U. S. NUCLEAR REGULATORY COMMISSION

REGION I

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Licensee:	Public Service Electric and Gas Company
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Inspectors:	C. S. Marschall, Senior Resident Inspector J. G. Schoppy, Resident Inspector T. H. Fish, Resident Inspector R. K. Lorson, Resident Inspector J. Laughlin, Emergency Preparedness Specialist E. H. Gray, Technical Assistant G. S. Barber, Project Engineer P. D. Kaufman, Emergency Response Coordinator
Approved by:	Larry E. Nicholson, Chief, Projects Branch 3 Division of Reactor Projects

EXECUTIVE SUMMARY

Salem Nuclear Generating Station
NRC Inspection Report 50-272/96-18, 50-311/96-18

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a six week period of resident inspection; in addition, it includes the results of announced steam generator replacement, emergency preparedness, and corrective action inspections.

Operations

During the inspection period operators completed four major evolutions for Salem Unit 2. They refueled the reactor, filled and vented the reactor coolant system (RCS), established a bubble in the pressurizer, and started each of the reactor coolant pumps (RCPs). In completing the evolutions, operators demonstrated a strong emphasis on nuclear and personnel safety. In each case, operators added a great deal of quality to the process through their careful review of procedures for adequacy, and through pre-evolution briefs focused on critical safety parameters. In each case, they delayed starting the evolution to deal with and remove other plant activities that could cause distraction. In some cases, they stopped the evolution to insure safety in their activities. Although Salem workers caused loss of containment closure for two days during refueling and an operator failed to correctly align two valves during the RCS fill and vent process, the inspectors considered operator performance generally good for the four evolutions. The inspectors noted specifically that operator safety focus, willingness to put plant safety before schedule adherence, and questioning attitude had improved significantly in comparison to their performance prior to June 1995. The operators demonstrated effective communications, proper procedure use and adherence, good safety focus, and improved senior reactor operator oversight of activities during the complex evolutions (Sections O1.1 and O4.1).

Chemistry technicians maintained reactor coolant chemistry within the required limits. They took appropriate action in response to slightly elevated chloride levels in Unit 2 reactor coolant. Salem Unit 2 operators did not know of the elevated chloride and did not routinely review chemistry sample results. The chemistry department superintendent and the operations manager previously identified the weakness, and initiated corrective actions (Section O4.2).

Inspectors reviewed progress in addressing operator workarounds and control room deficiencies, and effectiveness of the Quality Assurance (QA) program. The inspectors also reviewed operations staff progress in implementing the Operations Restart Plan, and assessed the effectiveness of the Corrective Action Program (CAP).

Aside from minor program weaknesses, the operations staff established adequate controls to identify, track, and correct operator workarounds and control room deficiencies. Operations and maintenance staff made significant progress in reducing the number of operator workarounds and control room deficiencies. Inspectors considered actions by the Salem staff to address these deficiencies adequate to support Salem unit 2 restart (Section O2.2).

Overall, the QA program performance was acceptable to support the restart of Salem Units 1 & 2. The organization is well staffed and capable of providing oversite for the Salem site activities, and has demonstrated the ability to identify and track corrective action items. The QA staff has conducted thorough and rigorous audits and assessments of operations, maintenance, engineering and support activities.(Section O7.2)

Operations personnel made significant progress toward operations department restart readiness. Operations personnel established themselves as leaders in the organization and resumed ownership of the facility. Operations management established high standards for department performance and made steady progress to improve operations' performance relative to those standbetween supporting departments (Section O8.1).

The Nuclear Business Unit has significantly improved, and continues to improve the corrective action program. They implemented appropriate controls to maintain CAP performance. The inspectors considered actions to improve the corrective action program and the corrective action restart plans adequate to support Salem Unit 2 restart. (Section O8.3)

Maintenance

Although Salem Unit 2 has a sizeable backlog of corrective maintenance, inspectors considered the total impact minor in scope. Also, with a single minor exception in a sample of about 100 work orders, the plant staff had properly classified the work orders as post restart. The inspector concluded that the Salem staff properly managed the backlog, and considered it acceptable to support the restart of Salem Unit 2 (Section M1.2)

As a result of ineffective work control, the Salem staff failed to maintain containment integrity while conducting Unit 2 core reload. Plant management responded promptly and appropriately to address associated weaknesses. Excepting the loss of containment integrity, the plant staff completed Unit 2 refueling safely and effectively (Section M2.1).

Engineering

During the inspection period, the engineering staff continued to produce many good engineering products. For example, the inspectors concluded that PSE&G satisfactorily managed the engineering backlog. The PSE&G staff effectively prioritized emergent items and knew the content of the backlog. Based on review of a sample of the backlog items, the inspector determined that the Salem staff had appropriately designated the items as "post restart." (Section E1.2) The Salem Unit 1 steam generator replacement project produced results characterized by good quality, few deficiencies, improved planning, work control, and adherence to procedure requirements (Section E1.4). The Salem staff effectively corrected Unit 2 safety injection pump deficiencies and subsequently demonstrated that pump performance met surveillance requirements. In addition, they completed modifications to the steam dumps and implemented related EOP changes. The inspector considered these corrective actions adequate for restart of Salem Unit 2 (Sections E2.1 and E2.2). The plant staff also took comprehensive corrective action to improve Auxiliary Feedwater performance and reliability. The inspectors considered the action adequate to support restart. The inspectors will observe pump testing during the Salem restart (Section E2.5.) The MRC performed a thorough review and evaluation of the Operations Department and System Engineering restart issue (Section E2.3.). The Nuclear Engineering Design department started to develop a modification to prevent service water voiding in Containment Fan Coil Unit heat exchangers and piping following a design basis loss of coolant accident (Section E1.3.)

The inspectors also saw examples of less than adequate engineering performance during the inspection period. During re-analysis of inadvertent safety injection, PSE&G failed to evaluate the PORV accumulator check valves for suitability of use, and failed to revise the IST check valve leak test procedure. An Offsite Safety Review group reviewer concluded that the reanalysis posed an unreviewed safety question that required a change to Technical Specification 3.4.5. In addition, the Salem staff identified that the safety evaluation incorrectly concluded that no safety evaluation existed due to the reanalysis. The Salem staff initiated corrective action, including a license change request (Section E1.1.) In addition, the inspector identified that PSE&G mis-classified valves SJ4 and SJ5 as passive components and, as a result, had not included them in the IST program for exercise and stroke testing in the closed direction. The inspector determined that the valves must close to stop charging flow to the RCS during a steam generator tube rupture event, and Salem should have included them in the IST program (Section E2.4.)

Plant Support

The licensee took adequate corrective actions for three violations resulting from the October, 1995 loss of annunciator event at Salem Unit 1. Emergency Response Organization (ERO) members demonstrated good overall performance during mini-drill scenarios. The efforts to improve the Emergency Response Program were found to be sufficient to support Salem restart. The inspectors noted several deficiencies with the emergency preparedness department's implementation of the action item tracking system (Sections P3 through P8.5.)

The inspectors observed certain examples of violations of the access control process as described in the NRC approved Salem and Hope Creek Security Plan. Further, the inspectors concluded that while station personnel took appropriate immediate corrective actions for each of the observed events, weaknesses still existed in implementation of access controls at both Salem and Hope Creek. (Section S1.1)

TABLE OF CONTENTS

Report Details

Summary of Plant Status

Salem Unit 1 remained defueled for the duration of the inspection period.

Salem Unit 2 began the inspection period defueled. On December 16, 1996, operators commenced refueling and entered mode 6. On December 21, operators completed refueling. On December 26, when plant staff finished tensioning the reactor head, Salem Unit 2 entered mode 5. Unit 2 remained in mode 5 for the remainder of the inspection period.

I. Operations

O1 Conduct of Operations

O1.1 General Comments (71707)

Using Inspection Procedure 71707, the inspectors conducted frequent reviews of ongoing plant operations. In general, the operators demonstrated professional and safety-conscious performance. During the inspection period operators completed four major evolutions for Salem Unit 2. They refueled the reactor, filled and vented the reactor coolant system (RCS), established a bubble in the pressurizer, and started each of the reactor coolant pumps (RCPs). In completing the evolutions, operators demonstrated a strong emphasis on nuclear and personnel safety. In each case, operators added a great deal of quality to the process through their careful review of procedures for adequacy, and through pre-evolution briefs focused on critical safety parameters. In each case, they delayed starting the evolution to deal with and remove other plant activities that could cause distraction. In some cases, they stopped the evolution to insure safety in their activities. Although Salem workers caused loss of containment closure for two days during refueling and an operator failed to correctly align two valves during the RCS fill and vent process, the inspectors considered operator performance generally good for the four evolutions. The inspectors noted specifically that operator safety focus, willingness to put plant safety before schedule adherence, and questioning attitude had improved significantly in comparison to their performance prior to June 1995.

O1.2 Reactor Coolant System Fill and Vent

a. Inspection Scope (71707)

The inspectors monitored and assessed operator performance during an infrequently performed evolution.

b. Observations and Findings

After completion of refueling, plant staff completed reassembly of the reactor and transitioned from mode 6 into mode 5. Subsequently, they made preparations to fill and vent the reactor coolant system (RCS) and draw a bubble in the pressurizer. In previous outages, the plant staff used repeated starts of the reactor coolant pumps (RCPs) to remove non-condensible gases from the RCS. In this case, plant managers decided to fill and vent by reducing the RCS water level to just above mid-loop, drawing a partial vacuum through the top of the pressurizer, then refilling the RCS from the reactor water storage tank (RWST).

The plant staff, especially operators, prepared for the first-time evolution with great care. They assigned a test manager to oversee the evolution because operators had not previously applied vacuum to fill and vent the RCS. Operators discovered several problems with the procedure during their review prior to implementation. For example, the operators initiated condition report (CR) 961229068 to document that the fill and vent procedure directed operators to isolate the manual isolation valves for cold leg safety injection, but did not direct the operator to reopen the valves in the event of a loss of RHR. They delayed implementation of the fill and vent procedure until they corrected all the problems they identified. The operators also conducted thorough shift briefings prior to starting to implement the procedure and used shift test managers to provide oversight and coordination during the course of the test. The briefings focused in detail on the critical points in the fill and vent process, and the expected plant response to various activities. Operators paid particular attention to the potential for inadvertent dilution, loss of RHR, and the need to insure reliable RCS level indication.

Despite the efforts to insure they completed the procedure correctly, a control room operator incorrectly performed a portion of the valve alignment in the control room. Procedure S2.OP-SO.RC-0002 (Q), *Vacuum Refill of the RCS*, Rev. 1, step 2.9 required the operator to verify pressurizer spray valves PS-1 and PS-3 open. In the reduced RCS inventory condition, opening the valves would have allowed vacuum to equally affect the RCS hot legs and cold legs. With the valves closed, however, all of the RCS level indications immediately indicated a significant increase in level when operators applied vacuum. Within two minutes, the Senior Nuclear Shift Supervisor directed the operators to stop the vacuum pump and break vacuum. Level indication immediately returned to normal. The operators completed proper system alignment, as required by procedure, then successfully completed filling and venting the RCS without a problem.

During the two minutes while vacuum affected only one side of the level indicators, operators could not monitor RCS level while in mid-loop operation. Although they had lost some of the means to anticipate loss off RHR due to pump vortexing, they still had the means to detect it through fluctuation in RHR pressure and pump current. Since RCS level did not actually change, the RHR pumps did not experience vortexing during the evolution. The inspectors concluded that the situation had no safety consequence and minor safety significance.

