U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Report Nos.	50-272/94-14 50-311/94-14 50-354/94-13
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:	June 26, 1994 - August 6, 1994
Inspectors:	C. S. Marschall, Senior Resident Inspector J. G. Schoppy, Resident Inspector T. H. Fish, Resident Inspector J. Laughlin, Emergency Preparedness Specialist B. J. McDermott, Reactor Engineer

Approved: John White 9/14/94
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Inspection Summary:

This inspection report documents inspections to assure public health and safety during day and backshift hours of station activities, including: operations, radiological controls, maintenance and surveillance testing, emergency preparedness, security, engineering/technical support, and safety assessment/quality verification. The Executive Summary delineates the inspection findings and conclusions.

EXECUTIVE SUMMARY

Salem Inspection Reports 50-272/94-14; 50-311/94-14

Hope Creek Inspection Report 50-354/94-13

June 26, 1994 - August 6, 1994

OPERATIONS (Modules 71707, 92901)

Salem: Operators responded appropriately to insure plant safety for a Unit 2 reactor trip on low-low steam generator water level and a Unit 1 loss of all circulating water pumps caused by a lightning strike. The licensee responded to each transient with appropriate corrective actions and a thorough investigation performed by a Significant Event Response Team (SERT).

Hope Creek: Operators took appropriate action to insure plant safety in response to a reactor scram caused by a damaged isolation transformer in the test equipment used during a surveillance test on the "C" intermediate range monitor. The licensee performed a detailed root cause investigation and took appropriate corrective actions. The use of the isolation transformer will remain unresolved pending review of the SERT report. Inspectors concluded that during May 1994, Safety Auxiliary Cooling System (SACS) pump trip, the pumps operated per the design. On July 7, 1994, the licensee corrected a design deficiency, discovered in March 1994, associated with operation of the residual heat removal (RHR) suppression pool suction valve from the remote shutdown panel (RSP). The inspectors determined that, due to inadequately performed surveillances, the licensee missed opportunities to identify and correct the design deficiency during surveillances conducted each refueling cycle. Failure to meet the TS requirement for RSP operation of the RHR suppression pool suction valve is a violation. The inspectors closed an unresolved item associated with the April 21, 1994, inadvertent loss of reactor pressure vessel inventory.

MAINTENANCE/SURVEILLANCE (Modules 61726, 62703, 92902)

Salem: The licensee took appropriate measures to ensure safety in response to an unisolable primary coolant leak from a flange joint associated with No. 22 reactor coolant pump seal package. This item is unresolved pending review of the licensee root cause determination and associated corrective actions. Inadequate technician training led to inappropriate maintenance of the No. 23 auxiliary feedwater pump turbine governor and overspeed test trip device. Inadequate training for safety related maintenance is a violation. However, workers recognized their errors and elevated them to the appropriate level of management, resulting in satisfactory resolution of the errors and proper restoration of pump operability.

Hope Creek: Hope Creek maintenance and surveillance activities appropriately supported safe plant operation during the inspection period.

ENGINEERING (Modules 71707, 92700)

Salem: The inspector closed two unresolved items, one associated with an October 1993 fire that occurred as a result of grinding activity, and one associated with the number of actual reactor trips exceeding the design number of trips.

PLANT SUPPORT (Module 71707, 92904)

Hope Creek: An individual leaving the protected area alarmed the portal monitor at the guardhouse. Subsequent licensee investigation determined the source of contamination was a stepladder in the fire pump house. Radiation protection personnel took prompt and comprehensive action to minimize the spread of contamination. This item is unresolved pending review of licensee investigation results and corrective actions.

Common: The inspectors observed good performance by Security Department personnel in performing routine activities, such as control of access to the plant and implementation of the security plan. The inspectors also found that the plants were very clean, well painted and lighted, with the exception of two of the four Salem service water bays and the Salem turbine building basement. The licensee plans to address these areas as part of the Salem revitalization project. In addition, the inspectors noted that the Salem units continue to suffer from unbalanced ventilation that results in fire doors not closing properly due to differential air pressure across the doors. Engineering analysis demonstrated that the open fire doors have not adversely affected the ability to achieve safe shutdown. In addition, fire protection personnel continue to provide short term compensation for the open doors.

