U. S. NUCLEAR REGULATORY COMMISSION

REGION I

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Facility:	Salem Nuclear Generating Station, Units 1 & 2
Location:	P.O. Box 236 Hancocks Bridge, New Jersey 08038
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EXECUTIVE SUMMARY

Salem Nuclear Generating Station
NRC Inspection Report 50-272/96-17, 50-311/96-17

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a 6-week period of resident inspection; in addition, it includes the results of inspections of radiological controls and steam generator replacement by regional specialists.

Operations

During this inspection period, conservative decisions characterized operator performance. Several of the decisions demonstrated the operators' high standards for equipment availability prior to commencing core reload (Section O1.1). Operators demonstrated improved performance in procedure adherence and initiated appropriate measures to improve procedure quality. Senior reactor operators maintained good control over control room evolutions and remained aware of equipment and safety system status (Section O3.1). Before the start of refueling the unit 2 core, inspectors confirmed that Salem refueling procedures insured compliance with the design basis and Technical Specification requirements for fuel handling (Section O1.2). The Salem Senior Nuclear Shift Supervisors maintained high standards for equipment and staff readiness in preparing for Salem Unit 2 refueling(Section O4.1) The operating shift demonstrated good safety focus in insisting upon a procedure to control a total station air outage. The plant staff, however, did not perform a 10 CFR 50.59 safety evaluation until prompted by the inspector. (Section O2.1).

The plant staff made significant progress in addressing station air and control air reliability concerns. The inspectors noted that plant staff continued to implement actions to improve station and control air reliability. Although performance problems continued to occur with the station and control air systems, the inspectors concluded that plant staff completed adequate corrective actions to support plant startup (Section O2.2)

Maintenance

Inspectors observed improved maintenance performance during the inspection period. For example, workers demonstrated ownership for their work by identifying additional small jacket water leaks, a thermocouple that needed to be replaced, and demonstrated the ability to effectively and safely diagnose and repair the EDG jacket water leak. During no. 23 service water strainer filter replacement, workers displayed familiarity with contents of the procedures and the work package. They maintained current documentation of the work and identified three items in the procedure that required clarification. The workers took steps to obtain the clarification. The inspectors noted close supervision of the SW work, and a good questioning attitude on the part of the workers (Section M1.1) In response to learning that the Salem preventive maintenance (PM) program did not prevent inappropriate lubrication of double-shielded bearings in the past, plant staff initiated changes to the PM program in June 1996 that effectively controlled bearing lubrications (Section M1.2). Plant staff appropriately identified use of instruments with insufficient accuracy during EDG surveillances, appropriately incorporated use of more accurate

instruments, and revised the EDG surveillance procedures to insure use of the new instruments (Section M1.3)

Engineering

As a result of development and use of safety evaluation procedures and training, the safety evaluations presented to the Station Operations Review Committee (SORC) showed significant improvement in comparison with the quality of safety evaluations in early 1995. They supplied comprehensive bases for concluding the changes did not constitute unreviewed safety questions. In addition, the SORC reviews of safety evaluations also improved (Section E1.1). The engineering staff had not resolved the effect of operating the penetration cooling system with air flows different than assumed design basis flows (Section E1.2).

The region-based steam generator replacement project (SGRP) Project Manager performed inspections at the Salem site and the contractor's engineering office to obtain an overview of current and planned work, related procedures, documentation, quality inputs and progress of the Salem Unit 1 SGRP. The inspector found generally high quality performance in the areas inspected and identified no safety significant project deficiencies. The inspector noted problems, however, with some first time evolutions that indicate a potential deficiency in planning, work control, or full understanding of procedure requirements by those performing work. The Salem SGRP management initiated corrective and preventive actions to improve project performance (Section E1.3).

The Salem staff implemented appropriate and timely corrective actions in response to identification of improperly installed welds during implementation of the control room ventilation modification (Section E1.4).

Plant Support

The inspector determined that the licensee met and exceeded the planned radiation protection (RP) staffing levels to support the steam generator replacement project (Section R1.2).

The additional remote surveillance capability of the RP command center was effectively used to review work areas. The inspector observed conservative use of the remote surveillance approach utilizing on-the-job RP technician resources to engage normal work control situations. Also, the containment clean areas and radioactive material outside of containment were effectively monitored and controlled during this inspection (Section R1.2).

An effective mockup training for installation of steam generator seal plates was performed. Important sequencing of work details was established and an understanding of the scope of work and radiological implications of the work were effectively discussed and communicated to those present. However, the licensee had not established a requirement that only those in attendance of the mockup training could perform the work and task qualification controls had not been established for the seal plate installation work (Section R1.3).

Contamination was well controlled and minimized. Through the use of temporary shielding and filling of steam generators, radiation levels of principal work areas were maintained at low levels without significant dose rate gradients. The inspector determined that excellent radiological conditions were established for conducting the steam generator replacement project (Section R2.1).

Although work packages were not all completed at the time of this inspection, general work descriptions of all radiologically significant work had been researched and individual RP job guidelines for each had been developed to provide some advance RP planning and to communicate a level of RP technician job performance expectation. These RP job guidelines provided a moderately effective vehicle for orienting and guiding the RP technicians in preparation for radiologically significant project work evolutions (Section R3.1).

The licensee had not dedicated specific quality assurance (QA) oversight review of the RP program performance during the SGRP and only routine QA surveillance activities were being provided. In response to this finding, the licensee obtained an additional member of the SGRP QA oversight group tasked with specific responsibility for radiation protection oversight (Section R7).

The inspector identified overall effective radiological controls for Salem Station radiological work activities, including preparation and transfer for disposal of the Unit 1 No. 14 steam generator. Internal exposure controls, including contamination controls, were very good. Augmentation of the staff was good with good training and qualification of personnel noted. Self-identification of radiological concerns was very good. However, a noteworthy weakness was identified in review and resolution of all issues identified in radiological occurrence reports. Further, improvement in the identification and control of alternate access paths to locked high radiation areas appeared warranted.

TABLE OF CONTENTS

Report Details

Summary of Plant Status

Salem Unit 1 remained defueled throughout the inspection period. Late in the period, workers removed the last of the four original steam generators from containment. The plant managers expect to move the first replacement steam generator into containment in early January 1997.

Salem Unit 2 staff neared completion of refueling preparations at the end 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 conduct of operations was professional and safety-conscious; specific events and noteworthy observations are detailed in the sections below. The inspectors noted several examples of conservative decisions by operators. Several of the decisions demonstrated the operators' high standards for equipment availability prior to commencing core reload.

O1.2 Preparations for Unit 2 Refueling

a. Inspection Scope (60705)

The inspector reviewed procedures and administrative requirements for refueling Salem, Unit 2.

b. Observations and Findings

The inspector reviewed Salem refueling procedures to determine whether they met the design basis of the plant as described in the Updated Final Safety Analysis Report (UFSAR). For example, the UFSAR states that, prior to refueling, the reactor is borated to refueling concentration. This requirement is captured in S2.OP-IO.ZZ-0009(Q), *Defueled to Mode 6*. The UFSAR also describes the capabilities and safety features of the manipulator crane, such as bridge, trolley and hoist interlocks. Maintenance procedure SC.MD-ST.CRN-0001(Q), *Fuel Handling Crane Periodic Inspections, Operational Tests and Limit Switch Adjustment,* tests these features. The inspector confirmed the refueling procedures adequately supported the Salem facility as described in the UFSAR.

The inspector also reviewed refueling procedures to determine whether they identified the Technical Specification requirements for entering Mode 6. Attachment 2 of Integrated Operating Procedure (IOP-) 9 lists the surveillance requirements that demonstrate operability for equipment required by Technical Specifications, including, for example, the emergency diesel generators, control room ventilation, and the radiation monitoring system. The inspector confirmed refueling procedures insured compliance with the Technical Specification requirements for entering Mode 6.

c. Conclusions

Inspectors confirmed that Salem refueling procedures insure compliance with the design basis and Technical Specification requirements for fuel handling.

O2 Operational Status of Facilities and Equipment

O2.1 Total Station Air Outage

a. Inspection Scope (71707)

The inspector observed operators' implementation and restoration of a total station air outage.

b. Observations and Findings

On November 12, 1996, Salem operations commenced a total station air (SA) outage. When tagging instructions for the SA outage expanded to five pages, the operators insisted that the staff develop a new procedure, TSC.OP-SO.CA-0101, *Maintaining Control Air System During Station Air System Manifold Replacement*, to control the work. The plan involved use of temporary station air compressors to supply Unit 1 safety-related control air, the station blackout (SBO) air compressor to supply Unit 2 safety-related control air, taking the safety-related emergency control air compressors (ECAC) out of automatic control, and bypassing a check valve to supply non safety-related control air from the safety-related piping. The inspector found that operations staff did not consider these to be changes to the facility as described in the safety analysis report. As a result, they did not perform a safety evaluation as required by 10 CFR 50.59. **(VIO 50-272&311/96-17-01)** In response, operations management appropriately ensured safe plant configuration and completed a thorough safety evaluation. The inspector determined that the safety evaluation appropriately concluded that the changes did not result in an unreviewed safety question (USQ).

The inspector noted that the procedure unnecessarily limited operators to use of only two of the three available temporary air compressors. The unnecessary restriction made operators more vulnerable to station air equipment problems. The Senior Reactor Operator (SRO) initiated an on-the-spot-change to correct this

deficiency. Operators subsequently needed the third temporary air compressor when one of the other temporary air compressors could not handle the load.

On November 15, the operating shift experienced several problems with station and control air components that delayed system restoration until November 20. These problems included: (1) no. 1 ECAC trip on start demand, (2) no. 1 station air compressor (SAC) would not stay latched in auto, (3) no. 2 SAC would not start, then experienced excessive amp swings, (4) no. 3 SAC lube oil reservoir heater controller malfunctioned, and (5) a temporary air compressor could not handle the load. The system manager initiated corrective action for each of the above deficiencies.

c. Conclusions

The operating shift demonstrated a good safety focus in insisting upon a procedure to control a total station air outage. The plant staff, however, did not perform a 10 CFR 50.59 safety evaluation until questioned by the inspector.

