U. S. NUCLEAR REGULATORY COMMISSION

REGION I

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Licensee:	Public Service Electric and Gas Company
Facility:	Salem Nuclear Generating Station, Units 1 & 2
Location:	P.O. Box 236 Hancocks Bridge, New Jersey 08038
Dates:	August 11, 1996 - September 14, 1996
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EXECUTIVE SUMMARY

Salem Nuclear Generating Station
NRC Inspection Report 50-272/96-12, 50-311/96-12

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a 5-week period of resident inspection; in addition, it includes the results of announced inspections by regional radiation, emergency preparedness, and chemistry inspectors.

Operations

During the inspection period, the inspectors found a significant failure of the Salem line organization to take corrective action. In December 1995, operators filled the refueling cavity and detensioned the reactor head without insuring that Salem Unit 2 met the refueling reactivity requirements specified in Technical Specification 3.9.1. An operator identified the failure after the fact and appropriately initiated a Condition Report. In response to the report, however, the operations staff inappropriately made a change to the refueling cavity fill procedure that effectively changed implementation of Technical Specification 3.9.1 and 4.9.1.1 requirements. The 10CFR50.59 applicability review failed to identify that the procedure change required a Technical Specification change. In addition, the operations staff failed to identify that procedures used to prepare the reactor coolant system and refueling cavity for entry into mode 6 (refueling) did not insure that plant conditions met the more restrictive of the reactivity requirements stated in TS 3.9.1. The inspectors concluded that the operations and staff acted to serve the outage activities, rather than insuring safety and quality in refueling activities (Section O3.1). The Salem staff promptly initiated corrective action for minor discrepancies in meeting administrative requirements for Station Operating Review Committee documentation. The plant staff had already implemented corrective action for a self-identified violation (Section O2.1). Although operators caused an unexpected depressurization of a service water header, it resulted in no safety consequence, since it did not diminish the supply of service water from the redundant header. The inspectors will assess the results of licensee corrective actions in the next inspection period (Section O4.1).

Maintenance

Inspectors noted several examples of poor maintenance staff performance. They included: planning service water pump repacking steps out of sequence (Section M4.1); failure to properly secure temporary control air fittings (Section M4.2); and swapping high and low pressure freon sensing lines following a chiller instrument calibration (Section M4.3). During Emergency Diesel Generator post-maintenance testing, technicians discovered that the fuel injector test rig did not work properly. The technicians also learned that, since they did not understand the operation of the test rig, they misinterpreted results obtained while using it. The technicians subsequently discovered that ineffective foreign material exclusion caused a minor fuel oil leak from a fuel line. The inspectors concluded that neither training or procedures insured quality maintenance in these instances (Section M4.4). Ineffective maintenance practices have become increasingly evident during the outage. As documented in NRC Inspection Report 50-272&311/96-08, during this reporting period Nuclear Business Unit and Salem senior management initiated a major effort to provide training for all Salem maintenance staff (Section M4.5).

Engineering

Although the quality in engineering activities varied somewhat, inspectors concluded that it was generally good during the inspection period. The system manager did not inform the Management Review Committee (MRC) that RHR minimum flow valve 22RH29 continued to malfunction. As a result, the MRC inappropriately accepted the package for closure (Section E1.1). The Salem staff developed and implemented a satisfactory corrective action plan for the Salem Unit 2 PORV problems, and planned to implement the actions for Unit 1 PORVs (Section E2.1) Salem staff completed effective corrective action for the Unit 2 positive displacement pump (PDP) reliability problems, however, they have not yet completed action for the Unit 1 PDP pump (Section E2.3). The quality of MRC reviews, an NRC concern identified in previous inspections, improved significantly during the inspection period (Section E7.1).

Plant Support

In general, the plant support organizations effectively supported outage activities. Chemistry technicians accurately quantified hydrazine, ammonia, and copper in the NRC standards during an inspection (Section R1.1). Sufficient radiological safety resources have been planned for the Salem Unit 1 steam generator replacement project. The Salem staff continued to formulate the radiological safety planning with less than two months remaining before the project, however, the inspector did not detect any significant planning deficiencies (Section R3.3). A radiation protection technician did not meet managements expectations for control of access to the radiologically controlled area.(Section R4.1). The NRC will document the details of an inspection of the emergency preparedness program in NRC Inspection Report 50-354/96-07.

TABLE OF CONTENTS

<u>Report Details</u>

<u>Summary of Plant Status</u>

Unit 1 and Unit 2 remained defueled for the duration of the inspection period.

I. Operations

O1 Conduct of Operations

O1.1 <u>General Comments (71707)</u>

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.

O2 Operational Status of Facilities and Equipment

O2.1 <u>Station Operations Review Committee (SORC)</u>

a. <u>Inspection Scope (71707)</u>

The inspector reviewed procedures governing the Station Operations Review Committee (SORC) activities, and reviewed examples of SORC meeting minutes and the distribution of those minutes.

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

The inspector found that procedure NC.NA-AP.ZZ-0004(Q), Revision 6, *Station Operations Review Committee*, Step 5.5.3 states:

"If changes to a document are required before a recommendation for approval will be made, then the recommendation for approval may be granted contingent upon such changes being incorporated. The specified changes should be entered in the meeting minutes and a statement made that approval is predicated upon these changes being made. The SORC Chairman or an assigned designee should verify that the changes are correct before the document is submitted to the General Manager."

During his review, the inspector found that required changes for a SORC reviewed document, Design Change Package (DCP), 2EC-3266, Pkg. 1, Rev. 0, were properly entered in the SORC meeting minutes # 96-034. However, one of the comments which required a change to section 3.2 of the DCP's 10CFR50.59 evaluation, was never incorporated. The inspector concluded that the omission did not affect the results of the 10CFR50.59 evaluation. Through review of an additional thirteen required changes for other SORC-reviewed documents, the inspector found that all had been properly incorporated.

The inspector also found that the SORC procedure, step 5.6.8, states:

"The Secretary should have the minutes copied and submitted to the TDR [Technical Document Room] for distribution within 30 working days of the SORC meeting."

The inspector learned through discussions with document room personnel that SORC no longer sends meeting minutes to the TDR. The inspector confirmed that plant staff distributed SORC minutes directly via E-mail as directed in a memo initiated by the Salem Project Manager. Although this change was intended as an improvement to the method of distribution, it is not in compliance with the current revision of the SORC procedure.

The inspector also learned PSE&G had identified a procedural noncompliance in that SORC meeting minutes were not being distributed to required recipients within the 30 day requirement. Additional staff has been assigned to reduce the backlog and the problem is being tracked to closure utilizing the Salem site deficiency tracking system.

c. Conclusions

The licensee promptly initiated corrective action for inspector identified violations of procedure requirements for SORC administration. Plant staff had already implemented corrective action for a self-identified violation. These minor examples of procedural noncompliance will be treated as a Non-Cited Violation, consistent with Section IV of the NRC Enforcement Policy.

O3 Operations Procedures and Documentation

O3.1 Refueling Cavity Fill

a. Inspection Scope (71707)

The inspector reviewed control room narrative logs, operating procedures, and plant status concerning fill of the Unit 2 refueling canal.

b. Observations and Findings

On September 11, 1996, Unit 2 operators used S2.OP-SO.SF-0003, Revision 7, *Filling the Refueling Cavity,* to commence filling the refueling cavity. The operating shift demonstrated a good questioning attitude. The shift appropriately used the "on-the-spot change" process to improve the procedure and subsequently stopped filling the cavity due to a question concerning available instrumentation.

