U. S. NUCLEAR REGULATORY COMMISSION

REGION I

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Report No. 50-272/98-01 & 50-311/98-01

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: February 2, 1998 - March 15, 1998

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EXECUTIVE SUMMARY

Salem Nuclear Generating Station
NRC Inspection Report 50-272/98-01 & 50-311/98-01

This integrated inspection included aspects of licensee operations, engineering, maintenance, and plant support. The report covers a six-week period of resident inspection; in addition, it includes the results of announced inspections by regional engineering inspectors of the Unit 1 motor-operated valve program and an emergency diesel generator turbocharger failure.

Operations

- In general, the conduct of operations was professional and safety-conscious. Activities associated with the shutdown of Unit 2 on February 11 and the heatup of Unit 1 on February 18, were performed in a deliberate manner with clear communications.

- Licensed operators' inadequate monitoring of plant parameters and maintenance of steam generator levels, combined with inadequate communications and crew teamwork resulted in an inadvertent automatic start of the auxiliary feedwater pumps when the 14 steam generator level decreased to 9%. The reactor operator did not follow procedure requirements to maintain the steam generator levels within the required band.

- The licensee's corrective actions to address the reasons for an apparently fatigued licensed control room supervisor were acceptable. However, there were some weaknesses identified in licensee management oversight of individual employee work hours which the licensee has initiated actions to address.

Maintenance

- Poor planning and inadequate maintenance practices resulted in an incorrect control switch being installed on the 12 Diesel Fuel Oil Transfer Pump (DFOTP), which rendered the pump inoperable. The licensee ascended to Mode 4 on Unit 1 with less than the required DFOTPs operable, which was a Technical Specification violation. The licensee's immediate corrective actions for this event were weak, including an untimely operability determination for the wrong part being installed on the 21 DFOTP, and untimely verification of correct part numbers for similar control switches on the four DFOTP electrical panels.

- Procedural adherence for the 2A Emergency Diesel Generator (EDG) post-maintenance testing was poor. Numerous procedural violations by maintenance and operations personnel resulted in the improper operation of the diesel. There was little safety significance to these violations as the diesel was out of service for maintenance. However, they showed a lack of questioning attitude and attention to detail by numerous personnel. Additionally, the engineering action plan utilized for the maintenance effort was not sufficiently detailed to promote smooth transition between the maintenance and operations procedures used.

- The licensee met all Technical Specification requirements for the 2C EDG outage and the crankcase alarm on the 2B EDG. The operator correctly followed the alarm response procedure for the 2B alarm. The operability determination for the 2B EDG after the cause of the alarm was determined was adequate, but the decision to run the 2B EDG during the 16-hour 2C EDG outage was not appropriate.

- On February 11, 1998, the 2A EDG turbocharger failed during a post maintenance test. The licensee formed a team to get the relevant facts, find the cause of the failure, evaluate its significance to the operability of the other EDGs, and establish corrective actions. The NRC reviewed the team activities to assess the evaluation scope, methods and results. This NRC inspection did not identify any factors that would provide a basis for disagreeing with the scope, method of investigation, or with the preliminary findings.

- The licensee had adequately implemented their Technical Specification Surveillance Improvement Program to support Unit 1 restart.

Engineering

- The licensee had adequately demonstrated design basis capability for Salem Unit 1 MOVs to support restart. Justifications for key program assumptions and the applied valve factors were adequate.

- The licensee continued to adequately pursue resolution of issues related to the control area ventilation system (CAVS). However, long term corrective actions are still necessary to eliminate the need for maintenance mode, a time-consuming, resource-intensive work around which ensures adequate dp margin between the control room and the adjacent spaces. When this mode is employed, then any circumstance which necessitates accident pressurized mode, such as an inoperable CAVS radiation monitor, would require a unit shutdown to Mode 5 so that the control room emergency air conditioning system intake could be lined up to a non-operating unit.

- Elevated grass levels in the Delaware River combined with degraded service water strainers and lack of service water reliability program oversight resulted in accelerated rates of service water biofouling. Weak management attention allowed biofouling to occur at unpredictable rates. Several instances of biofouling occurred in plant components before strainer degradation was identified and effective corrective actions were taken. In one instance, the biofouling contributed to the inoperability of a Unit 2 safety related chiller. Salem staff failed to take prompt corrective actions to determine and correct the cause of service water biofouling problems. System Engineering and Operations interfaces were weak during the analysis of those problems. The licensee did not adequately evaluate the extent of condition at both Salem Units. The inspector also concluded that the corrective actions taken in response to Licensee Event Report 50-272/96-34 were acceptable.

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Report Details

Summary of Plant Status

Unit 1 began the period in Mode 5, Cold Shutdown. On February 18, 1998, the operators increased the average coolant temperature above 200°F and entered Mode 4. The unit remained in Mode 4 through the end of the inspection period.

Unit 2 began the period operating at 100% power. On February 11, 1998, the licensee commenced a plant shut down in order to make repairs to the 2A emergency diesel generator following a failure of the turbocharger. During the shutdown, the licensee performed other repair activities which included replacement of two pressurizer code safety valves and repair of the 22 steam generator steam flow transmitters. On March 3, the NRC resident inspectors participated in the full participation exercise covered by Inspection Report 50-272, 311, 354/98-80. On March 14, the unit was returned to service and was operating at about 50% power at the end of the inspection period.

I. Operations

O1 Conduct of Operations (71707, 92901, 93702 & 40500)

O1.1 General Comments

Using Inspection Procedure 71707, the inspectors conducted frequent reviews of ongoing plant operations. In general, the conduct of operations was professional and safety-conscious. The inspectors observed activities associated with the shutdown of Unit 2 on February 11 and the heatup of Unit 1 on February 18, and noted that the evolutions were performed in a deliberate manner with clear communications. These evolutions were also observed by the NRC Readiness Assessment Team Inspection (RATI), as documented in Inspection Report 50-272 & 311/98-81. Additional specific events and noteworthy observations are detailed in the sections below.

O1.2 Unit 1 Inadvertent Automatic Actuation of an Engineered Safeguards Feature - Auxiliary Feedwater Pumps

a. Inspection Scope

On February 21, 1998, with Salem Unit 1 operating in Mode 4 (Hot Shutdown), the 11 and 12 auxiliary feedwater (AFW) pumps automatically started on Lo-Lo steam generator level in the 14 steam generator (SG). The licensee made a 4 hour telephone notification to the NRC as required to document this automatic actuation of an Engineered Safeguards Feature (ESF). The inspectors reviewed this event and the licensee's root cause evaluation and corrective actions which are documented in Action Request (AR) 980221128.

b. Observations and Findings

On February 19, the operators commenced warming the main steam lines in accordance with procedures being utilized to take the plant from Cold Shutdown to Hot Standby. Warming the main steam lines requires opening the main steam stop bypass valves (MS18s). In Mode 4, feedwater is manually supplied to the SGs on a periodic basis. This is usually accomplished by maintaining operating AFW pumps discharging against closed SG feedwater supply valves on recirculation and opening these valves when feedwater is needed. However, in this case the AFW pumps were cycled on and off because one of the SG feedwater valves was leaking through. To avoid frequent starting and stopping of the AFW pumps, the periodic filling of the SGs was performed on a less frequent basis, and SG level was allowed to vary over a wider range before refilling. Establishing flow through the MS18 valves increased the steaming rate of the SGs, thereby increasing the required frequency of providing feedwater to the SGs to maintain water levels. The MS18 valves were opened approximately 1 to 2 % of valve open position. The increased steaming rate required the starting of the AFW pumps approximately once per 12 hour shift in order to maintain SG levels.

On February 20, the night shift further opened all MS18 valves to approximately 4% valve open position. The SGs were filled to greater than 33% narrow range level at 4:51 a.m. on the morning of February 21. The additional steam demand, which caused water levels to fall at an increased rate, was not anticipated by the on-coming day shift. In addition, prior to the event, SG water level narrow range chart recorders and SG water level program deviation console alarms on control console 2 were inoperable due to Advanced Ditigal Feedwater Control System testing which was in progress. The Unit 1 reactor operator (RO) logged 14 SG narrow range level at 32 % at 7:30 a.m. At 1:30 p.m., while performing shiftly logs, the RO noticed 14 SG level to be 12%. The RO was about to start the AFW pumps and refill the SGs just as the automatic action occurred. At 1:32 p.m., the 11 and 12 AFW pumps automatically started on Lo-Lo SG level when 14 SG water level reached 9% narrow range level. Operators promptly established feedwater to all SGs to restore water levels. At the time of the event, the 11, 12, and 13 SG water levels were 21%, 31%, and 32% respectively. The 14 SG narrow range level dropped from 36% to 9% in approximately 8.5 hours.

