design in the RHR Pump Area</u>

<u>Introduction</u>: The team identified a finding of very low safety significance involving a non-cited violation of 10 CFR 50, Appendix B, Criterion III, Design Control. The Unit 2 design did not ensure that an internal auxiliary building flood, due to a postulated moderate energy line break, could not affect both RHR pump rooms as specified in UFSAR Section 3.6.5.12.5. This issue did not apply to Unit 1.

<u>Description</u>: Prior to this inspection, the NRC resident inspectors had questioned the design of the internal flood protection associated with the Unit 2 RHR pump areas. The concerns were previously documented in NRC Inspection Report 2005005 and an NRC Unresolved Item had been opened to perform a followup review. UFSAR section 3.6.5.12.5 stated, in part, “Flooding to the RHR pump rooms could also occur as a result of MEL fluid from breaks on upper elevations running down staircases and conceivably into both RHR pump rooms. To prevent this from occurring, curbs were installed on the elevation immediately above the RHR pump rooms such that fluid flow from MEL failures on elevations above can only flow to one RHR pump room, not both rooms.”

As a result of the resident inspectors’ questions, PSEG investigated the design of these curbs and initiated notification 20261503 on November 15, 2005. This notification addressed the potential that flood water could affect both RHR pump areas due to a floor drain that connected the auxiliary building sump tank area with the no. 21 RHR pump area. PSEG’s engineering personnel also performed a technical evaluation to address this issue. This evaluation concluded that the sump pumps installed in the no. 21 RHR pump area would have sufficient capacity to prevent flooding of the area. This notification recommended the installation of a curb at the entrance to the auxiliary building sump tank area.

The team questioned the adequacy of relying on the non-safety related sump pumps within the RHR rooms to mitigate this potential flood scenario. The team noted that there was no preventive maintenance or testing required or performed on them to assure their reliability. The team questioned if a formal operability determination had been performed, and if any compensatory measures had been implemented to ensure the availability of the sump pumps until the required curb was installed. In response to these questions, PSEG initiated notification 20269693 and CROD 06-05 during the inspection. These included compensatory measures to periodically verify the availability of the sump pumps. In addition, PSEG initiated Design Change No. 80088248 to install the required curb. This work was completed during the inspection.

Analysis: The team determined this issue was a performance deficiency because the flood barrier design did not comply with the design described in the UFSAR, and the safety-related RHR system could have been challenged due to a postulated internal flood. The finding is more than minor because it affected the mitigating systems cornerstone as related to the availability, reliability, and capability of the RHR system. The team reviewed this finding using the Phase 1 SDP worksheet for mitigating systems and determined the finding was of very low safety significance (Green), because it was a design deficiency confirmed not to result in loss of operability. Based on PSEG's analysis, this deficiency would not have resulted in the RHR system becoming inoperable due to the postulated internal flood.

The team identified concerns regarding the problem identification and resolution aspects of this issue. The performance deficiency had a problem identification and resolution cross-cutting aspect, because PSEG had previously reviewed the condition, and had failed to perform a formal operability evaluation or implement any compensatory measures to verify the continued availability of the sump pumps.

Enforcement: 10 CFR 50 Appendix B, Criterion III, Design Control, requires, in part, that design control measures be established and implemented to assure that applicable regulatory requirements and the design basis for structures, systems, and components are correctly translated into specifications, drawings, procedures, and instructions. Contrary to the above, the flood barrier design in the Unit 2 RHR pump areas did not comply with the described design found in UFSAR Section 3.6.5.12.5.

Because this violation was of very low safety significance and has been entered into PSEG's corrective action program (notification 20269693), this violation is being treated as a non-cited violation consistent with Section VI.A of the NRC Enforcement Policy. **(NCV 05000311/2006006-06,RHR Room Internal Flood Protection)**

4. OTHER ACTIVITIES

4OA2 Problem Identification and Resolution (PI&R)

a. Inspection Scope

The team reviewed a sample of problems that were identified by the licensee and entered into the corrective action program. The team reviewed these issues to verify an appropriate threshold for identifying issues and to evaluate the effectiveness of corrective actions related to design or qualification issues. In addition, notifications written on issues identified during the inspection were reviewed to verify adequate problem identification and incorporation of the problem into the corrective action system.

