U. S. NUCLEAR REGULATORY COMMISSION

REGION I

Report Nos. 50-272/90-11
50-311/90-11
50-354/90-08

License Nos. DPR-70
DPR-75
NPF-57

Licensee: Public Service Electric and Gas Company
P. O. Box 236
Hancocks Bridge, New Jersey 08038

Facilities: Salem Nuclear Generating Station
Hope Creek Nuclear Generating Station

Dates: March 17, 1990 - April 30, 1990

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Inspection Summary:
Inspection 50-272/90-11; 50-311/90-11; 50-354/90-08 on March 17, 1990 - April 30, 1990

Areas Inspected: Resident safety inspection of the following areas: operations, radiological controls, maintenance & surveillance testing, emergency preparedness, security, engineering/technical support, safety assessment/quality verification, and licensee event report and open item followup.

Results: The inspectors identified one violation for the Salem station. There were two Hope Creek licensee identified, non-cited violations. An executive summary follows.

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EXECUTIVE SUMMARY

Salem Inspection Reports 50-272/90-11; 50-311/90-11

Hope Creek Inspection Report 50-354/90-08

March 17, 1990 - April 30, 1990

Operations (Modules 71707, 60710, 93702)

Salem: Numerous operational events occurred during the period. Apparent causes are listed in the following table:

Date(s)	Event	Cause(s)
March 27, 1990	Unit 1 shutdown - inoperable safeguards equipment cabinet	equipment failure
March 28, 1990	Unit 1 main steam line isolation	spike due to air in lines; poor procedure
April 3, 1990	Unit 1 reactor protection system actuation	operator error; poor oversight
April 6, 1990	Unit 1 feedwater isolations	erratic steam dump operation
April 9, 1990	Unit 1 reactor trip	steam generator feed pump trip due to poor maintenance
April 10-20, 1990	Containment radiation monitor spikes	poor procedure and method for setting background

Licensed operator response to these events was good and in accordance with procedures.

Unit 2 refueling and outage operations were adequately performed.

Hope Creek: A marsh fire resulted in a unit scram. Operator response was consistent with procedures. Reactor feed pump and reactor protection system motor generator set trips were adequately responded to by the operators.

Radiological Controls (Module 71707)

Salem: The licensee responded adequately to high radiation in the Unit 1 auxiliary building due to a reactor coolant system crud burst.

Hope Creek: The licensee identified two technical specification violations: (1) failure to adhere to locked high radiation area door requirements; and (2) failure to include an inoperable radwaste effluent monitor in the semiannual effluent report.

Maintenance/Surveillance (Modules 61726, 62703)

Salem: A surveillance test was performed on the wrong train. Poor maintenance on the steam generator feed pumps resulted in a Unit 1 trip.

Hope Creek: Maintenance and surveillance activities were effectively performed.

Emergency Preparedness (Module 71707)

Unusual events declared at Hope Creek and Salem were timely and consistent with emergency plan requirements.

Security (Module 71707, 92709)

Strike contingency plans for a possible labor action were adequate.

Engineering/Technical Support (Modules 71707, 90713, 37700)

Salem: The root cause for MSIV slow closure times remains unknown. The licensee made a 10 CFR Part 21 report regarding defective keys in Limitorque valve operators.

Hope Creek: Licensee response to and corrective actions for the electrical transient and scram were thorough and aggressive. Licensee actions were adequate with regard to an allegation regarding a breaker failure in 1985.

Safety Assessment/Assurance of Quality (Modules 71707, 40500, 30703)

Salem: Failure to perform 2 year procedure reviews and take adequate corrective action associated with these overdue reviews is a violation. Significant Event Response Team (SERT) reviews of the two reactor trips on Unit 1 were timely and thorough.

Hope Creek: Licensee has taken actions to reduce the backlog of overdue 2 year procedure reviews. SERT review of the Hope Creek scram was also timely and thorough.

Details

1. SUMMARY OF OPERATIONS

1.1 Salem Unit 1

Salem Unit 1 began the report period operating at 92%, limited by an inoperable heater drain pump (HDP). Operation continued at 92% except for minor load reductions (to 80%) due to solar magnetic disturbances (SMDs) on March 20 and 25, 1990. The No. 11 HDP was repaired and the unit achieved full power on March 26, 1990. On March 27, 1990, a unit shutdown to Mode 3 (Hot Standby) commenced due to an inoperable emergency diesel generator load sequencer. The unit was subsequently shutdown to Mode 5 (Cold Shutdown) on March 28, 1990 due to continuing sequencer problems. Repair activities were subsequently completed and a unit startup commenced on March 30, 1990. The unit entered Mode 3 on March 31, 1990. Due to reactor coolant system leakage into the No. 12 cold leg accumulator, the licensee entered Mode 4 (Hot Shutdown) to perform leak rate tests on several check valves. Following the valve tests and resolution of the leakage concerns, the unit entered Mode 3 on April 3, 1990. Later that day, an automatic reactor protection system actuation occurred due to operator error. The reactor was made critical on April 4, 1990 and main steam isolation valve testing commenced. The unit was brought on-line on April 7, 1990 and reactor power was increased to 90% (for steam flow transmitter calibration) on April 8, 1990. On April 9, 1990, the reactor automatically shutdown due to an equipment problem in the No. 12 steam generator feed pump governor. On April 11, 1990, while in Mode 3, the licensee identified that the calculated flow rate for one of the two intermediate head safety injection pumps for each unit was greater than the maximum design value of 650 gpm. The unit was then placed in Mode 5 on April 13, 1990 so that a full flow discharge and flow balance test could be performed. The intermediate head safety injection pumps were tested. However, further flow distribution and pump capacity discrepancies were identified when the high head charging pumps were tested, and the unit remained in Mode 5 until the end of the inspection period.

1.2 Salem Unit 2

Salem Unit 2 began the report period operating at full power, and continued with the exception of load reductions to 60% on March 20 and 25, 1990 due to SMDs. On March 31, 1990, the unit was shutdown and commenced its fifth refueling outage. The outage is scheduled for 55 days. Mode 5 was entered on April 1, 1990. Mode 6 (Refueling) was entered on April 16, 1990. The core offload was completed on April 24, 1990.

1.3 Hope Creek

The unit began the report period at 98% with power limited as a result of the "1C" and "2C" feedwater heaters being isolated due to a leak in the "2C" feedwater drain cooler. The Hope Creek unit experienced an eight day forced outage due to a scram caused by a fire in the surrounding marshes (see section 2.2). During the outage, the drain cooler was repaired, and the unit returned to 100% power. The unit remained operational throughout the remainder of the inspection period. Power reductions occurred to accommodate maintenance and testing, and also as a precaution for solar magnetic disturbances.

2. OPERATIONS (71707, 93702, 60710)

2.1 Inspection Activities

The inspectors verified that the facilities were operated safely and in conformance with regulatory requirements. Public Service Electric and Gas (PSE&G) Company management control was evaluated by direct observation of activities, tours of the facilities, interviews and discussions with personnel, independent verification of safety system status and Technical Specification Limiting Conditions for Operation, and review of facility records. These inspection activities were conducted in accordance with NRC inspection procedures 71707, 93702 and 60710. The inspectors performed normal and back shift inspection, including deep backshift inspection as follows:

Unit	Inspection Hours	Dates
Salem	10:00 p.m. - midnight	3/19/90
	3:00 p.m. - 8:25 p.m.	3/31/90
Hope Creek	10:00 p.m. - midnight	3/19/90
	9:30 a.m. - 8:15 p.m.	3/25/90

2.2 Inspection Findings and Significant Plant Events

2.2.1 Salem

A. Engineered Safety Features (ESF) Actuations Caused by Radiation Monitoring Systems (RMS)

Several ESF actuations occurred during this inspection period initiated by the Unit 1 and Unit 2 RMS. In each case, the licensee adequately responded to the event, acknowledged the isolations, repaired or restored the RMS instrument as appropriate, made an emergency notification system (ENS) call and promptly informed the resident inspector.

The first event occurred at Unit 2 on April 3, 1990 at 1:45 a.m., when a containment ventilation isolation (CVI) resulted after an auxiliary operator inadvertently bumped an electrical breaker that in turn, actuated the 2R41 radiation monitors. This was a personnel error and will be submitted to the NRC as a separate licensee event report.

The following tabulation summarizes primary containment particulate and noble gas ESF actuations:

Date	Time	Unit	Rad Monitor
4/10/90	9:38 a.m.	1	1R12A
4/15/90	3:00 a.m.	2	2R12A
4/15/90	10:59 p.m.	2	2R12A
4/16/90	10:59 p.m.	2	2R11A
4/17/90	5:15 a.m.	2	2R12A
4/19/90	8:10 p.m.	2	2R12A
4/20/90	12:50 p.m.	2	2R11A

The above ESF actuations for Unit 2 were related to resetting the trip setpoint to 2 times background as required by Technical Specifications Table 3.3-6. The licensee concluded that a random spike would periodically exceed the trip setpoint. A review of background level determinations was undertaken. The licensee redefined background countrate based on expected values and standard deviation. The instruments were recalibrated and retested satisfactorily. The inspector reviewed the licensee's process and had no further questions.