Licensee evaluation of the event determined that the cause was human error. The two ROs on duty, and the control room supervisor did not adequately monitor SG water levels nor did they anticipate the increased feedwater requirements. A contributing cause was ineffective shift turnover and poor team communication. Although the additional steam demand on the SGs was discussed during the individual watch turnovers, the subject was never discussed at the pre-watch shift brief nor did the Unit 1 control room crew discuss any increased monitoring of SG water levels. The operating crew also did not discuss what SG water level should be maintained. The RO was unsure as to what level range was to be maintained in the SGs. Guidance provided in procedure S1.OP-SO.AF-0001, "Auxiliary Feedwater System Operation," and S1.OP-IO.ZZ-0002, " Cold Shutdown to Hot Standby," required level be maintained between 28-38%. Levels in the 11 and 14 SG were allowed to go below this level.

The licensee's corrective actions included discussion of lessons learned lead by the two ROs involved in this event. Also, an emphasis of responsibilities and the importance of safe operations was reinforced by the Operations Superintendents and reviewed with the operating crews. Also, the chart recorders and alarms were returned to operable status on February 21.

The inspectors discussed this event with the individuals involved and reviewed the licensee's corrective actions and found them acceptable. The safety significance of this event was minimal because the SGs were not being relied upon for decay heat removal. At the time of the event, core cooling was being provided by the 11 residual heat removal loop. Therefore, this licensee identified and corrected violation for failure to follow procedures for maintaining SG levels is being treated as a Non-Cited Violation consistent with Section VII.B.1 of the NRC Enforcement Policy. **(NCV 50-272/98-01-01)**

c. Conclusions

Licensed operators' inadequate monitoring of plant parameters and maintenance of steam generator levels, combined with inadequate communications and crew teamwork resulted in an inadvertent automatic start of the auxiliary feedwater pumps when the 14 steam generator level decreased to 9%. The reactor operator did not follow procedure requirements to maintain the steam generator levels within the required band.

O4 Operator Knowledge and Performance

O4.1 Inattentive Control Room Supervisor

a. Inspection Scope

At about 4:30 p.m. on March 11, 1998, during observation of a Unit 2 startup/reactivity briefing which was conducted in the conference room adjacent to the control room, the inspector noted that a control room supervisor (CRS) was having difficulty staying awake and appeared inattentive. The inspector informed the Operations Manager of the observed condition of the CRS. Licensee management took actions to address this condition, as discussed below.

b. Observations and Findings

The Operations Manager took prompt corrective action by suspending the briefing and initiating an investigation (AR 980311292). The CRS was relieved from his duties and tested for Fitness for Duty (FFD). The test results were negative, he was coached about the serious negative perception of his alleged actions, and returned to work the following day. Licensee investigation did not confirm that he was inattentive, but did determine that he was apparently tired at the briefing. Further licensee review determined that the CRS had worked six - 12 hour shifts the previous week and that March 11 was his ninth -12 hour day out of the previous 10 days. Although, this is within the licensee's overtime guidelines described in procedure, NC.NA-AP.ZZ-0005, "Station Operating Practices," (NAP 5), as a corrective action, licensee management stated that General Manager approval would now be required for any individual scheduled to work greater than 60 hours in a week and this requirement would be proceduralized in NAP 5. The intent of these actions was to minimize the impact of working excessive hours on employee quality of life and fitness for duty.

The inspectors questioned the extent of other operations personnel working excessive hours. In response, the licensee initiated an audit of operations department personnel work hours and identified several instances since January 1998 of licensed senior reactor operator's (SRO's) gate-to-gate times exceeding 72 hours in a seven day period. In addition, long turnovers were resulting in consecutive 13 to 14 hour work days. NAP 5 guidance is that an individual should not be permitted to work more than 72 hours in any seven day period, excluding shift turnover time. The inspector questioned the gate-to-gate times for two SROs, whose times in a seven day period were 83 and 87 hours. After further review, licensee management stated that these individuals had met the requirements of NAP 5, because they had worked 6- 12 hour shifts during the periods in question, and that the hours over 72, were the result of long turnovers. The licensee initiated AR 980318079 to document and evaluate the results of their audit and the corrective actions taken. Licensee management strongly stated that the results of this audit did not meet their expectations for individual work hours and that additional audits were being conducted to further understand the extent of this condition.

c. Conclusions

The licensee's corrective actions to address the reasons for an apparently fatigued licensed control room supervisor were acceptable. However, there were some weaknesses identified in licensee management oversight of individual employee work hours which the licensee has initiated actions to address.

O8 Miscellaneous Operations Issue

O.8.1 (Closed) LER 50-311/98-04: Failure to Comply with Technical Specification Surveillance Requirement 4.1.3.1.1.

On February 4, 1998, the rod position deviation monitor was declared inoperable when it was determined that the Plant Processing Computer System (P250) was not updating the rod position deviation computer data point "RODDEV". The "RODDEV" data point provides the input to an overhead alarm window which automatically alarms when the rods deviate beyond the required number of steps from the group demand counter. This computer point is the rod position deviation monitor required by Technical Specification Surveillance Requirement 4.1.3.1.1. On November 21, 1997, the computer point was disabled, apparently without informing the control room personnel. Since the operators were not aware that the rod position deviation monitor was inoperable, control rod positions were not verified every four hours as required by Technical Specification 4.1.3.1.1, however, they were verified once per shift. The licensee concluded that the apparent cause of the event was attributed to human error. Corrective actions associated with this event consisted of a lesson learned discussion and the implementation of periodic reviews of the P250 computer points to ensure Technical Specification associated points are not disabled.

Based on the minimal safety significance of this condition, the inspector performed an in-office review of the information provided in this LER. The inspector found the licensee's root cause and corrective actions discussed to be acceptable. Therefore, this licensee identified and corrected violation of Technical Specification Surveillance Requirement 4.1.3.1.1 is being treated as a Non-Cited Violation consistent with Section VII.B.1 of the NRC Enforcement Policy. **(NCV 50-311/98-01-02)**

O.8.2 (Closed) LER 50-311/98-05: Technical Specification Required Shutdown of Salem Unit 2 Due to the Failure of the 2A Emergency Diesel Generator Turbocharger.

This LER documents the February 11, 1998 controlled shutdown of Salem Unit 2 as required by Technical Specification 3.8.1.1, following the failure of the 2A emergency diesel generator (EDG) turbocharger. Since the licensee's root cause analysis and corrective actions for this event were previously reviewed and documented in Section M8.1 of this report and Section E.7.2 of NRC Inspection Report 50-272 & 311/98-81, the inspector performed an in-office review of this LER. The inspector found that no new information was provided and that no additional inspection effort was warranted. Therefore, this LER is closed.

II. Maintenance

M1 Conduct of Maintenance (50001, 62707, 61726, 92902, & 40500)

M1.1 General Comments

The inspectors observed all or portions of the following work activities and Technical Specification surveillance tests:

- W/O 950606013: 13 AFP Overspeed Trip Test

- W/O 970916012: 21 EDG Lube Oil Heater Clean and Inspection
- W/O 971006167: Replace 2PR3
- W/O 970818068: Replace 2PR4
- W/O 971006167: Repair 22 SG Steam Flow Channels (2FT523 and 2FA3472)
- W/O 980131065: 2C EDG Watt Meter Transducer Replacement
- W/O 980205085: 2B EDG Reliability Run While 2C EDG Inoperable
- W/O 970120269: 2A EDG Lube Oil Cooler Jacket Water Heat Exchanger dp Transmitter Work
- W/O 980301186: Inspect 23 Service Water Strainer
- W/O 980301188: Inspect 21 Service Water Strainer For Possible Bypass
- S2.OP-ST.SJ-0001: Safety Injection Pump Inservice Test
- S2.OP-ST.DG-001: 2A EDG Surveillance Test
- SC.CH-CA.ZZ-0325: Boron Sample by Titration of RWST Sample
- S1.RA-ST.SJ-0002: 12 Safety Injection Pump Inservice Testing

The inspectors observed that the plant staff performed the maintenance effectively within the requirements of the station maintenance program, and that the plant staff did surveillances safely, effectively proving operability of the associated system. Minor deficiencies noted by the inspector during the performance of the refueling water storage tank boron sample and analysis were promptly corrected by the licensee.

M1.2 Wrong Control Switch Installed on 12 Diesel Fuel Oil Transfer Pump

a. Inspection Scope

The licensee discovered during the 31-day surveillance run of the 12 Diesel Fuel Oil Transfer Pump (DFOTP) on February 19, 1998, that the pump would not start in automatic when required to do so. Troubleshooting revealed that the wrong control switch was installed on the pump. The inspector followed up on this self-revealing event through personnel interviews and documentation review.

b. Observations and Findings

The licensee replaced a degraded control switch for the 12 DFOTP on January 30, 1998. On February 19, 1998, while performing the 31-day surveillance run on the pump, it would not start in automatic control when the fuel oil day tank dropped to the appropriate level. Troubleshooting revealed that the wrong control switch was installed on January 30, which prevented the automatic start of the pump, rendering it inoperable. Unit 1 was in Mode 5 at the time the wrong switch was installed on January 30. Technical Specification (TS) 3.8.1.2 requires one of the two DFOTPs to be operable in Mode 5. However, the licensee entered Mode 4 on February 18 at 8:35 a.m., and TS 3.8.1.1.b.2 requires two DFOTPs to be operable in Mode 4. The 12 DFOTP was restored to operable status on February 20 at 2:31

a.m. The licensee's ascension to Mode 4 with one of two DFOTPs inoperable was a violation of TS 3.8.1.1.b.2. **(VIO 50-272/98-01-03)**

The inspector determined that there were multiple failures which caused this event. The Planning Department listed the wrong part number for the control switch on the work order (WO) and staged it for the work. Additionally, the WO listed the wrong print number for the electrical panel where the switch is located, and listed another print which does not exist. The post-maintenance test (PMT) was inadequate in that it did not test the automatic start feature of the pump. The PMT described on the WO was not specific, and operations and maintenance personnel did not question its adequacy.