The specific corrective action documents that were sampled and reviewed by the team are listed in the attachment to this report.

b. Findings

Section 1R21.2.2.1.7 of this report describes a non-cited violation associated with inadequate corrective actions for a degraded condition that impacted the existing design analysis for component cooling flowrates to safety-related components under certain accident scenarios. No other findings of significance were identified.

4AO6 Meetings, Including Exit

Exit Meeting Summary

On February 17, 2006, the team presented the inspection results to Mr. T. Joyce, Site Vice President - Salem, and other members of PSEG's staff. The team verified that no proprietary information is documented in the report.

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel
L. Gonzales, Engineer - Electrical/I&C Design
R. Downs, Engineer - Mechanical Design
M. Gwirtz, Manager - Operations Support
J. Duffy, Engineer - Mechanical Design
G. Meekins, SRO - Operations Services
D. Naik, System Engineer
T. Byykkonen, SRO - Shift Supervisor
J. Hilditch, Manager - Electrical/I&C Design
T. Carrier, PSA Engineer - Engineering Programs
T. Roberts, Manager - Engineering Programs
H. Berrick, Regulatory Compliance Engineer
J. Wearne, Regulatory Compliance Engineer
K. Wolf, System Manager
P. Williams, Licensed operator Simulator instructor
D. McCollum, Maintenance Engineer

NRC Personnel
D. Orr, Senior Resident Inspector
S. Alexander, NRR PRA & Maintenance Branch

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

None.

Opened and Closed

05000272/2006006-01	NCV	Degraded Component Cooling Water Valve Impact on CCW Hydraulic Analyses (Section 1R21.2.2.1.7)
05000272,311/2006006-02	NCV	Lack Of Supporting Analyses For TDAFW Operation Under SBO condition (Section 1R21.2.2.1.8)
05000272,311/2006006-03	NCV	Inadequate Supporting Analyses For Auxiliary Feedwater Pump Low Suction Trip Setpoint (1R21.2.2.1.8)

05000272/2006006-04	FIN	Failure of No. 11 SWGR Exhaust Fan Due To Lack of PM Performance (Section 1R21.2.2.1.13)

Opened and Closed

05000272,311/2006006-05	NCV	Inadequate Procedure for Loss of Component Cooling Water (Section 2.2.2.4)
05000311/2006006-06	NCV	RHR Room Internal Flood Protection (Section 1R21.3)

Closed

05000272,311/200005-02	URI	RHR Room Internal Flood Protection

LIST OF DOCUMENTS REVIEWED

Design Documents

DE-CB.125-0018(Q), Configuration Baseline Document (CBD) for 125V DC Control Power System, Rev. 4
DE-CB.4kV-0011(Q), Configuration Baseline Document (CBD) for 4kV Aux. Power System, Rev. 5
DE-CB.DG-0024(Q), Configuration Baseline Document (CBD) for Emergency Diesel Generator System, Rev. 4
DE-CB. 13/500-0057(Z), Configuration Baseline Document (CBD) for 13.8kV and 500kV AC Switchyard Power Systems, Rev. 0