The inspector noted that S2.OP-SO.SF-0003 step 5.1.8 could be strengthened to provide additional guidance. Step 5.1.8 specifies actions "when desired fuel transfer canal level is reached," however, the procedure does not specify a desired level. Two operating shifts interpreted "desired level" differently, resulting in two different approaches to cavity fill. In both cases, the shift operated within procedure guidance and maintained good control of the evolution. A specified minimum level minimizes the potential for high airborne activity due to excessive spill-over (splashing) from the vessel to the canal. A specified maximum level minimizes potential foreign material exclusion (FME) concerns involved with overflowing the refueling canal into the reactor vessel. The Senior Nuclear Shift Supervisor (SNSS) initiated a procedure revision request to improve the procedure. The inspector noted that operators did not perform an independent verification (IV) of repositioned valves, required by step 5.1.10, in a timely manner. The Nuclear Shift Supervisor (NSS) acted promptly to ensure IV completion following inspector reminder.

Technical Specification 3.9.1 requires that Salem maintain the boron concentration of all filled portions of the reactor coolant system and the refueling canal uniform and sufficient to ensure that the more restrictive of the following reactivity conditions is met: (a) either a Keff of .95 or less, or (a) a boron concentration of greater than or equal to 2000 ppm. Technical Specification (TS) 4.9.1.1 requires that the more restrictive of the above reactivity conditions be determined prior to removing or unbolting the reactor vessel head and withdrawal of any full length control rod in excess of three feet from its fully inserted position. The inspector identified that on July 22, 1996, operations staff added step 3.6 to procedure S2.OP-SO.SF-0003. Step 3.6 provided guidance to operators that "filling the transfer canal in preparation for flooding the refueling cavity does not constitute a filled portion of the refueling canal and therefore TS surveillance requirement 4.9.1.1 is not applicable." The inspectors determined that the fuel transfer canal consists of the lower portion of the refueling canal below the level of the reactor cavity. As described in the Salem UFSAR, section, 9.1.4.1.4, the refueling canal encompasses the transfer canal. The inspectors concluded that step 3.6 to procedure S2.OP-SO.SF-0003 contradicts TS 3.9.1 and the UFSAR. The inspectors reviewed the 10CFR50.59 review associated with the addition of step 3.6 and determined that the licensee incorrectly concluded that the addition of step 3.6 to procedure S2.OP-SO.SF-0003 did not require a Technical Specification change.

In addition, the inspectors determined that the operations management changed procedure SF-0003 in response to a condition that existed in December 1995. On December 7, 1995, a SNSS questioned whether operators violated TS 3.9.1 because operators failed to ensure that they maintained adequate boron concentration in the refueling canal prior to entering the refuel mode on December 6, 1995 (Condition Report 951207066). Salem licensing staff stated that "since the refueling canal was not filled at the time, there was no communication link with the reactor coolant system and therefore no potential to affect reactor criticality" (Memo CR-I955746). Operations management determined that if the refueling canal is not filled and the vessel head has not been removed, then TS 4.9.1.1 is not applicable. In addition, operations' response to CR 95120766 stated "A more conservative approach would be to require verification that any water in the refueling canal is greater than 2000 ppm boron prior to head detensioning. An uncontrolled RCS dilution and inadvertent criticality with all rods inserted and the reactor head studs detensioned could result in a serious accident with severe consequences" (PIR 951207066).

The inspector determined that operators did, in fact, fail to meet TS 3.9.1 requirements on December 6, 1995. Operators did not ensure that the filled portion of the refueling canal (eight inches of demineralized water) met the more restrictive of the TS 3.9.1 reactivity conditions prior to detensioning the reactor head and entering the refueling mode. In addition, by their failure to take thorough and effective corrective actions, Salem licensing and operations staff failed to identify that procedures S2.OP-SO.SF-0003, 2-IOP-7, Revision 10, "*Integrated Operating Procedure Cold Shutdown to Refueling* and S2.OP-IO.ZZ-007, Revision 0, *Cold Shutdown to Refueling*" did not require operators to meet **the more restrictive** of the two reactivity conditions required by TS 3.9.1. Inspectors concluded that operations management, expected to implement high standards for corrective action, failed to take appropriate corrective action for a TS violation identified by an operator. Failure to take action to preclude repetition of a violation of Technical Specification requirements is a violation of 10 CFR 50, Appendix B, Criterion XVI, *Corrective Action*(**VIO 50-272 & 311/96-12-01**).

c. Conclusion

By failing to ensure required boron concentration prior to entering the refueling mode in December 1995, operators failed to meet TS 3.9.1 requirements. In addition, in July 1996, Salem staff failed to determine, as required by 10 CFR 50.59, that a proposed cavity fill procedure change in contradiction to the UFSAR and the requirements of TS 3.9.1 required a TS change approved by the NRC. In addition, the operations staff response to the Condition Report that documented the failure to meet TS 3.9.1 did not identify and correct conditions adverse to quality. Specifically, the cavity fill procedures did not insure that boron concentration met the more restrictive of the TS 3.9.1 reactivity requirements. The inspectors concluded that the operations staff justified the incorrect operator actions of December 1995, rather than taking action to prevent the repetition of those actions.

O4 Operator Knowledge and Performance

O4.1 Service Water Bay Depressurization

a. Inspection Scope (71707)

The inspector reviewed control room narrative logs and strip chart recordings following an unexpected operator-induced service water (SW) bay depressurization. In addition, the inspector conducted a SW system walkdown and interviewed the operating shift.

b. Observations and Findings

At 3:55 a.m. on September 2, 1996, Unit 2 operators closed 22SW17, SW pump discharge header crossover valve, in preparation for 21SW17 valve maintenance. Due to the SW system alignment, closing the 22SW17 resulted in no. 4 SW bay depressurization. At 4:53 a.m. operators restored no. 4 SW bay pressure and reopened the 22SW17. Operators cross-connected the SW nuclear headers in the auxiliary building prior to closing 22SW17 and did not expect to depressurize no. 4 SW bay. Operators did not account for a SW check valve that prevented flow backward from the auxiliary building to the SW bay. The cross-connect of the SW nuclear headers in the auxiliary building prevented depressurization of the no. 22 SW nuclear header and resulted in no safety consequence. The Unit 2 senior reactor operator initiated a condition resolution (CR) report.

c. Conclusions

The inspector considered this item open pending Operations' completion and NRC review of corrective actions. **(IFI 50-272&311/96-12-02)**

O7.1 (Closed) LER 50-272/95-001: both trains of Solid State Protection System (SSPS) inoperable due to inadequate design. In February 1995 Salem staff learned that Diablo Canyon identified a possible common mode failure of SSPS wiring near high energy lines in the non-seismic turbine building. Although the NRC initially granted enforcement discretion to allow Salem to make changes at power, the NRC rescinded the enforcement discretion in response to SSPS power supply failures. The power supply failures resulted from lack of preventive maintenance resulting in age related component failures.

The licensee attributed the inoperable SSPS to inadequate design and lack of preventive maintenance. 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 these cases.