O2.2 Reliability of Control Air (NRC Restart Issue II.2) (Closed)

a. Inspection Scope (71707)

The reliability of the control air system, the control air dryers, and the service air system compressors that supply the control air system has been a long standing concern at Salem. Distractions caused by degraded control air conditions have frequently challenged operators. The NRC documented control air reliability concerns in NRC Inspection Reports 50-272, 311/94-19, 94-24, and 94-34. PSE&G initiated design changes, conducted refurbishment and performed preventive maintenance activities to address these long standing issues. Plant staff documented these actions in the Control Air System Reliability closure package, dated November 6, 1996. The inspector reviewed the closure package as well as related work documents, design change packages, test results, operating procedures, calculations, and Performance Improvement Requests (PIRs). In addition, the inspector conducted field observations to evaluate the material condition of portions of the service and control air systems.

b. Observations and Findings

From the review of the closure package, the inspector found that Salem staff identified the following issues as contributing to the control air reliability concerns:

Control Air Dryers - Air header pressure decreases during dryer maintenance, resulting in auto start of the ECACs and low pressure alarms in the power operated relief valve (PORV) accumulators.

PORV Accumulators - Low pressure alarm resulted in operators closing the PORV block valves.

Station air compressors (SACs) - Numerous high vibration trips and other problems resulted in concerns with SACs availability and reliability.

Plant staff completed the following actions:

To address the overall reliability of the control air system, plant staff completed the air dryer pre-filter PMs on schedule. Delaying this activity in the past compounded the effects on the control air system because the other pre-filter degraded during the delay. Subsequent removal of the first pre-filter from service for cleaning caused increased air flow through the remaining air dryer, resulting in an increased differential pressure across the air dryer, further degrading the control air header pressure. Prompt pre-filter maintenance will ensure control air pressure is maintained within acceptable limits during maintenance. In addition, plant staff refurbished the dryer skids, inspected and/or replaced the desiccant, rebuilt the switching valves, and replaced the control solenoid poppits. Maintenance staff issued a repetitive task PM for the control solenoid poppits to require annual inspection or rebuild.

The actions taken for the control air dryers will also preclude having to close PORV block valves as a result of degraded control air header pressure. In addition, plant staff discovered a problem with the PORV alarm and solenoid setpoints on Unit 2. They implemented DCP 2EC-3416 to correct this condition.

To address high vibration tripping of the SACs, Salem staff installed a design change (DCP 1EE-0324) to eliminate vibration trips as a result of displacement during compressor startup.

Workers had not completed implementation of SAC design change package DCP 1EC-3651 at the close of the inspection period. Installation of this DCP will address the following SAC issues, to further improve the reliability of the station air system, and thus the control air system:

- Condensate removal problems with the coolers and moisture separators will be corrected by installation of automatic drain valves. This condition has resulted in two (2).compressor trips due to high moisture levels in the moisture separators

- Rust in the discharge piping between the compressor and the aftercooler contributes to pre-filter clogging resulting in increased maintenance on the control air dryer skids. Plant staff will replace the degraded piping.

- The blowoff valves are too far from the compressor. The location has resulted in compressor surge conditions, reducing compressor overall. Plant staff will replace and relocate the blowoff valves.

- The SACs remain susceptible to vibration trips during load carrying conditions due to the cyclic loading and unloading of the compressors. Engineers expect installation of a constant pressure control option to provide

compressor stability during operation by significantly reducing the cycles imposed on the valves, relays, and switches.

During the review of the closure package, the inspector identified questions about past operation of the containment penetration cooling system. These are documented in section E1.2 of this report.

c. Conclusion

The inspectors concluded that plant staff made significant progress in addressing station air and control air reliability concerns. The inspectors noted that plant staff continued to implement actions to further improve station and control air reliability. For example, plant staff continued installation of DCP 1EE-0324 to convert the compressors to constant pressure operation, further reducing station air compressor trips. Although performance problems continued to occur with the station and control air systems (see section O2.1), the inspectors concluded that plant staff completed corrective actions and the measures to insure prompt air dryer maintenance were adequate to support plant startup.

O3 Operations Procedures and Documentation

O3.1 Procedure Use and Quality

The inspector observed control room operator use and adherence to implementing procedures. During the inspection period, operators demonstrated consistent attention to procedure compliance. Operators made a conscientious effort to use procedures to control activities whenever possible. Operators insisted upon new procedure development when required to perform complex evolutions that did not have adequate guidance. An example of this behavior was operations' staff development of TSC.OP-SO.CA-0101 to control an abnormal station air outage (see section O2.1). In addition, the operating shift, including the test engineers, stopped control room activities to implement procedure improvements. The inspector noted that the operating shift repeatedly sacrificed productivity to ensure the procedure was correct and appropriate. This was evident in "B" vital bus testing as the operating shift implemented no fewer then seven on-the-spot-changes. The inspector observed detailed shift briefings prior to complex evolutions and significant SRO involvement in all control room activities. The inspector concluded that operators demonstrated improved performance in procedure adherence and initiated appropriate measures to improve procedure quality. Senior reactor operators maintained good control over control room evolutions and remained aware of equipment and safety system status.

O4 Operator Knowledge and Performance

O4.1 Operator Standards for Plant Equipment

a. Observations and Findings (71707)

During the inspection period, operators demonstrated high standards for equipment acceptability on a number of occasions. For example, they identified generic aspects of a failure of the operator for the service water inlet valve to the no. 2B EDG lube oil cooler. They insisted on acceptable resolution prior to entering mode 6. When they learned about a hinge pin corrosion problem in an EDG service water check valve, they declared the associated EDG inoperable. In a meeting with the Management Review Committee, the Senior Nuclear Shift Supervisors (SNSSs) from the four crews slated to restart Salem Unit 2 identified several issues that required resolution prior to reloading the core. The issues included repair of the no. 2B EDG jacket water leak, complete review of the Technical Specification Limiting Condition for Operation (LCO) tracking log by each SNSS, and completion of training for the design change packages (DCPs) required for mode 6. In order to determine operator readiness for mode 6, the SNSS for each crew assessed the readiness of each member of their crew through interviews and observation. In addition, each SNSS reviewed surveillance results, outstanding operator workarounds, temporary modifications, and degraded control room indicators for equipment required for mode 6. In this manner, the SNSS for each crew determined the readiness to begin refueling operations.

b. Conclusions

The Salem Senior Nuclear Shift Supervisors maintained high standards for equipment and staff readiness in preparing for Salem Unit 2 refueling.

O7 Quality Assurance in Operations

O7.1 (Closed) Violation 50-272&311/96-12-01: failure to take adequate actions for a significant condition adverse to quality to preclude repetition. Inadequate procedures allowed operators to enter Mode 6 without ensuring that they met the reactivity requirements of TS 3.9.1. Although an operator identified and documented the failure to meet TS 3.9.1 requirements, the licensee failed to take adequate corrective actions. In response to the violation, operations staff revised the integrated operating procedure for Mode 6 to require proper boron concentration sampling. Operations staff revised the reactor cavity fill procedure, S2.OP-SO.SF-0003, and issued the violation response to the Operations and Licensing Departments as required reading. The inspector verified the S2.OP-SO.SF-0003 procedure revision and the required reading material.

The inspector noted that the response did not discuss the licensee's Quality Assurance (QA) program practices and procedures. The licensee did not review QA oversight practices to determine if QA should have identified the violation and what,

if any, measure need be taken to strengthen the QA program. The inspector observed that an inadequate procedure and inappropriate condition resolution (CR) corrective actions contributed to the violation. The inspector reviewed the QA Monthly Reports from December 1995 to August 1996 and noted limited QA oversight of procedure adequacy and corrective action thoroughness. During discussions with the inspector, QA managers stated that they had implemented measures to adjust the QA program based on observed weaknesses in plant staff and equipment performance. They also stated that they planned to continue to improve adjustments to QA program focus.

The inspectors concluded that the licensee implemented adequate corrective action for entering mode 6 without insuring compliance with TS 3.9.1. The inspectors will continue to monitor the QA adjustment to performance problems as part of normal inspector followup of violation responses.

O8 Miscellaneous Operations Issue

O8.1 (Closed) Violation 272&311/94-24-03

During a Salem Unit 2 shutdown in October 1994, plant staff failed to perform a daily heat balance calibration of the power range neutron flux functional unit. The plant staff determined that operators incorrectly interpreted daily as meaning once per day, as opposed to once per 24 hours. In response, plant staff revised the shift routine procedure, SC.OD-DD.ZZ-OD40, to clarify the surveillance frequency and separate actions required by Technical Specifications from actions required for other reasons. In addition, the operators received training specific to the missed heat balance calibration. The inspector verified implementation of the corrective actions and considered them adequate to prevent recurrence.

O8.2 (Closed) Violation 50-272&311/94-24-05

In October 1994, a security guard permitted two persons to enter the Salem Unit 2 no. 2C emergency diesel generator (EDG) room without verifying proper authorization prior to granting access. Security staff attributed the violation to personnel error. In response, they immediately relieved the guard, retrained and certified the guard in performance of control access in an emergency or on a compensatory post, and discussed the incident with guard force personnel during shift briefings. The inspectors considered the corrective actions adequate to address the cause of the violation. Inspectors and plant staff identified broader security performance weaknesses during routine inspection in August 1996. The NRC documented the broader issues separately and proposed escalated enforcement. The NRC will assess the effectiveness of corrective actions for those problems during subsequent inspection.

O8.3 (Closed) Violation 50-272&311/95-10-01

In June 1995, a technician failed to unlatch the no. 2R cylinder fuel pump rack on the no. 1C EDG. As a result, plant staff operated the EDG during a surveillance without fuel supplied to the affected cylinder. The EDG did not suffer damage as a result. Plant staff concluded that personnel error caused the violation. In response, maintenance managers counseled the technician, reviewed the applicable maintenance procedure for adequacy, and revised the procedure to add independent verification that the fuel racks are unlatched. The inspector reviewed the procedure, SC.MD-ST.DG-0003(Q) to ensure the procedure required independent verification that technicians unlatched all fuel pump racks.

In May 1995, inspectors discovered that operators had not ensured the no. 2C EDG fuel rack linkage remained in the open position after completion of a surveillance. Plant staff determined that personnel error was the most probable cause. They also determined that EDG design features automatically positioned the fuel racks to supply full fuel on an EDG start. As a result, plant staff concluded the procedure requirement for operators to reposition the fuel racks was not required for proper EDG operation. In response, the plant staff deleted the procedure requirements to manually position the fuel racks . In addition, operations staff reviewed department procedures to insure that the procedures included appropriate measures for independent verification. The inspectors verified that the operations staff deleted the requirement for manual fuel rack positioning from the applicable procedures and that the procedures contained appropriate requirements for independent verification.