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DETAILS

1.0 SUMMARY OF OPERATIONS

1.1 Salem Units 1 and 2

Unit 1 began the report period in Mode 2 (Startup) to support dredging in front of the circulating water intake structure. Following dredging, the operators increased power, and synchronized the turbine to the grid on June 27. The unit operated at power until July 14, when lightning strikes on the grid caused a loss of all circulating water pumps. The operators responded to the transient by manually tripping the reactor and placing the plant in Mode 3 (Hot Standby). The licensee restarted the unit on July 17 and synchronized the generator to the grid on July 18. The unit operated at power for the remainder of the report period.

At the beginning of the inspection period Salem Unit 2 was critical, but off line while circulating water inlet area dredging took place. A reactor trip occurred on June 29, during power escalation, due to a low-low steam generator water level. On July 2, the licensee identified an unisolable flange leak from a previously abandoned section of piping from No. 22 reactor coolant pump (RCP). The licensee removed the RCP from service, and began a plant cooldown and depressurization to support repairs. On July 10, after plant staff completed repairs, the licensee commenced a startup and subsequently increased power to 100%. Power remained at or near full power until August 5, when the licensee reduced power to 44% due to presumed inoperability of a reactor trip breaker when it apparently failed a surveillance test. The licensee identified the cause of the apparent failure to be related to electrical relays used to monitor the reaction time of the breaker, resolved the timing measurement error, successfully completed the trip breaker surveillance, and returned the unit to full power. The unit remained at full power for the remainder of the period.

1.2 Hope Creek

The plant operated at power until August 1, 1994, when the station experienced a reactor scram during a routine surveillance test on the "C" intermediate range monitor of the neutron monitoring system. Licensee investigation revealed that a ground on damaged test equipment induced a current spike on the local power range monitor cables, resulting in a high neutron flux signal that generated the scram signal. Operators restarted the reactor on August 3, and synchronized the generator to the grid on August 4. The plant operated at power at the end of the inspection period.

2.0 OPERATIONS

2.1 Inspection Activities

The inspectors verified that Public Service Electric and Gas (PSE&G) operated the facilities safely and in conformance with regulatory requirements. The inspectors evaluated PSE&G's management control by direct observation of activities, tours of the facilities, interviews and discussions with personnel, independent verification of safety system status and Technical Specification compliance, and review of facility records. The inspectors performed normal and back-shift inspections, including 31 hours of deep back-shift inspections.

2.2 Inspection Findings and Significant Plant Events

2.2.1 Salem

A. Reactor Trip on Low Steam Generator Water Level

On June 29, after completion of dredging operations to remove grass and silt in front of the circulating water intake structure, operators began to increase power from 2% to approximately 14%. At about 6% power the No. 21 steam generator feedwater pump recirculation valve (21BF32) cycled closed, causing a feedwater header pressure increase. Operators reduced No. 21 steam generator feedwater pump speed to reduce header pressure. The lower feedwater pump speed caused the recirculation valve to open. Following a second series of recirculation valve cycling, the No. 22 steam generator reached the high-high level (67%) causing automatic closure of the feedwater isolation valves. The shift supervisor instructed the reactor operators to reduce power, initiate auxiliary feedwater flow, and to follow the actions accordance with AB.CN-001, *Main Feedwater/Condensate System Abnormality*. However, prior to stabilizing the plant at 6% power, No. 23 steam generator water level dropped to the low-low level setpoint. The reactor tripped, as designed, due to a low-low water level (16%) condition in No. 23 steam generator. Operators performed the appropriate trip procedures to ensure plant safety, and safety-related equipment operated as designed.

Maintenance controls technicians verified that the steam generator level controls functioned as expected. Maintenance also verified the proper functioning of the recirculation valve automatic flow control circuit. The licensee determined that recirculation valve cycling resulted from operation of the feedwater system at flows varying just above and below the setpoint for recirculation valve closure. As a result, rapid opening and closing of the recirculation valve caused rapid changes in feedwater header pressure and steam generator feedwater flow.

Operations modified the procedure for plant startup to remove automatic flow control of the recirculation valve. The change directed operators to maintain the recirculation valve in the full open position until approximately 30% power. Additionally, the licensee added an immediate action step to direct the operator to manually trip the reactor following a loss of main feedwater with power greater than 10%. This step prevents power operation and steam generator water level oscillations while attempting to recover the plant from a loss of main feedwater above 10% power.