O7.2 (Closed) LER 50-272/95-003: four planned Technical Specification entries to support correction of Analog Rod Position Indication (ARPI) system drift affecting rods 2SA1, 2SA4, and 2SA2. Salem Unit 1 Technical Specification 3.1.3.2.1 required the ARPI system to provide rod position indication within twelve steps of the respective rod group demand counter. The Technical Specification did not allow any Limiting Condition of Operation action time for corrective action. The control rod indication drift resulted from temperature related instrument drift. Salem staff subsequently submitted and the NRC approved a Technical Specification change request to allow short periods to perform instrument adjustments. These licensee-identified and corrected violations are being treated as Non-Cited Violations, consistent with Section VII.B.I of the NRC Enforcement Policy.

O8 Miscellaneous Operations Issue

O8.1 (Closed) LER 50-272/95-025: single failure conditions that could have compromised the ability of the service water system to complete its safety function during the recirculation phase. During the Salem system Restart Readiness Reviews, Problem Reports (PRs) were identified describing conditions which could have resulted in Service Water System (SW) alignments with the potential for runout/cavitation. The licensee concluded that the applicable mode of operation was not clearly defined in plant design basis documents. Further, normal and emergency operating procedures did not provide adequate operating instructions for this mode of operation.

PSE&G initiated Performance Improvement Request No. 9510122244 to document the problem and to identify the corrective action items to resolve the issue. The inspector has determined that Salem has corrected the procedural deficiencies and initiated a design change notice to revise the system Configuration Baseline Document to clarify the design basis.

The inspectors concluded that the procedural inadequacies constitute a violation of 10 CFR 50, Appendix B, Criterion V, "Procedures." The inadequate design basis document constitute a violation of 10 CFR 50, Appendix B, Criterion III, "Design Control." These licensee-identified and corrected violations are being treated as Non-Cited Violations, consistent with Section VII.B.I of the NRC Enforcement Policy.

O8.2 (Closed) LER 50-272/95-026: main steam safety valves failed lift set test. During scheduled surveillance testing, it was discovered that nine out of twenty Salem Unit 1 Main Steam Safety Valves (MSSVs) exceeded the allowable lift set pressure tolerance specified in Technical Specification Table 4.7-1. The causes of this event were ring setting adjustments made without post adjustment lift setpoint testing, and the prior use of test equipment that was inaccurate. PSE&G reviewed the work history of the Salem Unit 2 MSSVs and determined that although they had undergone ring settings, setpoints had been corrected as appropriate utilizing alternate test equipment. PSE&G concluded that the problems identified on the Salem Unit 1 MSSVs do not exist on the Salem Unit 2 MSSVs.

PSE&G initiated Performance Improvement Request No. 951023245 to document the problem and to identify the corrective action items to resolve the issue. The inspector has determined that Salem has discontinued the use of the inaccurate test equipment and an action item has been identified to revise procedure SC.MD-ST.MS-0001(Q) to require lift set testing following ring sitting changes. The inspector verified that work orders have been issued for the removal, testing, and replacement of the Salem Unit 1 MSSVs. These work orders are in various stages of completion.

The inspectors concluded that the original procedures were inadequate in that post maintenance testing was not required following ring setting. This procedural inadequacy constitutes a violation of 10 CFR 50, Appendix B, Criterion V, "Procedures." This licensee-identified violation is being treated as a Non-Cited Violation, consistent with Section VII.B.I of the NRC Enforcement Policy.

O8.3 (Closed) LER 50-272/95-027: operation of Positive Displacement Pump (PDP) during a safety injection could have resulted in exceeding 10CFR100 and GDC 19 dose limit criteria. Previous analyses assumed that the PDP tripped after a safety injection (SI) signal. However, the PDP trips after a safety injection signal only with a concurrent loss of offsite power. During a LOCA, in the recirculation mode, the PDP seal leakage can increase the total contaminated leakage to the auxiliary building.

Additionally, the original dose evaluation was determined to be in error in that it assumed the Auxiliary Building Ventilation (ABV) system charcoal filter was aligned to provide filtration during the cold leg recirculation phase of a LOCA. The ABV system charcoal filter is not automatically aligned.

The cause of this event is inadequate design basis information. This resulted in the development and use of inadequate procedures regarding operation of the PDP and the ABV system.

PSE&G initiated Performance Improvement Request No. 951026244 to document the problem and to identify the corrective action items to resolve the issue. The corrective action items include a proposed revision to the Emergency Plant Implementing Procedures to manually place the Auxiliary Building Ventilation System charcoal absorber in service following a LOCA, and a proposed modification to the Auxiliary Building Ventilation System design to provide local manually operated valves to operate the charcoal absorber outlet dampers in the event of a control or mechanical failure. Another corrective action is identified to conduct a comprehensive review to ensure consistency between design assumptions, plant configuration, and operations. The inspector confirmed that these activities are being tracked in the corrective action tracking system. The inspector also verified that changes have been made to emergency operating procedures 1-EOP-LOCA-3 & 2-EOP-LOCA-3, "Transfer to Cold Leg Recirculation" to require operators to trip the PDP prior to placing the plant in the recirculation mode.

Although not all corrective action activities are complete, the licensee has committed to complete these items prior to Restart as stated in the LER corrective action section. The inspector has concluded that the corrective action tracking system and the documented commitment in the LER provide reasonable assurance that the activities will be tracked to completion.

The procedural inadequacies constitute a violation of 10 CFR 50, Appendix B, Criterion V, "Procedures." The inadequate design basis documentation constitute a violation of 10 CFR 50, Appendix B, Criterion III, "Design Control." These licensee-identified violations are being treated as Non-Cited Violations, consistent with Section VII.B.I of the NRC Enforcement Policy.

O8.4 (Closed) LER 50-272/95-28: lack of effective leakage monitoring program required by TS 6.8.4.a. The technical specification requires a program to monitor and reduce leakage from those portions of systems outside containment that could contain highly radioactive fluids during a postulated accident. PSE&G determined that although elements of this leakage monitoring program exist, they had not been controlled as an integrated program which would meet the requirements.

PSE&G initiated Performance Improvement Request No. 950920589 to document the problem and to identify the corrective action items to resolve the issue. The inspector has determined that procedure SC.SA-AP.ZZ-0051(Q), Leakage Monitoring Program, has been developed and issued. As a result of discussions with PSE&G personnel, and a brief review of this procedure, the inspector was able to conclude that it was designed specifically to satisfy the requirements of TS 6.8.4.a.

The inspectors concluded that prior to this event, adequate procedures were not in place to prescribe activities necessary to meet the requirements of the technical specifications. This procedural inadequacy constitutes a violation of 10 CFR 50, Appendix B, Criterion V, "Procedures." This licensee-identified and corrected violation is being treated as a Non-Cited Violation, consistent with Section VII.B.I of the NRC Enforcement Policy.

O8.5 (Closed) LER 50-272/95-029: GE SBM Control Switch Degradation. During the Salem Unit 1 outage, a design change for the replacement of mechanical linkages on 4KV vital bus breakers was implemented. Post modification testing revealed an electrical failure of the 1A vital bus high limit switch. Subsequent inspections by the licensee revealed subsurface cracking on the cam follower. During additional investigation, cracks were found on other switches. As a result, all 4KV vital busses were declared inoperable for Salem Unit 1 and 2.

The licensee's corrective action for this event is to replace all switches in the 4KV vital busses prior to mode 6 and 4KV group busses prior to mode 2. Additional corrective action is planned to locate and replace any suspect switches used in other applications.

The cause of this event was identified as an inadequate design of the component by the manufacturer. The inspector determined that this event did not constitute a violation of NRC requirements. This LER is considered closed.