At 11:00 a.m. on April 30, 1990, a control room ventilation occurred when radiation monitor 1R1B spiked inadvertently.

B. Unit 1 Shutdown Required by Technical Specifications

On March 27, 1990, a Unit 1 shutdown was initiated as required by Technical Specifications (TSs) due to an inoperable 1A safeguards equipment control (SEC) cabinet subsystem. The SEC provides 4 kV vital bus 1A load shedding and sequencing functions during accident conditions.

At 9:30 a.m., following the completion of a surveillance test for the 1A SEC, Procedure No. M3B, "SEC System Sequencer Step Timing Test", an automatic actuation of the 1A SEC occurred for no apparent reason. The 1A SEC cabinet door had been closed and the test was completed 3-4 minutes prior to the spurious actuation. The technicians had left the work area. The SEC actuation caused the non-vital loads to be shed from the "A" vital bus and caused the actuation of safety equipment such as the "A" emergency diesel generator (started, but did not load), No. 11 residual heat removal pump and No. 11 safety injection pump. The reactor was operating at 100% power and there was no safety injection flow to the reactor coolant system as a result of the actuation. The equipment that actuated was subsequently restored to a normal standby condition by plant operators and the 1A SEC was declared inoperable as of 9:30 a.m. on March 27, 1990.

Technical Specification (TS) 3.3.2.1 requires that with one SEC inoperable, the unit must be placed in Mode 3 (Hot Standby) within 6 hours and in Mode 5 (Cold Shutdown) within the following 30 hours. The licensee initiated troubleshooting activities immediately. However, since a root cause was not immediately apparent and the SEC was to remain inoperable, a unit shutdown to Mode 3 was initiated at 10:40 a.m. The licensee notified the NRC via the ENS of the initiation of the unit shutdown required by TSs and of the Engineered Safety Features (ESF) actuations in accordance with 10CFR50.72 reporting requirements.

Maintenance personnel replaced the chassis for the 1A SEC with a spare chassis. While returning the SEC to service, a second SEC actuation occurred at 11:39 a.m. on March 27, 1990. Most of the same equipment was actuated as before except that certain equipment such as service water system valves did not actuate because maintenance technicians had immediately reset the SEC during the process of placing the SEC in service per procedure M3B requirements. The second actuation occurred while at 75% reactor power. This second ESF actuation was also reported to the NRC via ENS as required.

The inspector observed portions of the licensee's troubleshooting activities. A troubleshooting action plan was developed by the responsible system engineers. Activities included reinstalling the original chassis following a satisfactory bench test, replacing the 15 volt logic power supply, inspecting selected relays, checking/repairing various SEC connectors and connecting a chart recorder to various SEC components. A source of electrical noise was detected on the chart recorder. While investigating the source of this noise, the installed original chassis sustained a "hard failure" on March 28, 1990. That is, the local SEC auto test fault light illuminated. Since the appropriate ESF equipment and SEC output were tagged out of service for the troubleshooting, no additional ESF actuations resulted. The licensee did not know why the second ESF actuation occurred with the spare chassis installed. A third chassis was installed following satisfactory performance of surveillance procedure M3B in an energized bench test rack.

During the licensee's troubleshooting activities, a root cause to the event was not confirmed. On January 29, 1990 (NRC Inspection Report No. 50-272/90-04), a similar 1A SEC problem had occurred. However, there were no ESF actuations associated with that event.

Following maintenance activities on March 28, 1990, the chart recorder was connected to monitor the SEC to assist in identifying the root cause in the event an additional failure were to occur. The recorder installation was classified as a temporary modification, and was reviewed by the Station Operations Review Committee on March 29, 1990. The inspector attended the meeting and no deficiencies were noted. The inspector participated in a conference call with Region I on March 30, 1990. The licensee explained their actions and their determination of SEC operability.

The inspector concluded that the licensee took the appropriate actions to comply with the TS requirements. Although the licensee was not able to reproduce the event or positively identify the root cause, the potential suspect components were inspected, tested, or replaced. Additionally, a chart recorder was temporarily connected to assist in SEC monitoring. The inspector had no further questions at this time. Removed equipment from the SEC, including the spare chassis that was subsequently removed, has been sent to the manufacturer for testing and analysis. The licensee has indicated that the SECs for each unit will be upgraded during future scheduled refueling outage periods.

C. Unit 1 Main Steamline Isolations

On March 28, 1990, while in Mode 4 (Hot Shutdown), a partial main steam line isolation (SLI) occurred at Unit 1 during surveillance testing at 6:35 p.m. A second complete SLI occurred at 8:54 p.m., also during surveillance testing.

Instrument and Control (I&C) technicians were in the process of performing sensor calibrations to the steam generator (SG) flow transmitters. The No. 14 steam flow channel was out of service for calibration when the No. 12 steam flow channel momentarily spiked high. This action satisfied the two out of four logic which caused an SLI for all four steam lines. The main steam isolation valves (MSIVs) were previously closed, but the MSIV bypass valves were open. Only two bypass valves closed, those associated with loops 13 and 14, while the remaining bypass valves (11 and 12) remained open. This is not the expected performance for the bypass valves. The partial SLI did not result in a plant operational transient, however, the reason for the partial actuation was not known immediately by station personnel. The ESF actuation was reported the to NRC via ENS in accordance with 10CFR50.72 reporting requirements.

The unit continued its shutdown to Mode 5 (Cold Shutdown) due to a diesel generator sequencer problem (Section 2.2.1.A). The licensee elected to continue with steam flow transmitter calibrations. However, with the No. 11 steam flow channel out of service for its calibration, another channel spike occurred (No. 14) at 8:54 p.m. The second isolation resulted in the automatic closing of the remaining MSIV bypass valves (11 and 12).

On March 29, 1990, the licensee conducted troubleshooting activities, including the injection of input spikes at the point where steam flow for the No. 12 channel would normally be sensed. The input spikes varied from approximately 10 to 45 milliseconds (ms). The results indicated that the number of bypass MSIVs that closed changed as the spike duration increased. For example, an 8 ms spike resulted in two valves receiving a close signal, a 10 ms spike caused one, and a 44 ms spike resulted in all four valves receiving a close signal. The licensee therefore concluded that the partial SLI was due to a spike that had not sealed-in due to its extremely short duration.

Further troubleshooting activities indicated that in both SLI events, the channel that spiked had just been returned to service following its sensor calibration. The licensee concluded that the most probable cause of the spikes was due to air trapped in the sensing legs during calibration. The air bubbles rising in the legs would expand as the pressure head above them decreased, displacing larger amounts of water as the bubbles approached the condensate pots. The licensee postulated that if air was trapped in the low pressure leg, a momentary high differential pressure signal could result when the bubble reached the surface. The action of the bubble breaking when it reached the surface and the increased differential pressure due to level loss in the leg could cause the channel to momentarily spike into the alarm state.

The licensee typically performs the steam flow calibrations at either steady state full power operation or in Mode 5 (Cold Shutdown). The calibrations performed on March 28, 1990, were performed in Mode 4 while approaching Mode 5. The licensee stated that the transient condition of the plant may have contributed to the event.

The inspector monitored the licensee's actions associated with the event. No deficiencies were identified. The inspector participated in a conference call with Region I on March 30, 1990. During this call, the licensee discussed their actions taken and what assurance they had that the SLI logic was operable. The licensee reviewed the calibration procedures and determined that changes to ensure the instrument is backfilled are appropriate to prevent the accumulation of air in the sensing lines and thereby prevent recurring incidents. The inspector had no further questions at this time and concluded that the licensee's troubleshooting activities and proposed corrective actions were acceptable.

D. Unit 1 Reactor Coolant System Leakage During Plant Startup

On April 1, 1990, while in Mode 3 (Hot Standby) and preparing for startup from the March 27, 1990 shutdown, Unit 1 experienced reactor coolant system (RCS) leakage into the No. 12 cold leg accumulator. The leakage was estimated to be about 1 gpm and possibly through several check valves. The flow path for the leakage was not known. The accumulator isolation valve was closed in order to minimize accumulator in-leakage and borated water volume dilution, and the appropriate Technical Specification (TS) Limiting Condition for Operation was entered at 9:18 a.m. The licensee commenced a unit cooldown to Mode 4 (Hot Shutdown) to find the source of the leak rate by performing check valve integrity surveillance test SP(O)4.4.6.3, "Emergency Core Cooling System - ECCS Subsystems". Mode 4 was entered at 2:20 p.m. and the TS Action requirement was terminated. The licensee then performed leak rate tests for several check valves as directed by the surveillance procedure. None were identified as having leakage rates in excess of acceptance criteria, and the previously identified RCS leakage had abated. The licensee attributed this to possible seating of the affected check valves during the testing process.

The inspector observed portions of the licensee's troubleshooting and testing activities and no deficiencies were identified. The unit was returned to Mode 3 at 1:30 a.m. on April 3, 1990 to continue with startup preparations. No similar leakage problems were subsequently encountered.