The operators responded quickly to the abrupt change in indicated level due, in part, to the importance they had associated with level indication. The control room staff immediately recognized the cause of the level change, and took the proper corrective actions. They completely verified proper system alignment. During initial assessment of the problem, the test manager noted that the procedure lacked independent verification of initial conditions. The operations manager also noted that the operating shift did not successfully employ teamwork, since several other shift personnel failed to take advantage of the opportunity to identify and correct the incorrectly positioned valve.

In addition to the immediate corrective actions to open PS-1 and PS-3 and verify the proper alignment, the operators initiated CR 970102085. In addition, the operations manager initiated an operator self-check practice. The operations manager required the operators to check each other's work for critical steps in many activities. He expected the operators to verify most activities such as valve alignments until the operations staff could incorporate specific requirements into the appropriate procedures. The operations manager also directed the procedure writers to review operating procedures to incorporate independent verification requirements.

c. Conclusions

Although the operators experienced a problem with RCS level indication as a result of a valve mis-alignment during the RCS fill and vent, the operators immediately recognized the problem. The problem had no safety consequence. Operators immediately recognized and responded to the problem as a result of their focus on RCS level, the critical safety parameter during mid-loop operation. In addition, the operators and operations manager immediately took comprehensive corrective action. This licensee identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII.B.1 of the NRC Enforcement Policy.

O2 Operational Status of Facilities and Equipment

O2.1 Operator Workarounds and Control Room Deficiencies, NRC Restart Item III.8 (Closed)

a. Inspection Scope (92901)

Operator workarounds exist to compensate for degraded plant conditions. Operators often implement compensatory measures that distract them from their normal duties and may seriously complicate their response to a plant transient. The inspector reviewed Salem's program to address operator workarounds.

b. Observations and Findings

Salem Operations staff developed SC.OP-AP.ZZ-0030, *Operator Workaround Program*, to identify, track, and manage operator workarounds and burdens. The operations workaround supervisor developed an effective tracking program and worked with maintenance staff to prioritize and schedule actions to correct the causes of operator workarounds and burdens. Since January 1996, Salem reduced the total number of Unit 2 operator workarounds and burdens from 134 to 21. During this time, Instrument and Controls technicians reduced the number of Unit 2 control room indication deficiencies from 280 to 185. Plant staff appropriately prioritized the planned work by operating mode to insure they repair control room indicators as required by plant conditions. For example, little deficient control room instrumentation affected the operator's ability to monitor required plant parameters in mode 5. Emergent deficiencies and repetitive abnormal alarms received prompt and appropriate attention. The inspector concluded that maintenance staff support of work to remove operator workarounds had improved since July 1996. (See Inspection Report 50-311/96-07 section M1.4)

The operations work control manager established challenging performance goals based on industry standards. The inspector noted a few minor weaknesses in the operator workaround program. For example, several minor deficiencies that required compensatory operator action did not appear on the workaround list. In addition, several out of service control room indicators did not appear in the Managed Maintenance Information System (MMIS) work order printout nor in the control room operator's supplemental control room instrumentation tracking log. The SNSS initiated a condition resolution report (CR 970124254) to correct this deficiency. The inspector also noted that operators did not routinely update work orders to reflect changes in the workaround or burden status, and plant staff did not include compensatory measures resulting from corrective actions in the workaround program (see Section O8.3). The operations staff initiated CR 970120173 to address this weakness. Overall, however, the inspector concluded that the operations staff had significantly reduced workarounds and burdens, and had implemented an effective program to identify and address them.

c. Conclusions

Aside from minor program weaknesses, the operations staff established adequate controls to identify, track, and correct operator workarounds and control room deficiencies. Operations and maintenance made significant progress in reducing the number of operator workarounds and control room deficiencies.

O4 Operator Knowledge and Performance

O4.1 Procedure Use and Adherence (92901)

The inspectors observed Unit 2 operator's use and adherence to operating procedures. Control room operators demonstrated effective communications and good attention-to-detail while controlling several complex evolutions. Senior reactor operators (SRO) maintained effective awareness of safety system status and demonstrated appropriate safety focus. In addition, the SROs increased oversight and control of activities in the field. Operators consistently and accurately implemented procedures and properly documented completion of procedure steps. The operators demonstrated a good questioning attitude by identifying needed procedure improvements. In each case, they safely placed the process on hold and implemented appropriate procedure changes using the approved process. The inspectors observed good operator procedure use and adherence during the following evolutions:

• S2.OP-SO.RC-0005:	draining the reactor coolant system (RCS) to ≥ 101 feet elevation
• S2.OP-SO.SF-0004:	draining the refueling cavity
• S2.OP-SO.PZR-0006:	RCS venting
• S2.OP-IO.ZZ-0001:	refueling to cold shutdown
• S2.OP-SO.RC-0002:	vacuum fill of the reactor coolant system (preparations for establishing a pressurizer steam bubble)
• S2.OP-SO.RC-0001:	reactor coolant pump operation (preparations for starting 23 reactor coolant pump)

O4.2 Reactor Coolant Chemistry Control

a. Inspection Scope

The inspector reviewed recent Unit 2 reactor coolant chemistry sample results and interviewed chemistry department personnel and several control room operators to determine the effectiveness of the licensee's chemistry control program.

b. Observations and Findings

The reactor coolant chemistry limits are specified in the Updated Final Safety Analysis Report (USFAR) section 5.2.3.4 and in Technical Specification (TS) 3.4.9. The chemistry limits ensure adequate water quality to minimize corrosion of reactor coolant system components and limit radioactivity levels of reactor coolant. The inspector reviewed a number of reactor coolant chemistry sample results and determined that they did not exceed the applicable limits. In addition, the inspector noted that a chemistry technician had identified and initiated corrective action for a slightly elevated Unit 2 reactor coolant chloride concentration.

The inspector noted a minor weakness in that the Unit 2 control room operating personnel questioned did not know about the elevated reactor coolant chloride levels. Additionally, the operators did not routinely review the readily available chemistry sample results. The acting chemistry department superintendent and the operations manager stated that they also identified the weakness and had initiated corrective actions.

c. Conclusions

Chemistry technicians maintained reactor coolant chemistry within the required limits. They took appropriate action in response to slightly elevated chloride levels in Unit 2 reactor coolant. Salem Unit 2 operators did not know of the elevated chloride and did not routinely review chemistry sample results. The chemistry department superintendent and the operations manager previously identified the weakness, and initiated corrective actions.

O7 Quality Assurance in Operations

O7.1 (Closed) LER 50-272/96-018 - potential performance impact on emergency core cooling system due to non-safety related refueling water storage tank (RWST) piping. In July 1996, a design review conducted by PSE&G identified that the refueling water purification loop was normally aligned to the RWST rather than isolated. Since the non-safety related purification loop is not seismically qualified, part of the RWST inventory would be lost in a seismic event, reducing the ability to maintain core cooling.

In response, operators immediately isolated the purification loop from the RWST. The long term corrective actions include upgrading an isolation valve to a safety related classification, revising procedures to clearly document limitations of operating the purification system, and to review other systems for similar conditions.

The discovery of this condition had minor safety significance because the purification system pipe consisted of the same material as the ECCS suction piping. Although failure to control operation of the purification loop to preclude adversely affecting emergency core cooling is a violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," this licensee-identified violation is as Non-Cited Violation, consistent with Section VII.B.I of the NRC Enforcement Policy.

O7.2 Adequacy of QA Program NRC Restart Item III.20 (Closed)

a. Inspection Scope

To determine the effectiveness, the inspector reviewed samples of Quality Assurance (QA) audits and assessments of Salem activities, a self assessment of QA performance and an example of the QA monthly report. In addition, the inspector reviewed two audit reports selected from the 1996 audit schedule and corrective action documents that resulted from the audits. Finally, the inspector held discussions with the Salem QA supervisor to assess the staffing.

b. Observations and Findings

The inspector considered QA staffing acceptable to support restart of the Salem units. The QA organization has the capability to perform detailed design reviews for selected plant modifications to help assess the acceptability of the design process. Also, the QA staff employs several personnel with previous experience in line organizations. The inspector learned that QA had filled nearly all staff positions for transition to a proposed new organization under review by the NRC.

Based on a review of six audits and assessments and the number and nature of corrective action items identified during those activities, the inspector considered QA audits rigorous and comprehensive. The inspector noted, in particular, that the audits identified significant performance and program deficiencies and entered them in the corrective action program to insure the appropriate corrective action. For example, in a 1996 assessment of work control and tagging, QA auditors identified enough significant problems to conclude that these areas were not acceptable to support the restart of Salem Unit 2. The audit of the in-service inspection program identified problems that resulted in 26 Action Requests (i.e., corrective action documents) and 57 observations. The inspector also concluded that QA use, in more recent audits, of technical experts from outside the company resulted in improved assessment.

The inspector found that performance indicators and the monthly Quality Assessment Report provided line managers with useful tools to monitor completion of corrective actions. Executive managers, directors, and department managers and directors use the QA report to manage the corrective action backlog. In a review of 10 corrective action documents that identified 50 specific corrective actions, the inspector found that plant staff had resolved the significant issues in a timely manner. The departments had appropriately scheduled procedure changes to address minor issues for the next scheduled biannual procedure review.

In a review of the audit schedule, the inspector found that QA conducted 13 audits in the past year and planned 16 for the upcoming year. The 16 audits cover most functional areas of the plant and support organizations. In addition, QA staff allotted time for the performance of contingency audits. The QA department also conducted less formal assessments for problem areas indicated by the corrective action program. The inspector concluded that QA scheduled and conducted appropriate audit activity to provide meaningful assessment of line organization activities.

The inspector noted that PSE&G has a stated corporate policy of receptiveness to valid safety concerns. In addition, PSE&G has an employee concerns department that encourages employees to communicate their concerns, anonymously if desired, for investigation and resolution. The inspector found information regarding the employee concerns program prominently displayed in several locations. This provides adequate guidance for employees to contact the employee concerns department by telephone, mail or in person. During this inspection, the inspector found that PSE&G tracked the number of employee concerns submitted each month and provided that information in the QA monthly report. From this data, the inspector found that the number of concerns submitted each month had dropped steadily over the past eleven months, from a high of 27 in January to a low of 2 in November 1996. The inspector considered the employee concerns program effective in surfacing and ameliorating the concerns.

c. <u>Conclusions</u>

Overall, the inspector concluded that the PSE&G's QA program is fully acceptable to support the restart of Salem Units 1 & 2. The organization is well staffed and is capable of providing oversite for the Salem site activities, and the tools are in place to enable identification and tracking of corrective action items. QA has demonstrated the ability to conduct thorough and rigorous audits and assessments of operations, maintenance, engineering and support activities. This item is closed.

07.3 Corrective Actions for Salem Unit 2 Trip - NRC Restart Inspection Item II.43 (Closed)

a. Inspection Scope (71707)

Inspectors reviewed the corrective actions to determine if they adequately addressed the causes of the Salem Unit 2 Trip on June 7, 1995.

b. Observations and Findings

The inspectors previously reviewed licensee corrective actions in NRC Inspection Report 50-272&311/96-08. The inspectors concluded, in that report, that plant staff had not completed the actions necessary to insure effective corrective action. Specifically, the package did not include evidence that plant staff had replaced the SBF-1 relays, identified as the cause of the trip. In addition, engineering had not completed their evaluation of the process for review, receipt, evaluation and routing of vendor and industry notifications.

During the current inspection period, the inspectors reviewed completed work orders demonstrating that the Salem staff had replaced the SBF-1 relays with upgraded versions for all four south 13KV ring bus breakers and all eight 500KV ring bus breakers. The north 13KV ring bus does not use SBF-1 relays. The inspectors also reviewed the completed Vendor Manual Program Assessment Report. The review documented, using the station Corrective Action Program, a number of required corrective actions. These included:

- Establish a vendor document process owner.
- Establish a baseline for vendor document information.
- Modify vendor contract commitment to a three year cycle
- Perform a sample of vendor re-contacts to provide a basis for Salem restart affirmation.
- Establish an enhanced vendor re-contact program.
- Evaluate vendor document backlog prior to Restart for potential safety significant issues.