The inspector reviewed applicable strip chart and sequence of events recordings. The inspector determined that the operators responded appropriately to the trip and that safety equipment performed as designed. The inspector considered the licensee's Significant Event Response Team (SERT) report adequate. The inspector noted that the SERT recommended a comprehensive performance assessment of the feedwater control system due to the significant number of plant trips caused by feedwater transients and perturbations. The inspector concluded that the corrective actions adequately addressed the immediate problem and that further improvements in the feedwater system are needed to assure long term reliable operation.

B. Manual Reactor Trip Due to Loss of All Circulating Water (CW) Pumps

At 9:34 p.m. on July 14, Unit 1 operators manually tripped the reactor from 100% power in response to decreasing condenser vacuum caused by the loss of all CW pumps. Lightning strikes on 500KV transmission lines caused supply voltage for the CW pump switchgear to drop. The voltage decrease caused the CW pump breakers and bus supply breaker to open, resulting in the loss of all CW pumps. Operators executed the appropriate procedures in response to the transient and stabilized the plant in Mode 3 (Hot Standby). All safety systems responded as designed.

Following the trip, the licensee convened a Significant Event Response Team (SERT) to conduct an assessment of the trip and determine the root cause. The SERT determined that a design inadequacy, lack of a time delay in the undervoltage (UV) pickup circuitry of the CW pump switchgear, resulted in unnecessary UV relay actuation. During the storm on July 14, the lightning-induced voltage drop lasted 3 cycles, or approximately 50 milliseconds. A time delay could have prevented the CW pumps from tripping. To correct this deficiency, the licensee added a time delay to the undervoltage pickup circuitry prior to restarting the unit. The licensee stated their intent to install a time delay in the Unit 2 CW electrical controls during the Fall of 1994.

The inspector reviewed the post trip data, and discussed the trip analysis and SERT report with Operations and Technical staff. The inspector considered the SERT report and trip analysis adequate and concluded that the licensee response to the transient and subsequent corrective actions were appropriate.

2.2.2 Hope Creek

A. Reactor Scram

On August 1, 1994, the station experienced a reactor scram while performing a surveillance on the "C" intermediate range monitor (IRM). Initial licensee investigation revealed that a damaged isolation transformer, used for the surveillance, allowed 120 volts alternating current (VAC) to exist on the case ground of the test equipment. Consequently, the damaged transformer passed 120 VAC to the test lead which the technician attempted to connect to the IRM pre-amplifier (located in the reactor building). The lead arced as the technician attempted to plug it in, shocking the technician and applying 120 VAC to the shield ground of the IRM coaxial cable. The resulting electrical spike in the IRM cable travelled from the pre-amplifier to the detector cabinet in the control room. The conduit containing the IRM cable run (from the pre-amplifier to the control room) also housed the local power range monitor (LPRM) cables for the "C" and "D" average power range monitors (APRMs). The licensee concluded that the potential on the "C" IRM cable induced sufficient current on the LPRM cables to exceed the current setpoint for the high neutron flux scram, resulting in a scram on both "C" and "D" APRMs. After the scram, operators stabilized the plant using emergency operating procedures and all safety equipment functioned as designed during the event.

During the event review the inspector identified two concerns: the potential risk to personnel safety posed by the use of ungrounded test equipment, and the adequacy of electrical separation for cables associated with nuclear instrumentation. The licensee stated that nuclear instrumentation design provided a ground in only one location to limit the introduction of noise through formation of ground loops. As a result of the very small amplitude of the nuclear instrumentation signal current, the additional noise caused by ground loop currents has the potential to hamper instrument maintenance and surveillance activities. Use of ungrounded test equipment prevented the introduction of electrical noise by preventing formation of a ground loop. In regard to electrical separation, the licensee demonstrated that the Hope Creek design conformed to design criteria. The design consists of four nuclear instrumentation cable runs, each with IRM and APRM cables, designed to fail safe for reactor safety, and electrically separated from the reactor protection system through isolation amplifiers.

Prior to startup the licensee repaired and retested the "C" IRM preamplifier, confirmed that "C" and "D" APRMs did not suffer damage, and verified the electrical separation design for nuclear instrumentation. The licensee also checked all remaining test equipment for damage similar to the faulty isolation transformer. Upon completion of these items, the licensee began a reactor startup on August 3, 1994, and synchronized the main generator to the grid on August 4.