The technician who performed the work did not verify the correct switch part number when replacing the switch. Also, he did not recall having the appropriate electrical drawings at the work site per management expectations, and did not verify proper operation of electrical contacts controlled by the switch after the work was done. Any of these actions would have revealed that the wrong control switch was installed.

The licensee's immediate corrective actions for this event were weak. A technician documented on February 19 that he had verified that the other three DFOTPs had the correct control switches. However, the 2A EDG was protected at the time due to maintenance on another EDG, so he did not verify the 21 DFOTP. He remembered this omission on February 27 and checked it for the correct control switch. He discovered that this DFOTP also had the wrong part number. This switch had been replaced in January 1994 with the wrong part number, but had passed all surveillance tests (STs) since then. The licensee did not know how the 21 DFOTP control switch was placed in its present configuration with the wrong part number. However, the switch appeared to function as designed.

Initially, there was no analysis performed to verify operability of the 21 DFOTP control switch for this abnormal configuration. Rather the licensee concluded that the 21 DFOTP was operable since it had passed all STs. The inspector brought this issue to management's attention on March 12, 1998. The Operations Manager stated that the 21 DFOTP was operable and the licensee ascended to Mode 1 on March 14 with no documented operability determination (OD). Subsequently, the licensee performed an OD on March 16, which the inspector concluded was adequate, but not timely. Additionally, the licensee did not verify correct part numbers for the remaining six control switches on each DFOTP electrical panel, three of which have the same control switch as the DFOTP, until questioned by the inspector.

c. <u>Conclusions</u>

Poor planning and inadequate maintenance practices resulted in an incorrect control switch being installed on the 12 Diesel Fuel Oil Transfer Pump (DFOTP), which rendered the 12 DFOTP inoperable. The licensee ascended to Mode 4 on Unit 1 with less than the required DFOTPs operable, which was a Technical Specification violation. The licensee's immediate corrective actions for this event were weak, including an untimely operability determination for the wrong part being installed on the 21 DFOTP, and untimely verification of correct part numbers for similar control switches on the four DFOTP electrical panels.

M1.3 Post-Maintenance Testing of 2A Emergency Diesel Generator after Turbocharger Failure

a. Inspection Scope

The inspector followed up on licensee post-maintenance testing (PMT) activities on the 2A EDG following the February 11, 1998 turbocharger failure.

b. Observations and Findings

On Thursday, February 19, 1998, maintenance personnel were completing maintenance activities on the 2A EDG in accordance with procedure SC.MD-ST.DG-0003, "Eighteen Month Diesel Engine Inspection Maintenance." The maintenance supervisor ordered technicians to close the EDG petcocks in preparation for returning the diesel to operation. Although the technicians stated that they closed the petcocks, this was not documented in step 5.17.4 of the procedure, as required.

On Friday, February 20, 1998, operations personnel barred the diesel over in accordance with procedure SC.OP-PT.DG-0001, "Diesel Generator Manual Barring," in preparation for running the engine. This procedure requires the diesel petcocks to be open for barring and closed for running the engine. Nuclear equipment operators signed off the procedure indicating that the petcocks were closed and independently verified (IV'd) as such. But when the diesel was subsequently started, the petcocks were found open because the operators did not understand how to properly position the petcocks.

On Sunday, February 22, 1998, at 1:35 a.m. operators started the 2A EDG in accordance with procedure S2.OP-ST.DG-0001, "2A Diesel Generator Surveillance Test" for an operability and 24-hour surveillance run. During the run, a maintenance engineer noted a strange sound coming from the left side of the engine. The operator checked engine cylinder temperatures and noted that the 5-Left cylinder temperature indicated that it was not firing. Further investigation revealed that the 5-Left cylinder fuel pump was locked out. All other cylinders were checked with no discrepancies noted. The 5-Left cylinder was restored and the 2A EDG run was completed successfully.

Step 5.17.9.M of the above maintenance procedure requires that cylinder fuel pump racks be checked unlatched (not locked out) and IV'd as such. Procedure review showed that the IV line was signed off, but not the initial check. Interviews with the technicians revealed that the initial check was completed but not signed off, and no IV was completed, but was signed off. Additionally, the maintenance supervisor signed the procedure without recognizing that the step 5.17.9.M initial check was not signed off.

The licensee took immediate corrective actions for the open petcock and cylinder lock-out issues, including stopping work to remediate personnel involved, and reviewing lessons learned with all maintenance personnel the week following the errors. The licensee is also planning other long-term corrective actions to address these issues.

In the above instances, maintenance and operations personnel failed to comply with station procedures for the control of safety-related systems. These licensee identified failures are a violation of TS 6.8.1 which requires that written procedures be implemented for safety-related equipment recommended in Appendix "A" of Regulatory Guide (RG) 1.33, Revision 2, February 1978. This RG recommends that written procedures be implemented for control of EDGs. **(VIO 50-311/98-01-04)**

c. Conclusions

Procedural adherence for the 2A Emergency Diesel Generator post-maintenance testing was poor. Numerous procedural violations by maintenance and operations personnel resulted in the improper operation of the diesel. There was little safety significance to these violations as the diesel was out of service for maintenance. However, they showed a lack of questioning attitude and attention to detail by numerous personnel. Additionally, the engineering action plan utilized for the maintenance effort was not sufficiently detailed to promote smooth transition between the maintenance and operations procedures used.

M2 Maintenance and Material Condition of Facilities and Equipment

M2.1 High Crankcase Pressure Alarm on the 2B Emergency Diesel Generator During a Technical Specification Required Run

a. Inspection Scope

The inspector observed the February 3, 1998 run of the 2B EDG, which was required by TS 3.8.1.1.b due to the 2C EDG outage for maintenance. The 2B EDG was shut down when the "Crankcase Blower Failure" alarm was received. The inspector followed up on this shutdown, the trouble-shooting of the cause of the alarm, and the post-maintenance EDG run after the problem was corrected.

b. Observations and Findings

On February 3, 1998, licensee operators were running the 2B EDG to satisfy TS 3.8.1.1, action b, since the 2C EDG was out of service for maintenance. The 2C EDG maintenance placed Unit 2 in a 72-hour shutdown action statement and required running the 2A and 2B EDGs to show reliability. Approximately 13 minutes after the diesel was fully loaded, the "Crankcase Blower Failure" alarm was received. The operator correctly carried out the alarm response procedure and attempted unsuccessfully to reset the alarm. Therefore, the 2B EDG was shut down and declared inoperable by the Control Room Supervisor, who was observing the diesel run. This placed the plant in a two-hour shutdown action statement, due to the inoperability of two diesels.

After the diesel was shut down, the operator again attempted to reset the alarm and this time was successful. Subsequent investigation revealed that the three-way root valve for the crankcase pressure switch had apparently vibrated out of position, porting air manifold pressure to the switch instead of crankcase pressure. Crankcase pressure is normally at vacuum, while air manifold pressure is at a vacuum with the diesel unloaded or lightly loaded, but at pressure when the diesel is loaded. This caused a false high crankcase pressure indication. The three-way valve was positioned correctly, and the 2B EDG was re-started with a Heise pressure gage connected to read crankcase pressure. This gage indicated normal pressure (about -1.2 inches wc) for the remainder of the run and no more alarms were received. The 2B EDG was declared operable approximately 13 minutes before the two-hour action statement expired.

The inspector questioned the Operations Superintendent concerning his operability determination. The OS declared the diesel operable after 20 minutes of the one-hour surveillance run after the pressure switch problem was corrected. He stated that since the alarm was received 13 minutes after the diesel was fully loaded, and that he was confident that the problem was corrected, he could declare the diesel operable after a similar amount of time (20 minutes) of a loaded run, once he had verified that the crankcase pressure was satisfactory. The Operations Manager concurred with that decision, and further stated that if other problems arose during the remainder of the one-hour run, that he would have used the original failure time (not the time the diesel was declared operable) to calculate time available before plant shutdown was necessary. The inspector concluded that these actions were satisfactory.

The inspector also questioned the OS concerning the timing of the 2B EDG reliability run. At the time of the run, the 2C EDG was out of service for on-line maintenance, which placed the plant in a 72-hour action statement, and which required the licensee to run the remaining two diesels within 24 hours of declaring the 2C inoperable. The 2A EDG was successfully run prior to taking the 2C EDG out of service. However, the 2C EDG was taken out of service at approximately 6:00 a.m. and was scheduled to be out of service for about 16 hours. The inspector questioned why the 2B was run at 11:00 a.m. that same morning instead of waiting until work was completed on the 2C. The OS stated that he was fully confident that the 2B EDG was operable and he did not anticipate any problems with running it. The inspector concluded that, based on the intended outage time of the 2C EDG, that it would have been more appropriate to run the 2B EDG before the 2C was taken out of service.