The licensee completed implementation of these actions on August 8, 1996. The Nuclear Engineering Design department performed a thorough review of the vendor manual program and developed comprehensive corrective actions. They completed implementation of the corrective actions required for restart. The inspector considered the corrective actions effective.

c. Conclusions

The inspectors concluded that the licensee implemented appropriate corrective actions to address the cause of the June 1995 Salem Unit 2 reactor trip.

O8 Miscellaneous Operations Issue

O8.1 Operations Restart Action Plan (Open)

a. Inspection Scope (92901)

The Salem Operations Restart Action Plan established a performance based approach to specify and control the actions required to demonstrate operations readiness for restart of both Salem units. The Operations Restart Action Plan aimed to improve the fundamental conduct of operations to ensure safe and controlled operation of the Salem units. The inspector reviewed operations progress toward restart readiness for Salem Unit 2.

b. Observations and Findings

The Operations Manager identified six major areas for improvement, and developed six problem statements to describe the weaknesses and outline corrective actions. On January 4, 1997, the Salem Management Review Committee (MRC) approved the operations department affirmation of readiness for restart based on completion of all but eight mode-dependent actions. The operations staff developed condition resolution corrective action (CRCA) reports to track completion of the remaining items.

Problem statement no. 1 identified deficient operations department leadership. The operations manager found weak direct supervision of activities in the control room and in the plant. In response, he strengthened shift resources through increased shift technical advisors (STA) staffing, hiring seven previously licensed SROs with significant operating experience, and balancing operating crews based on strengths, weaknesses, and personalities. The operators improved their leadership skills through peer visits to SALP I plants, establishment of shift mentors, and operator restart training. To improve oversight of plant activities, the operations manager created and staffed a field supervisor position, increased shift manning, and improved operations standards.

The inspector observed significantly improved operator performance. The STAs contributed additional independent safety focus and provided effective technical specification tracking. The newly hired SROs provided fresh insight allowing them to identify process and procedure deficiencies. Operations management routinely evaluated control room crews and took appropriate and timely action to improve crew performance in the simulator and in the plant. Operator ownership and leadership improved substantially. The SNSS's led the shift turnover meeting, directed the maintenance briefing and maintained strict control of the control room. Control room operators demanded reliable equipment, carefully controlled evolutions, and displayed improved professionalism. Although the operations manager had not developed a way to insure compliance with this expectation, the inspectors observed that the SNSS and SROs spent more time in the plant. As a result, field supervisors identified equipment deficiencies, procedure inadequacies, scaffolding shortcomings, and housekeeping issues. The inspector concluded that operations management adequately staffed the operating shifts to support Unit 2 restart. The inspector considered the actions to address problem statement no. 1 adequate to support restart.

Problem statement no. 2 identified deficient operations standards for plant and personnel performance. To address this deficiency, operations management developed SC.OP-DD.ZZ-0004, *Operations Standards*, and SC.OP-AP.ZZ-0002, *Organization and Responsibilities*. Operators received significant training and re-enforcement of these standards during the restart training program. In addition, operations management frequently provided guidance regarding adherence to standards in *Night Order Book* entries. The operations supervisors received Management Action Response Checklist (MARC) training to provide the tool to enforce department and station standards.

The inspector concluded that the new standards and organizational responsibilities documents provided practical guidance consistent with high standards of excellence. Since completion of restart training, the operators demonstrated improved adherence to procedures, vigilant monitoring and control of safety significant evolutions, conservative decision making, attention-to-detail, prompt identification of degraded conditions, and heightened professionalism. (See sections M2.1, and O4.1 of this report and sections O2.1, O3.1, and O4.1 of Inspection Report 96-17.) The *Night Order Book* entries and shift mentor observations provided clear, concise and timely re-enforcement of the standards and discussion of operator performance that fell short of the standard. The inspector considered the actions to address problem statement no. 2 adequate to support restart.

Problem statement no. 3 identified that operator ownership of the plant, communication of priorities and leadership in problem resolution needed improvement. Teamwork between operations, maintenance, engineering and planning also required improvement. To improve operator ownership of the plant, the operations manager assigned SROs as managers for each plant system. Each system manager inspected the assigned system, conducted readiness reviews, and coordinated with system and design engineers. As a result of their assigned system responsibilities, the SROs demonstrated significant ownership for their systems. For example, they documented degraded conditions, tracked work order status, verified post-maintenance tests, and concurred in system restart readiness. The control room modifications resulted in more direct SRO involvement and control of plant activities and improved SNSS oversight of both Salem units.

The plant managers implemented comprehensive control room modifications to enhance operating shift communications and SRO command and control. Operator restart training and operations standards implementation resulted in improved communications within the department and with other plant organizations. For example, the RO, SRO, SNSS, and STA turnovers incorporated improved communication of plant status, planned evolutions, and degraded conditions. Operators made timely and appropriate calls to operations management of equipment, process, and human performance problems. They aggressively documented deficiencies, communicated concerns to management, and involved the appropriate disciplines to address and resolve problems. The inspector concluded that operators demonstrated satisfactory plant ownership, acceptable leadership, and effective communications. The inspector considered the actions to address problem statement no. 3 acceptable to support restart.

Problem Statement No. 6 identified weaknesses in operator emergency preparedness that resulted in an ineffective emergency response organization (ERO) response during the October 5, 1995 Salem Alert. Inspectors reviewed the effectiveness of the ERO as part of NRC restart inspection item III.13 (see section P8 of this report.) The inspector considered the actions to address problem statement no. 6 acceptable to support restart.

The actions to address problem statements nos. 4 and 5 remain open pending NRC review.

c. Conclusions

The operations staff made significant progress toward operations department restart readiness. Operators established themselves as leaders in the organization and demonstrated plant ownership. Operations management established high standards and made steady progress to improve operator performance as measured against those standards. Operators demonstrated improved communications within the department and between supporting departments.

O8.2 (Closed) LER 50-272/95-019: operability functional test not performed prior to mode entry. On July 26, 1995, PSE&G identified that on July 25, 1995, Salem Unit 1 operators entered mode 6 with containment purge in service and containment purge valves inoperable. This is a violation of TS 3.9.9. The licensee attributed the failure to ensure purge valve operability to an inadequate Integrated Operating Procedure, inadequate operability status tracking, and inadequate tracking and follow through of maintenance activities.

Upon discovery, operators stopped the containment purge and satisfactorily stroked the purge valves to ensure operability. Operators determined that the plant staff did not perform any core alterations in mode 6 prior to the discovery. The plant staff revised procedures to ensure adequate review of outstanding work orders, condition resolution reports, operability determinations, technical specification LCOs, and surveillances prior to a mode change.

The inspector verified procedure revisions to the integrated operating and operability determination procedures. The inspector determined that the violation had minimal safety consequence based on purge valve operability and discovery prior to core alterations. This licensee identified and corrected violation is being treated as a non-cited violation, consistent with section VII.B.1 of the NRC Enforcement Policy.

O8.3 NRC Restart Item III.a.10 - Corrective Action Program (Closed)
NRC Restart Item III.b.7 - Licensee Restart Plans, Corrective Action (Closed)

a. Scope

The inspectors assessed the overall effectiveness of the licensee's corrective action program (CAP) by reviewing: program consolidation; action requests coding; program interfaces; timeliness of corrective actions; CAP backlog; control room deficiencies; operator workarounds; root cause analysis and corrective action effectiveness; and audits. The inspectors also reviewed the licensee's progress in completing their Corrective Action (CA) Restart Action Plan, Rev. 7, dated October 10, 1996.

b. Observation and Findings

Corrective Action Program - Overview & Consolidation

The licensee's Corrective Action Program begins with the submission of an Action Request (AR) for an actual or potential problem. This results in one (or more) of the following: a Condition Report (CR), a Corrective Maintenance (CM) work request, or a Business Practice (BP) evaluation. The Nuclear Business Unit (NBU) uses CMs to fix equipment degradations and failures. The NBU uses a CM, CR, or both to resolve problems that involve safety related structures, systems, or components (SSCs). The NBU uses BPs to address problems that involve non-safety related SSCs or to enhance organizational performance. In general, plant staff must evaluate CRs and formulate the necessary corrective actions (CAs) within 30 days. The plant staff then schedules the actions for completion over the next six months.

Salem divided Condition Reports into three levels based on their safety significance. Level 1 CRs have the most significance and require completed root cause evaluations prior to prescribing CAs. Level 2 CRs have moderate significance, and receive less rigorous apparent cause analysis. Level 3 CRs represent minor significance problems trended by the staff. The NBU uses various management reviews to improve the quality of level 1 and 2 CRs. They have developed performance indicators to assess CR timeliness and trend quality.

Prior to the current CAP, the NBU distributed multiple corrective action processes among separate programs. Some of the primary methods used for identifying and correcting problems at the station consisted of Incident Reports (IRs) and Document Evaluation Forms (DEFs). The Corrective Action Program consolidated and replaced the previous programs. Procedure NC.NA-AP.ZZ-0006(Q), "Corrective Action Program," Revision 14 describes the licensee's current consolidated CAP.

Action Request Classification

From the number of ARs initiated on a daily basis by the various departments, the inspectors concluded that all staff levels used the CAP. The inspectors found that the staff initiated ARs to identify potential conditions adverse to quality and appropriately classified them as CRs based on their significance. Department managers screened the significance level 2 and 3 CRs and significance level 2 CMs for the previous 24 hours. With few exceptions, managers ensured appropriate significance levels. However, a recent NRC inspection (50-311/96-16) identified some weaknesses. A self-assessment report (SA-96-05) revealed that plant staff incorrectly coded four ARs with conditions adverse to quality as Business Process (BP) instead of CRs. In addition, during the current inspection period, inspectors identified additional similar problems associated with the PORV accumulators (see section E1.1.)

Program Interfaces

The inspectors reviewed a list of Condition Reports (CRs) to verify that all of the departments used the CAP. The inspectors determined that the operations, maintenance, and engineering departments consistently initiated ARs for plant problems. Additionally, radiation protection, security, and emergency preparedness (EP) staff had increased AR initiation from the marginal levels of the past two months. The EP staff had started training a root cause specialist to improve the department's ability to do root cause evaluations. The inspectors considered continued management emphasis necessary to assure that support organizations use the CAP.

Occasionally, coordination problems occurred when using the CAP. For example, engineering and licensing improperly scheduled completion of corrective actions for inappropriate greasing of doubled shielded motor bearings (see NRC Information Notice 94-51) for a time after the projected Salem Unit 2 restart. Although the inspector found that plant staff had previously satisfactorily resolved this issue, the CR did not accurately reflect the overall status, and all of the parties did not know its status.

Timeliness of Corrective Actions

Although the CAP performance indicators through November 1996 indicated that the average for level 1 and 2 CR evaluations exceeded the 30 day timeliness goals, the inspector noted a generally improving trend in timeliness. This is noteworthy considering the large number of ARs entering the system. Plant staff routinely completed corrective actions within approximately 180 days, the industry norm. The performance indicators showed fewer overdue corrective actions over the past couple of months. The inspectors considered corrective action timeliness acceptable.