The licensee assigned a Special Event Review Team (SERT) to perform an in-depth investigation of the reactor scram. The inspector concluded that the licensee took appropriate action to ensure safety before reactor startup, and conducted the startup in a safe controlled manner with adequate management supervision. The root cause of the use of the isolation transformer will remain unresolved pending review of the SERT report. **(URI 50-354/94-13-01)**

B. "A" and "C" Safety Auxiliary Cooling System (SACS) Pump Trips

As documented in NRC Inspection Report 50-272,311/94-13, 50-354/94-11, the SACS pump tripped on May 30, 1994. At the time of the event, the "A" and "C" pumps supplied cooling to the Turbine Auxiliary Cooling System (TACS), while the "D" SACS pump supplied cooling to safety related loads. Operators shifted TACS to the "B" SACS loop and restarted the "A" SACS pump.

Licensee root cause analysis revealed that a high flow condition in the "A" SACS/TACS loop which caused the "A" and "C" pumps to trip on low differential pressure (dp) probably caused the event. The licensee could not prove this conclusively since no low dp alarms occurred. However, the inspector noted that conditions existed which could have caused the high flow condition. This did not pose a safety concern since TACS is a non-safety system that isolates in accident conditions. The inspector concluded that the system functioned as designed.

Licensee corrective actions included procedure changes to increase operator monitoring of TACS loop flow and insure operator review of the incident report during training. The inspector concluded that the licensee took adequate corrective action.

C. "A" Residual Heat Removal (RHR) System Suppression Pool Suction Valve

On March 6, 1994, during a surveillance on the Remote Shutdown System, the licensee discovered that the "A" RHR suppression pool suction valve did not function in accordance with the design. The valve is part of the alternate remote shutdown capability which functions as a backup to the remote shutdown panel, and is required by technical specifications to have remote control capability. When the operator attempted to close the valve remotely, it cycled repeatedly from the open to the closed position without further operator action. Only when an operator transferred the control room keylock switch from the normal locked open position to the overload enable position (for testing purposes only), could the valve be remotely operated, as designed.

Upon further investigation, the inspector found that operators observed this condition during two previous tests. When the operators noted the repeated valve cycling, they positioned the keylock switch to the overload enable position for the test, and signed the test off as satisfactorily completed. During the March 6 test, operators determined that the valve was not functioning as designed and documented this in an incident report. Licensee root cause analysis concluded that design of the valve control system was inadequate in that it did not isolate the local control logic from the control room logic. Additionally, the licensee considered lack of detail, describing the expected valve performance, in surveillance procedure HC.OP-ST.SV-0002(Q), *Remote Shutdown Control Operability*, a contributing cause.

In response to the inability to remotely operate the valve, the licensee immediately hung a caution tag on the valve and changed the abnormal procedure for control room evacuation, instructing operators to reposition the valve keylock switch to the overload enable position before evacuating the control room. On July 7, 1994, licensee staff implemented a design change to isolate the local control logic from the control room logic, effectively correcting the design deficiency.

The inspector concluded that, prior to the design change, remote operation of valve BC-HV-F004A did not meet the Technical Specification 3.3.7.4.b requirement for remote valve operation, since the valve could not be closed from the remote location with the control room switch in the "OPEN" position without further operator action. Failure to meet the TS requirement for valve operation is a violation. **(VIO 50-354/94-13-02)**

D. Inadvertent Reactor Pressure Vessel (RPV) Letdown

(Closed) Unresolved Item (50-354/94-09-03): On April 21, 1994, the plant experienced an inadvertent loss of RPV inventory while aligning the "A" residual heat removal (RHR) system for shutdown cooling (SDC). Initial licensee investigation revealed, although operators observed control room indication that the valve had closed, incomplete closure of the "B" RHR system suction valve provided a leak path from the reactor vessel to the suppression pool.

Licensee root cause analysis revealed that the surveillance procedure used to perform the post-maintenance test did not contain adequate guidance to ensure that valves of this type were left in the proper position during outage testing. The inspector determined, in addition, that operators stroked the valve for post maintenance test, but the normal valve stroking to demonstrate operability was not scheduled until several shifts later. The post maintenance test demonstrated that the corrective maintenance did not impair the ability to stroke the valve, but the test did not ensure operability or complete valve closure. The inspector concluded that the operators did not, in this instance, fully understand that the post maintenance test (designed to insure that maintenance had corrected an identified problem without introducing new deficiencies) and the operability test (designed to insure that the component could perform its intended function). As a result, operators did not recognize that the post maintenance test did not insure that the valve was returned to its correct position (closed).