E. Unit 1 Reactor Protection System Actuation

On April 3, 1990, a Unit 1 automatic reactor protection system (RPS) actuation occurred while in Mode 3 (Hot Standby) due to low-low steam generator (SG) water level. The reactor was subcritical with the shutdown bank control rods fully withdrawn. Plant operators were in the process of transferring steam control from the No. 11 to the No. 12 SG atmospheric relief valve. The transfer caused an increased steaming rate on No. 12 SG. However, the feedwater flow that was being supplied by the auxiliary feedwater (AFW) system, was not increased sufficiently by the reactor operator to prevent the water level in the No. 12 SG reaching its low-low reactor trip setpoint (16%). The licensee notified the NRC of this event via ENS in accordance with 10CFR50.72 reporting requirements.

The licensee initiated a Significant Event Review Team (SERT) to review the circumstances surrounding the RPS actuation. The SERT identified the root cause of the event to be poor judgement on the part of the licensed operator combined with weak command and control on the part of the licensed senior reactor operator (supervisor). The licensee stated that the reactor operator failed to establish favorable conditions on No. 12 SG before initiating the atmospheric dump valve transfer. Specifically, SG water level was at about 28% and had indicated a downward trend. Normal water level is 33% with a 5% operating band. The licensee also concluded that the senior reactor operator who was in the control room observing the activities, had failed to order a more appropriate operator response.

The AFW flow to the No. 12 SG was being manually controlled via a loop flow control valve. Console indicators available to the operators included AFW flow control valve demand and actual flow. Although zero flow indicated on the AFW flow indicator and SG level was decreasing, the operator maintained a relatively constant valve position, with only minor open valve demands. Both the licensed operator and supervisor recognized that, for unknown reasons, the loop 12 flow indicator did not indicate any flow until demand was near 20%. A work request was previously initiated on March 28, 1990 to address this same problem; that no AFW flow is indicated during low flow conditions. This was unique to loop 12 and the operators incorrectly believed that they were adequately providing sufficient AFW flow to the No. 12 SG.

The Station Operations Review Committee (SORC) performed a root cause determination for the event similar to that of the SERT. The inspector attended the SERT debriefing and SORC meeting on April 4, 1990. During a followup review of this event, the inspector concluded that the operation of the No. 12 AFW flow control system may have significantly impacted operator response to this event in an adverse manner.

The inspector reviewed the licensee's SERT report, and found that the abnormal response of the No. 12 AFW flow controller was considered to be a contributor to the level control problems. The licensee had initiated additional efforts to troubleshoot the control system, and had subsequently replaced a circuit card that corrected the problem. Previous troubleshooting activities had not identified any operational problems and did not result in timely resolution of the flow indication discrepancies.

This was the first unit startup since increasing the low-low SG reactor trip setpoint (on both units) from 8.5% to 16% to support a recently revised setpoint methodology. The operators on shift at the time of the event were aware of the increased setpoints. Licensee corrective actions for this event included briefing all oncoming crews of the event and the importance of establishing favorable plant conditions, and of the necessity to respond to operable control room indications. The licensee also directed that only experienced licensed operators, specifically trained at the simulator with the 16% trips, are to be at the feedwater system controls during plant startups.

The inspector concluded that the SERT completed a thorough and complete review of the event. Prior attempts by maintenance personnel to resolve problems with the AFW flow controller circuit were ineffective. Additional troubleshooting activities were conducted on the No. 12 AFW flow control circuit. A square root extractor was subsequently replaced which resolved the control room AFW flow indication problems on April 6, 1990. The inspector had no further questions at this time.

F. Unit 1 Feedwater Isolation During Plant Startup

On April 6, 1990, during a plant startup, a feedwater isolation (FWI) occurred at Unit 1 with the reactor operating at 7% power. While controlling steam pressure using the turbine steam dump system valve 12TB10 exhibited erratic behavior. The valve quickly opened and then reclosed, resulting in a severe water level transient in the No. 12 steam generator (SG). The level increased to the steam generator high-high setpoint of 67% (narrow range) and the FWI actuated. The FWI isolated feedwater flow to the SGs. This ESF actuation was reported to the NRC via ENS in accordance with 10CFR50.72 reporting requirements.

The programmed SG water level for the existing plant conditions was 33% narrow range. Operations personnel indicated that level was being maintained slightly higher than 33% just prior to the event, thereby decreasing the operating margin to the FWI. The licensee performed a packing adjustment on steam dump valve 12TB10 and lubricated the valve stem before resuming startup activities. The unit was subsequently placed on-line on April 7, 1990, and reached 90% power (for steam flow transmitter calibrations) the following morning.

The inspector reviewed the licensee activities associated with this event and no additional deficiencies were identified.

G. Unit 1 Reactor Trip on April 9, 1990

On April 9, 1990, a Unit 1 reactor trip occurred from about 90% reactor power due to low-low steam generator (SG) water level on the No. 12 SG. The No. 12 steam driven SG feedwater pump drove to idle speed due to separation of the turbine governor servo-motor linkage. The servo-motor amplifies the signal output from the governor linkage to the turbine's steam admission valve assembly. Operators responded to the transient by initiating a rapid load reduction and placing the rod control system in the automatic mode of operation. The low-low SG water level was reached on the No. 12 SG, resulting in the automatic reactor trip. The inspector responded to the control room following the trip. The licensee reported the event to the NRC via ENS in accordance with 10CFR50.72 reporting requirements.

The licensee assembled a Significant Event Response Team (SERT) to independently assess the trip. During licensee followup of the event, it was determined that there was an apparent abnormal rod control system (RCS) response when the operators placed the RCS in the automatic mode of operation. In that mode, a slower than normal insertion rate of the rods was suspected by the operators. The licensee performed extensive testing activities, including functionally testing the rod control system. No significant/relevant operational deficiencies were detected by the licensee. Since the unit was subsequently shutdown to Mode 5 the licensee continued with troubleshooting efforts. At the end of the inspection period, abnormalities related to the operator's observations of the rod control system were not identified.

During SG feedwater pump investigation and repair activities, the licensee identified that a pin bushing in the linkage assembly was missing. In addition, the lock nut that previously maintained the proper linkage connection was found to be incorrectly installed such that the locking side of the nut (flat side) was installed backwards. The last governor/linkage alignment was found to be conducted in 1986 as determined by a review of historical work order data. The licensee determined that four repairs had been accomplished to the governor in 1989, however, none of them should have directly affected the above linkage. NRC Inspection 50-272/90-200 provides further followup to these maintenance related issues.

The licensee conducted a Station Operations Review Committee (SORC) meeting on April 10, 1990. The inspector attended the meeting. The startup issues discussed were the repair of the No. 12 feedwater pump linkage, inspection of the No. 11 feedwater pump linkage, investigation of a potentially abnormal rod control system response, review of a post-event problem identified regarding erratic operation of an intermediate range neutron detector, and repair of an atmospheric dump valve controller that had experienced a minor automatic control problem about 10 minutes following the trip. All problems were repaired/resolved by the licensee.

The inspector reviewed the licensee's post-trip activities, including a review of SERT and SORC effectiveness. The inspector concluded that the root cause of the event can be attributed to the SG feedwater pump missing bushing and the incorrectly installed locking nut. The SERT determined that the root cause was unknown and the SORC identified the root cause of the trip to be SG feedwater pump linkage separation. Further review by the licensee determined the root cause to be poor maintenance due to inadequate corrective and preventive maintenance procedures. The proposed corrective actions were adequate, including inspecting similarly configured components. The inspector will continue to monitor the effectiveness of licensee event evaluations, with particular attention to root cause determination and documentation.

H. Salem Unit 2 Midloop Operation

On April 10, 1990, in order to perform maintenance on the steam generators, Salem Unit 2 entered midloop operations. In midloop operations, the reactor coolant level is lowered to the midpoint of the reactor vessel hot and cold leg nozzles. In this state of reduced inventory, additional instrumentation and monitoring of reactor water level is required to ensure proper core coverage and cooling. Licensee procedures require thermocouples to be used to monitor core exit temperatures and intermediate leg loop flow differential pressure cells be used to measure water level. Vessel water level is also measured visually by use of transparent tubing connected to an intermediate leg loop drain. Temperature and level alarm set points are adjusted to provide early indication of a loss of cooling or a decrease in coolant inventory. Additional monitoring and logging of these parameters is required as well.

Shortly after the reactor vessel water level had been established at the midloop point, the inspector toured the plant in order to review the licensee's controls. The inspector determined that the required instrumentation had been installed and all monitored parameters were indicating in the safe range. Through discussions with the control room operators, the inspector found the operators knowledgeable of present plant conditions, the indications available to them, and of the procedures to be followed if core cooling were to be lost. The inspector also reviewed the control room logs and found them to be complete and satisfactory. Based on his tour, the inspector concluded that midloop operations had been reached and was being maintained in a safe and proper manner.

I. Salem Unit 2 Defueling

The Salem Unit 2 reactor core was offloaded into the spent fuel pool beginning April 20 and defueling was completed on April 24, 1990. The inspector verified that reactor operators were knowledgeable of defueling activities. Contractor personnel in charge of core offload were also interviewed. The bundle pull sheets were checked and the core status board was verified to be accurate. Appropriate refueling procedures and technical specifications were also reviewed. No unacceptable conditions were noted.