O8.4 (Closed) Violation 50-272&311/95-10-02

In May 1995, the licensee completed a shutdown of Salem Unit 1, and did not report the shutdown within 30 days as required. The Salem staff determined that inadequate focus on reporting requirements, lack of follow up by plant staff on a known commitment, lack of ownership and accountability for the Licensee Event Report (LER) process, and a flawed submittal strategy contributed to the failure. In response, the licensee completed and submitted all overdue LERs, counseled plant staff concerning ownership and accountability, and modified the LER process to include timely scoping meetings. In addition plant staff initiated a report to identify the status of LERs in process to insure proper management attention to completing LERs. The inspector verified the use of the reporting system, including the Licensing LER Performance Indicators. In addition, the inspector noted discussion of the status of LERs at the Salem General Manager's staff meeting with appropriate attention to insuring timely submission of the reports.

II. Maintenance

M1 Conduct of Maintenance

M1.1 General Comments

a. Inspection Scope (62707)

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

- WO 961206309, procedure SC.MD-CM.DG-0002(Q), *Emergency Diesel Generator Cylinder Head Replacement*, Rev. 0, dated 1/28/91, and procedure SC.MD-PT.DG-0002(Q), *Post Maintenance Diesel Engine Break-in Run*, Rev. 0, dtd 12/13/96
- WO 961202133, procedure SC.MD-PM.SW-0003(Q), *Service Water Automatic Strainer Adjustment, Inspection, Repair, and Replacement*, Revision 13 dtd 12/5/96

While running the no. 2B EDG for testing, Salem operators observed a slow decrease in level in the jacket water expansion tank. Maintenance staff determined that jacket water leaked into the no. 1R cylinder at about 25 cc/min. They determined that the cylinder head had developed a small leak, and decided to replace the cylinder head and liner. Although the EDG had performed within acceptance criteria in recent tests, and although industry experience indicated that the EDG would continue to operate reliably for months with the minor leak, they decided to replace the cylinder head. After removing the head, the maintenance staff found that jacket water leaking into the cylinder had apparently caused polishing of the cylinder liner. Although they did not consider the liner significantly degraded, they replaced the liner also. During the replacement of the EDG cylinder head, inspectors noted that the workers had the work package on site and in use. Although maintenance staff concluded that the cylinder head and liner met design requirements for continued use, they conservatively decided to replace the liner and head. Workers demonstrated ownership for their work, as demonstrated by identifying additional small jacket water leaks, a thermocouple that needed to be replaced, etc. As a result of their efforts, the maintenance staff demonstrated the ability to effectively and safely diagnose and repair the EDG jacket water leak.

Inspectors also observed technicians replacing the filter elements in the no. 23 SW strainer. During discussions with the inspector, workers demonstrated familiarity with contents of the procedure and the work package. The workers maintained current documentation of the work and identified three items in the procedure that required clarification. The workers took steps to obtain the clarification. The inspectors noted close supervision of the work, and a good questioning attitude on the part of the workers.

b. Inspection Scope (61726)

The inspectors observed all or portions of the following surveillances:

- S2.OP-ST.FHV-0001: refueling operations - fuel handling building ventilation
- S2.OP-ST.RM-0001: radiation monitors - check sources
- S2.OP-ST.SSP-0002: engineered safety features manual safety injection 2A vital bus
- S2.OP-ST.RHR-0004: in service testing - residual heat removal valves
- S2.OP-ST.SSP-0004: engineered safety features manual safety injection 2C vital bus
- S2.OP-ST.DG-0002: 2B diesel generator surveillance test
- S2.OP-ST.DG-0014: 2C diesel generator endurance run
- S2.OP-ST.DG-0021: 2C diesel generator hot restart test
- SC.MD-ST.CRN-0002: manipulator crane periodic inspections and operational tests

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

M1.2 Double-shielded Bearing Inspection

a. Inspection Scope (62707)

The inspector reviewed lubrication preventive maintenance (PM) tasks for selected safety related motors that contain double-shielded bearings.

b. Observations

The inspector audited the lubrication PMs for the switchgear penetration area ventilation (SPAV) fan motors, the boric acid transfer (BAT) pump motors and the fuel handling ventilation (FHV) fan motors to determine whether technicians were performing the appropriate PM for the type of motor bearing . The bearing type -- double shielded, single shielded, or open -- determines the PM task. In particular, the PM program directs technicians not to lubricate double shielded bearings because this activity could pressurize the grease cavity, causing grease to inject into the motor. (NRC Information Notice 94-51, *Inappropriate Greasing of Double Shielded Motor Bearings*, of July 15, 1994 has additional details.) The inspector reviewed the PM history for SPAV, FHV, and BAT motors and found that, prior to improvements in the PM program, technicians inappropriately lubricated the double shielded bearings in nos. 11 and 12 BAT pumps (September, 1994, and January, 1995). Maintenance engineers inspected these bearings and did not find degraded conditions. Motor vibration data was also acceptable.

In June, 1996, Salem Maintenance staff wrote an Action Request (AR 960618077) that identified the PM schedule inadequately controlled bearing lubrication tasks. Subsequently, maintenance engineers identified the types of bearings for motors installed in both units, including the BAT pump motors, SPAV and FHV fan motors, and revised the lubrication tasks where applicable to clearly reflect that technicians are not to lubricate double shielded bearings.

Failure of Salem staff to identify and correct lubrication deficiencies in a timely fashion is a violation of the requirements in 10 CFR 50 Appendix B, Criterion XVI, *Corrective Action.* Since the NRC has taken significant enforcement action for Salem's failure to identify and correct conditions adverse to quality, and since PSE&G voluntarily maintained both Salem units shut down to address equipment and enforcement deficiencies, the NRC will not take additional enforcement action in this case.

c. Conclusions

Although the Salem preventive maintenance program did not prevent inappropriate lubrication of double-shielded bearings, the inspector found that changes to the PM program initiated in June 1996 effectively controlled lubrication of bearings.

M1.3 Emergency Diesel Generator (EDG) Surveillance

a. Inspection Scope (61726)

The inspector reviewed the engineering staff response to an operations department identified concern regarding the adequacy of using an installed watt meter to perform EDG surveillance testing (ST).

b. Observations and Findings

The operators, in accordance with pre-existing surveillance procedures, utilized an installed watt meter to satisfy several EDG technical specification (TS) surveillance requirements (SRs) including: monthly load testing (SR 4.8.1.1.2.a.2), semi-annual load testing (SR 4.8.1.1.2.c), 18 month load testing (SR 4.8.1.1.2.d.7) and hot restart testing (SR 4.8.1.1.2.f). The above SRs required the operators to maintain EDG loading between 2500 and 2600 KW. The installed watt meter, however, had an accuracy range of approximately +/- 65 KW. As a result, an indication of 2550 KW would indicate actual power somewhere within the range 2485 KW to 2615 KW. Operators, therefore, could not certify that the EDG had developed rated load during the surveillance.

The inspector reviewed the 2C EDG 18 month endurance run test procedure (S2.OP-ST.DG-0014(Q)) and noted that the test procedure had been revised on November 26, 1996 to incorporate the use of higher accuracy instrumentation. The operators utilized the revised procedure to perform testing on all three Unit 2 EDGs. The inspector observed portions of the 2B and 2C EDG testing and noted that the operators maintained the EDG output within the required band.

The operators subsequently revised remaining EDG test procedures to require the use of the high accuracy load instrumentation in order to satisfy the other SRs listed above. The operators performed the EDG tests in accordance with the revised procedures.

During the 2C EDG 18 month endurance testing, the system manager compared the load indicated by the installed watt meter to the load indicated by the high accuracy test instrumentation to better quantify the accuracy of the installed watt meter. The system manager determined, based on this comparison, that the previous 2C EDG endurance test run had exceeded the required TS range. The inspector independently reviewed the applicable test data and agreed with this conclusion.

The EDG test load restrictions had been incorporated into TSs by amendments 148 and 126 in November 1993. The inspector noted that TS amendment and the applicable EDG test procedures had not been properly reviewed at that time to insure that the TS load requirements would be satisfied during testing.

Previously performing surveillances with inadequate instruments had minor safety consequence, since, based on use of the less accurate instruments, the EDGs had been loaded during testing to within 2.5% of the required limits. This licensee identified and corrected issue meets the criteria specified in Section VII.b of the NRC Enforcement Manual and is considered a Non-Cited Violation.

c. Conclusions

Plant staff appropriately identified use of instruments with insufficient accuracy during EDG surveillances. They appropriately incorporated use of more accurate instruments, and revised the EDG surveillance procedures to insure use of the new instruments.

M8 Miscellaneous Maintenance Issues

M8.1 NRC Restart Issue II.36 - Safety Injection (SI) Relief Valves Performance History of Leakage and Lifting (Closed - Unit 2, Open - Unit 1)

a. Inspection Scope

The inspector reviewed the corrective actions which were taken to resolve a problem regarding repetitive Safety Injection system relief valve leakage. The inspector reviewed the Restart Issue T-36 Closure Package. The package included the closure summary, the root cause analysis for the problem, and PIR Nos. 950901391 and 960321090. The inspector also reviewed a design change package for Salem Unit 2 which increased the relief valve set points (DCP 2EC3582), and procedures which provided direction for setting and testing them. The design change package for the Salem Unit 1 change was not yet available.

b. Observations and Findings

The root cause analysis specified corrective action to reduce the risk of safety relief valve failures. One corrective action was to increase the relief valve set point. This was necessary because during safety injection pump startup, the pressure spike would at times be sufficient to lift the relief valve causing unnecessary wear. The inspector reviewed the design change engineering analysis and found it adequate. The change package also contained satisfactory documentation of setting and installation of the relief valves and documentation of satisfactory test results of the post installation functional testing. The inspector learned from discussions with the system engineer that there was no evidence of valve leakage during testing.

The root cause analysis also attributed a faulty test stand filter as a contributing cause. The filter was not well maintained and as a result, particles (sand and rust) would be introduced into relief valves and cause seat wear. The inspector verified that the filter was being periodically maintained as evidenced by work order documentation.