The inspector also found that operators received an alarm one hour before the event on annunciator A7-D3, *RHR B S/D CLG AND MIN FLOW VLV OPEN*, giving indication of the potential misposition of the "B" RHR suction valve. The operators believed the valve retest had verified valve closure, and since the annunciator trouble cleared, concluded that the valve was closed. Consequently, the operators did not confirm actual valve position before aligning "A" RHR for shutdown cooling; as a result the partially open "B" RHR suction valve provided a path to drain water from the reactor vessel to the suppression pool.

The inspector found the initial licensee root cause analysis incomplete in that it identified only the procedure deficiency. However, the licensee's June 17, 1994 incident investigation report provided a more comprehensive review of the matter, including the causes as discussed above. The inspector confirmed that corrective actions were taken to address the causes of the event, including revising applicable procedures to assure that component operability is confirmed following post-maintenance testing, prior to returning the affected component to service.

The inspector noted that timely operator actions mitigated the safety significance of this event by ensuring adequate core coverage at all times. This item is closed.

3.0 MAINTENANCE/SURVEILLANCE TESTING

3.1 Maintenance Inspection Activity

The inspectors observed selected maintenance activities on safety-related equipment to ascertain that the licensee conducted these activities in accordance with approved procedures, Technical Specifications, and appropriate industrial codes and standards.

The inspector observed portions of the following activities:

Unit	Work Order(WO) or Design Change Package (DCP)	Description
Salem 1	940622200	Remove 22SJ39 Valve and Lift Set Test (6/28)
Salem 1	940719098	Repair Train B SSPS Breaker CB28
Salem 2	94062606	Repair Steam Leak at Elbow Upstream of 2MS213 (6/28)
Salem 2	Various	22CV252 Flange Leak Repair
Salem 2	Various	Engineered Disassembly of 22CV252
Salem 2	94032118801	No. 23 Auxiliary Feedwater Pump Repairs

The maintenance activities inspected were effective with respect to meeting the safety objectives of the maintenance program.

3.2 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.

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

Unit	Procedure No.	Test
Salem 1	SC.OP-PT.DG-0001(Q)	Bar Over of EDG to Check for Jacket Water Leaks, Prior to Monthly Surveillance.
Salem 1	SI.OP-ST.DG-0003(Q)	1C Diesel Monthly Surveillance
Salem 1	SI.OP-ST.SJ-0002(Q)	12 SI Pump Quarterly Surveillance
Salem 1	SI.OP-ST.SW-0002(Q)	12 Service Water Pump IST Surveillance

Salem 1	SC.MD-PT.ZZ-0007	Bench Testing of 5 Inch and Smaller Relief Valves (6/28)
Hope Creek	HC.OP-ST.KJ-003	Emergency Diesel Generator CG400 Operability Test - Monthly
Hope Creek	HC.OP-IS.BH-0002	Standby Liquid Control Pump - Inservice Test
Hope Creek	OP-IS.BC-0001	Residual Heat Removal Quarterly IST
Hope Creek	OP-IS.BD-0001	Reactor Core Isolation Cooling Quarterly IST

The surveillance testing activities inspected were effective with respect to meeting the safety objectives of the surveillance testing program.

3.3 Inspection Findings

3.3.1 Salem

A. Flange Leak Repair

On July 2, with Salem Unit 2 in Mode 3, with a reactor coolant system (RCS) pressure of 2235 psig and a temperature of 531 degrees F, the licensee attempted to leak seal a small steam leak from a flange joint on a one inch pipe connected to No. 22 reactor coolant pump seal. During the repair attempt, the leak quickly increased to 14 gallons per minute (gpm). The leak was unisolable, and all personnel at the job site immediately evacuated the area, notified the control room of the leak, and exited the containment.

The operating shift immediately initiated the abnormal procedure for an RCS leak. Since the leak rate exceeded the 1 gpm allowed by Technical Specification 3.4.7.2.b, the operators initiated an RCS cooldown to cold shutdown, as required. The plant reached cold shutdown early on July 3. With reactor pressure reduced to approximately 15 psig, the leak slowed to less than 1 gpm. On July 4, maintenance personnel established a freeze seal just upstream of the flange to support disassembly of the joint and subsequent installation of a blank flange.

The inspector monitored portions of the plant cooldown and observed that the crew effectively controlled the evolution. The inspector also noted that management thoroughly researched and evaluated the flange repair strategy. Material inspectors from the Region I office observed key portions of repair activities, including the disassembly of the leaking flange and installation of the blank flange. The inspectors noted effective control of the repair.