Calculations

ES-1.002(Q), 13.8kV, 4.16kV and LV Buses Short Circuit Calculation, Rev. 2
ES-4.003(Q), 125V DC Short Circuit and System Voltage Drop Calculation, Rev. 1
ES-7.001(Q), Salem Differential Relaying Calculation, Rev. 0
ES-7.009(Q), Protective Relaying Set Point Calculation, Salem Unit 1 & 2 Emergency Diesel Generators, Rev. 4
ES-8.001, APT and 13.8 - 4.16kV SPT Transformer Loading, Rev. 2
ES-8.003, 500/13.8 kV Transformer Sizing Calculation, Rev. 1
ES-8.004(Q), 4160-240 Volt Vital Transformer Loading, Rev.1
ES-8.005(Q), 4160 - 480 Volt Vital Transformer Loading, Rev. 1
ES-8.007(Q), Transformer Tap Changer Setting Calculation, Rev. 2
ES-8.007(Q), Transformer Tap Changer Setting Calculation, Rev. 2
ES-9.002, Emergency Diesel Generator Loading, Rev. 5
ES-9.004, Diesel Generator Line Current Imbalance Capability, Rev. 4
ES-13.004(Q), Salem Units 1 & 2 Coordination & Loading Capability Study for Vital and Essential UPS'S, 3/10/03; Curve No.: UPS-1B, Normal Feed to Vital UPS 1A, 11/06/02; Curve No.: UPS-1, Normal Feed to Vital UPS 1C, 11/06/02; Curve No.:UPS -2, Alternate Feed to Vital UPS 1B, 1D, 2A, 2B, 2D

ES-13.006(Q), Breaker and Relay Coordination Calculation Safety-Related AC System, Rev. 3, 12/9/04; Curve No.: 13ASD, 1A 4160V Incoming Supply from #13 SPT, Curve No.:1A2D, 1A-4160V, #11 Containment Spray Pump, 5/8/95; Curve No.:1A3D, 1A-4160V, #15 Service Water Pump, 5/11/95; Curve No.: 1ADD, 1A-4160V, 1A Emergency Diesel Gen. 5/11/95; Curve No.: 1A7D, 1A-4160V #11 RHR Pump, 5/8/95; Curve No.:1A8D, 1A-4160V #16 Service Water Pump, 5/11/95
ES-15.004, Load Flow and Motor Starting Calculation, Rev. 3
ES-15-008, S1 & S2 Degraded Grid Voltage
ES-15.012, Bus Transfer, Rev. 2
ES-45.003, Station Blackout Duration, Rev. 0
ES-45.003(Q), Station Blackout Duration, Rev. 1
MD-ST. 125-0003(Q), Quarterly Inspection and Preventive Maintenance Of Units 1, 2 & 3 125V Station Batteries, Rev. 21
MPR Calculation 108-197-HS-0, EPRI PPM Analysis of Design Stem Torque for Valves 21 & 22SW122 and 11SW122, Rev.1
MPR Calculation 108-197-HS-1, Evaluation of SW122 Actuator Sizing and Settings, Rev.1
MPR Preliminary Evaluation of the Salem Station Turbine Driven Auxiliary Feedwater Pump Room Under Station Blackout Conditions, February 14, 2006
MPR Task 108-12, Verification of Heat Transfer Correlation for Salem Unit 1, No. 12 CCHX, Rev. 0
MPR Task 108-197, Determination of Limiting Input Torque of Valves 21 & 22SW122, Rev. 0
Report No. 1178, Actuator Sizing Analysis for Masoneilan Control Valves AF11/21, September 3, 1993
S-1-ABV-MDC-1836, ABV Appendix R Room Heat-up Scenarios, Rev.1
S-1-CC-MDC-1817, Component Cooling System Thermal-Hydraulic Analysis - Unit 1, Rev. 4
S1.RA-ST.SW-0001(Q), IST: 11 SW Pump, Rev. 8
S-1-RC-MDC-0889 (001), MOV Capability Assessment for 1PR6-MTRY, Rev. 1
S-1-RC-MDC-0889 (002), MOV Capability Assessment for 1PR7-MTRY, Rev. 1
S-1-SJ-MDC-0892 (014), MOV Capability Assessment for 11SJ45-MTRY, Rev.1
S2.OP-ST. 125-0001(Q), Electrical Power Systems 125VDC Distribution, Rev. 8
S2.OP-ST.125-0001(Q), 125VDC Distribution Rev. 9, and Data Sheets 10/19/03
S2.OP-SO.125-0005(Q), 2A 125VDC Bus Operation, Rev. 19 and Data Sheets 2/23/05
S-2-CC-MDC-1693, Component Cooling System Curves at Pump Runout, Rev 0
SC.MD-ST.125-0004(Q), 125 Station Batteries 18 Month Service Test and Associated Surveillance Testing Using BCT-2000, Rev. 20
SC.MD-ST. 125-0005(Q), Annual Inspection and Surveillance Of Unit 1 & 2 125 Volt Vital Batteries, Rev. 4
S-C-BF-MDC-1008, Miscellaneous Condensate System Calculation, Rev. 0
S-C-SW-MDC-1068, SW System Design Basis Temperature, Rev. 3
S-C-SW-MDC-1317, SW System Hydraulic Model, Rev.7
S-C-SW-MDC-1351, SW Pump NPSH Calculation, Rev. 2
S-C-SW-MEE-0953-1, SW Traveling Screen Classification Evaluation
SC.MD-ST.125-003(Q), Quarterly Inspection and Preventive Maintenance of Unit 1, 2, & 3 125 Volt Station Batteries, Rev. 21, and Data Sheets 4/12/04
SC.MD-ST.125-0005(Q), Annual Inspection and Surveillance of Unit 1 & 2 125 Volt Batteries, Rev. 3 and Data Sheets 7/28/03