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 960515214: no. 26 service water pump strainer troubleshooting
- WO 960727074: no. 1C emergency diesel generator engine low lube oil level alarm troubleshooting

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

b. Inspection Scope (61726)

The inspectors observed all or portions of the following surveillance:

- S2.OP-ST.RHR.0001: no. 21 residual heat removal pump performance test

The inspectors observed that plant staff did the surveillance safely.

M4 Maintenance Staff Knowledge and Performance

M4.1 Proper Pre-Job Planning

On September 2, technicians removed no. 25 SW pump from service and repacked the pump. On September 3, a maintenance supervisor identified a planning deficiency. Planning issued a work order (960805200) to repack no. 25 SW pump with another work order (960517060) in the system to add a sixth ring of packing in accordance with the SW pump design change package. After repacking the pump but prior to installing the sixth packing ring, a Salem worker initiated an additional work order to repack the pump due to packing leakage. Planners did not identify that they should have expected the leakage and implemented the work order to install the sixth packing ring. Instead, they planned to develop another work order to repack the pump. The maintenance supervisor demonstrated a good questioning attitude and initiated a condition report (960903102) to document the problem. The inspector concluded that poor maintenance planning resulted in increased SW pump outage time.

M4.2 Equipment Restoration

On September 5, 1996, the inspector observed an unattended temporary control air connection blowing air in the Unit 2 turbine building. Technicians believed that they isolated the connection on September 3, when they last performed work under work order no. 950110121. The Unit 2 Senior Reactor Operator (SRO) entered SH.OP-AP.ZZ-0007, Revision 0, *Suspected Tampering.* The SRO determined that no malicious intent existed concerning the control air leakage. Technicians removed the temporary connection from the control air source. The inspector concluded that technicians' failure to properly secure equipment following maintenance represented a poor maintenance practice.

M4.3 Configuration Control

On September 8, 1996, Unit 2 operators placed no. 21 chiller in service following maintenance. Operators stopped the chiller when the chiller condenser relief valve opened unexpectedly. The relief valve discharged approximately 10 pounds of Freon to the atmosphere. The work supervisor determined that technicians inadvertently switched the chiller compressor suction and discharge pressure sensing lines following instrument calibration. The vendor determined that the high discharge pressure did not damage the chiller unit. Maintenance initiated corrective maintenance (CM 9608096) and an action request (CR 9608096) to address the performance issues. The inspector determined that maintenance supervisors failed to ensure proper configuration control following pressure sensing line work. In addition, unlabeled compressor suction and discharge valves contributed to the misalignment.

M4.4 Quality of Maintenance

a. Scope

The inspectors observed portions of the 2B emergency diesel generator (EDG) engine overhaul and reviewed the controlling procedures to assess procedure adequacy.

b. Observations and Findings

On August 18, maintenance technicians completed an eighteen-month overhaul on the 2B EDG and performed a post-maintenance test run. During the test, operators noted four cylinders leaking small amounts of fuel around the injector seats. Technicians removed the injectors to inspect and perform a pressure test on them. Although the technicians did not see any defects, all four injectors failed the pressure test. The staff subsequently removed and tested the remaining fourteen injectors; twelve failed.

Maintenance personnel investigated the cause of the injector seat leakage and the failure of 16 of 18 injectors during the pressure test. The technicians noted that all injectors had passed the pressure test prior to installation. Technicians determined that inadequate seating caused the leaking. The technicians also determined that the injectors failed pressure tests because the test pump leaked. In response, they added a procedure requirement to perform a blue check of the injector seating surface and replaced the test pump and associated piping. Technicians retested the injectors and all but one passed. Personnel replaced the defective injector and, following satisfactory blue checks, reinstalled all injectors.

On August 22, operators commenced a second post-maintenance run and noted that no injector seat leakage. Operators did detect, however, a slight fuel oil leak from the fuel line fitting on top of a fuel pump. Technicians found three small paint chips on the seat area of the tubing. The subsequent EDG run was satisfactory.

The inspectors reviewed the procedure governing the overhaul, SC.MD-PM.DG-0019 (Q), *Diesel Engine Overhaul*, Revision 21 and concluded technicians complied with the procedure. Based on the problems noted above, however, the inspector noted several deficiencies. The procedure had no guidance for technicians to calibrate or check for proper operation of the pressure test pump; it lacked adequate direction to achieve proper injector nozzle seating; and it lacked requirements for fuel pump fitting cleanliness. The inspectors noted these deficiencies contributed to EDG unavailability and also permitted a fuel line fitting to become fouled, a condition that could lead to a clogged fuel line and therefore adversely affect EDG performance.

The deficiencies are a violation of the requirements of Technical Specification 6.8.1 for written procedures. The inspectors did not cite the non-compliance, however, because NRC Inspection Report 50-272 & 311/96-08 issued a violation for other examples of procedure deficiencies and Salem staff has not had the opportunity to respond to this issue.

c. Conclusions

Although maintenance personnel complied with the EDG overhaul procedure, deficient procedures combined with poor foreign material exclusion, lack of fit testing for injector seating, and inadequate training for fuel injector testing contributed to delayed EDG restoration. Salem staff initiated actions to improve the procedure and Salem management implemented a maintenance training intervention intended to address training and workmanship deficiencies.

M4.5 Maintenance Staff Knowledge and Performance Conclusions

During the inspection period, maintenance staff demonstrated several examples of poor planning, workmanship, training, and procedures. Ineffective maintenance practices have become increasingly evident during the outage. As documented in NRC Inspection Report 50-272&311/96-08, during this reporting period Nuclear Business Unit and Salem senior management initiated a major effort to provide training for all Salem maintenance staff.

III. Engineering

E1 Conduct of Engineering

E1.1 Reliability of Residual Heat Removal (RHR) Valves, NRC Restart Item III.30 (Open)

a. Inspection Scope (37551)

Inspectors reviewed the basis for closure of this package to determine if Salem staff had corrected valve reliability problems.

b. Conclusions

Although the MRC accepted this package for closure, the system manager did not inform them that 22RH29 did not perform reliably during testing on or about August 15, 1996. The 22RH29 valve malfunctioned again on August 30. The inspectors concluded that plant staff had not determined and corrected the cause for 22RH29 valve malfunctions. This NRC Restart Item remains open pending resolution of 22RH29 malfunctions.

E2 Engineering Support of Facilities and Equipment

E2.1 Pressure Operated Relief Valve (PORV) Seat Leakage, NRC Restart Issue II.22 (Closed)

a. Inspection Scope

An inspection of PORV's by PSE&G in April 1994 revealed degradation of the internal components. The condition included cracking, significant unexpected wear, and galling. The inspector reviewed the closure package which was prepared by Salem staff and reviewed by the Salem Management Review Committee (MRC) on August 20, 1996. The package included root cause analysis documentation, laboratory test results, industry reliability data and summary information regarding two Design Change Packages (DCPs). In addition to the closure package documents, the inspector also reviewed the completed work documents for the valve internal replacement work, engineering and vendor information, and test documents related to post modification testing.

b. Observations and Findings

The inspector found that the root cause analysis indicated that degraded conditions of the PORV internals was primarily due to the selection of materials being utilized. The inspector found that PSE&G had extensive testing conducted in December 1994, where 5 different valve designs were cycled open and closed 2000 times each. The valve designs varied in the selection of materials used and differed slightly in physical configuration. The inspector noted that PSE&G evaluated the test results and selected the valve design which exhibited the most favorable test results as replacement components for the Salem Unit 1 & 2 PORV internals.