J. Salem Licensed Operator Staffing

At 8:10 p.m., on March 17, 1990, due to a family emergency, an unexpected absence occurred for the Unit 2 reactor operator (RO). Unit 2 was operating at full power. The licensee responded by calling in a replacement RO who arrived at 9:45 p.m. The inspector verified that these actions were in accordance with Technical Specification Table 6.2-1.

During the inspection period, the licensee added 6 ROs to shift rotation who recently passed their licensee examination. These RO additions have added one operator for each of the 5 operating shifts. The licensee now has an extra RO for each shift.

2.2.2 Hope Creek

A. Reactor Scram on March 19, 1990

At 6:50 p.m., on March 19,1990, the Hope Creek unit experienced a low reactor vessel water level scram which was caused by the loss of all feedwater and condensate pumps in response to an electrical transient. Level decreased to less than -38 inches and the high pressure coolant injection and reactor core isolation cooling systems automatically started to recover level.

In accordance with station procedures, an Unusual Event was declared at Hope Creek from 7:00 p.m. to 7:25 p.m. due to the high pressure coolant injection initiation and injection. The electrical transient occurred when an offsite marsh fire produced a phase to phase short in the 500 KV Deans transmission line leaving the Salem switchyard. As a followup to the event, the licensee conducted a Significant Event Response Team (SERT) and had the Nuclear Department electrical engineering staff investigate various plant responses. A second Unusual Event was declared from 7:35 p.m. to 8:35 p.m. for the entire Artificial Island Complex due to a fire lasting more than 10 minutes which resulted in a mode change at Hope Creek. Salem Unit 1 was operating at 92% and Salem Unit 2 was operating at 100% prior to the incident. The event had no impact on power operation of either Salem unit. The marsh fire was fought by both the onsite and offsite local (Lower Alloways Creek) fire departments. The fire was extinguished by some counter burning and eventually by a rain storm which occurred about 10:30 p.m.

The licensee elected to keep Hope Creek shut down for approximately one week to repair the 1C feedwater heater.

On March 26, 1990, the engineering staff presented its conclusions to the Station Operations Review Committee (SORC) prior to the restart of the reactor. The team concluded that the plant responded as designed with the exception of an operator aid indication in the control room for feed pump status. The electrical transient caused a 50% voltage dip on the 500 KV line for approximately 4 cycles. A low voltage trip of the 7.2 KV and 4.16 KV busses did not occur due to the large induction loads on these busses which tended to maintain voltage during the momentary dip. The voltage drop was passed on to lower voltage 120 VAC control circuits. The degraded voltage condition on the 120 VAC busses produced false process control input signals for the condensate pumps. Specifically, the discharge valves of the primary condensate pumps indicated closed, and the secondary condensate pumps received a low lube oil pressure signal. These false signals tripped all condensate pumps which, in turn, tripped the feedwater pumps and produced the low reactor water level condition. The test results and conclusions of the engineering team were reviewed and concurred upon by both the licensee's SORC and SERT. Following SORC review of the root causes of the event, the plant restarted on March 26, 1990.

The inspectors responded to the station on March 19, 1990. Both Salem and Hope Creek control rooms were toured. The inspector verified that the Hope Creek unit was stabilized in the hot shutdown condition. The shift operators were interviewed, control room logs and chart recorders were reviewed, and sequence of events printouts were examined. The inspector concluded that immediate licensee actions were appropriate. The inspector also toured the fire area and interviewed security and fire fighting personnel.

Further followup included a review of GETARS printouts, the post trip review procedure, the LER, and incident reports. (Also see sections 7.2.A and 9.1).

The inspector observed the primary containment closeout of the drywell which appeared orderly and ready for reactor restart. The inspectors observed portions of the reactor startup including:

-- OP-GP.ZZ-002 Primary Containment Closeout

-- OP-IO.ZZ-0003 Startup From Cold Shutdown to Rated Power

-- OP-SO.AE-0001 Feedwater System Operation

Criticality was achieved at 4:14 a.m. on March 27,1990, and the plant returned to 100% power operation on March 28, 1990.

B. Reactor Feed Pump Trip

On April 3, 1990, the "B" reactor feed pump turbine tripped. Consequently, reactor water level dropped to the 31 inch level before the "A" and "C" pumps increased speed to account for the loss of "B" pump. Reactor water level was restored and, in fact, reached a maximum at a level of 39 inches before it stabilized at the normal level of 35 inches.

Upon investigation, the senior nuclear shift supervisor determined that, at the time of the feed pump trip, an instrumentation and control technician was performing the channel "C" reactor pressure vessel narrow range level 8 trip surveillance. The licensee organized a fact-finding team to determine a root cause for the event. The team concluded the most likely cause of the event was a spurious trip of an additional "B" feed pump trip relay while the technician was conducting the surveillance on the "B" feed pump trip relay associated with the "C" level 8 trip channel. If two relays had been in the tripped condition, the necessary logic coincidence would have been satisfied, and the "B" feed pump turbine would have been tripped. As a conservative measure, the licensee replaced both "B" feed pump trip relay units involved in the event and, as a precautionary step, initiated a design change to extend the test jacks used in the logic cabinet in order to preclude the possibility of any future personnel error.

The inspector reviewed the associated incident report and discussed the event with the Hope Creek maintenance manager, a member of the fact-finding team. The inspector concluded that the licensee had responded in a conservative manner and that no unresolved safety issues remain.

C. Containment Isolation Valve Inadvertent Closure

During the morning of April 9, 1990, a control room operator noted that valve BB-SV-4311 had inadvertently closed. The alarm chronolog showed that the valve (reactor recirculation sample outboard containment isolation valve) had been shut for approximately 15 minutes. The operator attempted to reopen the valve from the control room with no success. The instrumentation and control, and electrical maintenance department was notified in order to repair the problem. Upon investigation, the licensee determined that the control power for the valve had been de-energized during maintenance on valve BC-SV-F079A, the residual heat removal loop "A" sample valve. The control power fuse for the 4311 valve had been incorrectly wired at the terminal board common to the control power for the two valves. The hot side of the control power circuit for the 4311 had been wired in a series circuit with the fuse for F079A. When the F079A fuse was pulled, 4311 was de-energized and subsequently closed.

Maintenance department inspection determined that the wiring problem at the terminal board had existed since the terminal board was originally wired. The fuse for F079A was pulled in conjunction with a 5-year environmental qualification (EQ) rebuild of the same valve. This was the first time such work was done in association with the faulty terminal board. There were no precursors to this event. The licensee inspected selected similar circuits and no deficiencies were found.

The inspector reviewed the applicable electrical drawings and determined that they were correct. The terminal board has since been rewired correctly, and after discussing the event with the senior electrical maintenance supervisor, the inspector concluded that the licensee's response and corrective actions were appropriate and sufficient. The inspector had no further questions.

D. Reactor Protection System (RPS) Motor Generator Set Trip

At 7:40 a.m. on April 18, 1990 while at 100% reactor power, Hope Creek had an engineered safety feature (ESF) actuation due to the loss of power to the B RPS Motor Generator (MG) Set. This resulted in the subsequent loss of power to RPS channels B and D, and a half scram condition. Additionally, the Nuclear Steam Supply Shutoff System (NSSSS) isolated the reactor water cleanup system (RWCU), the reactor recirculation sampling system and the main steam supply drain valves.

The cause of the loss of power to the RPS MG set was a ground fault on Motor Control Center (MCC) 00B-582. This non-safety related MCC feeds the RPS motor generator, as well as other smaller loads including: radwaste pumps, two welding receptacles, and hydraulic pumps associated with the cooling system isolation valves. The MCC was entirely lost as well as all of the above mentioned loads.

Power was immediately restored to B RPS by placing the selector switch to the alternate power supply. The RPS logic was reset and systems associated with the NSSSS were unisolated within two minutes of the event. The licensee made an ENS call.

Ground isolation procedures were commenced. All MCC 00B-582 loads were meggered with no discrepancies identified. No welding receptacles associated with this MCC were being utilized at the time of the event.

The breaker in the MCC was replaced, and the power supply to the B RPS bus was shifted back to the MG set without incident. Inspection and testing of the breaker that had tripped on the ground fault was conducted by the Hope Creek electrical maintenance and electrical engineering staff. No problems were identified. The licensee concluded that the cause of the event was a spurious trip of the solid state trip device (SST) in the breaker. In discussing the matter with an electrical maintenance supervisor and a senior staff engineer, the inspector learned a similar SST had experienced the same type of trip approximately a year ago. That SST was returned to the vendor, General Electric, for further testing and evaluation, and Hope Creek Engineering is still awaiting the results. The licensee has deferred further testing of the second SST and breaker pending the arrival of additional information from General Electric. The inspector concluded that the licensee acted prudently in replacing the MCC breaker and its SST following the spurious trip and, now that a second similar trip has occurred, believes that a resolution of spurious SST trips is being more aggressively pursued by the Engineering Department. The inspector will follow up on this event when additional information is available.