The inspector asked the diesel system manager if the crankcase pressure switch was required to be calibrated. He stated that it was calibrated every three years, but that due to the present operational schedule, the calibration had been deferred from November 1997 to the next refueling outage in January 1999. The system manager stated that he intended to move the calibration of the switch up to the summer of 1998. The inspector concluded that since the pressure switch provided an alarm function only, and not a protective function, that the calibration deferral was acceptable.

c. Conclusions

The licensee met all Technical Specification requirements for the 2C emergency diesel generator (EDG) outage and the crankcase alarm on the 2B EDG. The operator correctly followed the alarm response procedure for the 2B EDG alarm. The operability determination for the 2B EDG after the cause of the alarm was determined was adequate, but the decision to run the 2B EDG during the 16-hour 2C EDG outage was not appropriate.

M8 Miscellaneous Maintenance Issues

M8.1 2A Emergency Diesel Generator Turbocharger Blade Failure

a. Inspection Scope

Approximately 44 minutes into a post-maintenance test on February 11, 1998, the Unit 2, 2A emergency diesel generator (EDG) turbocharger failed. The licensee formed a team to get the relevant facts, find the cause of the failure, evaluate its significance relative to the operability of the other EDGs, and establish corrective actions. In the month after the failure, the NRC resident inspector sampled the work of the team and a regional based engineering inspector met with team members to review the scope of activities of the team and its conclusions.

b. Observations and Findings

The turbocharger failure occurred when one rotating blade on the engine exhaust gas input side of the turbocharger broke loose subsequent to fatigue cracking of the blade where it was mechanically rooted in the rotor assembly. The team, formed to evaluate the failure, included in its scope: an examination of the diesel engine internals to verify that no engine components had been exhausted into the turbocharger; review of the history of the turbochargers on each Salem EDG; review of previous industry turbocharger failures; metallurgical and chemistry analysis on the blades and debris; dynamic factors, event facts, root cause and change analysis; and turbocharger service life. By March 12, 1998, most of the evaluation work of the team was complete, but the analysis of the dynamic factors that may or may not have led to the failure was in progress by an industry expert on turbines. In summary, the team conducted an extensive evaluation of the failure.

c. Conclusions

On February 11, 1998, the Unit 2 emergency diesel generator (EDG) turbocharger failed during a post-maintenance test. The licensee formed a team to get the relevant facts, find the cause of the failure, evaluate its significance to the other EDGs and establish corrective actions. The NRC reviewed the evaluation scope, methods and results. This NRC inspection concluded that the preliminary root cause evaluation of the failed turbocharger blade was thorough, detailed, and accurate. The inspector concluded that the licensee had properly responded to the EDG turbocharger failure by initiating a thorough evaluation.

M8.2 (Closed) LER 50-272/96-05, Supplements 6 through 16: Technical Specification Surveillance Requirement Implementation Deficiencies

These supplemental reports documented additional findings of the Technical Specification Surveillance Improvement Program (TSSIP), the licensee's long-term corrective action plan for surveillance testing deficiencies originally described in LER 96-005. The TSSIP project was initiated for Salem station as part of the corrective actions taken by PSE&G regarding surveillance deficiencies identified at Hope Creek (reference violation 50-354/95-11-02). Although these reports identified different surveillance requirements that were not appropriately implemented for ensuring technical specification requirements were met, the licensee took timely corrective action, demonstrated operability of the required equipment in each case, and provided adequate bases that no safety consequences resulted from the testing inadequacies. The associated root cause for these supplemental reports were the same as for supplemental reports one through five and constituted a violation of NRC Test Control requirements per 10 CFR 50, Appendix B, criterion XI. However, based on licensee identification and action taken to correct these deficiencies, this violation is being treated as a non-cited violation consistent with Section VII of the NRC Enforcement Policy. **(NCV 50-272 & 311/98-01-05)**

These minor issues were closed based on an in-office review of the licensee-provided information. However, the inspector also reviewed selected testing procedures to verify the licensee had implemented adequate procedural changes to address the deficiencies, as detailed in the LER. No discrepancies were identified.

The inspector noted that PSE&G prioritized and completed their actions in response to Generic Letter (GL) 96-01, "Testing of Safety-Related Logic Circuits" as described in their letters to the NRC dated April 16, 1996, and January 15, 1998, as part of the TSSIP. As the licensee stated in their letter dated January 30, 1998, these implementing procedures related to GL 96-01 review were completed for both Salem Units 1 and 2. Additionally, PSE&G appropriately assigned the next highest priority to technical specification procedures associated with relatively high risk surveillances and safety-related systems and the lowest priority to those procedures with relatively low risk surveillances and nonsafety-related systems. Further, the inspector noted that the licensee extended their commitment to complete their review of the remaining procedures from December 1997 to May 1998. However, the licensee stated that the higher priority procedures would be completed prior to Unit 1 restart/entry into Mode 2. At the time of this inspection the licensee had completed their review of 1,185 of the 1,293 (92%) technical specification implementing procedures. Based on the minor significance of all of the identified procedural deficiencies for both Units 1 and 2 as well as those enveloped by the Hope Creek TSSIP program, the inspector determined that the risk associated with restarting Unit 1 without completion of the lower priority procedure review was minimal and acceptable.

III. Engineering

E1 Conduct of Engineering (TI 2515/109, 37551, 40500 & 92903)

E1.1 Generic Letter 89-10 Motor-Operated Valve Program Review and (Closed) NRC Programmatic Restart Issue III.a.23: Adequacy of Motor-Operated Valve Program (Unit 1)

a. Inspection Scope

On June 28, 1989, the NRC issued Generic Letter (GL) 89-10, "Safety-Related Motor-Operated Valve Testing and Surveillance," requesting licensees to establish a program to ensure that switch settings for safety-related motor-operated valves (MOVs) were selected, set, and maintained properly. Seven supplements to the GL have been issued to provide additional guidance and clarification. NRC inspections of licensee actions implementing the provisions of the GL and its supplements have been conducted based on the guidance provided in NRC Temporary Instruction 2515/109. The most recent inspection of MOV activities at Salem was documented in IR 50-311/97-03, dated April 3, 1997, when the NRC's review of the GL 89-10 program for Salem Unit 2 was closed (Unit 1 was not inspected).

The purpose of this inspection was to review the actions implemented at Salem Unit 1 to closeout programmatic restart item III.a.23 and determine if those actions were sufficient to warrant closure of the NRC staff's review of the GL 89-10 program. Since the MOVs for both Salem Units are similar, the inspection focused on any performance differences between the Unit 1 and 2 MOVs, and included the review of:

1. Specific MOV issues experienced during the Salem Unit 2 review.

2. Load sensitive behavior, stem friction coefficient, and degradation margin.

3. Specific MOV problems encountered at Salem Unit 1.

4. Thrust margin improvement plans.

5. Measures to monitor industry actions regarding operator and motor performance.

6. Licensee's actions regarding existing MOV open items for Salem Unit 1.

The inspectors reviewed PSE&G'S-I-VAR-NEE-1266, "Generic Letter 89-10 Closure Summary for the Motor Operated Valve Program As Implemented at Salem Unit 1," Rev. 0, and documents associated with all MOVs in the GL 89-10 program. The closure summary document was in draft stage during the initial onsite inspection. It was completed on February 1, 1998, and further reviewed in-office by the inspectors. In addition to the onsite visit of January 15 and 16, 1998, comments on the closure summary document were discussed on several instances afterwards during a conference call on February 4, 1998, and most recently on March 4, 1998.

The findings discussed below refer to Revision 0 of the closure summary document although PSE&G had issued Revision 1 to address the inspectors' comments. The inspectors also referred to the similar document, S-C-VAR-NEE-1117, Revision 1, "Generic Letter 89-10 Closure Summary for the Motor Operated Valve Program As Implemented at Salem Unit 2," that had been used as a basis for the closeout of the Salem Unit 2 MOV program.

b. Observations and Findings

Two main program documents govern MOV activities at Salem. These documents are (1) Programmatic Standard NC.DE-PS.ZZ-0033(Q) which includes many appendices providing details for design basis reviews, MOV capability assessments, etc; and (2) Program Position Papers EE:A-O-ZZ-MEE-0609 which provide licensee positions on many MOV technical issues such as temperature effects on motor performance. The inspectors confirmed that significant changes had not been made to these MOV program documents. Essential program elements, such as the definition of MOVs in the program scope, tracking and trending of MOV performance, and post maintenance practices, were in place at Salem Unit 1 similar to that observed during the Salem Unit 2 review. The inspectors verified that the residual heat removal discharge-to-hot leg isolation valve, 1RH-26, had been added to the MOV program scope and had been dynamically tested. The comparable valve, 2RH-26, had also been added to the GL 89-10 MOV program at Salem Unit 2. There were no other MOV program scope changes.