Based on strong operator control of the unit during the shutdown, and effective management coordination of the flange repair, the inspector concluded that PSE&G took appropriate measures in responding to the primary coolant leak. This item remains unresolved pending NRC review of the licensee's root cause investigation of the RCS leak. **(URI 50-311/94-14-01)**

B. 23 Auxiliary Feedwater Pump Maintenance

On July 13, 1994, operators tagged the No. 23 auxiliary feedwater (AFW) pump out of service for minor preventive maintenance (PM) on the gear box that links the governor oil pump to the turbine shaft. The licensee did not expect this maintenance activity would affect the operability of the pump; however, when operators started the pump for a post maintenance operability test, the governor failed to control the turbine speed and it automatically tripped on overspeed. Investigation revealed that during the gear box maintenance, mechanics mistakenly adjusted the overspeed trip test device.

Work order 941125014 provided the mechanics instructions for changing the governor gear box lube oil, inspecting the governor gear box internals, and cleaning its breather cap. The work plan identified gear box parts by noun name and by vendor drawing item number. Although the work plan referenced the vendor drawing, plant staff did not use it during the pre-job briefing and did not include it in the work package.

The turbine governor is bolted to the governor gear box and the mechanics did not recognize the distinction between the two components. As a result, they mistook the overspeed trip test device on the governor for the governor gear box breather cap. Also, they mistook the governor oil fill cap for the governor gearbox fill cap. The incorrect identification of these items led the mechanics to disturb the adjustment of the turbine overspeed trip test device and add the gear box oil to the turbine governor. After the mechanics identified they had made an error, they contacted their supervisor. Based on a guidance provided by the system engineer, the maintenance supervisor directed the mechanics to flush and refill the governor with the correct oil and adjust the overspeed trip device. The workers did not use a procedure for the adjustment of the overspeed trip test device (none existed) and did not have guidance to confirm the proper adjustment. The work package called for the normal operability surveillance test to confirm that they had properly performed the PM. The mechanics completed the governor gear box PM and turned the AFW pump over to Operations for an operability test and return to service but did not inform the operators of the maintenance problems that had occurred. The operators made two attempts to run the AFW pump; the first try resulted in the turbine tripping on overspeed and during the second attempt operators manually tripped the turbine prior to reaching the overspeed trip setpoint. Operators informed the maintenance department and mechanics re-adjusted the turbine overspeed trip test device without procedures. Operators successfully retested the AFW pump and declared it operable on July 14, 1994. The maintenance supervisor counseled the mechanics involved on proper verification and greater attention to detail, and changed the work package to require a working copy of the vendor drawing.

The licensee concluded that the vendor drawing would not have precluded attempting maintenance on the wrong component, due to the complexity of the drawing. The licensee also concluded that, although the mechanics returned to their supervisor for guidance in one instance, they failed to return for additional guidance when they continued to be unsure of proper component identification for the oil change. The inspectors concluded that lack of supervisory oversight contributed to the maintenance problem, since the supervisor failed to insure that the mechanics identified the correct component for maintenance. The inspectors also concluded that, although the system engineer provided ineffective guidance for adjusting the test device, maintenance personnel took the appropriate action to obtain detailed guidance to correctly adjust the device, as required. Failure to provide the training necessary to assure that the mechanics effectively performed the oil change on the no. 23 AFW pump is a violation of the requirements of 10 CFR 50, Appendix B, criterion II. **(VIO 50-272 and 311/94-14-02)**

4.0 ENGINEERING

4.1 Salem

A. Open Item Followup

(Closed) Unresolved Item (50-272 and 311/93-21-01). This item concerned the root cause of a fire that occurred in October 1993 as a result of grinding activity that ignited pipe insulation.

The licensee identified several root causes for the fire: 1) The job supervisor did not ensure sufficient fire blanketing existed to prevent sparks from migrating to the pipe insulation, 2) Temporary ventilation set up in the work area contributed to the spread of the fire, and 3) Personnel believed, erroneously, that tarpaulins, used to ensure cleanliness of the surrounding area, were fire retardant.

The licensee initiated corrective actions that included reviewing the incident with station and contractor personnel, inspecting work areas to evaluate the positioning of fire watch and temporary ventilation, and alerted all personnel that protective tarps issued by the Radiation Protection Department are not fire retardant. The licensee instructed personnel to use fire blankets in lieu of the tarps.