Corrective Action Program Backlog

The inspectors reviewed the Incident Reports (IRs) and Document Evaluation Forms (DEFs) backlog through November 1996. Salem management requires that plant staff complete evaluations of all backlogged Incident Reports for restart of the Salem Units. The number of open IR evaluations for Salem 1 and 2 decreased from approximately 500 in July 1995, to 2 during the inspection. The inspectors considered the reduction significant. The total number of open DEFs decreased from 1386 in June 1995, to approximately 318 as of September 1996. Of these, engineering must resolve 203 before Salem Unit 2 restart. As a result of the DEFs, engineering has the oldest and largest number of backlogged CAP items. The inspector reviewed nine safety significant DEFs to ensure that engineering correctly assessed the backlogged DEFs for Salem Unit 2 restart. Inspectors noted only one minor deficiency.

In November 1996, 3,055 Unit 2 CRs remained open. In January 1997, 310 significance level 1 and 2 CRs remained to be resolved for prior to Mode 4 for Salem Unit 2. Based on review of a sample of open level 1 and 2 CRs, the inspectors determined the licensee appropriately evaluated CRs as a Mode 4 restraint or a post-restart CR.

The inspectors concluded that the NBU adequately tracked and monitored the corrective action backlog.

Control Room Deficiencies

The inspector observed control room activities and indications, and reviewed control room logs and other source documents to assess whether the use of the CAP has effectively eliminated control room deficiencies. The inspector noted that operators appropriately identified out of tolerance conditions and included explanations in the December 30 through January 5 operator logs. The inspectors noted a minor example of poor shift turnover concerning work on a ground on the 2B 125 VDC bus. In another case, technicians attempted to repair control room indication of steam generator blowdown flow on three separate occasions. Each repair attempt resulted in a failed retest. The inspector discovered that the plant staff had not involved engineering with the rework or initiated a CR to address the failed retests. The inspector also noted that NAP-6 does not require a CR for multiple failed retests, and the CM to correct the incorrect blowdown flow indication remained open. The inspector concluded that, although lack of a CR for multiple failed retests does not violate any requirements, it reduces the opportunity to identify design and human performance deficiencies .

Operator Workarounds

The inspector reviewed the licensee's management of operator workarounds in relationship to the Corrective Action Program. Inspectors documented assessment of the workaround program in section O2.1, above.

As of January 8, Salem Unit 2 had 10 open operator workarounds and 10 open operator burdens. Workarounds may result in the initiation of a plant transient or reduce mitigation effectiveness, whereas a burden typically requires compensatory action for a minor hardware deficiency. The inspector determined that the plant staff understood the nature of the open items and had entered each of the items into the CAP. The inspector noted, however, that operators considering the feasibility of lowering the Diesel Generator (DG) jacket water temperature alarm set point to account for expected low service water (SW) temperatures did not review the UFSAR or other licensing documents. The inspector noted that Hope Creek previously identified cooling water temperatures below those assumed in the system design basis. The inspector reviewed the Salem UFSAR and found no specific temperature limitations. The licensee issued a CR to consider the generic implications of this observation.

The inspector noted that the Salem staff developed the list of workarounds from a review of CMs and did not include CRs. The inspector noted that, as a result, the licensee may not have included corrective actions, such as compensatory measures, resulting from CRs. This would constitute an operator burden or workaround. For example, operators previously performed a workaround for the atmospheric relief valves, and past ventilation problems documented in incident reports (a precedent of CRs) required workarounds in the form of open doors. Although plant staff had documented the problems in incident reports, plant staff did not recognize them as workarounds, and did not correct the deficiencies. The licensee plans to revise their program to address this concern.

Root Cause/Corrective Action

Root cause analysis skills have improved as the corrective action program has matured. The Root Cause Manual (RCM) provides detailed instructions for apparent and root cause evaluations. The Corrective Action Review Board (CARB), a management team, reviews Level 1 CRs, to assure quality of corrective actions commensurate with safety significance,. The Corrective Action Review Committee (CARC) performs a similar review for level 2 CRs. The inspector noted that the CARB and CARC routinely rejected inadequate CRs, effectively ensuring high standards for corrective actions. Management also used CARB and CARC rejection rate trends to assure personal accountability and improve performance.

QA Audits

In 1996, Quality Assessment (QA) performed two audits of the corrective action program, and the Salem Integrated Readiness Assessment (SIRA) team performed a third audit. Based on a review of 10 level 1 CRs containing numerous examples of weak or inadequate performance, the first QA audit (96-190-1, May 13 to June 10) concluded that the CAP was ineffective. Weaknesses in these CRs included inadequate corrective actions, insufficient corrective action records, incomplete or unperformed corrective actions. The SIRA report also assessed the CAP as not ready for restart. The second QA audit noted improvement in the quality of level 1 CRs. It also identified improved use of ARs to identify plant problems; better control of documentation, including record transmittal and retention; and less maintenance staff reluctance to submit ARs for human performance issues. The audit identified timeliness of operability reviews for level 1 & 2 ARs, feedback to employees on the results of ARs that they initiated, and condition resolution verification as areas needing further improvement.

The inspector considered both QA audits and the SIRA audit comprehensive. The inspector also determined that the audit teams provided independent assessment. The audits probed the corrective action program in detail and contained appropriate observations and findings to support their conclusions.

Restart Plan

The corrective action program restart plan contains eight problem statements that relate to the following areas: program consolidation, roles/responsibilities, backlog, timely completion of CA, root cause analysis (RCA) and CA effectiveness, trending and common cause analysis, operating experience feedback (OEF) effectiveness, and the SIRA CA conclusion follow up.

Inspectors previously found the CAP roles and responsibilities acceptable. As noted above, the CAP consolidated the previous corrective action program to provide a single point of entry by initiating an Action Request. The CAP has a very low threshold for problem reporting, demonstrated by more than 1000 ARs per month. Inspectors found that the managers verified appropriate AR classification, and evaluation managers demonstrated improved accountability. Root cause analyses and CA implementation have continued to improve as a result of strong CARC and CARB quality oversight. The QA audits provided comprehensive assessment with well supported conclusions. Managers used performance indicators effectively to monitor CAP performance. The inspectors concluded that the NBU effectively implemented the important elements of the restart plan.

c. <u>Conclusion</u>

The corrective action program has continued to improve. The CAP has a low threshold for entry and, using it, the Salem staff routinely identified plant problems. Although some departments did not routinely use the program in the past, the number of ARs that they have written has increased over the two months preceding the inspection. Except for open DEFs in the process of conversion into ARs, the backlog of items from old corrective action systems items is low.

Control room operators willingly initiate ARs for observable deficiencies. The operators effectively entered burdens and workarounds in the corrective action program. The inspectors noted that, in one case, operators did not review the UFSAR or other licensing basis information prior to proposing CAs.

Root cause analyses and CA implementation continued to improve. The CARC and CARB provided very effective oversight. The QA audits provided comprehensive assessment of the CAP with well supported conclusions. The auditors found that many AR initiators did not receive feedback on the disposition of their concerns. Deferrals of work to post restart periods appeared appropriate. Evaluation managers understood their responsibilities to the CAP and their performance has improved. Performance indicators provided an effective way for managers to monitor departmental CAP performance. The quality of level 1 and 2 CR evaluations continued to improve.

In summary, the licensee has significantly improved, and continues to improve, the corrective action program. They implemented appropriate controls to maintain CAP performance. The inspectors considered actions to improve the corrective action program and the corrective action restart plans adequate to support Salem restart.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

a. Inspection Scope (62707)

The inspectors observed all or portions of the following work activity:

- 960904263: 22 RHR pump upper motor bearing oil leak

The inspectors observed that the plant staff performed the maintenance effectively within the requirements of the station maintenance program.

b. Inspection Scope (61726)

The inspectors observed all or portions of the following surveillances:

- S2.OP-ST.DG-0001: 2A diesel generator surveillance test
- S2.OP-ST.DG-0002: 2B diesel generator surveillance test
- S2.OP-ST.SW-0011: In service testing of service water--2SW26 valve, modes 5-6
- S2.RE-ST.ZZ-0002: shutdown margin calculation
- S2.OP-ST.CS-0006: containment spray valve verification modes 1-4
- S2.OP-ST.DG-0003: 2C diesel generator surveillance test
- S2.OP-ST.PZR-0002: In service testing PORV and PORV block valves modes 1-6
- S2.OP-ST.SSP-0011: engineered safety features - response time testing
- S2.OP-ST.AF-0004: In service testing auxiliary feedwater valves modes 1-6

The inspectors observed that plant staff did the surveillances safely, effectively proving operability of the associated system.

M1.2 Maintenance Department Backlogs, NRC Restart Item III.4.2 (Open Unit 1, Closed Unit 2)

a. Inspection Scope

Before the shutdown of the Salem units, Salem staff consistently operated the plants with a large (i.e., approximately 3500) backlog of corrective maintenance work orders. This contributed to the degraded material conditions and to the failure to properly identify and set priorities for work. To resolve this problem, PSE&G developed a formal plan to reduce the corrective maintenance backlog.

The Inspector discussed the plan with Salem planning personnel; reviewed the tools to monitor the backlog size, aging, and work-off rate; and evaluated the backlogged work orders for Unit 2. The inspector also evaluated the screening process for work orders. Finally, the inspector reviewed a sample of post restart backlog items to determine if the system engineer appropriately categorized them.

b. Observations and Findings

System managers determined whether a work order is restart required or post restart using the screening criteria in procedure SC.SE-DD.ZZ-0001(Z), System Readiness Review Program. The inspector had previously reviewed the criteria and found it satisfactory (see section E1.2 of this report.) The system managers performed the screening process formally three times per that procedure prior to restart. From this screening, system managers may categorize work orders as post restart and the work orders then become a part of the maintenance backlog. At the time of inspection, the backlog consisted of more than 3000 work orders.

The maintenance department plan for reducing this backlog focused on Unit 2 at the time of the inspection. Maintenance management developed the plan to reduce the backlog to 400 corrective maintenance work orders before the next refueling outage. As part of this plan, the maintenance department reviewed and verified the validity of the work orders by performing field walkdowns. This process confirmed the post restart categorizations, and insured accuracy and sufficient detail in the problem descriptions. Plant staff stated that they had completed the walkdowns for the backlog. The maintenance staff plans another review to evaluate the work orders for planning purposes and parts requirements in early March. The maintenance manager expected to reduce the backlog by about 1,000 work orders by early March.

The inspector reviewed the entire list of backlog work orders to independently determine if plant staff had correctly characterized the work as post restart, and to assess the resources required for completion. No work items required significant manpower (i.e., overhauls or replacements for major plant components) but 16 work orders appeared to meet the screening criteria for restart required work. The system readiness manager provided information that justified the post restart classification for 15 of the work orders. However, one post restart work order required verification of U-bolt torque values for 31 seismic restraints. Following engineering reevaluation, plant staff reclassified the work as restart required, and rescheduled implementation prior to Mode 4. The inspector noted that the torque verification had minor significance, and plant staff had correctly classified the great majority of post restart work.

The inspector found that Salem planning had implemented a comprehensive database to monitor the backlog reduction effort and various stages of work order processing, such as planning, work restraints, work status, retesting, and closure.

The database enables managers to identify and correct problem areas that reduce the effectiveness of the backlog reduction effort.

c. Conclusions

Although Salem Unit 2 has a sizable corrective maintenance backlog, the work would not impact plant safety or maintenance resources. Also, with one minor exception, plant staff properly classified the work orders as post restart. The inspector concluded that Salem staff adequately managed the backlog to support the restart of Salem Unit 2.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 Unit 2 Refueling Activities

a. Inspection Scope (60710)

The inspectors observed refueling activities from various locations to ensure plant staff properly controlled and conducted the activities.

b. Observations and Findings

On December 16, 1996, Unit 2 operators commenced refueling and entered mode 6. The control room operating shift properly controlled fuel handling activities using disciplined 3-point communications and safety-conscious monitoring of important control room parameters. In particular, operators controlled the pace of the core reload and verified source range counts and startup rate as each fuel assembly entered the core. In past Salem refuelings, operators monitored refueling activities for compliance with regulatory requirements, but contractors directed the refueling. During the December 1996 refueling, operators clearly controlled all facets of the evolution and demonstrated their ownership of the plant. For example, the operators appropriately suspended fuel movement to replace a faulty clutch mechanism that affected slow speed operation of the fuel handling crane. Reactor engineers and the Reactor Engineering Manager provided substantial oversight of fuel handling activities at each watch station. The inspector observed good maintenance technician control of foreign material exclusion, and radiation protection technicians ensured proper implementation of radiological controls.