The inspector reviewed the Design Change Package No. 2EE-0083 for the Unit 2 PORV modification and found the information adequate for the proposed change. The inspector also reviewed the completed work documentation, Work Order No. 950919133 and Work Order No. 950919136, for the installation of the Unit 2 PORV internals. The inspector found the documentation to be adequate. The inspector reviewed the applicable design drawings and vendor fabrication records to verify that the internals which were installed were fabricated of the desired material.

Finally, the inspector confirmed that operability testing will be required prior to the Restart of the Salem Units.

c. Conclusions

Based on the review of related documents, the inspector concluded that PSE&G has developed and implemented a satisfactory corrective action plan for the Salem Unit 2 PORV wear related problems. Corrective action documentation such as the work orders and DCPs have been generated for the Salem Unit 1 PORV work and provides reasonable assurance that the PORV internal wear problem will be satisfactorily resolved for Unit 1 as well. This item is closed.

E2.2 (Closed) Inspector Follow-up Item 50-311/94-11-01, PORV Operability

This issue pertains to the excessive wear and the cracking of the PORV internals. It is identified as Item II.22 of the NRC Restart Action Plan for Salem.

The NRC conducted a review of the licensee's actions to address this issue and found them acceptable. The details of the NRC review are contained in Section E2.1 of this Inspection Report. This item is closed.

E2.3 Poor Reliability of the Positive Displacement Pumps, NRC Restart Issue II.18 - (Open -Unit 1, Closed-Unit 2)

a. Inspection Scope

The Salem Unit 1 & 2 Positive Displacement Pumps (PDPs) have a history of maintenance and operating problems. In order to improve operational reliability, a root cause analysis was performed to identify the cause or causes and to prescribe corrective action for short and long term implementation. The inspector reviewed the closure package prepared by Salem staff and had been reviewed by the Salem Management Review Committee (MRC) on June 21, 1996. The package included the PSE&G root cause analysis documentation and the recommended corrective action plans and a root cause analysis conducted for PSE&G by an independent technical consultant. The inspector also met with the Chemical and Volume Control System (CVCS) system manager to obtain additional information such as implementing document numbers for maintenance work orders and design change packages. The inspector reviewed a sample of these implementing documents to verify completion of the work.

b. Observations and Findings

The root cause analysis included a review of the maintenance history for the period from January 1, 1987 to April 24, 1995. The analysis concluded that the failures resulted from numerous failure mechanisms. The analysis identified five primary areas for corrective action as follows:

- Packing Failures
- Pump Valve Cracking Failures
- Pump Valve Seat Cracks
- PDP Cylinder Block Cracking Failures
- Failure of the Suction Stabilizer

The inspector learned that the most frequent failure mode was packing failure. Packing failures accounted for 49 PDP failures in approximately nine years. Design changes, DCP 1S00402 and DCP 2S00303, were implemented early in 1994 to change the packing style. The inspector reviewed the operating data and confirmed that this has resulted in a significant improvement in continuous running time between packing failures for Unit 2. Running time has increased to over 2500 hours, an increase of about a factor of two. However, the operating data for Unit 1 indicates that although one 3900 hour run was achieved between packing failures, two subsequent packing related problems indicate that the problem is not resolved.

The inspector reviewed maintenance procedure SC.MD-CM.CVC-0001(Q), "Charging Pump Repacking, Plunger & Valve Repair or Replacement", and verified that changes had been incorporated per the corrective action plan to aid in ensuring that packing installation is correct and that the initial run-in was successful.

Numerous corrective action items were identified in the closure package which are intended to reduce the frequency of problems in the other four areas. These include the following:

Activity	**Status**
Plans to change the material used for valve disks.	Design Change Package identified, not yet complete.
Design changes to reduce pump nozzle stress loading.	Complete for Unit 2, not necessary for Unit 1.
Procedure changes to S1(2).OP-SO.CVC-0002(Q), *Charging Pump Operation*, to provides a method for venting the pump discharge.	Complete for both Units.
Design changes to reduce the failure suction stabilizers.	Complete for Unit 2, work started for Unit 1.

During a review of work order history for Unit 1 and Unit 2 PDPs, the inspector found there were numerous work orders incomplete for Unit 1, including one for an inspection of the pump internals and one for the inspection of the suction stabilizer. The inspector also found that the Unit 1 pump discharge valves were replaced early in January, 1993. Because the system manager had pointed out that these valves have experienced cracking failures after 2 to 3 years of operation, the inspector noted that these valves were likely to be near the end of their service life. By comparison, the Unit 2 pump discharge valves were replaced in April, 1995.

The inspector verified that the PDP will be tested to verify proper operation prior to core load as part of the Salem Restart Test Plan. In addition, future pump performance will be monitored and trended to assess whether the corrective action items have been successful in achieving reliable PDP operation.

c. Conclusions

The inspector considered the root cause analysis comprehensive and the corrective action plan aggressive. Although the effectiveness of the corrective action plan can only be determined by monitoring future performance, the inspector concluded that the PDP reliability issue received satisfactory attention and that for Salem Unit 2, the corrective action items which are complete provide reasonable assurance that PDP operating reliability will be improved. Because of the continued packing problems on Salem Unit 1, and because of the incomplete work orders and the length of time the discharge valves have been in service, the inspector was not able to reach the same conclusion for Unit 1. This technical issue is closed for Unit 2 but will remain open for Unit 1.

E7 Quality Assurance in Engineering Activities

E7.1 Management Review Committee (MRC)

a. Inspection Scope (37551)

Inspectors assessed MRC review of NRC restart inspection item closure packages, final system readiness reviews, and system affirmations to determine the effectiveness of the reviews.

b. Observations and Findings

Early in the inspection period, the MRC inappropriately approved closure of RH29 valve closure package without determining that the controls for the 22RH29 valve had recently malfunctioned. Later in the period, the MRC did not approve final affirmation of the radioactive waste gas system readiness, since the system review team reviewed an uncontrolled operability determination list instead of reviewing the controlled Condition Resolution Operability Determinations. The MRC appropriately concluded that the service water system readiness depended on demonstration of reliable system performance. As recommended by the System Manager, the MRC concluded that service water was not ready for the final system readiness review since they had not yet observed reliable service water performance. Members of the MRC also deferred approval of the final affirmation of 4KV system readiness, since they identified that each vital bus did not have at least one spare breaker cubicle in good working order.

c. Conclusions

The MRC improved the quality of reviews during the inspection period. They accomplished the improved performance by insuring that MRC membership consisted of senior Salem managers and through use of specific closure package review criteria.

E8 Miscellaneous Engineering Issues

E8.1 RHR Pump Minimum Flow Instruments (37551)

a. Observations and Findings

Inspectors discovered that the Updated Final Safety Analysis Report (UFSAR), section 6.3.5.3, *Flow Indication, Residual Heat Removal Pump Minimum Flow*, states that a flow indicator is installed in each RHR pump minimum flow line. The inspectors noted that the RHR pump minimum flow line does not have a flow indicator. The inspectors discussed the lack of a flow instrument with plant staff from licensing, system engineering, the operations staff (an SRO), and the Salem General Manager's staff. The licensing staff and the General Manager's staff appropriately concluded that procedures required them to initiate an Action Request (AR). The Salem managers concluded that failure to initiate an AR constituted an additional condition adverse to quality; they initiated an AR to address it.