The inspector considered the corrective actions appropriate. This item is closed.

(Closed) Unresolved Item (50-272/93-29-01). This item concerned the engineering justification for allowing the number of actual reactor trips per cycle to exceed the expected number per cycle. At the time the item was identified, Unit 1 had experienced 174 reactor trip transients, slightly above the expected 170; Unit 2 had experienced 122, slightly above the expected 120.

Salem Nuclear Department compiled the historical trip data for both units. The data indicated the units experienced an excessive number of trips during the initial years of commercial operation, Unit 1 from 1977 to 1981, and Unit 2 from 1981 to 1986. Since then the units have had a low rate of trips such that the Nuclear Department predicts the number of actual transients for both Salem units will be less than designed.

The inspector reviewed the data provided by the Nuclear Department and determined that the rate of actual reactor trip transients had declined to below the design rate: 10 trips per year, per unit, 40 year design life of unit. The inspector considered the licensee determination appropriate. This item is closed.

5.0 PLANT SUPPORT

5.1 Radiological Controls and Chemistry

5.1.1 Inspection Activities

The inspector verified on a periodic basis PSE&G's conformance with the radiological protection program.

5.1.2 Inspection Findings - Salem

A. Inoperable Radioactive Liquid Effluent Monitoring Instrumentation

At 7:49 p.m. on June 17, 1994, the licensee discovered the Unit 2 liquid radwaste effluent line (2R18) radiation monitor in the blocked position while a liquid release was in progress. Technical Specification (TS) 3.3.3.8 permits a release with 2R18 inoperable provided that plant staff analyzes two independent samples, and verifies release rate calculations and discharge line valving. The licensee did not realize that 2R18 was blocked during the release and subsequently failed to perform the TS required actions.

Upon discovery, the licensee immediately unblocked 2R18, terminated the release, and verified that the hourly average radiation monitoring system (RMS) reading remained below the 2R18 alarm setpoint during the release. The licensee determined that the radioactive liquid released did not exceed Technical Specification limits. The licensee concluded that a weakness in release procedure S2.OP-SO.WL-0002, *Release Of Radioactive Liquid Waste From 22 CVCS Monitor Tank*, caused the unmonitored release. The licensee found the procedure less than adequate in that the procedure did not require the operator to verify that the 2R18 was unblocked. Additionally, the licensee found that the operability retest, performed when returning the 2R18 to service following maintenance, did not require verification that the instrument was unblocked. (The licensee determined that hours prior to the release, operators retested 2R18 following a maintenance activity, declared the 2R18 operable, but failed to unblock 2R18.) The licensee made changes to the operability retest and liquid release procedures to ensure proper alignment of 2R18 prior to permitting a liquid release.

The inspector reviewed the hourly average RMS readings and determined that the radioactivity level in the discharged liquid was less than allowable and provided no additional risk to public health and safety. The inspector concluded that the licensee's corrective actions were prompt and appropriate. In addition, the inspector found that this violation of Technical

Specifications was not a recurring problem and was not done willfully. The inspector determined that the violation satisfied the criteria in section VII.B of the Enforcement Policy and, consequently, will not be cited.

5.1.3 Inspection Findings - Hope Creek

A. Contamination Outside the Radiologically Controlled Area (RCA)

On July 14, 1994, an individual leaving the protected area alarmed the portal monitor at the security guardhouse. Radiation protection (RP) technicians frisked the person and found contamination levels of 100-150 counts per minute (cpm) on his pants, shirt, and hat. This individual had not been in the RCA since June 9, and had passed through the portal monitor previously that day without causing an alarm. The RP technicians surveyed areas where the person had been and found gloves and rags in the Unit 2 reactor building contaminated with the isotopes Co-60, Zn-65, and Mn-54.

On July 15, RP staff again interviewed the individual to ensure that they had identified and surveyed all areas he had visited. They learned the worker had also visited the fire pump house. In the fire pump house the RP technicians found a stepladder with contamination levels up to 120,000 disintegrations per minute (dpm) Co-60, Zn-65, and Mn-54. Other than the contaminated ladder, gloves, and rag, the technicians did not find any contamination. Further investigation revealed that the ladder had come from a storage van outside the maintenance shop. Surveys of all storage vans and of the person transporting the ladder revealed no contamination.