3. RADIOLOGICAL CONTROLS (71707, 93702)

3.1 Inspection Activities

PSE&G's conformance with the radiological protection program was verified on a periodic basis. These inspection activities were conducted in accordance with NRC inspection procedure 71707.

3.2 Inspection Findings and Review of Events

3.2.1 Salem

A. High Radiation Area in Unit 1 Auxiliary Building

During the morning meeting on April 16, 1990, the inspector learned that radioactive crud (Cobalt-58) was deposited in the safety injection (SI) system piping in Unit 1 auxiliary building on April 14-15, 1990 during SI pump testing. The inspector verified that the licensee controlled the affected areas as high radiation areas. Tours of the areas were conducted on April 16 and 17, 1990. The inspector reviewed survey data, the specific radiation work permit, and interviewed radiation protection and chemistry personnel.

The licensee initiated actions to flush the piping. These actions were successful to reduce the radiation levels. The inspector concluded that licensee actions were appropriate in response to this event.

3.2.2 Hope Creek

A. High Radiation Area Doors

Radiation protection technicians at Hope Creek check all locked high radiation area doors once per shift to ensure that the doors are indeed locked. On the morning of March 15, 1990, the radiation protection technician performing this check found the door to the 6C feedwater heater room unlocked. The door was closed, but because the radiation level in the room is greater than 1 Rem/hour when the plant is at power the door is required by Technical Specification 6.12.2 to be kept locked. The radiation protection technician immediately locked the door from the outside using his master key.

Upon investigation, the licensee determined that the turbine building 137' elevation master key had been checked out and returned by an equipment operator earlier the same morning. The radiation protection supervisor on shift notified the resident inspector and began an investigation into the cause of the event. When questioned, the equipment operator stated that as he exited the room the latch on the door stuck, but when he turned the inner knob the latch unstuck and he was able to shut and lock the door. In order to determine the cause of the latch sticking, the licensee replaced the latch on the door and had the original latch dismantled. Inspection of the door latch internals revealed a small burr that might have caused the latch to jam, giving the impression that the door was indeed locked, but the licensee concluded that it was most probable that the method the equipment operator used to check the door was not sufficient to reveal the door was not properly locked. As part of the investigation of the event, the Radiation Protection Department reviewed all exposure records for the morning of the event to ensure that no one had made an inadvertent entry into the room. The review showed no abnormal exposures and it was determined that the high radiation area had not been entered while the door was unlocked.

As a result of this event the licensee initiated the following corrective actions:

-- The equipment operator's self monitor radiation protection qualification was suspended pending requalification and an interview with the radiation protection engineer and the radiation protection supervisor.

-- Each time a locked high radiation area door key is checked out and returned, an independent verification of the door being locked is required to be performed by a second operator.

-- The locked high radiation area log has been changed to require an initial by the radiation protection technician who checked the doors locked during the normal shift rounds.

The inspector tracked the progress of the investigation of the event and reviewed the findings as they developed. The licensee's response to the event was aggressive, and the conclusions reached were accurate. The inspector concluded that the corrective actions taken were sufficient to prevent a recurrence of the event. This is a licensee identified violation of Technical Specification 6.12.2 (50-354/90-08-01).

B. Containment Tour

The Hope Creek drywell was inspected on March 26, 1990. No unacceptable conditions were noted.

C. Radwaste Effluent Monitor

The licensee reported that the radwaste effluent radiation monitor was out of service for more than 30 days. The monitor was operable but its isolation functions were bypassed. This was not reported in the plant's semi-annual radioactive effluent release report as required by Technical Specification (TS) 3.3.7.10. Apparently personnel making up the report looked at the component as being in operation but they did not look to see if it was fully functional. The reportability of this event was discussed with the NRC on April 24, 1990, and the licensee concluded that this event was reportable in accordance with 10 CFR 50.72 requirements at 2:00 p.m. on April 25, 1990. Liquid releases were made to the radwaste system when the radiation monitor was not fully operable. In these instances, two independent samples were analyzed of the releases made to the radwaste system and two independent people verified the release rates of each discharge to the radwaste system which is in accordance with TS 3.3.7.10.

The inspector reviewed the event and concluded this was a licensee identified violation of TS 3.3.7.10 (50-354/90-08-02).

4. MAINTENANCE/SURVEILLANCE TESTING (62703, 61726)

4.1 Maintenance Inspection Activity

The inspectors observed selected maintenance activities on safety-related equipment to ascertain that these activities were conducted in accordance with approved procedures, Technical Specifications, and appropriate industrial codes and standards. These inspections were conducted in accordance with NRC inspection procedure 62703.

Portions of the following activities were observed by the inspector:

Unit	Work Request/Order (WR/WO) or Procedure	Description
Salem	WO 900327193	Replace 1A SEC chassis with spare
	SC.IC-GP.ZZ-006(Q)	Troubleshoot 1A SEC
	WR 0088183	Investigate reason for partial steamline isolation
	WO 900106105	Installation of sequence of events recorder per DCP 2EC-2272
	M6G/WO 900413098	No. 12 charging pump repair electrical systems troubleshooting
Hope Creek	WO 900423104	Scram solenoid pilot valve replacement
	WO 900424168	"B" main steam line radiation monitor power supply replacement
	WO 900315108	"C" circulating water pump replacement

With the exception of poor maintenance on No. 12 steam generator feed pump (see section 2.2.1.G and NRC Inspection 50-272/90-200), the maintenance activities inspected were effective with respect to meeting the safety objectives of the maintenance program.

4.2 Surveillance Testing Inspection Activity

The inspectors performed detailed technical procedure reviews, witnessed in-progress surveillance testing, and reviewed completed surveillance packages. The inspectors verified that the surveillance tests were performed in accordance with Technical Specifications, approved procedures, and NRC regulations. These inspection activities were conducted in accordance with NRC inspection procedure 61726.

The following surveillance tests were reviewed, with portions witnessed by the inspector:

Unit	Procedure No.	Test
Salem 1	OP-TEMP-9013-1	Main Steam Isolation Valves - Fast Closure Test
Salem 1	SP(O)4.7.1.5	Main Steam Isolation Valves - Emergency Close Time Response
Salem 1	SP(O)4.4.6.3	Emergency Core Cooling System Subsystems
Salem 1	1IC-18.1.010	Solid State Protection System Train A, Reactor Trip Breaker Undervoltage Coil and Automatic Shunt Trip Test
Salem 2	OP-ST.SJ-0013(Q)	Emergency Core Cooling System Flow Verification Test
Hope Creek	OT-ST.AC-002	Turbine Control Valve and Stop Valve Test
Hope Creek	1C-TR.SM-010	Time response testing of reactor vessel level Rosemount transmitter
Hope Creek	OP-ST.AC-002	Turbine stop valve testing
Hope Creek	RE-ST.BF-001	Control rod drive scram time determination
Hope Creek	OP-ST.BJ-001	Monthly high pressure coolant injection system flowpath verification

With the exception stated below (4.3.1.A), the surveillance testing activities inspected were effective with respect to meeting the safety objectives of the surveillance testing program.

4.3 Inspection Findings

4.3.1 Salem

A. Surveillance Test Performed on Wrong Train

On March 31, 1990, an Instrument and Control (I&C) technician performing a Unit 1 operability surveillance test of the "A" reactor trip breaker (RTB) undervoltage coil and automatic shunt trips inadvertently performed a portion of the test on the "B" RTB Solid State Protection System (SSPS) cabinet. The unit was in Mode 3 (Hot Standby) at the time. In accordance with the surveillance procedure, No. 1IC-18.1.010, "SSPS Train A, RTB Undervoltage Coil and Automatic Shunt Trip Test", the technician entered the Train "B" cabinet to place the multiplexer test switch to normal, however, when proceeding with the test, the technician reentered Train "B" instead of Train "A". Operators subsequently closed the "A" RTB per the procedure instructions. Several steps later, when the technician released the Block Shunt Trip pushbutton (associated with the "B" RTB), the operators and technician noted that the "A" RTB did not open. It was then identified that the I&C technician had performed that portion of the test in the opposite train. Both Trains "A" and "B" were immediately returned to normal and the test was terminated. Emergency safeguards were not disabled at any time during the test.

The inspector reviewed this event and identified several concerns. The surveillance procedure is provided with a specific precaution, which states that it is extremely important that the doors to only one train at a time are open, to preclude the introduction of test conditions into both trains. That precaution was not followed by the technician, thereby contributing to him entering the wrong train. Also, this test requires that Quality Control (QC) shall be present for the performance of the procedure. The licensee used an experienced Hope Creek inspector (due to increased resource demand for the Unit 2 refueling outage), however, he had spent very little time at Salem and was unfamiliar with the system and the procedure. Although there was not a specific hold point for that evolution, the QC inspector failed to identify that the wrong train was entered or that both doors had remained open. The third concern identified by the inspector was that the recently instituted peer review was not implemented by the licensee. In September 1989, the licensee instituted the peer review of critical steps for testing of sensitive safety related systems in an effort to preclude reactor trips and ESF actuations. The licensee informed the inspector that they had intended the peer review to occur primarily at power operations, but committed to further review their practice for non-power operations.