Another corrective action was a procedure change to require leak testing before and after set point verification on the test stand. This would provide evidence of the as found condition and assurance that the valve was leak tight prior to installation. Although the long term effectiveness of corrective actions taken has not yet been determined, the inspector did verify that PIR No. 960321090 contained an action item to verify the effectiveness by periodically reviewing relief valve lift and leak test data.

c. Conclusions

From his review, the inspector was able to conclude that it was reasonable to expect that implementation of the corrective actions would resolve the long term problem of leaking relief valves. This item is closed for Salem Unit 2 but will remain open for Unit 1 pending implementation of the design change and subsequent testing and installation.

M8.2 (Closed) LER 272/96-027-00: This LER described the use of the installed EDG watt meter to perform EDG testing as discussed in Section M1.3 of this report. No new issues were identified by the LER.

III. Engineering

E1 Conduct of Engineering

E1.1 Safety Evaluations

. Observations and Finding

During the inspection period, plant staff prepared several safety evaluations required by 10 CFR 50.59, and presented them for SORC review. The safety evaluations included:

- DCP 1EC-3453, package 1 of 3, *Unit 1 EDG Fuel Oil Day Tank Setpoint Change*.
- Minor modification S-96-023, *Removal of 22/23 CCW Pump Room Door*.
- UFSAR change notice 96-169, *Change Temperature Range in UFSAR for SPAV System*.

The safety evaluations, prepared using procedure NC.NA-AP.ZZ-0059 (Q), *10 CFR 50.59 Safety Evaluation*, included references to Technical Specification and UFSAR sections reviewed for applicability, and other documents referenced by the evaluator. The evaluations also listed plant procedures, affected parameters and systems, and credible failure modes associated with the change.

The inspectors reviewed the safety evaluations and observed their presentation at SORC. As a result of training and use of procedure NC.NA-AP.ZZ-0059 (Q), the preparers developed consistently thorough safety evaluations that included broad consideration of the effects of the proposed change on plant operation. In addition, the inspector observed that the SORC obtained a reasonable basis for approving the safety evaluations through review of the package and questioning the presenters.

. Conclusions

The inspector concluded that the safety evaluations supplied reasonably comprehensive bases for concluding the changes did not constitute unreviewed safety questions. In addition, the inspector observed that, as a result of the safety evaluation procedures and training, the quality of safety evaluations and SORC reviews has increased significantly in comparison with that observed by NRC inspectors in early 1995.

E1.2 Containment Penetration Cooler Issues

a. Inspection Scope (37551)

The inspector reviewed design calculations, test data, system descriptions, work orders, UFSAR Section 9.1 (Compressed Air Systems), and Configuration Baseline

Documentation (CBD), to assess the material condition of the containment penetration cooling system.

b. Observations and Findings

UFSAR Section 3.8.1.6.5, Containment Penetrations and Openings, states in part: "Cooling, by both free and forced convection, is provided where necessary to maintain concrete temperatures adjacent to hot pipe penetrations below 150 degrees F. The potential heat transfer [for radial conduction] ... can be significant. The heat is removed by compressed air flow in plate type heat exchangers (coolers) installed within the penetration sleeves. It has been shown that for constant exposure of concrete to temperatures up to 150 degrees F, the loss in strength is quite small; and for temperatures as high as 500 to 600 degrees F, the deterioration in structural properties is tolerable. Considering the redundancy in air supply lines, the only cause of loss of penetration cooling would be complete loss of the station air compressors, a condition which would not be permitted to persist long enough to cause significant localized concrete deterioration."

During an NRC inspection of Salem's licensing basis in May, 1996, the NRC requested the licensee provide the basis for the minimum penetration cooler throttle valve positioning to ensure the proper flow of compressed air to the penetration coolers.

PSE&G located a calculation that provided the basis for the throttle valve positions, but determined that the calculation was not reproducible and was not officially part of the CBD. The basis was re-developed in calculation S-C-PC-MDC-1657, Penetration Cooling Valves Adjustment, Revision 0. The inspector reviewed the calculation and determined that the minimum throttle valve positions for the penetration coolers had been determined. The calculation also documented the actual position of the penetration cooler throttle valves in the field. In all cases the documented field throttle valve positions were at least the minimum specified in the calculation.

Based on concerns the inspector had with the number of penetrations equipped with forced air cooling, the inspector reviewed the following documents to determine how the penetration cooling air flow rates were accounted for in the station air consumption calculations.

UFSAR Section 9.3.1, Compressed Air Systems

CBD DE-CB.CA-0014(Q), Configuration Baseline Documentation for Control Air and Station Air Systems, Revision 3;

Calculation S-C-CA-MDC-1639, Integrated Air Load Management Program Update, Revision 0;

Calculation S-C-SA-MDC-0525, Station Air System Load Study, Revision 0;

Calculation S-C-CA-MDC-0549, Station Air and Control Air Systems Analytical Flow Model and Test, Revision 0;

System Description SD-M946, Containment Penetration Cooling, Revision 0; and,

Data Acquisition DCP 1SX-2286, Determination of Air Consumption Rates and Operating Pressures for CA and SA Systems, Revision 0.

Based on these reviews, the inspector made the following observations:

1. The Integrated Air Load Management Program Update calculation provided documentation that a single station air compressors (SAC) capacity was 4232 scfm and the worst case load demand was 4439 scfm. A note contained in this calculation stated: "The total load of 4439 scfm, exceeds the capacity of a single SAC (4232 scfm) by 207 scfm or 5%. This is well within the conservative margin inherent in the development of the individual loads as discussed in Section 5.1 and 5.2 of Reference 11 [Station Air System Load Study calculation). Therefore, based on the results of this evaluation, it is concluded that a single SAC is capable of supporting the worst case continuous and intermittent loads."

   To account for the penetration cooling system contribution to the SAC air load, PSE&G uses an air consumption value of 636.8 scfm per Unit (1273.6 scfm total) based on the penetration cooling throttle valves being positioned at their minimum throttle setting. The minimum required throttle valve positions were listed in the original Containment Penetration Cooling system description. Further, the inspector determined that the penetration cooling air consumption value of 636.8 scfm per Unit (1273.6 scfm total) was based on air flow through a total of 20 penetration coolers per Unit and did not account for penetrations No. 30, 36, 54, and 55. The documented field position for the additional throttle valves (eight per Unit) for these penetrations were "full open". The inspector estimated that the additional air consumption due to air flow through these open throttle valves would be 300 - 400 scfm per Unit (600 - 800 scfm total), which would exacerbate the worst case air load consumption values used in the Integrated Air Management Program calculation. Based on this estimate, the total worst case air load would exceed a single SAC by 19 - 24% as compared with the 5% stated in the calculation (discussed above). The inspector's estimate was based on information contained in the original Penetration Cooling system description and the Penetration Cooling Needle Valve Adjustment calculation.

   Salem UFSAR, Section 9.3.1, Compressed Air Systems, Paragraph 9.3.1.2.2, states: "The dual station service air headers are fed by three 100 percent capacity air compressors, any one of which can supply the total service and control air requirements for both units." Based on the inspector's observation, the accuracy of this UFSAR statement is in

question, which may impact the operation and maintenance practices with regard to the station air compressors.

2. The Station Air System Load Study calculation was performed on September 18, 1990. Section 5.2.4 of this calculation contained information that reflected Unit 1 "as found" penetration cooling air flow measurements significantly below the stated design flow rate (250 scfm versus 636.8 scfm). Engineering's actions documented in response to this condition was a recommendation that the throttle valve settings be checked, and where necessary, adjusted to the design position. At the conclusion of the inspection period, PSE&G personnel were unable to provide a documented engineering evaluation to show that the reduced flow through the Unit 1 penetration cooling system had not adversely degraded the containment concrete surrounding these penetrations as a result of the reduced air cooling flow, and whether operations had found the throttle valves out of position, thus requiring repositioning or further flow evaluation.

3. The Station Air System Load Study calculation also contained information that reflected Unit 2 as found penetration cooling air flow operating at flow rates in excess of their design capacity. The magnitude of the air consumption could not be established because the measuring instrument was damaged by the excess flow. Again, engineering's recommendation was to check the throttle valve settings, and where necessary, adjusted to the design position.

4. Based on discussion with the operations staff, the inspector determined that the operation of the pressure regulators that supply the penetration cooler air headers are not contained in operating procedures. Valves associated with the station air and penetration cooling systems are included in the Tagging Request Inquiry System (TRIS) which requests the performance of system valve alignments on a rolling 3 year basis. According to PSE&G, the Unit 2 penetration cooling regulators and the penetration cooling valves had last been aligned by TRIS lineup in May of 1993. The operations staff does not require routine monitoring of the penetration air regulator outlet pressure to ensure they are operating properly, nor are there any routine PM tasks conducted on the air regulators.

   During a search of the corrective action data base the inspector found three (3) corrective maintenance work orders (WOs) that had been written on August 8, 1996 to correct problems with the penetration cooler air regulating valves for Units 1 & 2. Specifically, the normal and backup air regulator for Unit 1 and the backup air regulator for Unit 2 were found to be maintaining 15 psig to the penetration coolers instead of the required 75 psig. The 75 psig setting requirement was included as part of the assumptions in the air load calculations to ensure the proper amount of air flow to the penetration coolers. After the inspector questioned the commonality of the three (3) WOs, PSE&G personnel initiated a Condition Report to document the failures. At the close of the inspection period, the WOs were still open. After

questioning by the inspector, the Unit 2 WO was changed from "post restart required" to "restart required".

The inspector noted, that while the Action Request Process did not specifically require the improper regulator settings to be identified as a condition report, the fact that all three regulators were identified in the same condition on the same day should have been questioned and result in the issuance of a condition report. This missed opportunity to identify a Condition Report issue represents a continued weakness in the corrective action process.

c. Conclusions

Based on the above observations, the inspector concluded that there are unresolved questions associated with the penetration cooling system, including:

1. The affects of the additional air consumption on the UFSAR and the CBD, including the Integrated Air Load Management and the Station Air Load calculations.

2. The affects the additional air consumption has on plant operations and maintenance activities.

3. The adequacy of the operational configuration control of the penetration cooling system, including throttle valve positions, air regulator status, and system air flows.

4. The material condition of the containment concrete surrounding the affected penetration due to potential long term overheating as a result of measured air flows lower than design (250 scfm versus 636.8 scfm) and/or pressure regulators maintaining pressure less than design (15 psig versus 75 psig).