PSE&G dynamically tested about 50% of the 95 MOVs in the GL 89-10 program at Salem Unit 1. PSE&G provided information for the 95 MOVs which were grouped into 16 MOV families. The inspectors reviewed the following MOV families where specific issues had been discussed during the closeout review of the Salem Unit 2 MOV program.

Specific MOV Issues Experienced During the Salem Unit 2 Review

- Family 6: 14" Copes Vulcan 2500 psi Parallel Double Disk Gate Valves

  This family consisted of the reactor coolant system (RCS) hot leg to residual heat removal (RHR) suction header valves (1RH1 and 1RH2). The comparable valves (2RH1 and 2RH2) had been discussed during the MOV program review at Salem Unit 2. Specifically, PSE&G revised its initial 0.55 valve factor basis for these valves to 0.61 which was based on the maximum value of valves tested at Salem Unit 2. This was considered acceptable for GL 89-10 program closure based on PSE&G's commitment to pursue an improved valve factor basis for these valves as part of their periodic verification program.

  For Salem Unit 1, PSE&G continued to assume a valve factor of 0.61 for these valves. Using a design basis differential pressure (DBDP) condition of 381 psid, a stem friction coefficient of 0.20, actuator pullout efficiency, and a 212°F environment for the actuator temperature to determine motor performance, PSE&G calculated a thrust margin of 16% and 11% for 1RH1 and 1RH2, respectively. In pursuing an improved valve factor basis as part of the periodic verification program, PSE&G agreed to use the Electric Power Research Institute (EPRI) Performance Prediction Methodology (PPM). Also, efforts would continue with other reactor facilities to seek valve factor information regarding these valves. The plan to further assess these valves was included in the licensee's corrective action program by revising an existing Action Request 970418119 which had been issued to address the issues from the Salem Unit 2 MOV program review. The inspectors considered PSE&G's actions acceptable for restart. An inspector Followup item **(IFI 50-272/98-01-06)** is opened to verify implementation of this action for GL 89-10 program closure.

- Family 9: Power Operated Relief Valve (PORV) Block Valves (1PR6 and 1PR7)

  PSE&G modified the Salem Unit 2 PORV block valves to operate them based on limit switch control, and thereby take advantage of full actuator motor capability for valve closing. A similar modification has been accomplished for the Salem Unit 1 valves. PSE&G calculated the thrust margin to be 19% and 8% for 1PR6 and 1PR7, respectively, based on a DBDP of 2510 psid, a 0.61 valve factor, a 0.20 stem friction coefficient, and using actuator pullout efficiency in demonstrating design basis capability. (Note: Similar parameters were used during the Salem Unit 2 review.)

In following up on an issue discussed during the Salem Unit 2 review, PSE&G acknowledged that they had not fully addressed the NRC request regarding the adequacy of the valve factor basis and any non-predictability for these valves. Internal dimensions had been taken for the Salem Unit 1 valves to assist in determining the valve predictability and thrust requirements at both Salem Units in accordance with the EPRI PPM. However, since this dimensional information had not yet been translated into a calculation of a design standard valve factor according to the EPRI PPM, PSE&G intends to complete these calculations (Action Request 970418119). PSE&G stated preliminary calculations indicated that there were no nonpredictability concerns for these valves. The inspectors considered PSE&G's actions acceptable for restart. **IFI 50-272/98-01-07** will include verification of licensee completion of these calculations for GL 89-10 program closure.

- <u>Family 9: Reactor Coolant Pump (RCP) Thermal Barrier Isolation Valves (1CC131 and 1CC190)</u>

Both RCP thermal barrier isolation valves reviewed during the Salem Unit 2 inspection demonstrated positive thrust margins, with valve 2CC131 the least at 8% using torque switch control in the closed direction. While this was considered acceptable for GL 89-10 closure, PSE&G plans to take measures to improve the actuator capability for these MOVs. PSE&G also plans to confirm the adequacy of the valve factor basis and to evaluate any non-predictability for these valves as part of the Salem Unit 2 periodic verification program.

Both RCP thermal barrier isolation valves at Salem Unit 1 were modified in accordance with design change DCP 1EE-0368 to operate under limit switch control to improve their design basis capability. A similar modification will be implemented at Salem Unit 2 during the next refueling outage. Based on a DBDP of 2241 psid, a 0.61 valve factor, a 0.20 stem friction coefficient, and using actuator pullout efficiency in demonstrating design basis capability, PSE&G calculated a thrust margin of about 30% for the Salem Unit 1 valves which was acceptable.

In following up on an issue discussed during the Salem Unit 2 review (similar to the discussion above for 1PR6 and 1PR7), PSE&G acknowledged that they had not fully addressed the NRC request regarding the adequacy of the valve factor basis and any non-predictability concerns for these valves.

Accordingly, PSE&G plans to complete calculations using the EPRI PPM to evaluate these issues (Action Request 970418119). PSE&G stated preliminary calculations indicated that there were no non-predictability concerns for these valves. The inspectors considered PSE&G's actions acceptable for restart. **IFI 50-272/98-01-07** will include verification that the calculations were completed for GL 89-10 program closure.

<u>Load Sensitive Behavior, Stem Friction Coefficient, and Degradation Margin</u>

The Salem Unit 2 Closure Summary included a statistical analysis of 75 data points and determined an average load sensitive behavior of 3.7% with an associated standard deviation of 9.6%. To properly account for load sensitive behavior, PSE&G's error analysis added 4% error in thrust calculations directly as a bias margin, and an additional 21% error as a random value that was included with other uncertainties using the square root sum of the squares method. Also, PSE&G had completed a comprehensive stem friction coefficient review of the results from in-plant testing to justify the use of a stem friction coefficient value of 0.20 and revised their setup methods to include a 5% bias margin to account for degradations as a part of their standard error analysis. The results of the analyses for load sensitive behavior, stem friction coefficient, and degradation margin were included in the Salem Unit 2 Closure Report (S-C-VAR-NEE-1117, Revision 1) as Attachments 19, 20, and 21, respectively.

The additional data obtained from Salem Unit 1 testing done during the past year was factored into updated analyses for load sensitive behavior, stem friction coefficient, and degradation margin. This data supported the Salem Unit 2 data and did not invalidate any of the conclusions. It was included in similar Attachments to the Salem Unit 1 Closure Report (S-I-VAR-NEE-1266) where PSE&G concluded that the margins allocated for load sensitive behavior (4% as a bias and 21% as a random value) and degradation (5% as a bias) and the stem friction coefficient value of 0.20 for the Salem Unit 1 MOVs should be the same as that established for the Salem Unit 2 MOVs. Where stem friction coefficient values just above 0.20 were experienced for 1CC118 (0.21) and 12CC3 (0.22) during recent differential pressure testing, PSE&G plans to inspect and correct these conditions. It is noted that these MOVs did demonstrate positive thrust margins.

The inspectors found this approach for addressing load sensitive behavior, stem friction coefficient, and degradation margin to be acceptable for Salem Unit 1 restart. Inspector followup item **(IFI 50-272/98-01-08)** is opened to verify completion of the PSE&G actions regarding correction of the high stem friction coefficient values of 1CC118 and 12CC3 as part of the licensee's MOV periodic verification program being implemented per GL 96-05, "Periodic Verification of Design-Basis Capability of safety-Related Motor-Operated Valves."

Specific MOV Problems Encountered at Salem Unit 1

- Family 5: 6" Anchor Darling 150 psi Parallel Double Disk Gate Valves

The RCP bearing cooling water outlet containment isolation valves (1CC136 and 187) are six-inch Anchor Darling, double disk gate valves. (Note: During the Salem Unit 2 review, PSE&G agreed to improve the thrust margin of 2CC136.) Both 1CC136 and 187 exhibited high closing forces during recent dynamic testing at Salem Unit 1. Each valve failed to close during the initial dynamic test on December 30, 1997, with the valves set at the as-found torque switch settings. No similar failure-to-close problems were experienced with the related 1CC117 and 118 valves in this family although 1CC117 did exhibit a higher than expected valve factor of 0.68 based on its differential pressure test at 73% of design basis conditions. PSE&G plans to repeat this test during the next refueling outage.

Since the component cooling water system had been de-chromated for an extended period, corrosion products in the valve internals were attributed, in part, to the poor performance. This parallel disk valve design is intended to force the disks apart by the sliding action of angled upper (or fixed) and lower disk (or floating) wedges (sometimes called wedge shoes). Valves with the upper wedge located downstream of the flow (the non-preferred direction) can require more thrust to achieve full wedging of the disk into its seat. To enhance the valve performance, the wedge shoes for these valves in Salem Units 1 and 2 had been modified in the past year with stellite hardfacing. The performance of 1CC187 was worse because its wedge shoes were found installed in the non-preferred orientation. The wedge shoes for 1CC136 were oriented correctly.