Inspectors learned from the SRO that flow indication had previously existed for the RHR minimum flow line, but plant staff removed it. The inspectors could not determine, prior to the end of the inspection period, why Salem staff had not updated the UFSAR to reflect current RHR configuration. This issue will remain unresolved pending assessment of licensee compliance with 10 CFR 50.59 and 10 CFR 50.71(e) **(UNR 50-272&311/96-10-03)**.

b. Conclusions

When inspectors discovered a minor discrepancy between UFSAR description of RHR minimum flow line instrumentation and actual plant configuration, only two of four plant staff recognized this as a condition adverse to quality that required them to initiate an AR. Plant managers subsequently initiated an AR to address the failures to initiate an AR. The discrepancy between the UFSAR and RHR configuration will remain unresolved pending inspector assessment of compliance with 10 CFR 50.59 and 10 CFR 50.71(e).

IV. Plant Support

R1 Radiological Protection and Chemistry (RP&C) Controls

R1.1 LWR Water Chemistry Control and Chemical Analysis (79701)

a. Inspection Scope

Standard chemical solutions were submitted to the licensee for analysis. The standards were prepared by the Oak Ridge National Laboratory (ORNL) for the NRC and were analyzed by the licensee using current routine methods and equipment. The analysis of standards is used to verify the licensee's capability to monitor chemical parameters in various plant systems (steam generators in the case of this inspection) with respect to Technical Specifications and other regulatory requirements. In addition, the analysis of standards is used to evaluate the licensee's analytical procedures with respect to accuracy and precision. The standards were submitted to the licensee for analysis in triplicate at three concentrations spread over the licensee's normal calibration and analysis range. However, the ammonia standards were analyzed at five concentrations in order to duplicate the concentrations normally analyzed by the licensee.

b. Observation and Findings

The results of the standards measurements comparisons indicated that all of the measurement results were in agreement or qualified agreement under the criteria used for comparing results. (See Attachment 1 to Table I.) The data are presented in Table I. The hydrazine and copper analyses were performed in both the primary laboratory and the secondary laboratory, while the ammonia analyses were performed in the secondary laboratory only. The primary laboratory is the laboratory used to analyze reactor systems samples and the secondary laboratory is the laboratory used to analyze non-reactor systems samples such as steam generator samples. During shutdown conditions steam generator samples are taken in containment, and, therefore, the primary laboratory is sometimes used to analyze these samples for hydrazine and copper.

c. Conclusion

The licensee accurately quantified the hydrazine, ammonia, and copper in the NRC standards. Therefore, the licensee can accurately quantify these analyses in steam generator samples.

R2 Status of RP&C facilities and Equipment

During this inspection, the inspector conducted tours of the plant during outage conditions and noted that all required radiological postings and locked areas met regulatory requirements and that the areas were free of safety hazards.

R3 RP&C Procedures and Documentation

During this inspection period, the steam generator replacement project staff (SGRP) was engaged in a planning preparation phase and a review was made with respect to the radiological safety plans for the project. The SGRP project is intended to effect the complete replacement of four steam generators at Salem Unit 1 during the fall of 1996, utilizing replacement steam generators from the mothballed Seabrook Unit 2 nuclear power plant.

R3.1 RP & ALARA Planning

a. Scope (50001)

The inspector reviewed the licensee's planning documents and interviewed cognizant project staff to determine the adequacy of radiation protection (RP) and ALARA preparations for conducting the SGRP.

b. Observations and Findings

The inspector reviewed the licensee's resource commitments and radiological control plans for the SGRP. The planning documents included incorporation of lessons learned from the following SGRPs: Millstone, V.C. Summer, Surrey, North Anna (1&2), and Ginna.

At the time of this inspection, the licensee had completed a preliminary exposure estimate of 164 person-rem. The inspector reviewed the details of the estimate and determined that no contingency was built into the estimate and that it consisted of a mixture of detailed project-based estimating and historical information derived from other SGRPs. As it now exists, this preliminary exposure estimate represents a challenging exposure standard for the project.

To allow the additional personnel access to the Salem Unit 1 containment, the SGRP will provide a temporary access facility (TAF) adjacent to the Unit 1 Service Building to include protective clothing change facilities, RP briefing location, RP Command Center, and a radiological control area (RCA) access control station. Additional electronic dosimeters, readers, and electronic turnstiles are planned for the TAF. In addition, cellular phones will be issued to the work groups to allow for direct communication with the RP group from the TAF's RP Command Center. Extensive video camera monitoring of containment work areas is also planned with three remote monitoring stations located in the RP Command Center.

Mockup training is planned for pipe cutting, beveling, and welding; pipe end decontamination; and feedwater thermal sleeve modifications. Mockup training and schedule details were not available for review during this inspection.

At the time of this inspection, approximately 20,000 pounds of temporary lead blankets were installed in the Unit 1 containment to shield many of the transit paths and miscellaneous sources. SGRP plans call for an additional 25,000 pounds of lead to be installed around the primary piping, inside severed primary piping, and around the steam generator platform areas to further reduce working area dose rates.

The licensee has recently been piloting the use of radiation work permits (RWPs) to focus on limiting individual RCA entry doses via customized electronic dosimetry setpoints, and through RP technician dialogue before and after RCA entries with the workers. This approach is planned to be continued during conduct of the SGRP. Individual administrative exposure limits have been established at 500 mrem per year.

The radioactive material control organization has elected to not pursue large-scale onsite equipment decontamination. The SGRP is considering offsite vendor services for the decontamination and release of project equipment and materials.

Work package design included the incorporation of ALARA requirements. Hold points and records of hold point signoffs were made available to RP/ALARA for use in the work packages. At the time of this inspection, the work packages had not been approved and were not available for review.

Detailed RP contingency planning had not been evaluated by the licensee at the time of this inspection.

For reducing internal exposure hazards, the licensee plans on utilizing eight 2000 cfm HEPA ventilation units for the reactor cooling system (RCS) loop areas. At the time of this inspection, the licensee had not established a plan for providing investigational whole body count measurements. Currently the licensee does not have the measurement capability onsite, however a memorandum of understanding exists for providing bioassay services at Brookhaven National Laboratory in Long Island, New York.

c. Conclusions

The inspector determined that sufficient radiological safety resources have been planned. The radiological safety planning was still being formulated with less than two months remaining before the project, however, the inspector did not detect any significant planning deficiencies.

R3.2 Shipment Classification of Old Steam Generators

a. Scope (50001)

As of April 1, 1996, the DOT radioactive material shipping regulations were significantly revised. In particular, a new shipping category of surface contaminated object (SCO) was defined. The licensee has determined that the four old steam generators meet the new SCO II definition and can be transported under the new DOT regulations. The inspector reviewed the licensee's SCO evaluations, DOT correspondence, and conducted interviews with cognizant licensee personnel.

b. Observations and Findings

The licensee determined that the steam generators met the contamination concentration limits for SCO II through utilizing external dose rate measurements from the outside of each steam generator and by taking smear scrapings from the inside of a steam generator primary manway. The fixed contamination concentration was determined by computer modeling the steam generator as a simple cylinder with homogenous air/iron contents and utilizing the highest external dose reading, and calculating the source radioactivity estimated to produce the external dose readings. The resultant source activity was divided over the known surface area of the steam generator tubes and channel heads to determine the surface contamination concentration. The smear scrapings were analyzed by an offsite laboratory to determine radionuclide constituents, which were also utilized in the radioactivity calculations. The licensee determined that the average total surface contamination for the worst-case steam generator was 3.01 uCi/cm^2 as compared to the SCO II limit of 20 uCi/cm^2. The licensee had also determined, through analysis, that the highest unshielded dose rate at three meters was 410 mrem/hr as compared to the DOT limit of 1000 mrem/hr.