SC.MD-ST.125-002(Q), 125V Station Batteries Performance Discharge Test, Rev. 19 and Data Sheets 4/13/05
S-C-4kV-EEE-1792, Assessment of Salem Bus Transfer Capability, Rev. 0
S-C-4KV-CEE-0590, 91% Undervoltage Relays Setpoint Drift, 7/5/91
S-C-4KV-EEE-0836, 4KV Vital Bus-second Level of Undervoltage Relay Operability, 9/16/96
S-C-4KV-EEE-1751, Safety Related Medium Voltage Cable Issues Routed below Grade in Duct Bank or Potentially Submerged Condition for Salem Unit 1 and 2, 2/20/03
S-C-4KV-EEE-1792, Assessment of Salem Bus Transfer Capability, 10/14/03
S-C-4KV-EEE-1795, Establishment of New Lower Voltage Limit for Vital Buses at Salem Stations, 9/12/03
S-C-4KV-JDC-959, Degraded Vital Bus Undervoltage Relay Setpoint, Rev. 5, 11/10/93
S-C-4KV-EEE-0836, Engineering Evaluation for Continued Operation of Salem Units 1&2 4KV Vital Bus - Second Level of Undervoltage Relay Operability
S-C-ABV-MEE-1472, Effect of Loss of auxiliary Building Ventilation on Appendix R Safe Shutdown Electrical Equipment and the Heat Stress Effect on the Capability to Perform Manual Actions, Rev. 0
S-C-AF-MDC-0432, NPSHa Calculation for MAFPs, Rev. 0
S-C-AF-MDC-0445, Auxiliary Feedwater System Hydraulic Analysis, Rev. 2
S-C-AF-MDC-1108, Cavitation Induced Pump Damage Assessment, Rev. 0
S-C-CC-MDC-1798, Component Cooling System Heat Exchangers, Rev. 3
S-C-CVC-MDC-2016, High Head Safety Injection Pump Minimum Differential Pressure, Rev. 0
S-C-RHR-MDC-1463, RHR Pump TDH Calculation, Rev. 1
S-C-VAR-MDC-1429, Minimum Useable Volumes for Various Safety-Related Tanks -Salem Units 1 & 2, Rev. 9
S-C-VAR-NEE-1117, Attachment 1, 21SJ45 and 22SJ45 - RHR to SI Pumps Stop Valve, Rev. 1
S-C-VAR-NEE-1117, Attachment 4, 21RH4 and 22RH4 - RHR Pump Suction Isolation Valve, Rev. 1
S-C-VAR-NEE-1117, Attachment 4, 21SJ44 and 22SJ44 - Containment Sump Outlet Isolation Valve, Rev. 1
S-C-VAR-NEE-1117, Attachment 6, 2RH1 and 2RH2 - RCS Hot Leg to RHR Suction Header Valve, Rev. 1
S-C-VAR-NEE-1117, Attachment 9, 2PR6 and 2PR7 - Pressurizer Relief Block Valve, Rev.1
S-C-ZZ-MEE-0860, Evaluation of the Impact of Changes in Temperature of Component Cooling and Service Water Systems, Rev. 0
SC-AF002-01, Unit 1&2 AFST Level Indication and Alarm, Rev. 4
SC-SJ006-01, Salem Unit 1 RWST Level Uncertainty Calculation, Rev. 0
Technical Evaluation 70048711, MOV *RH4 and *SJ44 Design Review for Higher Pressures, September 8, 2005
Technical Evaluation 70048711, Pressure Difference Across 11SJ44 and 12SJ44 Valves when RHR Pumps Operate in Minimum Flow Recirculation Mode, September 9, 2005
Technical Evaluation 70050352, SJ44 Valve DP is Higher than Originally, September 30, 2005
VTD 322738, MPR Calculation 108-197-HS-2, Determination of Limiting Input Torque of Valves 21 & 22SW122 & 21SW122, Rev. 2, January 22, 1998
VTD 322553, CC Pump Runout Evaluation, Rev. 2, November 21, 1996
VTD 322836, EPRI PPM Analysis of Design Stem Torque for Valves 21 & 22 SW122, Rev 2, February 16, 1998