At 10:05 a.m. on December 19, while walking down Unit 2 containment penetrations, the inspector identified that maintenance technicians removed a service water (SW) valve (24SW223) that potentially affected containment integrity. The Senior Nuclear Shift Supervisor (SNSS) promptly dispatched an equipment operator to verify loss of containment closure and at 10:18 a.m. the SNSS suspended fuel handling. With 24SW223 removed from the piping, a release path existed from the atmosphere inside containment (through tagged open valves 24SW269 and 24SW63) to the atmosphere outside containment (through 24SW223). The pathway violated the containment integrity requirements of Technical Specification 3.9.4.

Preliminary Salem investigation revealed significant weaknesses in the work control process. Initial investigative results indicated that on December 7, the work control center (WCC) authorized the work on 24SW223. The job supervisor signed on the work order on December 9. On December 13, technicians removed the actuator for 24SW223. On December 15, operators verified the 24SW223 valve intact in accordance with S2.OP-ST.CAN-0007, *Refueling Operations - Containment Closure*, in preparation for moving fuel. On December 17, technicians removed the 24SW223 valve to inspect the internals. The licensee also identified pilot holes drilled in 21 and 24 CFCU SW piping that the WCC authorized on December 5 for design change package (DCP) 2EC-3590. These holes added additional vent paths outside containment.

The licensee initiated a significance level 1 root cause analysis of the event (CR 961219244) and reestablished containment integrity. The actions included reinstalling 24SW223, closing additional SW containment isolation valves (21SW58, 21SW72, 24SW58, 24SW72), performing S2.OP-ST.CAN-0007, reviewing all work in progress, and inspecting containment penetrations. In addition, the Salem general manager implemented a requirement that all workgroup leads brief the SNSS twice daily on the specific items they intend to work that shift. The operations manager provided immediate "lessons learned" to all operations personnel. At 10:29 p.m. on December 20, Unit 2 operators recommenced fuel handling activities. At 2:51 p.m. on December 21, Unit 2 operators completed core reload with no further problems.

The event had no actual safety consequence, since the fuel handling accident did not occur during the period of time that the licensee failed to maintain containment integrity. The potential existed to release radioactive material to the auxiliary building if a fuel handling accident had occurred. In that case, the release could not have met design requirements for a filtered flow path, but the plant vent radiation monitors would have monitored the release. The inspectors noted that since Salem unit 2 had not operated for 18 months, the spent fuel involved had very little decay heat or fuel gap radioactivity. The inspector concluded that movement of irradiated fuel in the containment building without containment closure is a violation of Technical Specification 3.9.4 **(VIO 50-311/96-18-02)**.

c. Conclusions

The licensee failed to maintain containment closure while conducting Unit 2 core reload. Plant management responded promptly and appropriately to address the associated weaknesses. Excepting the loss of containment closure, the operating shift demonstrated improved plant ownership in the professional and safety-conscious conduct of fuel handling activities.

M2.2 (Closed) LER 50-272/96-014 - potential hydrogen embrittlement on 4KV breaker parts. In July 1996 during 4KV breaker maintenance, technicians found a broken roll pin. Each breaker has two roll pins. The breaker would still operate with the failure of one pin but would not open or close with the failure of both pins. The plant staff determined that hydrogen embrittlement, resulting from zinc plating during vendor refurbishment, caused the roll pin failure. The corrective action plan included removing affected breakers, and sending them for the appropriate repairs. Prior to the repair work, PSE&G QA placed a stop work on the vendor until subsequent inspections demonstrated that they had resolved the problems. The licensee planned to complete the repairs prior to considering any of the breakers operable. The inspector noted that the breakers did not affect plant safety due to plant conditions, and considered the completed and planned corrective actions appropriate to resolve the problems. This LER is closed.

III. Engineering

E1 Conduct of Engineering

E1.1 Undersized Power Operated Relief Valve (PORV) Accumulators (NRC Restart Issue II.23 - Unit 2 only)(Open)

a. Inspection Scope

To determine the acceptability of PORV accumulator sizing, the inspector reviewed the restart item closure package, the 10 CFR 50.59 safety evaluation, the UFSAR change notice, engineering evaluations, calculations, test procedures, training records, condition reports, and work orders.

b. Observations and Findings

In the original safety analysis of an inadvertent safety injection (SI), a Condition II event, PSE&G assumed operators would act to terminate the event prior to the pressurizer completely filling with water. As a result of reanalysis, and since Salem had not qualified the code safeties to operate with water flow, PSE&G determined that the pressurizer PORVs would have to actuate automatically to control RCS pressure. A stuck open code safety valve resulting from water flowing through it would result in a small break loss of coolant accident (LOCA), a Condition III event. One design requirement for a Condition II event is that it should not propagate into or cause a more serious fault (e.g., a Condition III event).

Two air accumulators per PORV provide air to open the pressurizer PORVs. Check valves in the accumulator air piping prevent the air pressure from bleeding down, thus preserving the air for PORV operation. During reanalysis, PSE&G determined that mitigating an inadvertent SI may require the PORVs to automatically cycle 220 times. Based on this determination, PSE&G did an evaluation of the adequacy of the PORVs, including supporting systems and equipment.

Engineering Review

The engineering evaluation of the PORVs included a review of the thermal-hydraulic effects and piping loading, determination of operator action times, verification of accumulator adequacy, evaluation of controls and air system adequacy, and evaluation of PORV endurance. Engineering evaluation S-2-RC-MEE-1108, *Salem Unit 2 Evaluation of the Pressurizer PORVs for Inadvertent SI*, Rev. 0, dated August 23, 1996, documented this review. The engineers calculated that the PORV air accumulators could support 305 full strokes and an additional 486 partial strokes (50% or greater opening). The calculation credited RCS system pressure in assisting the PORV opening and assumed the accumulator check valves would not leak more than 147 standard cubic centimeters per minute (sccm.) The inspector reviewed the engineering evaluation and other related documents and identified the following issues:

In a review of the testing and maintenance history on the Unit #2 accumulator check valves from 1993 through 1996, the inspector identified repetitive failures of the valves to meet leak rate acceptance criteria. As a result of leakage, Salem replaced two out of four check valves in 1993, one of four in 1994, and two of four again in 1996. The inspector concluded that PSE&G had not considered the past failure history of the check valves during the re-analysis of the event.

The inspector determined that PSE&G had not revised the accumulator check valve leak test procedure, SC.RA-IS.PZR-0024(Q), *Leakage Test of PORV Accumulators*, Rev. 3, dated March 15, 1996, to compensate for the maximum function pressure across the accumulator check valves as required by ASME Section XI, Pump and Valve In service Test Program, 1983 Edition. The test procedure specifies conducting the check valve seat leak test at a pressure differential of five psid. The inspector determined that the test should consider an actual pressure differential during the inadvertent SI, of eighty-five psid. The ASME code Section XI, Subsection IWV, paragraph IWV-3420, *Valve Leak Rate Test*, Step IWV-3423 (e) permits reduced pressure differential leakage testing provided the test compensate the results to the function maximum pressure differential. The Salem staff failed to compensate the results as required.

The failure to consider the adequacy of the accumulator check valves for suitability of application, and the failure to revise the accumulator leak test procedure as a result of the re-analysis of the inadvertent SI at power event, is considered a violation of 10 CFR 50, Appendix B, Criterion III, Design Control **(VIO 50-272&311/96-18-03)**

Review of 10 CFR 50.59 Safety Evaluation Process

The Offsite Safety Review (OSR) Group initiated CR 970106283, documenting a conflict between the inadvertent SI event safety evaluation (S96-125) and the Salem PORV TS basis. The previous analysis of inadvertent SI concluded that operators would terminate SI flow before the pressurizer filled with water. The reanalysis concluded that the operators would **not** terminate the SI flow before the pressurizer filled with water. As a result, the re-analysis took credit for the automatic operation of the PORVs in controlling RCS pressure and preventing the pressurizer code safety valves from opening. Since Salem qualified the PORVs for operation with water flow and had not qualified the pressurizer code safety valves for water flow, the reanalysis credited automatic operation of the PORVs to prevent a small break LOCA resulting from a stuck open pressurizer code safety valve.

The OSR reviewer concluded, however, that the reanalysis required a change to Technical Specification for PORVs. Salem Unit 2 Technical Specification 3.4.5 allows continuous operation in Modes 1, 2, and 3 with one or both PORVs inoperable and capable of being manually cycled, provided the associated block valve is shut. The TS bases state that the PORVs may be inoperable due to *automatic control problems* as long as the cause does not prevent manual use or create the possibility for a small break LOCA. The reviewer correctly concluded that the reanalysis required a change to TS 3.4.5 to prohibit continued plant operation with both PORVs inoperable due to loss of automatic function. At the close of the inspection, development of a License Change Request neared completion.

The inspector determined that the safety evaluation incorrectly concluded no unreviewed safety question existed for the following reasons:

1. The probability of an accident previously evaluated in the SAR increased. In the previous analysis, operators terminated the inadvertent SI before it filled the pressurizer and presented the potential that a code safety valve would stick open as a result of water flow through the valves. In the new analysis, the operators did not terminate the SI before it filled the pressurizer. The safety evaluation did not identify increased probability of an accident previously evaluated.

2. The probability of occurrence of a malfunction of equipment important to safety previously evaluated in the SAR slightly increased. Since the SI filled the pressurizer in the reanalysis, the probability of malfunction of a code safety increased, since Salem has not qualified the code safeties for operation with water flowing through them. The safety evaluation did not identify increased probability of occurrence of a malfunction of equipment important to safety previously evaluated in the SAR.

3. The change creates a possibility of a malfunction of a different type than any evaluated previously in the SAR, since the SAR did not previously credit automatic operation of the PORVs to mitigate an inadvertent safety injection. The PORVs are not safety related equipment, and, although credited as active components, do not have the ability to withstand a single active failure. The safety evaluation did not identify the possibility of a malfunction of a different type than any evaluated previously in the SAR.

4. The proposal results in a reduction in the margin of safety as defined in the basis for the PORV technical specification due to the fact the basis does not consider the requirement for PORV automatic control availability. The safety evaluation did not identify a reduction in the margin of safety for Technical Specification 3.4.5.

The engineering staff failed to recognize that it **changed the licensing basis for an inadvertent safety injection**, and therefore required prior NRC review and approval. The NRC clearly stated this guidance in NRC Inspection Manual Part 9900 Guidance on 10 CFR 50.59, dated 4/9/96. The Salem QA staff identified the USQ and the requirement to change Technical Specification 3.4.5. As a result, the licensee initiated a License Change Request to change Technical Specification 3.4.5, and obtain NRC review of the proposed change. Since both Salem units have remained shut down since June 1995, inability to mitigate inadvertent SI had no immediate safety consequence. This licensee identified and corrected violation of 10 CFR 50.59 is being treated as a non-cited violation, consistent with Section VII.B.1 of the NRC Enforcement Policy.