This inspectors will review resolution of this issue in the next inspection period. **(IFI 50-272&311/96-17-02)**

E1.3 Steam Generator Replacement Project (SGRP)

a. Scope (37001, 50001)

Inspections were performed by the Region-based SGRP Project Manager to obtain an overview of 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 work in progress at the replacement steam generator (RSG) staging area, welding preparations, lifting and rigging oversight; work packages and procedures; identified problems and corrective actions; independent review of the site SG haul path; discussions with the responsible engineers and observation of conditions and activities inside the containment building.

An offsite inspection was conducted of SGRP engineering at the Framatome office in Lynchburg to review the engineering task scopes, calculation methods, results and documentation to confirm that acceptable engineering practices were applied in development of information for safety evaluations required by the 10CFR 50.59 process.

b. Findings

By December 14, 1996, one original steam generator (OSG) had been shipped offsite by barge, two were in the preparation area for shipping and the fourth was outside the containment building prior to movement to the shipment preparation area. A significant portion of the pre-installation work on the RSGs was complete. The movement of the OSGs by Chem Nuclear and Bigge transporters on the designated haul paths was done per the planning without incident. Preparation for the shipment of the first OSG was observed to be well planned and executed. Work in the RSG staging area and preparations for lifting in the containment building were observed to be generally proceeding in an orderly manner with appropriate supervision and work control packages.

However, the licensee has identified several problems during the progress of the SGRP and has initiated root cause analysis, developed corrective actions and selectively stopped work. The more significant problems were not nuclear safety-related, but included a failure to field verify the orientation of the OSG support feet which delayed the down ending of the first OSG, welding of T1 steel with a vertical up technique not shown in the welding procedure, limiting only craft workers to signing the Work Package logs of one contractor and not fully following the procedure (WCP-2) in storing coated weld electrode in a rod heating oven. The root cause analysis determined that problems were mostly associated with first time activities. Corrective and preventive actions emphasized additional independent review of first time sequences, increased PSE&G specialty oversight, and improved pre-job briefings.

Engineering

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 are being performed by the project contractor, Framatome (FTI), with parts of the work being done by Westinghouse and PSE&G. Inspection of a sample of SGRP engineering work recently completed at FTI was initiated to confirm that reasonable inputs were being developed for the safety evaluations required under the 50.59 process.

The inspector reviewed the FTI method and extent of engineering for the SGRP in the 50.59 area. The engineering and related licensing scope are discussed in the SGRP Work Scope Description dated August 15, 1996, and the SGRP Conduct of Operation Plan, PSBP 322391, dated September 13, 1996. Included in the engineering work scope is a review of the FSAR Chapter 15 Safety Analysis and other Safety Analysis where the steam generators are involved; SG performance

calculations; deadweight, thermal, seismic and high energy line break loads and structural stress analysis; review and update of the affected parts of the FSAR, Technical specifications and SER's; and operator training support.

The engineering process includes a Salem Unit 1 set of Analysis Input Data, an Analytical Input Summary for each engineering task, the specific calculation packages and guidelines for preparation and processing of calculations. The inspector reviewed these and portions of the calculations on Low Temperature Over Pressure Protection, SG performance and SG structural supports.

Engineering evaluations and design changes associated with steam generator (SG) replacement reviewed during this inspection were found to be done in conformance with requirements in the facility license, the applicable codes and standards, licensing commitments, and the regulations. Some minor issues were identified. These included a lack of clarity on identification of some data curves in calculation 51-1258559-00 for design transients and the Analysis Inputs Data not having been compared against the findings of the PSE&G FSAR project applicable to steam generators. The licensee acknowledged both issues and proposed to review these for appropriate action.

b. Conclusions

Inspections were performed at the Salem site and at the contractor's engineering office by the Region-based SGRP Project Manager to obtain an overview of current and planned work, related procedures, documentation, quality inputs and progress of the Salem Unit 1 steam generator replacement project (SGRP). The inspections found a generally high level of project performance in the areas inspected and identified no safety significant project deficiencies. However, problems were noted with some first time evolutions at the site that indicate a potential deficiency in planning, work control or full understanding of procedural requirements by those performing work. The Salem SGRP management initiated corrective and preventive actions to improve project performance.

In the area of engineering activity that provides input to the required 10CFR 50.59 safety evaluations within the FTI work scope, the calculation process was found to be well organized, significant factors were considered and no items of regulatory concern were identified.

E1.4 Modifications to Control Room Ventilation

As a result of a concern about the implementation of the control room ventilation modification, the Salem staff inspected 100 percent of the welds completed during installation of modification 1EC-3505. The staff identified a number of welds that workers had not installed in accordance with the final modification drawings. In addition, they found that workers had used uncontrolled drawings to install portions of the modification. Salem managers took disciplinary action with the contractor, and resolved the incorrect welds through analysis and removing and replacing welds. In addition, the Salem staff inspected a sample of welds for other ventilation

system modifications completed during the outage, and found no additional examples of incorrectly completed welds. The inspectors concluded that the Salem staff responded appropriately to the concern.

E2 Engineering Support of Facilities and Equipment

E2.1 (Closed) Inspector Follow-up Item 50-311/94-24-02: Auxiliary Feedwater Pump Trip Evaluation

This issue pertains to two trips of the turbine driven auxiliary feedwater pump. The operators determined that in each case, the trip latch was not properly engaged and vibration on pump startup caused the trip valve to operate. The inspector conducted a review of the licensee's actions to address this issue. The inspector found that Salem staff made changes to procedure S1/S2.OP-SO.AF-0001(Q), Auxiliary Feedwater System Operation, to provide clear instructions to set and verify proper trip latch engagement. The inspector also verified by a review of corrective action data base that there have been no recurrences of this failure mode. This item is closed.

E2.2 NRC Restart Issue II.42 - Auxiliary Feedwater (AFW) Performance and Reliability (Update)

a. Inspection Scope

The inspector reviewed the closure package for this issue as well as related work documents, design change packages, surveillance test results and the AFW operating procedure. The inspector held discussions with system engineering personnel and inquired about recent AFW performance and state of readiness. The inspector also reviewed the system readiness exception list and performed a field walkdown of the AFW pump rooms.

b. Observations and Findings

From the review of the closure package, the inspector found that Salem staff attributed most of the problems regarding AFW reliability to turbine driven pumps; specifically, they were attributed to the turbine governor. The following factors were identified as having caused failures of the turbine driven pumps:

- Poor control of oil quality
- Incorrect oil use
- Governor valve stem corrosion
- Governor internal configuration incorrect

The inspector verified that corrective action had been taken to resolve each of those problems. Salem has implemented a control oil sample program to ensure satisfactory oil quality. A minor modification has been made at the governor cooler to ease governor removal and reduce the risk of water being introduced into the

governor during the removal process. A recurring maintenance task has been initiated to periodically inspect the governor valve stem for corrosion. Measures have also been taken to control the governor control oil inventory and Salem management has formally delegated responsibility to maintenance for administration of the oil control program.

Salem staff attributed the governor internal configuration problem to parts being installed which were not identical to those being replaced. The vendor had made these replacements without PSE&G knowledge. (The issue of configuration control, in general, is being addressed under NRC Restart Issue III.2, Configuration Control.) The corrective action for the turbine governor problem included sending the units back to the vendor to have them inspected and, if required, rebuilt to assure their configuration was in accordance with the Salem design specification. The inspector verified by field inspection and document review that the units had been returned to the Salem site and, for Unit 2, had been reinstalled.

The inspector obtained a copy of the "AFW System Unit 2, System Readiness Review Final Affirmation," dated November 13, 1996. This document had been approved by the system manager and identified approximately 60 incomplete items most of which were tests to demonstrate acceptability of components which had been repaired or modified. Examples include a manual trip of the turbine driven pump to demonstrate operation of the trip and throttle valve, flow instrumentation operational check, valve indication verification, check valve operational check, and an evaluation of potential over pressurization damage to the actuator of valve 2MS132 (Isolation valve for steam to the turbine). The inspector determined that all of the system readiness items were a restraint to entering Mode 3 or Mode 4.

c. Conclusions

The inspector concluded from his inspection that the actions taken by the licensee to improve AFW performance and reliability should be effective. However, because of the large number of outstanding items which remain to be tested, this Restart Item will remain open until satisfactory AFW performance has been demonstrated.

E2.3 (Closed) LER 50-272/96-015: inadequate Containment Fan Coil Unit (CFCU) heat removal capability due to bio-fouling. During the first quarter of 1993, the individual CFCUs had been tested and noted to be performing at less than the acceptance criteria. However, the combined effect of poor performance of three units was not addressed. The total heat removal capability requirement is 250.8 million BTU/hr. In July 1996, an engineering review determined that the actual capability during the first quarter of 1993 was 201.2 million BTU/hr for Salem Unit 1 and 209.6 million BTU/hr for Unit 2. The LER documented that there was no safety consequences because under worst case accident scenarios, the containment spray pump would be available to provide sufficient additional heat removal capability.

PSE&G has determined that one cause of the CFCU performance degradation was bio-fouling as a result of the service water chlorination system being inoperable between June 1991 to at least June 1993. PSE&G has also determined that lack of organizational and management sensitivity to the maintenance and operation of the chlorination system was also a cause of this event. Additionally, the absence of controlled and accurate test acceptance criteria in the test procedure was a cause.

The inspector reviewed the corrective action identified for this event. The corrective action includes implementation of a CFCU monitoring plan, procedure revisions to emphasize the importance of maintaining the service water chlorination system, and procedure revisions to ensure the chlorination system is in service prior to placing the Service Water System in service. In addition, training was developed to stress the importance of maintaining the service water chlorination system in service. The inspector confirmed that the procedure revisions are complete, training has been conducted, and the CFCU performance monitoring program is being developed with an expected completion scheduled for December 1996.

The inadequate procedures constitute a violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings." The inadequate test procedure constitutes a violation of 10 CFR 50, Appendix B, Criterion XI, "Test Control". The failure to adequately maintain the service water chlorination system constitutes a violation of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Action." In light of the fact that these problems are licensee-identified and corrected and in recognition of the ongoing PSE&G efforts to address the generic issues of management effectiveness, procedural shortcomings, and maintenance problems as part of the Salem Unit 1 & 2 restart effort, these violations are being treated as Non-Cited Violations, consistent with Section VII.B.I of the NRC Enforcement Policy.