VTD 322837, MPR Calculation 108-197-HS-1, Evaluation of SW122 Actuator Sizing and Settings, Rev. 3, March 16, 1999
VTD 322838, Weak Link Analysis of Masoneilan 71-32112 Valve, Rev. 2, March 9, 1998

Notifications and Orders

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20098210	20163470	20235015	20269584*	60040989
20098392	20166518	20246267	20269613	60041628
20098431	20168323	20248499	20270041*	60047491
20114821	20171082	20249358	20270042*	60049026
20115126	20171360	20250868	20270466	60052485
20124225	20171399	20251278	20270913*	60054765
20124447	20185351	20255886	20271319*	70028834
20114821	20185616	20256504	20271520*	70035761
20115126	20195237	20257785	20271869*	70038837
20124225	20200880	20259399	20271904*	70040334
20124447	20205376	20261503	20271935*	70044979
20137125	20205727	20266682	20271971*	70051208
20137237	20208634	20267475*	20271973*	70052802
20137237	20212648	20267597*	20271993*	80024465
20139333	20218146	20267640*	20272356*	80053046
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20146651	20224794	20269297*	30071181	
20149430	20226471	20269693*	30112336	
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* Indicates Notifications written as a result of the team's inspection activities

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LIST OF ACRONYMS USED

ASME	American Society of Mechanical Engineers
CCW	Component Cooling Water
CDBI	[NRC] Component Design Bases Inspection
CDF	Core Damage Frequency
CFR	Code of Federal Regulations
CVCS	Chemistry and Volume Control System
ECCS	Emergency Core Cooling System
EOP	Emergency Operating Procedures
GL	[NRC] Generic Letter
gpm	Gallons per Minute
GTG	Gas Turbine Generator
HRA	Human Reliability Analysis
IMC	[NRC] Inspection Manual Chapter
IN	[NRC] Information Notice
IP	[NRC] Inspection Procedure
LOCA	Loss of Coolant Accident
LOOP	Loss of Off-site Power
NCV	[NRC] Non-cited Violation

NEI	Nuclear Energy Institute
NPSH	Net Positive Suction Head
NRC	Nuclear Regulatory Commission
OE	Operating Experience
P&ID	Piping and Instrument Diagram
PI&R	Problem Identification and Resolution
PRA	Probabilistic Risk Analysis
PSEG	Public Service Enterprise Group
RCP	Reactor Coolant Pump
RG	[NRC] Regulatory Guide
RHR	Residual Heat Removal
RWST	Refueling Water Storage Tank
SBO	Station Blackout
SDP	Significance Determination Process
SI	Safety Injection
SRA	Senior Reactor Analyst
SSC	System, Structure, or Component
TB	Technical Bulletin
TS	Technical Specification
WO	Work Order
UFSAR	Undated Final Safety Analysis Report
VAC	Volts Alternating Current
VCT	Volume Control Tank