Following the event, I&C personnel implemented a procedure change which provided a caution statement to ensure that the steps are performed on the appropriate train. Similar procedures were also reviewed and changed as necessary. The inspector concluded that this event occurred as a result of technician and QC inspector inattention to detail. Increased supervisory oversight may be appropriate in preventing recurring events.

4.3.2 Hope Creek

No noteworthy findings were identified.

5. EMERGENCY PREPAREDNESS (71707, 93702)

5.1 Inspection Activity

The inspector reviewed PSE&G's conformance with 10CFR50.47 regarding implementation of the emergency plan and procedures. In addition, licensee event notifications and reporting requirements per 10CFR50.72 and 73 were reviewed.

5.2 Inspection Findings

A. Unusual Events

Unusual Events declared at Hope Creek and Salem due to a marsh fire and Hope Creek scram were consistent with emergency plan requirements (see section 2.2.2.A).

B. Hope Creek Emergency Preparedness Drill

On April 26, 1990, the PSE&G Emergency Preparedness Department conducted a training drill for the Hope Creek station. The drill was not pre-staged and included activation of the Emergency Operations Facility and Emergency News Center offsite and the Technical Support Center (TSC), Operations Support Center (OSC) and Control Point (CP) onsite. The Hope Creek simulator in the offsite training center was utilized in place of the Hope Creek control room. The inspector observed portions of the drill conducted at the onsite locations and, at the conclusion of the drill, discussed the results with both drill participants and referees. The inspector noted that the drill was well controlled and that good communications existed between the various drill locations. Based on the responses received from the participant and referee interviews, the inspector concluded that the drill had been a worthwhile training exercise for those involved.

6. SECURITY (71707, 92709)

6.1 Inspection Activity

PSE&G's conformance with the security program was verified on a periodic basis, including the adequacy of staffing, entry control, alarm stations, and physical boundaries. These inspection activities were conducted in accordance with NRC inspection procedures 71707, 92709.

6.2 Inspection Findings

A. Strike Contingency Plans

The licensee was notified of possible labor actions by site contractors. The licensee initiated strike contingency plans including the activation of an alternate security gate. Other plans were adopted by the licensee and reviewed by the inspector. Both Salem and Hope Creek operations planned for control room coverage if the labor actions were to occur. The inspector reviewed the auxiliary security guard house operation during the period and no unacceptable conditions were noted. No strike or work interruption actually occurred.

7. ENGINEERING/TECHNICAL SUPPORT (37700)

7.1 Salem

A. Safety Injection Pump Flow In Excess of Design Requirements

On April 11, 1990, with Unit 1 in Mode 3 (Hot Standby) and Unit 2 in Mode 5 (Cold Shutdown), the licensee identified that the calculated flow rate for one of the two intermediate head safety injection pumps for each unit was greater than the 650 gpm maximum specified in Technical Specifications. A shutdown was initiated on Unit 1 and Mode 5 was reached on April 13, 1990. Both units plan to correct the condition by performing a full flow discharge and flow balance test while in Mode 5 prior to startup. This event is discussed in detail in NRC Special Inspection Report No. 50-272/90-12 and 50-311/90-12.

B. Main Steam Isolation Valve (MSIV) Closure Times

Technical Specifications (TSs) require that the MSIVs be demonstrated operable by verifying full closure within five seconds every 92 days unless the unit is on line. If an MSIV is slow it remains closed until the cause has been corrected. The licensee routinely tests the MSIVs during plant startup. On October 14, 1989, during a Unit 2 controlled shutdown, the licensee elected to perform the test to preclude subsequent startup delays. However, 3 of 4 MSIVs failed to meet the 5-second stroke closure time criteria. (See NRC Inspection 50-311/89-19).

Salem Units 1 and 2 utilize main steam isolation valves (MSIVs) manufactured by Hopkinsons (distributed in the U.S. by Atwood & Morrill). The valves are reverse acting double disk gate valves, with two integral operating pistons and cylinders. Emergency fast-closure of the valves is accomplished by using the force of steam pressure acting on a lower steam cylinder, while the upper electrohydraulic cylinder acts as a snubber. During normal operation, the lower steam cylinder, which is divided into two chambers, has equal steam pressure in each of the two chambers because of an equalizing orifice. A drain tube is also provided in each dividing plate for drainage of condensation from the upper to lower steam chamber. Each MSIV has two air operated dump valves connected to the upper chamber of the steam cylinder. Dump valve position is controlled by a solenoid valve, located in the air supply line to each valve. The solenoid valves allow air pressure to hold the dump valve in the closed position unless an MSIV emergency fast closure signal is received. Upon receipt of an MSIV fast closure signal, steam evacuates from the upper chamber through the two dump valves. Since the high pressure steam cannot make up to the upper chamber through the small equalizing orifice as fast as it is exhausted, the resulting differential pressure closes the MSIV.

The licensee believes the slow closure problem to be attributable to condensation buildup in the upper steam chamber thereby creating a hydraulic lock when the condensation is discharged through the dump valves. Only one other U.S. plant (D.C. Cook) and several French plants use the same type valve and they have experienced similar problems. It was suspected that the condensation was allowed to buildup and not drain from the upper chamber during sustained operating periods. When the surveillance test is normally run during unit startup, closure times are typically less than 5 seconds. The licensee believes this is primarily due to draining of the condensation while in outage conditions.

An NRC Region I Waiver of Compliance was granted for Unit 2 on March 30, 1990, to allow one additional MSIV closure for each valve if the first closure time was between 5 to 8 seconds for the testing scheduled for March 31, 1990.

On March 31, 1990, during a Unit 2 shutdown for its fifth refueling outage, a similar fast closure test was performed to obtain data relative to the slow closure times. One MSIV was initially closed in less than 5 seconds, while the remaining three were between 5 to 8 seconds. Subsequent fast closure times for these 3 MSIVs were less than 5 seconds.

Unit 1 was shutdown to Mode 5 due to equipment problems on March 27, 1990 (see section 2.2.1.B). An NRC Headquarters Temporary Waiver of Compliance and Emergency Technical Specification Amendment request was submitted by the licensee to allow similar Unit 1 MSIV testing. The licensee expected to perform the initial startup surveillance test, then allow a 14 hour soak time while in Mode 2 and perform testing to confirm whether the slow closure phenomenon recurred. However, on April 5, 1990, during the first Unit 1 MSIV test, the closure time was 7.32 seconds. The test was immediately terminated. The licensee remained in Mode 2 pending resolution of the related technical concerns and issuance of a TS Temporary Waiver of Compliance by the NRC. The waiver was issued on April 15, 1990 allowing MSIV closures time up to 8 seconds for the current operating cycle. Subsequent testing was performed, and each Unit 1 MSIV closure time was greater than 5 seconds but less than 8 seconds. On retesting, each MSIV closed in less than 5 seconds. The resolution of this slow MSIV closure issue, including root cause, remains open pending NRC licensing actions.

C. Service Water System Motor-Operated Valve (MOV) Shaft-To-Pinion Key Failure

While investigating a failure of a Limitorque operator at Unit 1 and 2, the licensee determined that shaft keys between the motors and the pinion gears in six service water (SW) MOVs were damaged (one) or had sheared (five). These SW valves (Nos. 11, 12 , 21, 22SW20; and 1, 2SW26) were unique in that they are quick shutting MOVs with high torque in conjunction with a high gear ratio operator in order to close within 10 seconds.

PSE&G found that vendor-supplied Woodruff ASTM-1018 keys installed in the six SW MOVs (three per unit) were sheared and wedged between the motor shafts and the pinion gears at the key-slots. The keys apparently failed due to impact loading and possibly too soft a key material. The wedging allows valve operation under limited conditions while disguising possible unreliable operation under high-torque conditions. The valve units involved use high-speed (3600 rpm) SMB-0 Limitorque operators with 25 foot-pounds of torque operating 30-inch Jamesbury butterfly valves through a converter head. The licensee had replaced the original 60-second shutting valves with the subject 10-second shutting valves during a recent upgrade program. This type of valve is only used for high-speed isolation of non-safety SW cooling following an accident.

A four hour ENS call was made on April 19, 1990. A 10CFR part 21 notification was made on April 27, 1990. Licensee corrective actions include an intention to replace the key material, cycle the MOV and check for wear, coordinate efforts with the vendor and periodically inspect each key during refueling outage periods. The inspector participated in discussions with the licensee and vendors and notified NRC headquarters of the potential generic implication.

D. Charging Pump Casing Cracking

During rotor replacement for Unit 1 No. 12 CCP, the licensee identified cracks/indications in the pump casing. The CCPs at Salem are Pacific pumps supplied by Dresser, model 2-1/2" RL Type IJ eleven stage centrifugal. Since 1980, the licensee has been performing inspections of the pump casing stainless steel clad material based on vendor and Westinghouse information. Recent inspections on No. 12 CCP have found numerous cracks and indications, some of which are through the clad material and into the carbon steel casing. The licensee believes the cause of cracking to be as follows: corrosion caused by boric acid attack on the carbon steel casing after the stainless steel cladding was cracked due to fatigue caused by differential expansion of the dissimilar metals. The licensee attempted repairing the cracks in the No. 12 CCP. However, non-destructive examination determined the cracks to be less than minimum wall thickness and current plans are to changeout the pump casing. The remaining Unit 1 and Unit 2 pumps are being reviewed by the licensee. Final disposition will be reviewed in subsequent inspections.