In addition to the above, the inspector identified the following weaknesses in the 10 CFR 50.59 safety evaluation:

The safety evaluation described the required operator action for the PORV block valves differently from the assumptions in the FSAR re-analysis. The re-analysis assumed that the operators would verify the block *valves* opened within ten minutes of the onset of the event. The safety evaluation described this as making *one* PORV available by opening its associated block valve.

The safety evaluation inappropriately implied that NRC Generic Letter 90-06 approved use of the PORVs and block valves for safety related functions, including steam generator tube rupture (SGTR) accident mitigation. Although Generic Letter 90-06 stated that some plants rely upon the PORVs for safety related functions, it did not provide NRC approval of PORV and block valve use for these functions. The inspector further noted that Salem PORV use to mitigate the SGTR event differed significantly from PORV use to mitigate the Inadvertent SI event. The inspector considered comparison of the two events without describing the differences misleading.

EOP and Training Review

The inspector reviewed the EOPs and Operator Training to determine how PSE&G met the requirement that the PORV block valves had to be opened within ten minutes from an inadvertent SI initiation. The continuous action steps of 2-EOP-TRIP1, Reactor Trip or Safety Injection, Revision 20, direct the operators to verify that the PORV block valves were opened. The inspector found that the four Unit 2 restart operating shifts had completed training on the new requirements for inadvertent SI. The operators successfully completed an inadvertent SI event on the simulator in October 1996 with no preparation. The operator performance times during the test varied from seven to nine minutes. The inspector concluded that the combination of EOP requirements and operator proficiency training provided confidence that the PORV block valves would be opened within ten minutes of an inadvertent SI event.

c. Conclusions

Engineering staff failed to evaluate the PORV accumulator check valves suitability for use and failed to revise the IST check valve leak test procedure. An OSR reviewer identified that reanalysis of the inadvertent SI involved an unreviewed safety question and required a change to Technical Specification 3.4.5. This restart issue remains open until resolution of the above issues.

E1.2 Management of the Engineering Backlog, NRC Restart Item III.4.1 (Closed)

a. Inspection Scope

The inspector reviewed PSE&G's methods to monitor the backlog size, assess the significance of backlog items on plant operation and safety, and to keep management informed of emergent issues. The inspector reviewed the technical adequacy of screening criteria used to categorize items as post restart. The inspector also reviewed a sample of backlog items categorized as post restart to determine if any should have been categorized as restart required.

b. Observations and Findings

The inspector found that managers used several tracking methods to monitor the number of outstanding corrective action work items, design change packages and engineering work requests. The managers also used performance indicators to monitor work schedule completion. The engineering performance monitoring system tracks open work items in four categories; Design Engineering, System Engineering, Projects, and Fuel Engineering. This tracking system provided warning indicators when backlog exceeded acceptable levels. The inspector observed red indicators for Design Engineering, representing a larger than acceptable backlog. The manager of Design Engineering knew of the "red" status and, although focused on the items required for Mode 4, he also addressed the total backlog in meetings held three times weekly.

The inspector reviewed the screening criteria in procedure SC.SE-DD.ZZ-0001(Z), *System Readiness Review Program*. The criteria provided sufficient guidance to correctly classify engineering work as required for restart or post restart. The inspector also reviewed a list of approximately one-hundred post restart Design Change Packages (DCPs) and found two with descriptions that lead the inspector to suspect that they might be required for restart. The inspector reviewed the two DCPs and concluded that one had minor safety significance, was not critical for restart and was categorized satisfactorily. The other DCP (DCP-2EC-3546), related to Appendix R requirements, and is the subject of NRC restart inspection Item III.1.

During a previous inspection, inspectors reviewed a sample of work documents (Action Requests) assigned to engineering and concluded that Salem staff had appropriately deferred only items of minor safety significance until after restart. Also as part of that inspection, inspectors found that the Salem Engineering Department had integrated key engineering personnel into daily plant meetings to ensure that emerging engineering issues and problems were presented to system engineering staff for review, prioritization, and resolution. The inspector concluded that the Salem Engineering Staff successfully implemented a process for ensuring identification and appropriate corrective action for emerging technical issues. The inspector determined that the processes insured management awareness of emerging technical issues and the content of the backlog. (Reference Inspection Report 50-272,311/96-16)

The inspector reviewed two PSE&G self-assessments conducted to evaluate the technical adequacy of the Nuclear Engineering Backlog Reduction Project (Report 95-17 and 96-03). The assessments identified many questions for response and resolution by PSE&G Engineering. The inspector found that PSE&G had either resolved the issues or initiated appropriate corrective measures to address the concerns. The inspector determined that none of the questions posed a significant safety concern.

c. Conclusions

The engineering staff effectively managed the engineering backlog. Engineering managers actively participated in prioritization of emergent items and, in so doing, remained aware of the content of the backlog. For those items sampled, the inspector considered the post restart categorization either acceptable or, in one example, not yet finalized. This restart item is closed.

E1.3 Containment Fan Coil Unit Operability

The purpose of the CFCUs is to cool the containment atmosphere during post accident conditions. There are six two-speed (slow and fast) CFCUs. Normally, three of the CFCUs run in fast speed to cool the containment during power conditions. Post-LOCA conditions require all six CFCUs to run at slow speed to provide long term containment cooling.

During accident conditions, all running service water (SW) pumps trip and restart in the prescribed load sequence. Prior to restoration of power, service water will drain from the elevated CFCU heat exchangers down toward the river elevation. This causes voids to form in the CFCU heat exchangers and SW piping. When the SW system restarts on restoration of power, the voiding causes rapid acceleration of flow through the system piping, in turn causing severe water hammer at the 90 degree pipe bends. If the water hammers cause failure of the SW pipe in containment, a containment breach would result, providing a release path to outside of containment. Isolation of the affected SW pipe would also result in loss of the containment cooling function.

The PSE&G Nuclear Engineering Design department started to develop a standpipe modification to address this concern. The standpipe will preclude CFCU cooler and pipe voiding during the time delay prior to restarting SW pumps.

E1.4 Steam Generator Replacement Project (SGRP)

a. Scope (50001)

The inspector reviewed current and planned work, related procedures, documentation, quality inputs and progress of the Salem Unit 1 steam generator replacement project (SGRP). The site inspection included observations of conditions and work in and outside the containment structure.

The inspector reviewed project nonconformance reports (NCRs), and temperature limits on lifting equipment and SGs. The inspector observed original steam generator (OSG) shipping preparation area, structural steel welding in containment, and the weld rod ovens and weld rod issue conditions at the fabrication shop and in containment. The restoration process including sea-van and Hope Creek storage of equipment and plant components was examined. The SGRP related tasks including project self assessment, Quality Assurance by PSE&G, Raytheon Nuclear (RNI) and Framatome Technologies (FTI); the FSAR Project relation to SGRP engineering data inputs, SGRP improvement progress, fire control and the work package closeout process were reviewed.

b. Observations and Findings

By January 17, 1997, the licensee had shipped two OSGs offsite for burial and prepared the remaining two for shipping in the preparation area. During the inspection, workers transported the first replacement steam generator (RSG) to the Unit 1 containment building. Project staff had substantially completed work in the RSG staging area, with work package documentation and review in progress.

The inspector reviewed nonconformance reports (NCRs) written as of 12/23/96 to determine the scope of identified nonconformances and related corrective actions. Welding of lower support structural steel for the RSGs used proper preheating and welding techniques. The supervisors controlled work packages in the work area.

The inspector verified appropriate implementation of temperature limits to prevent brittle fracture or low temperature equipment failure of steam generator rigging, lifting and movement in the winter months. The work planning identified a low temperature limit of 15 degrees above zero, Fahrenheit, for the lower runway system.

The project staff initiated the component restoration process in the work packages for component removal early in the SGRP sequence. The inspector sampled removal work packages, the lists of removed components and examined the sea-van and Hope Creek storage of equipment and plant components to establish the level of control on removed components. Although the manufacturer's manual for snubbers (PA88780) provides a prolonged storage temperature range of 40 to 120 degrees F for hydraulic snubbers, the inspector found the hydraulic snubbers stored in a sea-van subject to temperatures less than 40 degrees F. The snubber manufacturer indicated that for the short storage term involved, exposure to the lower temperature should cause no degradation of the snubbers. The inspector identified no other potentially environmentally sensitive components stored in a condition outside the recommendation of the manufacturer.

The inspector found no areas of concern with the SGRP related tasks including project self assessment, Quality Assurance by PSE&G, RTI and FTI, the SGRP improvement progress, fire control or the work package closeout process.

Engineering

The project contractor FTI performed a major portion of the engineering evaluations to determine the effect of differences between the OSGs (Model 51) and RSGs (Model F) on Unit 1 plant performance, with Westinghouse and PSE&G doing part of the work. Inspection of SGRP engineering work as discussed in NRC Inspection Report 50-272/96-017 noted that the Analysis Input Data prepared for FTI engineering had not been compared against the findings of the PSE&G FSAR project applicable to steam generators. The inspector reviewed PSE&G letter SG-96-0309, dated 12/20/96, summarizing the PSE&G review of FSAR Project findings (Problem Reports) against the SGRP Design Calculation Inputs. The PSE&G review concluded that the FSAR Project had identified no adversely affected Design Analysis Inputs for the SGRP engineering evaluations.

c. Conclusions

Inspections of current and planned work, related procedures, documentation, quality inputs and progress of the Salem, Unit 1 steam generator replacement project found generally good performance and identified no safety significant deficiencies. The management-initiated corrective and preventive actions improved project performance. In the area of engineering, PSE&G compared the FSAR project findings against the SGRP Design Inputs with no input changes resulting.

E2 Engineering Support of Facilities and Equipment

E2.1 NRC Restart Issue II.34 - Safety Injection (SI) Pump Deficiencies (Closed, Unit 2 only)

a. Scope

NRC Inspection Report 96-08 documented Salem staff's resolution of SI pump deficiencies, however, the issue remained open because the operators had not tested the pumps by the end of the inspection period. Subsequently, operators completed pump performance tests. The inspectors observed portions of the tests and reviewed performance data.

b. Observations and Findings

The inspectors previously documented SI pump deficiencies. For example, no preventive task existed for technicians to periodically refurbish SI pump motors, the

Salem staff had not addressed industry experience regarding improperly fastened SI pump impeller locknuts, and both pumps exhibited excessive shaft run out during pump reassembly. Salem staff appropriately resolved these issues (NRC Inspection Report 50-272&311/96-08 has details).

Subsequently, during pump performance tests, system engineers noted that the no. 22 pump discharge pressure was higher than no. 21 pump for the same test flow rate. The engineers, with support from Westinghouse, determined no. 22 pump was a slightly stronger pump than no. 21. This condition also resulted in no. 22 pump motor drawing more current than no. 21 pump motor (51 amperes compared to 47 amperes). Salem staff appropriately determined that the higher load would not exceed the no. 2C emergency diesel generator capacity.

The operators performed surveillance tests on both SI pumps in accordance with S2.OP-ST.SJ-0001(2)(Q), *21(22) SI Pump Surveillance Test*, and S2.OP-ST.SS-0002(4)(Q), *Engineered Safety Features Manual Safety Injection 2A Vital Bus.* The inspectors observed portions of the tests, reviewed test data, and determined pump performance met Technical Specification surveillance requirements.

Inspectors also reviewed restart-required work orders for the SI pumps and noted that 32 minor items remained open. Plant staff had completed most of these items; final closure awaited retests that required the plant to be in Mode 4 or 3 (for example, valve leak tests that require reactor system pressure of 1000 psig). The inspector did not find any items that would preclude safe plant restart or challenge pump reliability.

c. <u>Conclusions</u>

Inspectors determined that Salem staff effectively corrected Unit 2 SI pump deficiencies and subsequently demonstrated pump performance met surveillance requirements. The inspector considered the corrective actions adequate for restart of Salem Unit 2.