E2.4 (Closed) LER 50-272/96-012: potential loss of residual heat removal capability due to inadequate valve design. The maintenance history for the residual heat removal (RHR) flow control valves provided evidence that there have been seven key/keyway failures since 1993. PSE&G engineering determined that the original design provided little or no design margin. For reasons not known at the present time, the original Westinghouse specification and data sheet did not specify any flows or pressure drop across these valves.

PSE&G determined that these RHR valves would need to be replaced prior to entering Mode 6 for Salem Units 1 & 2. Also, a review was made to determine if any other valves of the type installed at Salem had similar problems. That review lead to the conclusion that adequate margin existed for other valves in use at Salem and there was no record of the key/keyway failure mode for these valves.

The inspector verified that the Salem Unit 2 RHR flow control valves have been replaced and a design change package is being prepared to replace those in Unit 1. The inadequate design is considered a violation of 10 CFR 50, Appendix B, "Design Control." This violation is considered a Non-Cited Violation, consistent with Section VII.B.I of the NRC Enforcement Policy.

IV. Plant Support

R1 Radiological Protection and Chemistry (RP&C) Controls

R1.1 Exposure Goal/Status

The licensee's annual exposure goal for 1996 was 208.745 person-rem and was based, in part, on the restart of both Units 1 and 2. The goal however, did not anticipate the Unit 1 steam generator replacement project. Not including the steam generator replacement project, total Salem exposures for 1996 through December 12, 1996 was 202.408 person-rem. The steam generator replacement project was originally estimated at 166.733 person-rem with a project goal set at 158.253 person-rem. The SGRP estimate was revised on November 11, 1996, to add an additional 31.529 person-rem resulting in a new project estimate of 198.262 person-rem. The reasons for the additional exposure included: additional detailed planning was completed for the new steam generator structural support modifications indicating significantly more work was required; the steam generator downending ring required significant repair due to insufficient field verification prior to fabrication; and overall project schedule delays have extended the SGRP an additional 6 weeks. As of December 12, 1996, the SGRP had accrued 110.595 person-rem versus an estimated 178.444 person-rem to date. Total Salem Station personnel exposures for 1996 through December 12, 1996 was 313 person-rem.

R1.2 Radiological Work Controls

a. Inspection Scope

During inspection from 10/28 until 11/4 of the Salem Unit 1 SGRP outage, the inspector observed work control practices, interviewed workers and RP staff, and reviewed licensee procedures. The inspector observed licensee postings, use of contamination controls, and locked high radiation areas.

b. Observations and Findings

During the inspection period, all areas reviewed were properly posted, contamination areas were controlled, and locked high radiation areas were found to be locked as required.

Appropriate RP/worker interfaces were established during entry through the temporary access facility (TAF) and upon entry to containment; and at the refueling floor satellite RP control point and upon entry into the bioshield wall in the basement of containment. The TAF provided dress out facilities, RWP sign-in, cellular phone issue, and dosimetry issue. Once inside containment, cellular phone contact was made by each work party with the RP remote command center located in the TAF. The TAF RP command center consisted of three remote monitoring stations; one for the refueling floor, and one for each pair of steam generator platforms. The RP monitoring stations consisted of remote video monitors of their

respective areas. During the inspection, approximately 9 different camera views were simultaneously displayed at each RP monitoring station. The RP command center RP technicians controlled the remote camera pan, tilt, and zoom functions and could call the work parties and associated RP technicians in the areas of their responsibility to provide additional RP oversight, and potential remote constant RP coverage capability. During the inspection, no remote constant coverage use of the RP command center was observed.

The licensee had identified four project tasks that would require continuous RP coverage: pipe end decontamination, seal plate installation, pipe severance and steam generator removal. The inspector questioned the positive control aspect of the remote setup when audio communications relies on recognition of the worker and dialing the applicable cellular phone number to establish contact to provide direction to the workers. The inspector questioned the RP technicians ability to recognize the workers in containment (especially due to the uniform protective clothing dress). The licensee resolved this concern by requiring each individual carrying a cellular phone into containment to label the last two digits of the phone number on their hard hat cover. This provided the visual reference needed during remote surveillance to establish audio communications when necessary.

The inspector observed effective setup and controls associated with the clean area side operations. The refueling floor inside containment consisted of a partial clean area that extended out through the equipment hatch. The inspector noted that appropriate contamination monitoring equipment and dedicated RP technician resources were devoted to these clean areas to ensure personnel and radioactive material control were maintained. The clean areas mentioned and the "yard" areas outside were effectively monitored and controlled during this inspection.

c. Conclusions

The inspector determined that the majority of the project work activities would be conducted without the need to establish high radiation areas and associated requirements. Sufficient RP technician resources were provided inside containment to provide the surveying and radioactive material control aspects of the project. The additional remote surveillance capability of the RP command center provided another level of review of the work areas and was being considered for possible applications involving remote surveillance of high exposure jobs. Also, the containment clean areas and control of radioactive material outside of containment were effectively monitored and controlled during this inspection. No discrepancies or violations of any radiological work control requirements were identified.

R1.3 Mockup Training

a. Inspection Scope

During inspection from 10/28 until 11/4 the inspector observed mockup training for installation of steam generator RCS seal plates and for RCS pipe end

decontamination. The inspector also interviewed applicable licensee personnel and reviewed RP job guideline documentation.

b. Observations and Findings

Prior to removing the old steam generators, after severing the reactor coolant piping, a steel plate is welded to the steam generator end of the reactor coolant piping to provide a contamination boundary. Prior to performing this work evolution, mockup training was performed. The mockup training involved 3-4 ALARA personnel, 3-4 pipefitters and 2 construction supervisors. The mockup training session involved a good test of the planned work technique. The mockup facility was full-scale as were the seal plate and welding equipment. No protective clothing or steam generator platforms were modeled and no communications equipment were utilized as the actual work performance environment would entail. Attendance was taken of the training participants for archival purposes only. The inspector observed that no quality assurance personnel attended the seal plate installation mockup training. Several days later, the RCS pipe end decontamination mockup training was also performed. This training was conducted inside a contaminated area inside the fuel handling building with appropriate RP, FTI, ALARA, pipefitter, and quality assurance personnel in attendance.

c. Conclusions

An effective mockup training for installation of steam generator seal plates was performed. Important sequencing of work details was established and an understanding of the scope of work and radiological implications of the work were effectively discussed and communicated to those present. The inspector noted that important details of the work method that incorporated the radiological work hazards were established during the mockup training. Although the mockup training was performed in street clothes and was unencumbered by protective clothing, platform restrictions, and communication system usage, the inspector determined that the most important aspects of the training were met. However, the licensee had not established a requirement that only those in attendance of the mockup training could perform the work. Task qualification controls had not been established for the seal plate installation work. The lack of quality assurance personnel in attendance was noted.

The licensee responded to this NRC identified weakness by delineating that the responsibility for worker qualifications was with the work contractor (principally Raytheon Nuclear Incorporated (RNI), and FTI). In response to this concern, RNI included a worker qualification matrix into applicable work packages with a work package step requiring review of personnel qualifications prior to commencement of the mockup specific work. FTI had previously included their personnel qualification records in the applicable task deployment letter (work package) for review. Approximately 12 local pipefitters' qualifications were not originally included in the documentation packages. Late in the inspection, RNI and FTI mockup qualification

documentation records were completed and reviewed and verified by the inspector. Later performance of pipe end decontamination mockup training incorporated these enhancements.

R1.4 Pipe End Decontamination Controls

a. Scope (83750)

During inspection from 12/9 until 12/13, the inspector observed the setup, implementation, and RP coverage controls associated with sponge-media blast decontamination of RCS pipe ends of steam generator No. 12.

b. Observations and Findings

The inspector observed effective contamination controls and confirmation of negative ventilation of the operating equipment before beginning the decontamination work. The decontamination equipment was remotely operated from a low dose rate area of containment by reference to closed circuit television cameras inside the RCS pipe. Excellent air sampling was provided at several locations on the steam generator platform and two CAMs were provided to allow for the rapid detection of airborne radioactivity.

The inspector noted that the effectiveness of the pipe end decontamination dose rates was monitored outside of the RCA in the temporary access facility RP Command Center. A remote readout of dose rates was provided to the RP technician providing oversight of the area. In order to understand decontamination goals and hold points, the inspector asked the RP technician and an ALARA radiological engineer where the dose rate detector was located and how the dose rate information was used to determine when the decontamination operation was completed. The inspector noted that such information was important in understanding when decontamination was complete to the maximum extent possible to avoid unnecessary personnel exposure. Both individuals did not know where the dose rate detector was located and indicated that the vendor would determine when the decontamination was completed. The inspector noted that the dose rate detector configuration was accurately described in the applicable RP Job Guideline that was available to the staff in the RP Command Center. In response to this concern, the licensee implemented a read and sign order to ensure the applicable RP technicians were knowledgeable of the decontamination monitoring configuration. The inspector noted that the pipe end decon RP job guideline provided only marginal guidance on acceptance criterion for the decontamination and also noted that the RP Job Guidelines were not station-approved procedures and did not appear appropriate for control of work. The licensee responded by modifying the pipe end decon work package to include an RP hold point before completion of the decontamination work evolution.

c. Conclusions

RP surveying and monitoring of the pipe end decontamination operation were effective and exposures were minimized. However, the control of decontamination to maximize effectiveness was not well established. The licensee added an appropriate RP holdpoint to the pipe end decontamination work package in response to this concern.

R1.5 Internal Exposure Assessments

a. Scope (83750)

During inspection from 12/9 until 12/13, the inspector reviewed the investigational whole body counts for 1996 and reviewed and verified calculations of internal exposures recorded for 1996.

b. Observations and Findings

The inspector's review indicated that approximately 50 whole body counts (WBCs) were performed during 1996 for investigational purposes as possible internal exposures. Of these, 41 WBCs were determined to be below procedural action levels. Several others represented low level contaminations that fell below procedural action levels after a day later recount. Only two individuals indicated detectable internal contamination. Both individuals were associated with steam generator eddy current inspection work at Salem in June 1996. One individual was assessed a CEDE of 7 mrem as a result of the internal contamination. The 7 mrem was below the 10 mrem level of recording. The other individual was assessed an internal exposure of 32 mrem CEDE which was assigned to his personnel exposure record.