7.2 Hope Creek

A. Evaluation of the Electrical Transient

The Hope Creek unit scrammed on March 19, 1990 due to an electrical transient offsite. (See section 2.2.2.A) The following discusses an evaluation of that transient and the on-site effects.

Three independent offsite power sources supply the Hope Creek unit. One source is the Salem-Hope Creek 500kV tie line. The other two sources are from the Kenney Switching Station and the New Freedom Switching Station. The 500kV system supplies the preferred power for the plant via the 13.8kV switchyard ring bus.

This supplies both class IE and non-class IE loads during plant startup, normal operations, shutdown and post-shutdown. Even though Salem and Hope Creek have separate 500kV switch yards, they are electrically interconnected through the 500kV grid. Any heavy fault in the 500kV system would be felt in the nearby distribution system. The 500kV grid stability and analysis of critical faults are discussed in the Hope Creek Final Safety Analysis Report.

The 500kV "Deans" line leaving the Salem Generating Station experienced a phase B to phase C short which was seen and was properly cleared in approximately 4 cycles by the carrier protection relaying. The magnitude of the voltage transient at the 500kV level was recorded in the plant oscillograph, and verified by the hand calculation to be 0.512 per unit, on the affected phases to neutral. This transient was felt throughout the medium and low voltage distribution system at both Salem units and the Hope Creek unit. The 4.16kV and 7.2kV buses did not see the entire transient since large induction motor loads were contributing voltages to the system. The lack of undervoltage targets and alarms, and the oscillograph readings on these buses indicated that the voltage was approximately 80% of the normal voltage. The voltage did not dip below the under voltage trip set point of 70% of bus nominal voltage. However, the 120V AC systems experienced the full voltage drop caused by this transient. This fact was verified by the undervoltage relay alarms at both stations.

During this event, none of the electrical buses lost its power. However, several non-safety loads were tripped as a result of the transient. The only safety related load affected by this transient was the control room area chiller. These loads are discussed in the following paragraphs. The licensee's engineering staff reviewed this event and concluded that the root cause of the plant trip was due to the loss of the condensate/feedwater system resulting from the undervoltage condition in the 120V AC interruptible power system caused by the 500kV transient.

The inspector reviewed the licensee's engineering evaluation of the event, Significant Event Response Team's (SERT) evaluations, the chronology of the event, various electrical loop drawings and logic diagrams, oscillograph readings, hand calculations and computer chronolog showing plant parameters and sequence of events. The purpose of the evaluation was to assure that the electrical equipment performed as designed and to assure that the design was adequate. Based on the review, the inspector noted that licensee's analyses of the 480 volt and high voltage motor trips were reasonable and they were substantiated through bench tests. The tripping of the 480 volt motors was due to the seal-in dropouts and contactor coil dropouts.

Cutler-Hammer (CH) 42 Contactor Coils are provided by the motor control manufacturer within each breaker cubicle. These loads are manually operated and are maintained in the required condition by means of a circuit sealing arrangement, i.e., relay contact in parallel with momentary initiating contact. Although the relay which provides the seal-in feature is not an undervoltage relay, it is affected by momentary undervoltages and deenergizes under degraded conditions. The voltage level at which the relay deenergizes is unpredictable. It is controlled by the manufacturer's tolerance. A bench testing of these relays showed that the relay dropout time and dropout voltage were consistently within the range specified by the manufacturer. A full dropout occurred between 50 and 60 VAC in 30 milliseconds. Cutler-Hammer type D26M pilot relays are also used in the starting circuit of some of the loads as interposing relays, to assist in picking up the CH 42 contactor coils. Bench testing of this relay showed a full dropout between 30 and 45 VAC in 30 milliseconds. Therefore, the voltage reduction in the 120 VAC control circuit caused the seal-in circuit to open and tripped various motor loads. The undervoltage was also experienced in the Salem units, but none of the motors were tripped due to the absence of seal-in (maintained contact) circuit design.

The failure of the 4.16kV and 7.2kV primary condensate pumps (A/B/CP102) and secondary condensate pumps (A/B/CP137) was due to the temporary degradation in 120 VAC interruptible power to the discharge valve limit switches and low lube oil pressure trip signals in the motor trip logic cabinets. These circuits are normally energized and the loss or interruption of the interrogation power to this signal immediately causes the logic to change state resulting in a pump trip. The cause of the reactor feed pump trips was due to the loss of the condensate pumps. The only unexplainable event that was not fully analyzed by the licensee was the failure of the condensate pump indication to flash in the control room showing a non-commanded trip condition. The licensee's preliminary study indicated that a possible ground loop existed during the transient. Further analysis is planned for the next refueling outage. The inspector determined that the lack of flashing of the indication lights is not a concern since the trip condition of the pumps was indicated as a solid light. The root cause of the pump trips was thoroughly analyzed by the licensee and concluded to be the 120 VAC interruptible power voltage drop. This was further clarified by the field tests.

The inspector noted that the feedwater/condensate system worked as designed. However, the inspector emphasized the need for a complete review of the feedwater/condensate control system to avoid any further pump trips due to a similar electrical transient.

The control room area chiller (1AK400) was the only safety related load that was affected by this transient. The normally energized seal-in control circuit was dropped out in approximately 2 cycles during this voltage dip. This load is supposed to be shed during a loss of offsite power scenario, and then sequence back onto the vital bus fed from the diesel. Therefore, the interruption of this load is not a safety concern.

Several other loads were tripped as a result of the normal plant response to the process signals and in some cases, due to deenergization of the process control relays. These events are normal and no abnormal conditions were noted. However, unrelated malfunctions of some instruments were noted. They were analyzed and corrected by the licensee. The licensee's Tower group inspected the affected transmission lines and confirmed that no damages resulted from the fault.

During the review, the inspector observed that the voltage information from the oscillograph was very hard to interpret accurately. The licensee stated that they are planning to install a computerized analysis system to study the electrical transients. The inspector had no further questions at this time.

In conclusion, the licensee responded promptly and effectively in dealing with the transient. The root cause of the event was properly identified. Analyses were descriptive and thorough. The undervoltage condition existing during the transient was not outside the design basis. The loss of feedwater and loss of offsite power scenarios were analyzed in the accident analysis. The control room operators responded appropriately and the plant engineering staff and the SERT team responded effectively to identify and to assure that no adverse conditions existed before returning the plant to operation.

B. <u>Motor Control Center Breaker Failure (Allegation RI-A-90-0026)</u>

The NRC received an allegation concerning an electrical circuit breaker failure at Hope Creek during construction on January 12, 1985. The alleger stated that the breaker failed during testing due to an apparent defect resulting in injury to a worker and damage to the breaker and associated motor control center (MCC).

The breaker (10-B-232-023) was for main steam stop valve 1AB-HV-3631A. The alleger also stated concerns regarding breaker coordination issues and inadequacies associated with the licensee's corrective actions.

The inspector confirmed that such an event did occur. The inspector reviewed the event by discussions with the licensee and by reviewing the following documents: electrical schematics, piping drawing, component data forms, non-conformance significant deficiency report (SDR) No. AB-0024, equipment troubleshooting form number GWP-MD.ZZ-001, and work order number 85-1-14-31.

The licensee concluded that the cause of the breaker failure was a ground fault on the line side of one phase (A). In addition, the licensee identified that undersized breaker thermal overloads were used in the breaker. The most probable scenario was that the breaker overloads overheated and exploded, resulting in grounding the A phase line side to the breaker bucket. This action caused the upstream feeder breaker from the load center to trip on overcurrent. The licensee also concluded that this breaker action was consistent with design. Licensee corrective actions included:

-- initiating the SDR documenting the event and failure of the breaker,

-- troubleshooting the failure using approved construction procedures,

-- replacing the breaker with a new one with correctly sized overload devices,

-- retesting the breaker satisfactorily.

The inspector concluded that licensee actions taken during startup and construction activities in 1985 were consistent with procedures. The inspector had no further questions at this time. The inspector concluded that the allegation addressed an event that did occur. However, licensee corrective actions appear to have been appropriate. This allegation is considered closed.

8. SAFETY ASSESSMENT/QUALITY VERIFICATION (40500, 71707)

8.1 Salem

A. Two Year Procedure Reviews

The inspector evaluated (unresolved item 90-80-007) the status of two year Salem procedure reviews and determined that approximately 27% of the station's 2922 affected procedures were currently overdue. This includes overdue procedures from the following departments:

--	Operations	401 out of 953
--	Instrumentation & Controls	380 out of 1718
--	Maintenance	30 out of 251

The inspector determined that the overdue procedure backlog was approximately 10% in August 1989, when management reallocated procedure reviewers to support the procedure upgrade program (PUP). The PUP was implemented in June 1989, to improve the quality of Salem's procedures. The PUP has prioritized its upgrade effort based on the relative strength of procedures as determined by the user department. Although this ensures the weakest procedures receive the most immediate review, it contributes to the overdue backlog as weak procedures within their two year review are worked before overdue procedures.