E2.2 <u>NRC Restart Issue II.17 - Main Condenser Steam Dumps Malfunction (Closed)</u>

a. <u>Scope</u>

Inspectors documented, in NRC Inspection Report 50-272&311/96-08, action by the Salem staff's resolution of main steam dump deficiencies. The issue remained open, however, because Salem staff had not completed modifications to the system or implemented a revision to the Emergency Operating Procedures (EOPs).

b. <u>Observations and Findings</u>

Salem staff completed modifications to steam dump components. Modifications included valve upgrades and valve positioner linkage improvements. The inspector noted that Salem staff included the steam dumps in the startup and power ascension sequencing program. Operators will test the system in Mode 5 per procedure TS2.SE-SU.RCP-0002(Q), *Steam Dump Control Loop Functional Test (Mode 5 Portion)* and again in Mode 3 or 2 per procedure TS2.SE-SU.RCP-0008(Q), *Steam Dump Control Loop Functional Test (Mode 3 or 2 Portion)*. Operators will also monitor system performance during advanced digital feedwater control system testing.

In addition to completing the field modifications, Salem staff implemented an appropriate EOP revision, effective October 21, 1996. The inspector considered this issue acceptable for restart, however, inspectors will observe restart testing. **(IFI 50-311/96-18-04)**

c. Conclusions

The Salem staff completed modifications to the steam dumps and implemented related EOP changes. The inspector considered the corrective actions for the steam dump deficiencies comprehensive and sufficient for restart of Salem Unit 2. The inspectors will observe operation of the steam dumps during plant operation.

E2.3 Management Review Committee (MRC)

a. Inspection Scope (37551)

The inspector assessed MRC review of NRC restart item closure packages, the Operations Department and System Engineering Department restart affirmations, and the operator workaround and control room indicator restart issue, to determine the effectiveness of the reviews.

b. Observations and Findings

The inspector verified that Salem senior managers representing operations, engineering, maintenance, radiation protection, licensing, special projects, and quality assurance met MRC quorum requirements for the January 4, 1997, meeting. The MRC members and the presenters engaged in spirited and extensive discussion, and thoroughly explored each subject prior to voting on approval. The MRC opened action items to obtain additional information or require additional action as appropriate. For example, during the restart affirmation presentation by system engineering, the MRC determined that design engineering had not affirmed readiness to support Salem restart. The MRC opened an action item to require design engineering affirmation prior to Salem Restart. The MRC reviewed and approved NRC Restart Issue III.8, "Operator Workarounds, Including Control Room Deficiencies," the system engineering restart affirmation, and several operations department restart plan items.

c. Conclusions

The MRC performed a thorough review and evaluation of the Operations Department and System Engineering Department restart affirmations, and the operator workaround and control room indicator restart issue. The MRC initiated Action Items as appropriate.

E2.4 In Service Testing (IST) of Valves SJ4 & SJ5

a. Scope

The inspector reviewed IST testing of SI valves SJ4 and SJ5, inlet isolation valves to the boron injection tank during a review of NRC Restart Issue II.23.

b. Observations and Findings

Salem FSAR, Chapter 15, Accident Analysis for a SGTR event, requires several operator actions, within fifty minutes of event initiation, to terminate steam release from the faulted steam generator (SG) and primary to secondary leakage. The required operator actions include termination of SI flow.

The inspector reviewed emergency operating procedure (EOP) 2-EOP-SGTR-1, Steam Generator Tube Rupture, Revision 20, and discussed the SGTR event with Salem operators and training department personnel. From this review, the inspector learned that the operators terminate SI flow by *closing* valves SJ4 and SJ5 from the control board, as required by the SGTR EOP.

Salem TS 4.0.5 requires in service inspection and testing of ASME components in accordance with Section XI of the ASME Boiler and Pressure Vessel Code and applicable Addenda. Article IWV-3000 of ASME Section XI requires category A and B valves to be exercised to the position required to fulfill their function and requires full-stroke time testing. Salem's in service testing program defines valves SJ4 and SJ5 as category B valves, but only requires testing in the open position. Salem's IST program states that valves SJ4 and SJ5 have *no safety function in the closed position* and that inlet isolation of the boron injection tank is not required for accident mitigation. The inspector concluded that failure to include testing of SJ4 and SJ5 in the closed direction is a violation of TS 4.0.5. The IST staff initiated CR 970118091 to address the inspector's findings **(VIO 50-272 & 311/96-18-05.)**

c. Conclusions

The inspector identified that PSE&G mis-classified valves SJ4 and SJ5 as passive components and, as a result, had not included them in the IST program for exercise and stroke testing in the closed direction. The inspector determined that the valves must close to stop charging flow to the RCS during a steam generator tube rupture event, and Salem should have included them in the IST program. Failure to exercise and stroke test valves SJ4 and SJ5 as part of the Salem's IST program is a violation.

E2.5 <u>NRC Restart Issue II.42 - Auxiliary Feedwater (AFW) Performance and Reliability (Open Unit 1, Closed Unit 2)</u>

Inspectors documented review of this restart item in NRC Inspection Report 50-272&311/96-17. In that report, the inspector considered the actions taken by the licensee to improve Auxiliary Feedwater performance and reliability effective, but the inspector did not close the issue at that time because of the large number of outstanding items that remained to be tested. Since the plant staff implemented acceptable corrective action and because they must operate the system to perform the testing, this issue is considered closed for Salem Unit 2 restart. The NRC will monitor completion of testing during the plant restart. **(IFI 50-272&311/96-18-06)**

E8 Miscellaneous Engineering Issues

E8.1 <u>(Closed) LER 50-272/95-016</u>: difference between containment design parameters and accident analysis. On July 20, 1995, engineering identified a discrepancy between the design basis for the containment structure as described in TS, the Updated Final Safety Analysis Review (UFSAR) Chapter 15 accident analysis, and the containment structure design calculations.

Engineers determined that, following a main steam line break accident, the containment liner plate may yield, however, the containment would still perform its function because the pressures and temperatures would not overstress the reinforced concrete. The engineers concluded that the liner would maintain leak tight integrity. In addition, they identified a potential limited failure of Unit 1 containment spray piping supports and identified that the reactor coolant pump (RCP) platform supports would yield for both units. The licensee identified that engineering did not consider all sections of the TS and UFSAR in evaluating previous changes in containment temperature profiles.

The licensee modified Unit 1 containment spray piping supports. Engineering modified the Unit 2 RCP platforms (DCP 2-EE-0097). On June 18, 1996, licensing submitted LCR S9606 to address the peak containment temperature discrepancies between the design basis and that stated in TS. Engineering conducted training on 10 CFR 50.59 safety evaluations and revised their 10 CFR 50.59 program guidance to require a text search when performing safety evaluations.

The inspector verified the DCP and LCR status, and the 10 CFR 50.59 program guidance. The inspector determined that the licensee took appropriate corrective actions. The licensee identified and corrected failure to properly evaluate previous changes in containment temperature profiles, as required by 10 CFR 50.59, is being treated as a non-cited violation, consistent with Section VII.B.1 of the NRC Enforcement Policy.

IV. Plant Support

P3 EP Procedures and Documentation

a. Inspection Scope (92904)

The inspector reviewed various Emergency Plan (Plan) and Emergency Plan Implementing Procedure (EPIP) revisions to determine if the changes reduced the effectiveness of the Plan.

b. Observations, Findings and Conclusions

Based on the licensee's determination that the changes do not decrease the overall effectiveness of the Plan, and that it continues to meet the standards of 10 CFR 50.47(b) and the requirements of Appendix E to Part 50, the changes did not require NRC approval. The inspector determined that the changes met the requirements of 10 CFR 50.54(q).

P4 Staff Knowledge and Performance in EP

a. Inspection Scope (92904)

The inspectors observed table-top mini-drills for Salem/Hope Creek (S/HC) operators, S/HC Technical Support Center (TSC) groups, and Emergency Operations Facility (EOF) groups (common to S/HC), to determine EP training effectiveness, and to ensure that emergency response organization (ERO) managers could correctly classify emergency events using the new Nuclear Management and Resources Council (NUMARC) emergency action levels (EALs).

b. Observations and Findings

Licensee responders demonstrated good overall performance during the mini-drill scenarios. Simulated emergency event classifications were accurate and timely. Offsite notifications were also timely, and professionally completed. Protective action recommendations (PARs) were formulated in accordance with licensee procedures, and were appropriate for the scenarios. Emergency responders routinely double-checked each other regarding EAL usage and event classifications. Post-drill critiques were held, were generally open and self-critical, and identified most items identified by the inspectors.

The inspectors determined that the fission product barrier (FPB) table associated with the NUMARC EALs was not consistent with the PAR flowchart found in the Event Classification Guide (ECG), Attachment 4, "General Emergency." The FPB table identified criteria for determining a loss or a partial loss of a barrier, whereas the PAR flowchart used only the loss of barriers for the determination of a PAR. This caused confusion for some Emergency Coordinators (ECs) during PAR formulation. For example, both of the Salem Senior Nuclear Shift Supervisors observed by the inspectors, determined a PAR based on the loss of all three FPBs, when in reality two barriers were lost, and one was partially lost. The FPB table gave discretion to ECs to declare a barrier lost if they felt that the loss was imminent, and both managers exercised that discretion for the partially lost barrier. In both cases, the result was a PAR that recommended a more extensive evacuation than was necessary, and that was inconsistent with the expected PAR on the licensee-approved scenario. The inspectors concluded that these PARs were acceptable. However, one of those managers stated that he had been trained to treat a partial loss of a barrier as a loss for PAR formulation.

Licensee drill observers also observed this inconsistency between the FPB table and the PAR flowchart, and pointed it out during the mini-drill critiques. The acting EP manager stated that the PAR flowchart would be revised to be consistent with the FPB table, thus, resolving the inconsistency, as well as the above training issue concerning partially lost barriers.

Inspectors also concluded that ERO managers generally found their response procedures to be cumbersome, in that they were required to use and sign off on two checklists concurrently, one from an EPIP, and one from an ECG attachment. This sometimes resulted in emergency actions being somewhat delayed. For example, one TSC EC was not as timely as he could have been in initiating accountability after he had declared a site area emergency. This was self-identified during the ensuing critique. In another case, an EOF EC could have been more timely in announcing a general emergency (GE) declaration to the EOF staff, and in notifying the TSC of the event. In assessing these delays, the inspectors took into consideration the fact that the emergency groups observed did not have the full team of responders that would normally be present during an emergency. The delayed events could have been prompted by the additional responders, e.g., the Security Team Leader could have prompted the initiation of accountability, since he is the person responsible for its completion.

The licensee stated that it had initiated a procedure upgrade program to address this issue. Implementing procedures were being revised to incorporate all required manager actions into one procedure. The revised procedures are scheduled for implementation in early 1997.

The licensee used enlarged laminated copies of the NUMARC EAL tables during the mini-drills. These were well-received by the ECs who generally found them easy to use. However, these laminated copies were presented in a different format than those in the ECG. The ECG presents the EALs in a flowchart format, with events progressing from an Unusual Event (UE) to GE. The laminated copy presents the EALs in a tabular format, with GEs in the left-hand column, progressing to UE, from left to right. This was an improvement since ERO managers routinely review the EALs from the most severe classification level to the least severe, to ensure that the highest level applicable to an event is declared. The inspectors questioned whether these copies would be formally controlled and marked with the appropriate revision number when distributed for general use and whether the laminated copies would be included in or referenced in the Plan. The licensee stated that they would.

c. Conclusions

Licensee ERO responders demonstrated that EP training was effective through good mini-drill performance. The ERO managers demonstrated the ability to accurately classify emergency events using the NUMARC EALs.