The inspector reviewed the applicable bioassay measurement data and independently performed an internal exposure assessment for the latter individual. The inspector calculated 29 mrem CEDE, which agreed well with the licensee's result.

c. Conclusions

There were few internal exposure incidents identified at the Salem and Hope Creek Stations in 1996. One internal exposure of 32 mrem CEDE was recorded. This is indicative of very good contamination controls at both Stations.

R2 Status of RP&C Facilities and Equipment

R2.1 Unit 1 Radiological Conditions

a. Inspection Scope

During inspection from 10/28 until 11/4 the inspector toured the principal radiological work areas of Salem Unit 1 during the steam generator replacement project. Independent survey measurements were made, licensee surveys and log book documentation were reviewed in order to assess the radiological hazards presented to the workforce.

b. Observations and Findings

The Unit 1 containment radiological conditions were determined as follows.

Refueling floor: general area dose rates were <1 mR/hr in most areas with areas over the reactor head on the cavity deck grating of 1-6 mR/hr. Inside the upper biological shields surrounding each steam generator were dose rates from 1-20 mR/hr. The refueling floor contamination levels were maintained to approximately 1,000 dpm/100 cm^2 (the station clean area limit). Log entries indicated that some structural steel was contaminated from 6,000-20,000 dpm/100 cm^2. The steel was wiped down controlled to maintain area contamination levels to approximately 1,000 dpm/100 cm^2.

Basement floor, inside the bioshield area (with steam generators full): general area dose rates of 1-15 mR/hr were found, with steam generator platform dose rates of 5-15 mR/hr and reactor coolant pump catwalk dose rates of 5-15 mR/hr. The reactor coolant piping averaged 30 mR/hr contact. Contamination levels in the lower levels of containment were maintained between 1,000 to 2,000 dpm/100 cm^2, although log entries documented occasional occurrences of contamination excursions up to 350,000 dpm/100 cm^2. These were promptly decontaminated and maintained at the low contamination levels, previously stated.

Although, the containment was posted as a high radiation area, the principal work areas were less than 15 mR/hr and contamination levels were maintained at very low levels.

Shielding

The licensee provided approximately 70,000 pounds of temporary lead shielding to provide the excellent dose rate environment previously mentioned. Areas that were shielded included: reactor head, pressurizer surge line, regenerative heat exchanger, pressurizer spray line, safety injection lines, residual heat removal piping, intermediate RCS loops, steam generator platforms, reactor coolant pump platforms, and pressurizer relief tank.

c. Conclusions

Contamination was maintained at near clean levels, and through the use of temporary shielding and filling of steam generators, radiation levels of principal work areas were maintained at low levels without significant dose rate gradients. The inspector determined that excellent radiological conditions were established for conducting the steam generator replacement project.

R2.2 Unit 2 Radiological Conditions

a. Scope (83750)

The inspector toured the principal radiological work areas of Salem Units 1 and 2 during extended outage conditions. Independent survey measurements were made and licensee surveys were reviewed.

b. Observations and Findings

During inspection tours of the Unit 2 containment from 12/9 until 12/13, the inspector noted a variety of protective clothing dress by workers in the same areas. The variations ranged from only shoe covers and gloves; to lab coats, shoe covers and gloves; to full protective clothing dress. The licensee indicated that during the extended outage period, both containments had been decontaminated in many areas to below the clean area contamination limit. Survey documentation of floor areas confirmed the low contamination levels. Survey documentation of the walls and low hanging interferences in these areas were not well documented, although the licensee believed these surfaces were also decontaminated and represented a low risk to the workers. The inspector performed gross masslin wipedowns of the easily accessible wall surfaces and low hanging overhead surfaces to evaluate the contamination hazards. None of the inspectors' gross contamination samples indicated any detectable contamination, confirming the licensee's understanding that resulted in the reduced protective clothing dress practices in containment.

During a tour of the Unit 2 Auxiliary Building, the inspector noticed a posted locked high radiation area at the entrance to the No. 21 waste holdup tank (WHT) room. Entry to the room is obtained by climbing a 6-foot vertical ladder over a weir wall and then down another ladder into the room. Access was prevented by a ladder lock which covered the rungs of the ladder and successfully prevented access by way of the ladder. The inspector noted an adjoining mezzanine platform at the same level as the top of the weir wall that could allow a worker to circumvent the ladder lock and gain access to the room from the mezzanine. A current survey of the room indicated a maximum dose rate of 700 mR/hr at 30 centimeters, which did not meet the Technical Specification requirement for locking to prevent unauthorized access. In addition, there was no indication that any unauthorized entries had been made into the room. The licensee immediately locked a gate preventing access to this area and was evaluating a means to prevent access to the No. 21 WHT room from the adjoining mezzanine. No violations were identified in this area.

c. Conclusions

The inspector concluded that radiological controlled areas at the Salem Station were properly posted. Further, locked high radiation areas were properly controlled. However, a possible access path to the No. 21 WHT room was identified. The licensee maintained contamination within the reactor containment to low levels. This was a very good initiative.

R3 RP&C Procedures and Documentation

R3.1 RP Job Guidelines

a. Inspection Scope

During inspection from 10/28 until 11/4 the inspector found that the licensee was conducting the SGRP with very limited advance planning. The work package review process was continuing during this inspection for work yet to be performed. It was during this review that the ALARA and RP control requirements are specified in the work package. In order to facilitate timely communication of expected RP job performance during radiologically significant work evolutions, RP Job Guidelines were often written for RP staff use before the work package was completed. The inspector reviewed these documents to determine if adequate RP precautions and considerations had been planned.

b. Observations and Findings

The RP job guidelines reviewed provided a good description of each job. The guidelines included some RP setup requirements and specified some RP requirements for surveying, monitoring, and air sampling. The RP job guidelines provided clear definition of work steps that predicate changes of radiological conditions. The inspector noted that there was no discussion of dosimetry placement when working inside or in close proximity of open reactor coolant piping. Also, no radiological contingency planning was built into the RP job guidelines. Instead, there were occasional work control restrictions that caused work be stopped for evaluation of conditions and controls.

During tours of the plant, the inspector noted that the RP job guidelines were only available in the RP command center. RP technicians in the field were not provided with this information. Later during the inspection, the licensee distributed the RP job guidelines to all containment satellite RP stations.

c. Conclusions

Although work packages were not all completed and detailed work requirements were therefore not available for RP planning purposes, general work descriptions of all radiologically significant work had been researched and individual RP job guidelines for each had been developed to provide some advance RP planning and

to communicate a level of RP technician job performance expectation. These RP job guidelines provided a moderately effective vehicle for orienting and guiding the RP technicians in preparation for radiologically significant project work evolutions.

R3.2 Transportation Shipment of Old Steam Generator

a. Scope (86750)

On December 6, 1996, the inspector reviewed the licensee's shipping records and preparations for shipment of the first Unit 1 steam generator to be shipped to the Barnwell Low Level Radioactive Waste Disposal Facility. The shipment review was made with respect to DOT regulations including specific DOT Exemption No. 11745 requirements.

b. Observations and Findings

In preparation for shipment, the licensee decontaminated Steam Generator No. 14 to below Station release limits. All exterior penetrations were sealed and the RCS pipe nozzles, in addition to being seal welded, had three-inch thick shield covers welded in place. The generator was also painted. The lifting trunions were defeated by welded gussets at each 90-degree location. The steam generator was secured to a special flatbed trailer transporter that included steel plate shielding around three sides covering approximately the lower 2/3 of the steam generator. The inspector observed the licensee performing final survey measurements of the shielded transport vehicle and the inspector performed independent dose rate measurements. All contamination and dose rate measurements were within regulatory requirements. The shipment was properly marked with the specific DOT exemption number of the shipment as well as the shipping classification, Radioactive-Surface Contaminated Object, and other required markings.

The inspector reviewed the shipping manifest (No. 96-218) and noted that the licensee accounted for the internal solid metal oxides residues and accounted for any liquid remaining in the plugged steam generator tubes. All required information was included and no discrepancies with regulatory requirements were identified.

c. Conclusions

The licensee properly prepared the No. 14 steam generator for shipment. Shipping records were complete and met all regulatory requirements.

R5 Staff Training and Qualification in RP&C

a. Scope (83750)

During inspection from 12/9 until 12/13, the inspector reviewed applicable procedures and lessons plans associated with contractor RP technician training and qualification. The inspector also conducted interviews with the training staff.

b. Observations and Findings

The inspector determined that contractor senior RP technician candidates were required to pass a generic RP technician screening examination within the past 3 years followed by station specific procedure training and testing. The contractor RP technicians were also subjected to a practical evaluation performed by permanent RP staff to complete the qualification process. The inspector reviewed the lesson plan materials for the station specific procedure training and determined that they were of good quality. The inspector also reviewed the station specific procedure examination and noted that it had been upgraded since previously inspected.

c. Conclusions

The licensee maintained a good training and qualification program for contractor RP technicians. No discrepancies were identified.

R6 RP&C Organization and Administration

R6.1 Unit 1 SGRP Radiation Protection Organization

a. Inspection Scope

During inspection from 10/28 until 11/4, the inspector reviewed the licensee's RP staffing organization in support of the steam generator replacement project. The review consisted of organization documentation review and observations of program implementation during the project.

b. Observations and Findings

The original staffing plan called for 58 contractor senior RP Technicians and 24 contractor junior/decon RP technicians making use of 10 permanent station senior RP technicians. The actual RP organization staffing utilized a total of 75 contractor senior RP technicians and 24 contractor junior/decon RP technicians. An additional 7 radiological engineers were provided by RNI and FTI. The licensee utilized existing PSE&G RP personnel in overall RP operations supervision capacities to oversee all ALARA and RP operations functions. All major radiological work areas were observed to be well staffed with cognizant RP staff.

c. Conclusions

The inspector determined that the licensee met and exceeded the planned RP staffing levels to support the steam generator replacement project. Through observation, the inspector determined that very good RP staff resources were available to provide the radiological survey and job coverage needs of the project.

R6.2 Unit 2 Outage RP Organization

a. Scope (83750)

During inspection from 12/9 until 12/13, the inspector reviewed the licensee's RP outage organization responsible for support of Unit 2 restart outage activities and Unit 1 steam generator replacement project activities. The review consisted of review of organizational documents and observations of work area coverage during the inspection.

b. Observations and Findings

The RP Department had increased the staffing of 36 permanent plant senior RP technicians to include the contracted services of 86 senior RP technicians and 26 junior RP technicians. Approximately 30 contracted senior RP technicians were utilized for radiological coverage of Unit 2 and the Unit 1 non-containment RCA areas. The SGRP RP organization utilized the balance of the contracted RP technicians to provide all Unit 1 containment RP support. Inspection tours of both Unit 1 and 2 containments and Units 1 and 2 Auxiliary Buildings, the Solid Radwaste Building and the "yard" RCA areas, indicated that all areas were effectively monitored by radiological controls personnel.

c. Conclusions

Appropriate RP staffing levels were obtained and used to support the outage activities of both Salem Units 1 and 2.