Both valves were cleaned and installed correctly. Static and dynamic tests were performed satisfactorily. The inspectors were concerned regarding the long term performance of these and related (1CC117 and 118) MOVs in this family at Salem Units 1 and 2. To address these concerns, PSE&G plans to do the following:

Unit 1: Issue action requests to perform differential pressure testing of 1CC117&118 at degraded voltage at the start of the next Unit 1 refueling outage. Open and inspect the valves to verify correct wedge shoe orientation. Expand the testing scope to 1CC136 and 1CC187 if there is a significant change in valve performance.

Unit 2: Issue action requests to perform differential pressure testing of 2CC117, 2CC118, 2CC136, and 2CC187 at degraded voltage at the start of the next Unit 2 refueling outage. Open and inspect the valves to verify correct wedge shoe orientation if there is a significant change in valve performance since the last differential pressure test.

The inspectors considered PSE&G's actions acceptable for restart. Inspector followup item **(IFI 50-272/98-01-09)** is opened to verify completion of these actions as part of the licensee's MOV periodic verification program being implemented per GL 96-05.

Measures to Monitor Industry Actions Regarding Actuator Performance

The inspectors reviewed the licensee's measures taken and expected in response to forthcoming information from Limitorque regarding the modification of previously published actuator efficiencies. This subject had also been addressed in NRC Information Notice 96-48, "Motor-Operated Valve Performance Issues."

As explained in Attachment 22, "Actuator Efficiency Evaluation," of the Salem Unit 1 MOV program summary report, PSE&G has performed many differential pressure tests at degraded voltage at Salem Units 1 and 2. This was done to better characterize in plant motor performance under these conditions and to provide assurance regarding their use of run efficiency in the closed direction for all torque seated gate and globe valves. PSE&G indicated that it had reviewed the information in NRC Information Notice 96-48, it was monitoring industry information for further developments, and any additional guidance issued on this topic in the future by Limitorque would be reviewed and appropriate actions taken in accordance with the Vendor Document and Corrective Action Programs.

Thrust Margin Improvement Plans

Inspector followup item 50-272/96-11-06 had been opened to review thrust margin improvements needed for MOV 12CC16 (RHR heat exchanger component cooling water outlet isolation valve) which previously evidenced a negative thrust margin at design basis conditions. PSE&G has modified the control circuit to close this valve under limit control. This action acceptably resolved the problem since the thrust margin for the closing direction is currently about 17%.

The inspectors noted that several Salem Unit 1 MOVs were scheduled for margin improvements. Although the following MOVs had adequate basis for the applied thrust requirements, they had low thrust margins and were identified by the inspectors to ensure that they were included in PSE&G's margin improvement plans: 1CC118, 1CC30, 1PR7, and 1SJ4.

The licensee was requested to review these MOVs and to include them as part of their margin improvement program. PSE&G personnel agreed to conduct this review. Closure of these MOVs under the GL 89-10 program was contingent upon the licensee's agreement to improve the margin of these MOVs as part of Salem Unit 1's periodic verification program conducted per GL 96-05.

c. Conclusions

PSE&G had adequately demonstrated design basis capability for Salem Unit 1 MOVs to support restart. Justifications for key program assumptions and the applied valve factors were adequate to support closure of Restart Issue III.a.23 for Unit 1. Regarding GL 89-10 program closure, PSE&G was requested to update and clarify program summary S-I-VAR-NEE-1266, "Generic Letter 89-10 Closure Summary for the Motor Operated Valve Program As Implemented at Salem Unit 1," consistent with the inspector followup items in this report.

E1.2 Update on Control Area Ventilation System Issues

The Control Area Ventilation System (CAVS) is comprised of two subsystems: the control area air conditioning system (CAACS) and the Control Room Emergency Air Conditioning System (CREACS). When one train of CREACS is inoperable, the CAVS cannot maintain the Technical Specification (TS) required 1/8 inch water column differential pressure (dp) between the control room and adjacent spaces. As a compensatory measure, the licensee aligns CAVS in the "maintenance mode," wherein the adjacent spaces are vented to atmosphere to maintain the required dp.

The licensee addressed two issues which prohibited two-unit operation while in the maintenance mode. Engineering Evaluation (EE) S-C-CAV-MEE-1285, "Control Room Ventilation-Radiological Contaminated Air Intrusion," was completed to address the issue of a radiological cloud potentially entering the control room adjacent spaces while in maintenance mode, which could affect control room watchstanders. This evaluation confirmed that positive pressure in the adjacent spaces from CAVS operation would prevent such an intrusion. Long-term corrective actions to remove the necessity of maintenance mode are a TS change to change the dp reference to the outside atmosphere instead of the adjacent spaces, and ventilation equipment changes to increase the dp margin. The inspectors concluded that the EE was adequate to address the radiological cloud issue.

The second issue concerned the Unit 2 Radiological Monitoring System (RMS) inverter (power supply), which has a non safety-related battery backup. The CAVS radiation monitors are powered from the inverter and would fail high if the inverter was lost. This would open the CREACS air intakes on both Salem units, placing control room personnel at risk to adverse radiological conditions. The licensee completed an operability determination for the inverter and is pursuing a design change to provide a safety-related battery backup.

The inspectors concluded that these actions were adequate to address the two issues mentioned. However, the long-term corrective actions mentioned above were necessary to eliminate the need for maintenance mode. It is a time-consuming, resource-intensive work around which ensures adequate dp margin between the control room and the adjacent spaces. When this mode is employed, then any circumstances which necessitate accident pressurized mode, such as an inoperable CAVS radiation monitor, would require a unit shutdown to Mode 5 so that the CREACS air intake could be lined up to a non-operating unit. This would ensure that control room personnel dose limits are not exceeded during accident conditions. The licensee stated that the TS change would be submitted to the NRC within the next two weeks, and that ventilation equipment changes to increase the dp margin are still under evaluation.

E2 Engineering Support of Facilities and Equipment

E2.1 Service Water Biofouling and (Closed) LER 50-272/96-34

a. Inspection Scope

Several safety related and non-safety related service water (SW) cooled heat exchangers (HX) experienced accelerated biofouling from marsh grass from the Delaware River from January to March 1998. As a result, degraded plant conditions and in one instance, equipment inoperability occurred. The inspector analyzed the events and the licensee's response to evaluate the effectiveness of licensee controls to resolve this problem. The inspector also reviewed the corrective actions specified for Licensee Event Report (LER) 50-272/96-34: service water strainer design deficiency potentially outside design basis.

b. Observations and Findings

During the weeks of January 18 and 25, 1998, operators noted increasing temperature trends on the Unit 2 turbine auxiliaries cooling (TAC) and main turbine lube oil (MTLO) HXs. Operators also noted an increasing temperature trend on the No. 3 station air compressor (SAC). Inspections of the TAC, MTLO HXs and SAC identified that the SW inlet tube sheets were clogged with river grass, which resulted in degraded thermal performance.

On January 21, a differential pressure (D/P) test to monitor SW biofouling revealed that the gear oil cooler exceeded the D/P limit across the HX for the 21 charging pump. An internal inspection revealed that the inlet tube sheet was clogged with river grass. However, SW flow through the HX was still above the minimum required. The licensee initiated Action Request (AR) 980120280, and performed a detailed self assessment to review the effectiveness of the SW reliability program. Weaknesses in the licensee's response to this issue are discussed in NRC RATI Inspection Report No. 50-272&311/98-81, Section E4.

The self assessment revealed a lack of SW reliability program oversight that resulted from the ongoing engineering department reorganization. Procedure NC.NA-AP.ZZ-0039, Rev. 0, "Service Water Reliability Program," specifies that Specialty Engineering is responsible for the implementation of the program, and that a program manager is responsible for oversight, control, and technical adequacy of the program. Specialty Engineering no longer exists and no program manager was assigned to ensure proper program implementation. PSE&G's commitments to Generic Letter (GL) 89-13, "Service Water System Problems Affecting Safety-Related Equipment," include a test program to verify the heat transfer capability of all safety-related HXs cooled by SW. Temperature and pressure trending was established for safety injection pump lube oil coolers, centrifugal charging pump gear and lube oil coolers, SW pump motor coolers, and diesel generator jacket water and lube oil coolers. Trending was not continued after the startup of Unit 2 in August 1997, since the SW reliability program manager assumed a new position within the organization, and a new program manager was not assigned. The licensee has assigned a new SW reliability program manager, and has delegated trending responsibilities to the Salem in-service testing program manager. In addition to GL 89-13 commitments, the licensee established a SW biofouling D/P test program in January 1998, based on industry guidance for monitoring of macro biological fouling. At the time of inspection, only about one half of the Unit 2 safety related HXs were D/P tested, and no Unit 1 HXs were tested. The licensee determined that the biofouling D/P monitoring program was not promptly implemented.

On February 25, the 22 chiller tripped on high condenser pressure during realignment of the control room ventilation system to normal operation. The licensee initiated AR 980225270, and declared the chiller inoperable. Internal inspection of the chiller condenser found river grass covering the inlet tube sheet. Grass was also found in the chiller's recirculation pump discharge check valve, 22SW99, during a surveillance test performed one week earlier. As a result the check valve failed its surveillance requirement. Further investigation revealed that the chiller had passed its biofouling D/P test in January. Salem operations initiated supplemental data logging of SW HX differential pressures after biofouling was discovered in the 21 charging pump gear oil cooler. The inspector reviewed the data logged by the equipment operators and noted that the SW inlet pressure readings for the 22 chiller were being logged as failed due to clogging from river silt since February 9. The inspector reported the data to system engineering, who were unaware of the supplemental data. Although no requirement exists for the logging and evaluation of this data, the inspector concluded that a weakness existed in the interface between operations and system engineering.