P8 Miscellaneous EP Issues

P8.1 Effectiveness of Licensee Controls

a. Inspection Scope (92904)

The inspectors reviewed Condition Reports (CRs), generated by the licensee's action item tracking system, to close outstanding items. They also interviewed EP, licensing, and quality assessment staff members concerning the use of the tracking system.

b. Observations and Findings

The inspectors reviewed the licensee's CRs, and in many of the cases, found that they were not able to determine what actions had been taken to correct the deficiencies. The inspectors often had to request additional documentation or interview the individual responsible for closing the item, in order to understand the corrective actions.

The inspectors informed the licensee that the depth of CR closure documentation varied between reports. The following items were identified: 1) the EP staff did not have the opportunity to review corrective actions pertaining to their area, but assigned to and closed by other departments; 2) the EP staff did not have a dedicated tracking system coordinator like most other departments; 3) no EP staff member was qualified to perform high priority (level one) root cause analysis for EP issues; and 4) discussions with EP staff members indicated that they did not fully understand the capabilities and operation of the system. Licensee representatives stated that they were aware of these problems and would review this area further prior to the Salem Unit 2 restart.

The inspectors also found that in August, 1995, the owner-controlled area siren system failed a surveillance test and was subsequently found to be inoperable from its remote actuation point, the security central alarm station. The licensee modified the system to enable manual actuation of the sirens in the evacuation mode by placing actuation switches on each of the three siren poles, and issuing a directive for security force members to actuate the sirens manually when directed. The modification, however, did not allow actuation in a previously existing second mode--the assembly (relocation) mode. While the relocation mode would probably have little use during an actual emergency and its function could be accomplished by other means, that feature of the system, as originally designed, was essentially removed. The licensee could not produce any documentation to indicate that the removal of that feature was evaluated at the time it occurred or that it was entered into a corrective action/tracking system for later evaluation. The problem was identified by the licensee and entered into the tracking system on December 13, 1996, but the inspectors noted that the entry failed to include the need for review under 10 CFR 50.54(q). The licensee was advised of that need.

c. Conclusions

The licensee's action item tracking system was adequate for tracking and resolving EP issues, but inspectors noted several deficiencies with the implementation of the system by the EP Department. The foregoing issues will be reviewed further in conjunction with the Salem restart item III.a.10 concerning the licensee's corrective action system.

P8.2 (Closed) Violation 50-272/95-81-01: Alert for loss of annunciators not within time limits.

The Unit 1 senior nuclear shift supervisor (SNSS) who failed to declare the Alert in a timely manner was counseled in accordance with the Public Service Electric and Gas (PSE&G) disciplinary process.

The loss of annunciators event was discussed with all SNSSs. During the discussions, the proper use of the Salem ECG was stressed. This was also reinforced at a SNSS meeting held on February 1, 1996. The inspector discussed with the acting EP Manager, the Salem and Hope Creek licensed operator training concerning management expectations for proper use of the ECGs. The inspector also verified the Salem training by reviewing the lesson plan, handouts, and attendance sheets for the classes. Licensee representatives stated that Hope Creek operators received similar training.

Proper use of the Salem and Hope Creek (S/HC) ECGs and lessons learned from this event and selected previous events were, and will continue to be, reviewed and emphasized during the operator training scheduled to support the restart of the Salem Units, and during the continuing training program. The inspector interviewed the Salem Operations Manager and the acting Operations Training Manager, both of whom stated that they personally communicated their expectations for ECG use during licensed operator requalification training (LORT) classes. Additionally, the managers stated, and the inspector confirmed, that during LORT training scenario cycles, with full shift complements, event classifications and all necessary actions required by the EPIPs would be performed during the scenarios instead of at the conclusion of the scenarios, that was the normal procedure for license examinations. This requirement was being incorporated into the present scenario guides as they are routinely reviewed, and into new guides as they are generated.

The S/HC ECGs were evaluated and revised by the licensee based on the NUMARC National Environmental Studies Project (NESP) 007 guidance. The revisions were submitted to the NRC for review and approval on August 24, 1995. The NRC completed its review and issued a Safety Evaluation Report, approving the revisions, on December 19, 1996. The States of New Jersey and Delaware reviewed and concurred in the revisions. The training for implementation of the NUMARC ECGs has been under way since August, 1996, and is almost complete. The licensee planned to complete the training and implement the NUMARC ECGs, prior to the Unit 2 startup. S/HC operators, TSC groups, and EOF groups were evaluated in mini-drills during this inspection, on the correct use of the NUMARC ECGs. (See Section P4.)

Additionally, the inspector reviewed documentation of other incidents that involved missed/incorrect event classifications during training and actual events, and the associated corrective actions. Some corrective actions were: 1) EP has reinstated the announced control room mini-drills on an approximately biweekly basis, and unannounced mini- drills on a quarterly basis; 2) The lessons learned from these incidents were being incorporated into EP and operator training lesson plans and; 3) EP is now involved in the review and validation of simulator scenarios to ensure that proper event classifications are identified in the scenario guide.

Based on the findings of this inspection, this item is closed.

P8.3 (Closed) Violation 50-272/95-81-02: Emergency response staffing for loss of annunciators not within time limits.

The licensee evaluated and tested its callout pager system and identified some system deficiencies. The vendor corrected these problems, made enhancements, and retested the system. The enhancements streamlined the automated pager activation process and resulted in a reduction in time between the group pager activations. Additionally, the licensee conducted quarterly call-out muster drills (with responders required to physically report to the ERFs), weekly on-duty team pager tests (responder call in with an estimated time of arrival), and monthly pager tests for the entire ERO. The inspector reviewed the 1996 records for these drills/tests and verified that all were conducted. The inspector concluded that the drill/test results indicated that the licensee was able to fully staff and activate the emergency facilities within the required time limits.

Individuals who failed to adequately respond to a pager test were contacted by telephone to determine if there was a system or pager problem. If not, then an "Emergency Response Callout Accountability Form" was sent to the individual's supervisor, who was required to counsel the individual, and then return the form to the EP group to document the inadequate performance. If that same individual failed to respond a second time, the Vice President (VP)-Nuclear Operations pulled the person's security badge to preclude site access. The inspector reviewed the 1996 forms and noted that in the second half of 1996, the forms had significantly decreased in frequency. Also, trending reports for the monthly pager tests indicated that there was a 100% callout response since April, 1996.

During this inspection, the licensee conducted an unannounced pager test for the on-duty team responders. All responders were timely except one. That individual stated that he had a personal commitment at the time the test was initiated. An accountability form was issued to the individual's supervisor.

The licensee stated that in the past eight months, senior management has been very proactive in supporting the EP program and believed this to be the major contributing factor to changing attitudes and improving responsiveness by ERO personnel. The inspector reviewed a letter sent to ERO personnel from the Senior VP-Nuclear Operations, in that management's expectations were clearly defined. The letter also defined ERO roles, responsibilities, and proper cultural attitudes for response personnel. This letter was added to all ERO responder packets distributed at EP training sessions and is periodically reprinted in an EP monthly newsletter.

Based on the findings in this inspection, this violation is closed.

P8.4 (Closed) Violation 50-272/95-81-03: Changes to EALs not discussed and agreed on with state officials. After the October 4, 1995 loss of annunciator event, the licensee appropriately revised the EALs covering such events. However, the licensee failed to discuss and seek agreement with the states (New Jersey and Delaware) prior to the implementation of the revised EALs.

The licensee determined that the root cause of the violation was a misinterpretation of 10 CFR 50.54(q) and 10 CFR 50 Appendix E in that it believed that only an annual review of the EALs with offsite officials was required. To prevent recurrence, the licensee planned to implement the following corrective actions: 1) conduct NUMARC EAL training with offsite officials; 2) conduct team-building sessions with offsite officials to improve communications; 3) modify the change review procedure to ensure state approval for EAL changes is received prior to their implementation and; 4) develop an EAL review form to be used for submittal of EAL changes to the states, and to document state agreement or disagreement with the proposed revisions.

The inspector reviewed documentation verifying that representatives of offsite agencies (states and counties) attended the NUMARC EAL training. The inspector determined that the training material was thorough and informative. The inspector also reviewed documentation of the team- building sessions. Past sessions were well attended and future sessions are planned. The inspector reviewed EPIP 1003, "Review and Approval of Plan/Procedures/ECG," and determined that, as part of the change review process, the procedure reminded the reviewer that state agreement is required prior to EAL change implementation. The licensee informed the inspector that EPIP 1003 will be revised to include verification that state agreement was received prior to implementation. Finally, the inspector reviewed the EAL review form and several instances of its usage in communicating EAL changes with the states. For example, the inspector verified that the states have agreed to the NUMARC EALs that are to be implemented prior to the Salem Unit 2 reactor startup.

The inspector also reviewed other aspects of the licensee interface with offsite entities to ensure the existence of good communications and good program implementation in areas affecting those entities. The inspector verified that letters of agreement with offsite officials and support organizations have been maintained current for the last three years. He also verified that annual EAL training had been conducted for offsite officials during the past three years. Lastly, the inspector verified that the licensee had made the portion of the 10 CFR 50.54(t) audit reports that assessed the licensee's offsite interfaces, available to offsite agencies. The inspector reviewed the assessments of the offsite interfaces in the past three audit reports, that indicated good performance.

The inspector verified that the corrective actions developed by the licensee were complete, comprehensive and thorough. Therefore, this violation is closed.

P8.5 Updated Final Safety Analysis Report (UFSAR) Review

A recent discovery of a licensee operating their facility in a manner contrary to the UFSAR description highlighted the need for a special focused review that compares plant practices, procedures, and/or parameters to the UFSAR descriptions. While performing the inspections discussed in this report, the inspector reviewed the applicable portions of the Plan that related to the areas inspected, since the UFSAR does not specifically include emergency preparedness matters. No deficiencies were noted.

S1 Conduct of Security and Safeguards Activities

S1.1 Protected Area/Vital Area Access Controls

During this inspection period, the inspectors observed several examples of inadequate implementation of the Salem and Hope Creek Security Plan. The inspectors documented the observations and the associated Notice of Violation in NRC Inspection Report 50-354/96-10. (VIO 50-272&311/96-18-01; 50-354/96-10-03)

V. Management Meetings

X1 Exit Meeting Summary

The inspectors presented the inspection results to members of licensee management at the conclusion of the inspection on January 29, 1997. The licensee acknowledged the findings presented.

The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

INSPECTION PROCEDURES USED

IP 61726:	Surveillance Observations
IP 62707:	Maintenance Observations
IP 71707:	Plant Operations

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-272&311/96-18-01	VIO	inadequate security plan implementation
50-311/96-18-02	VIO	lack of containment closure during refueling
50-272&311/96-18-03	VIO	design control of PORV accumulator check valves
50-311/96-18-04	IFI	main condenser steam dump testing
50-272&311/96-18-05	VIO	SJ4 & 5 not included in IST program
50-272&311/96-18-06	IFI	AFW pump performance

Closed

50-272/95-016	LER	difference between containment design parameters and accident analysis
50-272/95-019	LER	operability functional test not performed prior to mode entry
50-272/95-020	LER	inoperable 230 volt motor control centers due to failed bus bar bolting (discussed in IR 50-272&311/95-017)
50-272/95-023	LER	failure to plug steam generator tubes due to missed eddy current indications (discussed in IR 50-272&311/95017 and 96010)
50-272/96-014	LER	potential hydrogen embrittlement on 4kv breaker parts
50-272/96-018	LER	potential performance impact on ECCS due to non-safety related RWST piping

LIST OF ACRONYMS USED

PDR	Public Document Room
NRC	Nuclear Regulatory Commission
PSE&G	Public Service Electric and Gas
SRO	Senior Reactor Operator