The inspector questioned the accuracy of the computer model method of deriving the contamination concentration and unshielded dose rate values. In response, the licensee committed to provide an uncertainty analysis. Also, due to the possibility of fairly large uncertainty values, the inspector asked if a benchmaking calculation had been considered utilizing an independent method. The licensee indicated that there were available steam generator tube samples and that direct measurements would be made and those survey results would be compared to the computer calculation results. Future evaluation of this additional information will provide the basis for evaluating the adequacy of the licensee's classification of the steam generators as SCO II. The licensee has issued a letter to the Department of Transportation (DOT), dated August 5, 1996, providing the preliminary waste characterization information mentioned above, and an engineering evaluation concluding that the steam generators can meet the one-foot drop test as specified for an Industrial Package 2 package. This letter also requested DOT approval for an exemption to the packaging requirement of SCOs as specified in 49 CFR 173.427(b)(1).

c. Conclusions

While no significant weakness in the licensee's assessment and approach for handling the eventual shipment of steam generators was detected, additional study by the licensee and regulatory review of additional characterization remains to assess the adequacy of the licensee's determination of shipping classification.

R3.3 Steam Generator Water Chemistry

a. Inspection Scope (79701)

The inspectors reviewed the following analytical procedures:

- SC.CH-CA.ZZ-0332(Z), Hydrazine by PE Lambda-2 Spectrophotometer,
- SC.CH-CA.ZZ-0348(Q), Metals by Perkin-Elmer Model 5100 PC Atomic Absorption Spectrometer, and
- SC.CH-TI.ZZ-0351(Q), Ion Chromatograph Applications.

b. Observation and Findings

The inspector noted that the above procedures were well written, easy to follow, and contained sufficient level of detail. The inspector also noted that these procedures contained QC requirements for verifying analytical results.

c. Conclusion

Based on the above reviews, the inspector determined that the licensee had very good analytical procedures to quantify hydrazine, copper, and ammonia in steam generator water samples.

R4 Staff Knowledge and Performance in RP&C

R4.1 Radiation Area Access Control

a. Inspection Scope (71707)

The inspector observed radiologically controlled area access controls and postings.

b. Observations and Findings

On August 26, 1996, the inspector observed the radwaste truck bay door open, the associated gate unlocked, and no radiation protection personnel monitoring the access point. Failure to maintain access point vigilance did not meet radiation protection managements' expectations for the area. Although the assigned radiation protection technician lost visual contact of the access point, technicians had established proper radiation area postings. Radiation protection management counseled the technician.

c. Conclusions

A radiation protection technician did not meet managements expectations for control of access to the radiologically controlled area.

R5 Staff Training and Qualification in RP&C

a. Scope (83750)

Since June 25, 1996, the Salem Radiation Protection Manager (RPM) has been 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 stead. In addition, the acting RPM has been designated as an alternate RPM member of the SORC. The inspector reviewed the individual's qualifications for RPM with respect to regulatory requirements.

b. Observations and Findings

Salem TS 6.3.1 specifies the RPM qualifications as those contained in Regulatory Guide 1.8, September 1975. These requirements specify a bachelor's degree in science or engineering or equivalent, and five years professional experience in applied radiation protection. The inspector reviewed an RPM qualification evaluation dated June 26, 1996 that was signed by the current RPM. This evaluation indicated that a bachelor's degree had not been completed and indicated that the individual had accrued nine years of supervisory experience including one year as the Senior ALARA Supervisor. The inspector noted that the RPM qualification evaluation form (NC.NA-AP.ZZ-0014-4) required the general manager or a director's signature when education exemption was granted based on experience. The evaluation form was not signed as specified by the procedure. Upon further review of the individual's resume, it was determined that he acted as an RP Operations Supervisor and an ALARA Supervisor for a combined period of eight years and that he has held the position of Senior ALARA Supervisor for the past one year. Based on the inspector's knowledge of the Salem RP organization, ALARA supervisors are the technical lead for an RP support area, known at other power plants as lead technicians. The inspector was not provided enough details of the individual's activities/duties while acting as a RP Operations and ALARA Supervisor to enable the inspector to make a specific determination of professional RP experience. The need for additional information has resulted in an unresolved item **(50-272/96-12-04)**, which was communicated by telephone to the station licensing engineer on August 27, 1996.

The inspector also reviewed the use of RPM duty delegation as applied to SORC membership. Station procedure (NC.NA-AP.ZZ-0004(Q)) indicates that SORC alternate members should meet the same qualification requirements as SORC members. The inspector reviewed a letter dated April 25, 1995 that designated the subject acting RPM individual as an alternate RPM representative on the SORC. This letter was supported with a verification of qualification form for RPM dated April 28, 1995 that referenced ANSI N18.1-1971 as the standard of comparison as requiring eight years in responsible positions. The subject individual has, since that time, represented the RPM at SORC meetings.

c. Conclusions

The inspector reviewed two evaluations of an acting RPM individual that determined the individual to be RPM qualified that were based on two different standards. The correct standard, Regulatory Guide 1.8, September 1975, was most recently used with the result that bachelor's degree equivalency was given and a determination that five years of professional level experience had been met. Station procedure requirement for General Manager or Director approval was not evidenced. Details of experience as an RP supervisor require further review in order to verify and validate the qualifications of the individual.

R6 RP&C Organization and Administration

The inspector reviewed the SGRP staffing plans for the project. The licensee plans on providing approximately 58 contractor senior RP technicians and 24 contractor junior/decon RP technicians to provide the additional RP control for the project. The inspector noted that the licensee intends on utilizing 10 permanent station RP technicians in lead technician positions and that there will exist an additional pool of 25 contractor RP technicians, assigned to the Unit 2 restart, that may be available if necessary. The inspector did not note any discrepancy or lack of manpower associated with the above plans.

R7 Quality Assurance in RP&C Activities

a. Inspection Scope (79701)

The laboratory QA/QC programs were reviewed in order to evaluate the licensee's control with respect to analyzing and evaluating data for the implementation of the chemical analysis program.

The inspectors reviewed the licensee's Quality Assurance (QA) and Quality Control (QC) Programs for analytical measurements of chemical parameters in various plant water samples including, interlaboratory and intralaboratory comparison programs. The following procedures were reviewed:

- SC.CH-DD.ZZ-0001(Z), Salem Chemistry Data Trending Program Roles and Responsibilities,
- SC.CH-DD.ZZ-0006(Z), Technical Calculation Preparation and Validation,
- SC.CH-DD.ZZ-0009(Z), Salem Chemistry Independent Verification Program Guidelines,
- SC.CH-TI.ZZ-0901(Q), Laboratory Quality Control Program,
- SC.CH-TI.ZZ-0902(Q), Chemical Shelf Life Program,
- SC.CH-TI.ZZ0904(Q), Laboratory Quality Control Chart Preparation, and
- SC.CH-TI.ZZ-0905(Q), Laboratory Quality Control Chart Evaluation and Corrective Actions.

b. Observation and Findings

The laboratory maintained internal/external QA/QC programs including: (1) spike samples; (2) blind samples; (3) intralaboratory comparisons; (4) instrument and procedures control charts; (5) trending and tracking analyses; and (6) QC Reports. The inspector also noted that when discrepancies were found, reasons for the discrepancies were investigated, resolved, and reported in QC Reports. During the review, the inspector noted that the licensee used actual matrix samples (e.g., S/G water) for preparing QC spike samples. The inspector stated that this was the best method to evaluate analytical technique and capability because the analyst could encounter the chemical interferences present in actual samples.