R7 Quality Assurance in RP&C Activities

R7.1 QA Oversight of RP

a. Inspection Scope

During inspection from 10/28 until 11/4, the inspector reviewed the resources dedicated to providing oversight of the radiation protection program implementation during the steam generator project. Applicable quality assurance documents were reviewed and interviews with cognizant personnel were conducted.

b. Observations and Findings

The licensee provided a Quality Assurance (QA) steam generator replacement project (SGRP) oversight plan, that provided for the identification of high risk events and plans for assessing the adequacy of the contractor's QA controls over the high risk planned activities. Four individuals were contracted by PSE&G for performing this QA oversight work, each having had recent steam generator replacement experience. Each major contractor (RNI, FTI) was required by contract to provide their own QA monitoring and controls. The inspector noted that the SGRP did not

contract the RP function, that this function was supplied directly by PSE&G. No additional QA oversight had been specifically planned to cover the RP area. One PSE&G individual having normal responsibility for reviewing the RP and Chemistry areas was involved due to normal job performance. Limited SGRP QA surveillance observations had been documented by this individual during the project. Two days of observations were documented during the project. These included observations of RP command center remote monitoring of RCS pipe cutting of old steam generator no. 12 and the review of one radiological occurrence report. No discrepancies were recorded by the QA inspector. Also, a limited SGRP RP preparation review was performed by an outside RP consultant, however the review indicated that a comprehensive RP preparation audit should be conducted prior to project commencement, which was not performed. The inspector questioned the adequacy of QA oversight of the SGRP RP program. In response to this inspection concern, the licensee added a fifth member to the QA oversight group with specific responsibility for radiation protection oversight.

c. Conclusions

The inspector determined that the licensee had not dedicated specific QA oversight review of the RP program performance during the SGRP and only routine QA surveillance activities were being provided. In response to this finding, the licensee obtained an additional member of the SGRP QA oversight group tasked with specific responsibility for radiation protection oversight.

R7.2 Radiological Occurrence Reports (RORs)

a. Scope (83750)

During inspection from 12/9 until 12/13, the inspector reviewed the licensee's program for identifying, investigating, and correcting radiological occurrences at Salem Station. The inspector reviewed selected RORs for 1996 to assess the licensee's performance in this area. The inspector also conducted interviews with applicable RP staff.

b. Observations and Findings

During 1996, the licensee recorded 154 level 1 RORs, 40 level 2 RORs, and 8 level 3 RORs (level 1 ROR indicates least significant and level 3 ROR the most significant). The inspector observed that the level 1 RORs were predominantly personnel contaminations. The inspector reviewed in detail selected level 3 and level 2 RORs. Based on this review, the inspector noted that most of the radiological occurrences were of low exposure consequence and that there was a good low threshold for reporting radiological incidents. Also, the investigations of the level 2 and 3 RORs were thorough and detailed. However, corrective action resolution of the level 2 and 3 RORs frequently did not address all of the issues identified in the investigations and the corrective actions were often limited to counseling of the involved individual and informing the staff. The following two examples are provided for illustration.

ROR No. 96-123 was written in response to a series of work control errors associated with a valve repair that took place inside the unit 2 regenerative heat exchanger room. The ROR identified that I&C technicians had entered the room to perform work and were stopped due to a system tagging conflict. Mechanical maintenance made several unnecessary entries into the room due to a failure to drain the piping system, failure to bring valve parts, and rework of the valve repair caused by failure to remove the old gasket before installing a replacement. The ROR captured the various planning deficiencies. The one exception was the ALARA prejob planning meeting that serves to ensure a radiologically significant job is adequately prepared. In this case, an ALARA meeting was held and did not identify the planning inadequacies prior to the start of the job. This was not captured by the ROR. The ROR assigned I&C and Mechanical Maintenance with corrective action resolution. This consisted of holding departmental review meetings to communicate this incident to their respective staffs. The ROR corrective actions were subsequently approved by the RPM. Planning and departmental interfaces with operations and ALARA were not reviewed or evaluated to improve maintenance practices.

ROR No. 96-168 was written in response to a worker entering a high radiation area (Unit 1 containment bioshield) without being monitored by a TLD (although his exposure was monitored by EPD). The ROR investigation determined that when the individual entered the security guardhouse, he was issued his security badge without his TLD attached. The individual failed to notice the missing TLD and was later admitted inside the bioshield of Unit 1 containment by an RP technician and allowed to work. The ROR identified that the security guard, the individual, and the RP technician, were inattentive to the missing TLD and the ROR also identified that the security badge clasp or snap that held the TLD badge to the security badge was weak and had failed. The ROR corrective actions consisted of counseling the individual on the applicable RP procedures and receiving disciplinary action from his supervisor. Also, the incident was a topic of discussion during a safety meeting.

The inspector determined that the ROR had identified several failure mechanisms but had only pursued one. The inspector noted that the individual was issued his security badge improperly since the TLD was found in the applicable security badge slot. The slots are too small for the security/TLD badge assembly which cause the badges to be folded and twisted into the badge slots. Repeated cycling apparently caused the snap to fail. This was not addressed in the ROR. Also, entry into the containment bioshield area requires RP technician permission to gain access. Plant policy allows dosimetry to be placed inside or outside of protective clothing and when dosimetry is placed inside of protective clothing, RP technicians cannot verify that workers are in compliance with requirements prior to allowing access to certain high radiation areas. Review and evaluation of this plant practice was also not reviewed in the ROR.

c. Conclusions

The inspector concluded that; radiological occurrences were of low exposure consequence, that there was a good low threshold for reporting radiological

incidents; and that the investigations of level 2 and 3 RORs were thorough. Corrective action resolution of the level 2 and 3 RORs frequently did not address all of the issues identified in the investigations and the corrective actions were often limited. Additional attention in this area was warranted.

R8 Miscellaneous RP&C Issues

R8.1 (Closed) Violation 50-311/96-01-05:

During late 1995, the licensee reported several instances of entering the RCA without electronic dosimetry monitoring and other related access control procedure violations. The repetitive nature of these procedure violations resulted in issuance of a violation against 10 CFR 50 Appendix B, Criteria XVI, failure to provide effective corrective actions to prevent recurrence.

The inspector determined that establishing the electronic locking turnstiles at the RCA entrance provided substantial positive control over workers accessing the RCA to ensure each worker's exposure is monitored by an electronic dosimeter. Two software system modifications were made that served to enhance worker performance during RCA entry procedures. This violation is closed.

R8.2 (Closed) Unresolved Item 50-272/96-12-04:

Since June 25, 1996, until early November 1996, the Salem Radiation Protection Manager (RPM) was assigned to a temporary position in the Salem Unit 2 Outage Management group. The RPM designated the Senior ALARA Supervisor as the acting RPM in his absence. During the previous inspection, sufficient information was not available to determine if the individual met the applicable regulatory requirements, specifically 5 years of professional radiation protection experience.

During this inspection, the licensee provided a breakdown of RP supervisory experience for the acting individual that, in aggregate, equated to 5.5 years of professional experience. As a result, the subject individual was found to meet the regulatory requirements for the RPM position. This item is closed.

R8.3 Updated Final Safety Analysis Report (UFSAR)

The inspector reviewed current Salem Station practices with respect to Section 12.1.5 of the UFSAR. This section describes the semi-annual leak checks, control and storage of radioactive sources. The inspector verified the source inventory and reviewed documentation indicating successful completion of the semi-annual leak checks. All sources were controlled in locked storage cabinets with keys controlled by RP or RP instrumentation personnel. The inspector determined that the UFSAR wording was consistent with the observed plant practices and procedures.

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 December 24, 1996. 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.

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-272&311/96-17-01	VIO	failure to perform required safety analysis report
50-272&311/96-17-02	UNR	possible degradation of containment penetrations

Closed

50-272/96-12-04	UNR	radiation protection manager qualification
50-311/94-24-02	IFI	auxiliary feedwater pump trip evaluation
50-311/96-01-05	VIO	repetitive RCA access control procedure violations
50-272&311/95-10-01	VIO	failure to relatch EDG fuel rack
50-272&311/96-10-02	VIO	failure to report shutdown required by Technical Specification
50-272&311/96-12-01	VIO	failure to take adequate actions for a significant condition adverse to quality to preclude repetition
50-272&311/96-24-03	VIO	missed heat balance
50-272&311/96-24-05	VIO	inadequate access control
50-272/96-012	LER	potential loss of RHR capability due to inadequate valve design
50-272/96-015	LER	inadequate CFCU heat removal capability due to bio-fouling
50-272/96-027	LER	diesel watt meter inaccuracies not accounted for in surveillance testing

LIST OF ACRONYMS USED

AFW	Auxiliary Feedwater
ALARA	As Low As Is Reasonably Achievable
BAT	Boric Acid Transfer
CFCU	Containment Fan Coil Unit
CR	Condition Resolution
ECAC	Emergency Control Air Compressor
EDG	Emergency Diesel Generator
FHV	Fuel Handling Ventilation
FTI	Framatome Technologies Incorporated
NRC	Nuclear Regulatory Commission
PDR	Public Document Room
PIR	Performance Improvement Request
PM	Preventive Maintenance
PORV	Power Operated Relief Valve
PSE&G	Public Service Electric and Gas
QA	Quality Assurance
RCA	Radiological Controlled Area
RCS	Reactor Coolant System
RHR	Residual Heat Removal
RNI	Raytheon Nuclear Incorporated
RP	Radiation Protection
RP&C	Radiological Protection and Chemistry
SA	Station Air
SAC	Station Air Compressor
SBO	Station Blackout
SGRP	Steam Generator Replacement Project
SI	Safety Injection
SPAV	Switchgear Penetration Area Ventilation
SRO	Senior Reactor Operator
SRs	Surveillance Requirements
ST	Surveillance Testing
TAF	Temporary Access Facility
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
USQ	Unreviewed Safety Question