On March 1, the 21 charging pump gear and lube oil coolers failed the biofouling D/P test, after being in service for approximately 14 days following its D/P test failure in January. Inspection of the coolers revealed that both were completely clogged with river grass. The licensee initiated AR 980301138, which was subsequently upgraded to significance level one to address all recent SW biofouling issues. On February 27, the licensee had assmbled an engineering team to determine corrective actions and root causes. Immediate corrective actions included additional Unit 2 HX inspections, D/P testing, SW strainer inspections, and determining apparent causes. Testing and inspection revealed that the 21 component cooling water HX tube sheets were clogged with river grass. However, SW flow remained above acceptable limits. No other biofouling problems were identified. Each SW strainer consists of a rotating basket with approximately eleven hundred perforated disks retained in place with a threaded plastic ring. Strainer inspections revealed that two disks were missing from the 22 SW strainer basket, and the 21 SW strainer basket internal clearance exceeded the maximum tolerance. Each of these conditions results in SW flow bypassing the strainer media. While troubleshooting high D/P across the 25 SW strainer in January, maintenance workers found two disk retaining rings partially backed out. Inadequate maintenance practices were attributed to this condition.

The engineering team determined the apparent cause to be elevated river grass level compounded with degraded strainer conditions, noncontinuous traveling screen operation, and lack of appropriate HX biofouling trending. On March 12, abnormal operating procedure SC.OP-AB.ZZ-0003, Rev. 0, "Component Biofouling," was implemented. SC.OP-AB.ZZ-0003 specifies operator actions to be taken for excessive river grass loading, such as continuous SW traveling screen operation and more frequent biofouling D/P testing and data logging. The licensee is also planning to perform internal SW strainer inspections during the associated SW pump bimonthly silt inspection. The inspector concluded that the implementation of the abnormal operating procedure and the more frequent strainer inspections would adequately detect any significant SW biofouling.

During the previous Unit 1 and 2 refueling outages, SW pump discharge strainers were modified by design change packages 1EC-3685 and 2EC-3600. Strainer disk hole sizes were increased from 1/32" to 1/16", and the backwash setpoint was lowered from 7 psid to 5 psid. The modification was made to improve strainer reliability, because the strainer motors were experiencing overload trips that resulted from high D/P across the strainer disks. Additionally, design calculations assumed that an average of one SW strainer would operate continuously in backwash mode during accident conditions. An engineering review determined that the disks with 1/32" diameter holes may cause more frequent strainer backwash cycles resulting in more than one strainer in backwash mode during accident conditions. The licensee reported this condition in LER 50-272/96-034. PSE&G attributed the cause of this reportable condition to the failure to recognize long term clogging effects on the strainer disks. The filter disks were replaced along with a recurring task to inspect the SW strainer disks. The inspector reviewed the 10 CFR 50.59 applicability review for this modification and did not note any problems. This LER is closed.

The Salem SW system is susceptible to biofouling from river grass, and accumulation of grass in components may occur over extended periods of time. Several indications of accelerated SW biofouling existed before the 22 chiller tripped. However prompt management actions to determine and correct the causes were not initiated until the after the chiller tripped. The licensee's corrective actions were mainly focused on Unit 2 and did not include a detailed evaluation of SW biofouling effects on Unit 1. The inspector also noted that on January 25, maintenance identified that the 14 SW strainer had one disk missing, however no

AR was initiated until questioned by the inspector on March 13. Failure to promptly identify and correct SW biofouling problems is a violation of 10 CFR 50, Appendix B, Criterion XVI, Corrective Action **(VIO 50-272 & 311/98-01-10).**

c. Conclusions

Elevated grass levels in the Delaware River combined with degraded service water strainers and lack of service water reliability program oversight resulted in accelerated rates of service water biofouling. Weak management attention allowed biofouling to occur at unpredictable rates. Several instances of biofouling occurred in plant components before strainer degradation was identified and effective corrective actions were taken. In one instance, the biofouling contributed to the inoperability of a Unit 2 safety related chiller. Salem staff failed to take prompt corrective actions to determine and correct the cause of service water biofouling problems. System Engineering and Operations interfaces were weak during the analysis of those problems. The licensee did not adequately evaluate the extent of condition at both Salem Units. The inspector also concluded that the corrective actions taken in response to Licensee Event Report 50-272/96-34 were acceptable.

E8 Miscellaneous Engineering Issues

E8.1 (Closed) Violation 50-272/96-11-01: In NRC Inspection Report 50-272&311/96-11 violations were identified concerning inadequate test control measures during dynamic testing conducted on valves 1&2CV68 and 1&2CV69 (Charging Header Stop Valves). The inspectors determined that the differential pressures assumed by the dynamic test analysis were uncertain because: 1) the upstream pressure instruments did not account for the presence of pressure control valves located between the pressure instruments and the test valves and 2) the test procedure specified the use of a downstream pressure gage with an abnormally wide range which provided insufficient sensitivity for the expected test conditions. More importantly the questionable test data obtained was used as the valve factor basis for the PORV block valves (1&2PR6 and 1&2PR7).

The inspectors had reviewed PSE&G'S corrective actions to this violation for Salem Unit 2 and found them to be adequate as documented in IR 50-311/97-03. The inspectors confirmed that similar corrective actions were taken for Salem Unit 1. For example, PSE&G reviewed other Salem Unit 1 dynamic tests to identify if similar test control mistakes were made. No significant problems were noted. Also, PSE&G noted that continuous pressure data acquisition was being used where possible to enhance the accuracy of test results. This violation is now closed.

E8.2 (Closed) Inspector Followup Item 50-272/96-11-02: Complete load sensitive behavior study for Salem Unit 1. As documented in Section E1.1 of this report, for restart PSE&G has completed an acceptable load sensitive behavior study to establish adequate margins to account for this factor for MOVs at Salem Unit 1. This item is closed.

E8.3 (Closed) Inspector Followup Item 50-272/96-11-03: Complete stem friction coefficient study for Salem Unit1. As documented in Section E1.1 of this report, for restart PSE&G has completed an acceptable stem friction coefficient study for Salem Unit 1. This item is closed.

E8.4 (Closed) Inspector Followup Item 50-272/96-11-04: Revise test feedback method to include margin for valve degradation. As documented in Section E1.1 of this report, PSE&G has revised their MOV setup methodology for Salem Unit 1 to specifically include a 5% margin for potential valve degradations. This item is closed.

E8.5 (Closed) Violation 50-272/96-11-05: Incorrect assumptions in the mechanical design calculations for the residual heat removal suction header valves (1&2RH1 and 2) resulted in low torque switch settings. The incorrect settings for these risk significant pressure isolation valves created the possibility that they might not close under design-basis conditions since the torque switch was wired in series with the limit switch for these limit-controlled MOVs. PSE&G responded to the Notice of Violation by letter LR-N96332 dated November 1, 1996, wherein they stated the corrective actions to be taken to prevent recurrence for both Salem Units 1 and 2.

The inspector had reviewed PSE&G'S corrective actions to this violation for Salem Unit 2 and found them to be adequate as documented in Inspection Report 50-311/97-03. The inspector confirmed that similar corrective actions were taken for Salem Unit 1. For example, PSE&G had corrected the mechanical design calculations for 1RH1 and 2 and set the torque switches to the maximum allowable such that the torque switch settings would not prevent full closure of these MOVs. The inspector also verified that the licensee had checked other limit controlled MOVs, including butterfly valves, and confirmed that they were not impacted similarly. The inspector concluded these actions to be appropriate for closing out this item.

E8.6 (Closed) Inspector Followup Item 50-272/96-11-06: Review thrust margin improvements needed for MOV 12CC16 (RHR heat exchanger component cooling water outlet isolation valve) which previously evidenced a negative thrust margin at design basis conditions. As discussed in Section E1.1 of this report PSE&G has modified the control circuit to close this valve under limit control. This action acceptably resolved the problem since the thrust margin for the closing direction is currently about 17%. Therefore, this item is closed.

E8.7 (Closed) Inspector Followup Item 50-272/96-11-07: Request for PSE&G to increase the capability of marginal MOVs. As discussed in Section E1.1, PSE&G has agreed to review measures to improve the capability of certain MOVs in conjunction with their periodic program verification efforts. The inspectors concluded that these actions were acceptable for closing this item.

E8.8 (Closed) Inspector Follow Item 50-272/96-11-08: Verify MOV switch setting requirements for Pratt service water system butterfly valves. Family 16 consisted of 8" and 24" Pratt butterfly valves. Similar to the final setup of these MOVs at Salem Unit 2, PSE&G has used the EPRI PPM butterfly model to develop the torque requirements for the Salem Unit 1 valves. No spring pack modifications were needed to increase the output capability as was the case at Salem Unit 2. The inspector concluded that the methodology for setting the torque switches for these valves was acceptable for closing this item at Salem Unit 1.