Later on July 15, another individual in the same work group alarmed the portal monitor while returning to the plant. A frisk of the individual revealed 100-300 cpm on his clothes. The licensee then frisked all personnel of this working crew, and found no more contamination. The RP technicians conducted surveys of all areas where the individuals had been working and found no further contamination.

At the conclusion of the inspection period, the licensee had not completed the analysis of the event, or the investigation into the source of contamination on the stepladder. Inspectors determined that the licensee took prompt and comprehensive action to minimize the spread of contamination. This item is unresolved pending review of licensee investigation results and corrective actions. **(URI 50-354/94-13-03)**

5.2 Security

5.2.1 Inspection Activities

The NRC verified PSE&G's conformance with the security program, including the adequacy of staffing, entry control, alarm stations, and physical boundaries. The inspectors observed good performance by Security Department personnel in their conduct of routine activities.

5.2.2 Inspection Findings - Common

During routine inspection activities, the inspectors noted that security staff adequately controlled plant access and implemented the site security plan.

5.3 Housekeeping

5.3.1 Inspection Activities

The inspector reviewed PSE&G's housekeeping conditions and cleanliness controls in accordance with nuclear department administrative procedures.

5.3.2 Inspection Findings - Common

In general, inspectors found that the plants were very clean, well painted and lighted. Notable exceptions include two of the four the Salem service water bays and the Salem turbine building basement. The licensee plans to address these deficiencies as part of the Salem revitalization project.

5.4 Fire Protection - Common

5.4.1 Inspection Activities

The inspector reviewed PSE&G's fire protection program implementation in accordance with nuclear department administrative procedures. Items included fire watches, ignition sources, fire brigade manning, fire detection and suppression systems, and fire barriers and doors.

5.4.2 Inspection Findings

While conducting inspection activities the inspectors found generally good condition of fire detection, prevention, and suppression equipment. The inspectors noted that the Salem units continue to suffer from unbalanced ventilation that results in fire doors not closing properly due to differential air pressure across the doors. Engineering analysis concluded that the open fire doors have not adversely affected the ability to achieve safe shutdown. In addition, fire protection personnel continue to provide short term compensation for the open doors. The inspectors considered compensatory measures for the fire doors adequate.

6.0 LICENSEE EVENT REPORTS (LER), PERIODIC AND SPECIAL REPORTS, AND OPEN ITEM FOLLOWUP

6.1 LERs and Reports

The Salem and Hope Creek Monthly Operating Reports for May and June were reviewed for accuracy and content, and were determined to be acceptable. The inspectors also reviewed the following LERs to determine whether the licensee took the corrective actions stated in the report, and to determine if licensee responses to the events were adequate, met regulatory requirements conditions, and commitments:

Salem LERs

Unit 1

Number	Event Date	Description
LER 94-009	June 10, 1994	Turbine/Reactor Trip Due to Main Generator Ground Fault Protection Actuation
LER 94-010	June 25, 1994	Entry into TS 3.0.3 to Support Maintenance on the Analog Rod Position Indication System

Unit 2

LER 93-011-01	October 19, 1993	Supplement Report to Update the Event Causal Analysis and Corrective Action for Inoperable Radioactive Liquid Effluent Monitors

Hope Creek

None

For the LERs listed above, the inspectors determined that there were no violations or deviations, and considered the LERs closed.

6.2 Open Items

The inspector reviewed the following previous inspection items during this inspection. These items are tabulated below for cross reference purposes.

Site	Report Section	Status
Salem		
50-272 and 311/93-21-01	4.1.A	Closed
50-272/93-29-01	4.1.A	Closed
Hope Creek		
50-354/94-09-03	2.2.2.D	Closed

7.0 EXIT INTERVIEWS/MEETINGS

7.1 Resident Exit Meeting

The inspectors met with Mr. J. Hagan and Mr. R. Hovey 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 NRC Region I review and discussions with PSE&G, it was determined that this report does not contain information subject to 10 CFR 2 restrictions.

7.2 Specialist Entrance and Exit Meetings

Date(s)	Subject	Inspection Report No.	Reporting Inspector
6/27 - 7/1/94	Effluents Inspection	50-354/94-17	Peluso
6/27 - 7/1/94	10 CFR PA Inspection	50-272 and 311/94-17; 50-354/94-16	Noggle
7/11-15/94	Emergency Preparedness	50-272 and 311/94-15; 50-354/94-14	Silk