In order to expedite the PUP progress, resources were transferred from the two year review process to support PUP activities. The large backlog of overdue procedures indicates that the management decision made in August 1989, regarding resource allocation did not adequately assess the negative consequences of the reallocation. This corrective action taken in response to poor procedure quality exacerbated the backlog of biennial procedure reviews as required by Technical Specification 6.8 and Administrative Procedure No. 32 Step 5.1.6. Although the licensee identified this violation, it is being cited because of the ineffective corrective action that was implemented. Also, the licensee made no attempt for formal notification to or relief from the NRC (50-272/90-11-01).

Due to the large backlog of overdue procedure reviews, Salem has recently implemented the following interim compensatory measures:

-- Complete a full two-year review (per procedure TI-10) and all additional research required by the PUP project for all procedures not reviewed within five years by April 20, 1990.

-- For all procedures exercised via a work order (principally maintenance and I&C):

- Perform a review of all current advance change notices (ACNs) and revision requests outstanding by April 20, 1990. Any that are judged to be technically significant or that could significantly impact the proper use of the procedure will be identified and the procedure changed.

- A four week look-ahead report will be generated each week. For all procedures overdue for the two year review, a complete two year review will be done prior to the procedure being used.

-- For all procedures exercised without a work order (principally operations procedures):

  - Perform a review of all current ACN's and revision requests outstanding by April 20, 1990. Any that are judged to be technically significant or that could significantly impact the proper use of the procedure will be identified and the procedure changed.

  - A complete two year review will be completed by July 31, 1990.

By the end of the inspection period the number of overdue procedures had been reduced to 246 for Operations, 288 for I&C, and 2 Maintenance procedures.

8.2 Hope Creek

A. Biennial Procedure Review Backlog Followup

(Closed) 50-354/89-80-08; NRC Inspection Report No. 50-354/89-80 issued a violation for having a significant backlog of procedures that were overdue for their 24 month review. The review is required by procedure SA-AP.ZZ-032(Q), "Review and Approval of Station Procedures and Procedure Revisions". The NRC special maintenance team inspection report at Hope Creek dated February 7, 1990, stated that approximately 50% of mechanical maintenance procedures and approximately 40% of instrumentation and control (I&C) and electrical maintenance procedures were overdue for their biennial review.

By a letter dated March 9, 1990, PSE&G responded to the Notice of Violation and committed to adding two additional procedure writers to the permanent staff along with six consultants, in order to eliminate the procedure review backlog by June 1990. During the inspection period, the inspector met with the Hope Creek Technical Manager and the technical engineer managing the procedure review program to ascertain the progress that had been made in reducing the identified backlog. The inspector was informed that the technical review staff had been supplemented and upon reviewing the weekly progress report issued by the Technical Department, determined that both the mechanical procedure and the I&C and electrical procedure backlogs had been reduced to approximately 5% each. The Technical Manager informed the inspector that the present program will be kept in place until the backlog is eliminated and, in fact, until the procedure review program is a month or two ahead of schedule. The purpose of working ahead is to account for events, such as refueling outages, that traditionally delay the procedure review process. The inspector found the licensee's program effective, and no inadequacies were identified.

Based on the licensee's response to the violation, corrective actions taken, the significant reduction in the backlog, and plans to eliminate the backlog, the violation is considered closed.

8.3 Individual Plant Examinations for Severe Accident Vulnerabilities -- NRC Generic Letter 88-20 (Salem)

On November 23, 1988, the NRC issued Generic Letter (GL) 88-20 to request individual Plant Examination (IPE) for severe accident vulnerabilities from all licensees. The general purpose of this examination is to (1) develop severe accident behavior, (2) understand the most likely severe accident sequences that could occur, (3) gain quantitative understanding of the overall probabilities of core damage and fission product releases, and (4) reduce the core damage and fission product releases by modifying hardware and operating procedures that are intended to prevent or mitigate severe accidents.

The NRC issued NUREG 1335 in August 1989 to provide specific guidance for IPE. Supplement No. 1 to GL 88-20 was issued on August 29, 1989 to announce the issuance of NUREG 1335. GL 88-20 and its supplement requested the licensee to submit their proposed program for completing IPE to the NRC within 60 days of the publication of NUREG 1335 and address the following:

-- Identify the method and approach selected for performing the IPE.

-- Describe the method to be used for the examination, and

-- Identify the milestones and schedules for performing the IPE and submitting the final results to the NRC.

Additionally, the GL requested the licensee to complete the IPE and submit the final report within 3 years of the issuance of NUREG 1335.

The licensee's proposed program in response to GL 88-20 was submitted to the NRC on October 31, 1989.

As stated in this proposed program, the licensee uses NUREG /CR 2300 (PRA Procedures Guide) to develop the Salem IPE. NUREG /CR 2300 is one of the methods considered adequate in GL 88-20 for performance of IPE. The final submittal for Salem Units 1 and 2 IPE is presently scheduled for September 1, 1993.

At the time of the inspection, the licensee's staff had developed a detailed IPE Program Plan for management review. This plan describes a series of actions and a schedule for a comprehensive IPE program at PSE&G. The general scope of this program is to develop a risk model based on current as-built configuration of both Salem Units and to increase the awareness of PRA concepts within station operations. The plan also has provision to develop and document a computer risk model for predicting the core damage frequency and the ability of containment to mitigate accident sequences at the Salem Units. The results from the study will be used for future plant betterment activities related to Technical Specification improvement, design change package (DCP) review and screening, reliability centered maintenance (RCM) and support for licensing in resolution of technical issues. Licensee had completed a preliminary Level 1 PRA in October 1988. The results of this study were being refined using plant specific data at the time of this inspection.

The licensee's IPE activities are primarily carried out under the cognizance of the risk assessment group. This group has a full time supervisor and an authorized staff of six personnel. The expertise of this group is further augmented by the use of contractor personnel. At the time of this inspection, the risk assessment group consisted of three licensee employees and two contractors. The licensee was actively recruiting to fill the three vacant positions by the end of 1990.

The licensee also arranged a contractor to conduct a PRA workshop in June 1990 for its employees.

The contractor personnel, the group supervisor and one employee of the Risk Assessment group were familiar with details of the activities related to GL 88-20. The other two personnel were recently assigned to this group and were gaining expertise by performing analyses as directed.

This review was primarily to determine the status of licensee activities in response to GL 88-20. As such, the observations and conclusions made in this report are preliminary. Formal NRC assessment of the licensee actions in response to the above NRC GL will be made separately.

9. LICENSEE EVENT REPORTS (LER), PERIODIC AND SPECIAL REPORTS, AND OPEN ITEM FOLLOWUP (90712, 90713, 92700)

9.1 LERs and Reports

PSE&G submitted the following licensee event reports and, special and periodic reports, which were reviewed for accuracy and the adequacy of the evaluation:

Salem and Hope Creek Monthly Operating Reports for March 1990.

Hope Creek LER

LER 90-03 concerns a reactor scram which resulted from transmission line faults caused by an offsite marsh fire on March 19, 1990. The event is discussed in paragraph 2.2.2.A of this report. The cause of the event was determined to be ionized air and carbon ash generated by the fire which caused a flashover of two phases of an offsite 500 KV transmission line. The subsequent low voltage transient was propagated through Hope Creek's electrical distribution system and, at the 120 VAC level, caused a trip of the condensate pumps. The loss of the condensate pumps caused the reactor feed pumps to trip, resulting in a low reactor water level and a subsequent reactor scram. The licensee's corrective actions were reviewed and determined to be appropriate and satisfactory. This is the first such event at either Hope Creek or Salem, and the licensee intends to try and reduce the potential for marsh fires around the site and determine any improvements which would enhance electrical system reliability during voltage transients.

9.2 Open Items

The following previous inspection items were followed up during this inspection and are tabulated below for cross reference purposes.

Hope Creek	Section	Status
354/89-80-08	8.2.A	Closed

Salem	Section	Status
272/90-80-07	8.1.A	Closed

10. EXIT INTERVIEW (30703)

10.1 Resident

The inspectors met with Mr. L. K. Miller and Mr. J. J. Hagan and other PSE&G personnel periodically and at the end of the inspection report period to summarize the scope and findings of their inspection activities.

Based on Region I review and discussions with PSE&G, it was determined that this report does not contain information subject to 10 CFR 2 restrictions.

NRC Commissioner Rogers visited Salem and Hope Creek Generating Stations on March 26 and 27, 1990, respectively. The visit included plant tours and interviews with selected station and NRC personnel. The Commissioner was accompanied by a NRC Region I management representative and a technical assistant.

10.2 Specialist

Date(s)	Subject	Inspection Report No.	Reporting Inspector
3/29-23/90	Requalification Examinations	272/90-09; 311/90-09	Hughes
4/9-27/90	Maintenance Team	272/90-200; 311/90-200	Ball
3/17-23/90	Operator Licensing Examinations	354/90-05	Walker
4/16-20/90	Transportation and Solid Radwaste	354/90-09	Furia