E8.9 (Closed) Inspector Followup Item 50-272/96-11-09: An independent assessment of the Salem MOV program to evaluate its readiness for closure was conducted in August 1995 by two individuals who were MOV project members at another nuclear facility. The assessment appeared to be highly constructive with strengths and weaknesses noted and various recommendations presented for assuring Salem MOV program closure. However, PSE&G had not established firm management controls for providing their action plans or addressing the other items in the independent assessment report.

The inspector had reviewed PSE&G'S corrective actions regarding this issue for Salem Unit 2 and found them to be adequate as documented in IR 50-311/97-03. The corrective actions consisted of a formal review of the 1995 independent assessment findings. No new issues had been identified by PSE&G then and the licensee indicated that similarly now no new issues were developed from subsequent reviews. The inspector concluded that this issue was resolved for Salem Unit 1.

E8.10 (Closed) Unresolved Item 50-272/96-11-11: PSE&G had submitted an MOV program closure letter on June 25, 1996, for Salem Unit 1 and March 20, 1995 for Salem Unit 2 and had not amended these letters. In light of this fact and the nature and extent of the findings in NRC Inspection Report 50-311/96-11, a question regarding compliance with 10 CFR 50.9, "Completeness and Accuracy of Information" was raised. This issue was identified as an Unresolved Item for both Units. The issue was discussed at a public meeting held on November 12, 1996, between PSE&G and the NRC. PSE&G indicated that engineering evaluation A-O-ZZ-MEE-0926 served as a technical basis for the Salem Units 1 and 2 MOV program closure letters. PSE&G maintained that there was no significant negative information that occurred subsequent to the June 25, 1996 or March 20, 1995 letters which would have warranted an amended response. MOV changes that were made were considered to be minor enhancements to improve performance and were not significant deviations from the MOV program technical basis.

This issue was reviewed and closed out satisfactorily for Salem Unit 2 as documented in IR 50-311/97-03. The inspector reviewed the reasons for satisfactorily closing this issue for Salem Unit 2 and concluded that no new significant factors developed since the Salem Unit 2 review was conducted that should prevent closure of the issue at Salem Unit 1.

In summary, the inspector concluded that the question regarding compliance with 10 CFR 50.9 had been resolved in that there was not a compliance problem. This unresolved item is closed.

E8.11 (Closed) Unresolved Item 50-311/96-80-01: Single Failure Licensing Basis of Fuel Handling Ventilation System.

This issue involved determination of the fuel handling ventilation system's original licensing and design basis with respect to single failure. The NRC Office of Nuclear Reactor Regulation (NRR) performed a review, and based on the research conducted, could not conclude that the fuel handling ventilation system for Salem Unit 2 was required to meet the single failure criterion. Therefore, no violation of NRC requirements occurred. This item is closed.

E8.12 (Update) Violation 50-311/97-21-05 and (Closed) LER 50-311/96-07-02: Missed Surveillance of Containment Penetration Overcurrent Protection Devices.

This supplement to LER 96-07 was submitted to identify that on January 30, 1998, one additional containment protection overcurrent device for each unit was identified as not being tested per the Technical Specification requirements. This issue was recently discussed in Inspection Report 97-21 and Violation 50-311/97-21-05 was issued. Therefore, the cause of the condition and the corrective actions identified by the licensee in this LER will be reviewed as part of the licensee's response to the violation. This LER supplement is closed.

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 March 24, 1998. The licensee acknowledged the findings presented. The bases for the inspection conclusions did not involve proprietary information, nor was any such information included in this inspection report.

X2 Management Meeting Summary

On February 27, 1998, a meeting was held between the management of PSE&G and NRC Region I and the Office of Nuclear Reactor Regulation (NRR), at the Salem Units 1 & 2 Nuclear Generating Station. The purpose of the meeting was for the licensee to present an assessment of their readiness to restart Salem Unit 1, as required by Confirmatory Action Letter (CAL) 1-95-009. Overheads used in the licensee's presentation at this meeting were included as Attachment 1 to Readiness Assessment Team Inspection Report Nos. 50-272,311/98-81.

INSPECTION PROCEDURES USED

IP 37551:	Onsite Engineering
IP 40500:	Effectiveness of Licensee Controls in Identifying, Resolving, and Preventing Problems
IP 61726:	Surveillance Observations
IP 62707:	Maintenance Observations
IP 71707:	Plant Operations
IP 71750:	Plant Support Activities
IP 92901:	Plant Operations Followup
IP 92902:	Maintenance Followup
IP 92903:	Engineering Followup
IP 92904:	Plant Support Followup
IP 93702:	Event Followup
TI 2515/109	Inspection Requirement for Generic Letter 89-10, Safety-Related Motor-Operated Valve Testing and Surveillance

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

50-272/98-01-03	VIO	Wrong control switch installed on 12 DFOTP.
50-311/98-01-04	VIO	Failure to comply with procedures for control of EDGs.
50-272/98-01-06	IFI	GL 98-10, Safety-Related MOV Testing and Surveillance Program Closure.
50-272/98-01-07	IFI	Closeout review re MOV issues of PORV block valves, RHR/RCS isolation valves, and RCP thermal barrier cooling valves.
50-272/98-01-08	IFI	Closeout review re MOV issues of stem friction coefficient, load sensitive behavior, and stem lubrication degradation.
50-272/98-01-09	IFI	Closeout review re MOV issues of RCP bearing water cooling valves.
50-272&311/98-01-10	VIO	Failure to promptly identify and correct SW biofouling problems.

Opened/Closed

50-272/98-01-01	NCV	Failure to follow procedures for maintaining SG levels.
50-311/98-01-02	NCV	Failure to comply with TS Surveillance Requirement 4.1.3.1.1
50-272&311/98-01-05	NCV	Test control violations related to TSSIP.

Closed

50-272/96-11-01	VIO	Inadequate test control and application of MOV test data
50-272/96-11-02	IFI	Basis for load sensitive behavior margin used in thrust calculations
50-272/96-11-03	IFI	Basis for stem friction coefficient used in thrust calculations
50-272/96-11-04	IFI	Basis for valve degradation margin used in thrust calculations
50-272/96-11-05	VIO	Inadequate design control of switch settings for MOVs 2RH1 and 2
50-272/96-11-06	IFI	Improve thrust margin for 12CC16
50-272/96-11-07	IFI	Request to improve thrust margin for selected MOVs
50-272/96-11-08	IFI	Evaluate torque requirements for Pratt butterfly valves
50-272/96-11-09	IFI	PSE&G to evaluate and document response to MOV program assessment.
50-272/96-11-11	URI	Resolve question regarding Salem Unit 2 MOV program completion in the context of 10 CFR 50.9(b)
50-311/96-80-01	URI	Single failure licensing basis of fuel handling ventilation system.
50-311/96-07-02	LER	Missed surveillance of containment penetration overcurrent protection devices.
50-272/96-34	LER	Service Water strainer design deficiency potentially outside design basis.
50-311/98-04	LER	Failure to comply with TS surveillance requirement 4.1.3.1.1.
50-311/98-05	LER	TS required shutdown of Salem Unit 2 due to the failure of the 2A EDG turbocharger.

Discussed

50-311/97-21-05	VIO	Missed surveillance of containment penetration overcurrent protection devices.

LIST OF ACRONYMS USED

AR	Action Request
AFW	Auxiliary Feedwater
CAACS	Control Area Air Conditioning System
CAL	Confirmatory Action Letter
CAVS	Control Area Ventilation System
CREACS	Control Room Emergency Air Conditioning System
CRS	Control Room Supervisor
D/P	Differential Pressure
DBDP	Design Basis Differential Pressure
DFOTPs	Diesel Fuel Oil Transfer Pumps
EDG	Emergency Diesel Generator
EE	Engineering Evaluation
EPRI	Electric Power Research Institute
FFD	Fitness For Duty
GL	Generic Letter
HX	Heat Exchangers
IFI	Inspector Followup Item
IV'd	Independently Verified
MOV	Motor-Operated Valve
MTLO	Main Turbine Lube Oil
NCV	Non-cited Violation
NRC	Nuclear Regulatory Commission
NRR	Nuclear Reactor Regulation
OD	Operability Determination
OS	Operations Superintendent
PDR	Public Document Room
PMT	Post-Maintenance Test
PORV	Power Operated Relief Valve
PPM	Performance Prediction Methodology
PR	Primary Relief
PSE&G	Public Service Electric and Gas
RATI	Readiness Assessment Team Inspection
RCP	Reactor Coolant Pump
RCS	Reactor Coolant system
RG	Regulatory Guide
RHR	Residual Heat Removal
RO	Reactor Operator
RWST	Refueling Water Storage Tank
SAC	Station Air Compressor
SRO	Senior Reactor Operator
STs	Surveillance Tests
SW	Service Water
TAC	Turbine Auxiliaries Cooling
TS	Technical Specification

TSSIP	Technical Specification Surveillance Improvement Program
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
WO	Work Order