During a discussion with the Chemistry staff, the inspector noted that the responsible individuals had very good knowledge in the areas of: (1) importance of QA/QC; (2) plant water systems; (3) potential chemical interference in various system water samples; and (4) validating of measurement results.

c. Conclusion

Based on the above reviews and discussions, the inspectors determined that the licensee had excellent laboratory QA/QC programs.

R8 Miscellaneous RP&C Issues

R8.1 Other Issues Previously Identified

(Closed) Violation 50-272/96-01-05:

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.

a. Scope (83750)

During this inspection, the inspector reviewed the licensee's root cause and corrective actions associated with the violation as well as verified completion of the corrective actions.

b. Observations and Findings

The result of the licensee's investigation determined that there had been 17 recorded instances of RCA access control procedure violations during 1995. Several root causes were identified that were all associated with human performance weaknesses. Corrective actions included incorporating two software changes in the electronic dosimeter reader program that resulted in producing dosimeter alarms if an electronic dosimeter is removed from the battery charger rack and is not placed into a reader within three minutes, and in causing the dosimeter to alarm if the dosimeter is left in the reader for more than four seconds after completing sign-in to the RCA. Additionally, positive control electronic turnstiles were installed at the entrance to the RCA and at the exit from the protective clothing change area. To access the station radiological controlled area requires passage through an electronic gate turnstile. In order to unlock the turnstiles, an electronic dosimeter must be inserted and if the dosimeter is found to be activated and functional, the gate is unlocked permitting entry. During this inspection, the inspector verified that the above changes had been completed.

To alert the workers of this plant access change, a training video will be developed to be shown to radiation workers during general employee training. The training video had not been completed at the time of this inspection. The licensee projected a completion date of September 15, 1996 for producing the video training aide.

c. Conclusions

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. Although the training video has not been completed, the inspector determined that all of the controls necessary to prevent recurrence of the violation have all been completed and were verified to be in place. This violation is closed.

R8.2 Review of UFSAR Commitments

A recent discovery of a licensee operating their facility in a manner contrary to the Updated Final Safety Analysis Report (UFSAR) description highlighted the need for a special focused review that compares plant practices, procedures and/or parameters to the UFSAR descriptions.

While performing the inspection discussed in this report, the inspector reviewed Section 12.3 of the Salem Station UFSAR that related to the areas inspected. The inspector verified that the UFSAR wording was consistent with the observed plant practices, procedures and/or parameters.

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 September 18, 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.

TABLE I
Salem Chemistry Test Results

Chemical Analysis	Method of * Analysis	NRC Known ** Value	Licensee ** Value	Comparison
Hydrazine (Secondary Lab Analysis)	SP	34.1 ± 0.5 56.1 ± 1.0 68.2 ± 1.0	34.97 ± 0.15 55.9 ± 0.7 68.8 ± 0.4	Agreement Agreement Agreement
Ammonia (Secondary Lab Analysis)	IC	22.0 ± 0.8 30.5 ± 0.8 48.2 ± 1.2 110 ± 4 305 ± 8	22 ± 2 31.0 ± 1.1 48.3 ± 0.5 102 ± 2 283 ± 6	Agreement Agreement Agreement Agreement Agreement
Copper (Secondary Lab Analysis)	AA	40.4 ± 0.6 80.6 ± 1.2 162 ± 3	34.3 ± 1.5 89 ± 2 167 ± 3	Qualified Agreement Agreement Agreement
Hydrazine (Primary Lab Analysis)	SP	34.1 ± 0.5 56.5 ± 1.0 85.2 ± 1.2	34.8 ± 0.4 57.1 ± 0.4 86.9 ± 1.1	Agreement Agreement Agreement
Copper (Primary Lab Analysis)	AA	40.4 ± 0.6 80.6 ± 1.2 162 ± 3	41 ± 3 76.3 ± 1.5 160 ± 4	Agreement Agreement Agreement

* Methods: AA = Atomic Absorption
IC = Ion Chromatography
SP = UV-Vis Spectrophotometry

** All reported uncertainties are ± one standard deviation (1s).

ATTACHMENT 1 TO TABLE I

Criteria for Comparing Analytical Measurements from Table II

This attachment provides criteria for comparing results of capability tests. In these criteria the judgement limits are based on data from Table 2.1 of NUREG/CR-5244, "Evaluation of Nonradiological Water Chemistry at Power Reactors". Licensee values within the plus or minus two standard deviation range (±2Sd) of the ORNL known values are considered to be in agreement. Licensee values outside the plus or minus two standard deviation range but within the plus or minus three standard deviation range (±3Sd) of the ORNL known values are considered to be in qualified agreement. Repeated results which are in qualified agreement will receive additional attention. Licensee values greater than the plus or minus three standard deviations range of the ORNL known value are in disagreement. The standard deviations were computed using the average percent deviation values of each analyte in Table 2.1 of the NUREG.

The ranges for the data in Table I are as follows.

Analyte	Agreement Range	Qualified Agreement Range
Chloride	± 8%	± 12%
Fluoride	± 12%	± 18%
Sulfate	± 10%	± 15%
Silica	± 10%	± 15%
Sodium	± 14%	± 21%
Copper	± 10%	± 15%
Iron	± 10%	± 15%
Boron	± 2%	± 3%
Ammonia	± 10%	± 15%
Hydrazine	± 10%	± 15%
Lithium	± 14%	± 21%

INSPECTION PROCEDURES USED

IP 50001:	Steam Generator Replacement
IP 61726:	Surveillance Observations
IP 62707:	Maintenance Observations
IP 71707:	Plant Operations
IP 79701:	LWR Water Chemistry Control and Chemical Analysis-Program
IP 83750:	Occupational Radiation Exposure

ITEMS OPENED, CLOSED, AND DISCUSSED

<u>Open</u>

50-272&311/96-12-01	UNR	Ineffective corrective action
50-272&311/96-12-02	IFI	Inspector followup of SW operation
50-272&311/96-12-03	UNR	RHR flow instrument not present as stated in UFSAR
50-272&311/96-12-04	UNR	Acting radiation protection manager qualifications

<u>Closed</u>

50-272/96-01-05	VIO	Repetitive RCA access control procedure violations

LIST OF ACRONYMS USED

ALARA	As Low As Reasonably Achievable
DOT	Department of Transportation
FME	Foreign Material Exclusion
IV	Independent Verification
NSS	Nuclear Shift Supervisor
NRC	Nuclear Regulatory Commission
ORNL	Oak Ridge National Laboratory
PDR	Public Document Room
PSE&G	Public Service Electric and Gas
QA	Quality Assurance
QC	Quality Control
RCA	Radiological controlled area
RCS	Reactor Coolant System
RP	Radiation Protection
RP&C	Radiological Protection and Chemistry
RPM	Radiation Protection Manager
RWPs	Radiation Work Permits
SCO	Surface Contaminated Object
SGRP	Steam Generator Replacement Project
SNSS	Senior Nuclear Shift Supervisor
SORC	Station Operations Review Committee
SRO	Senior Reactor Operator
SW	Service Water
TAF	Temporary Access Facility
TLD	Thermoluminescent dosimeter
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
WO	Work Order