U. S. NUCLEAR REGULATORY COMMISSION
REGION I

Report No.	50-272/88-22 50-311/88-24
License	DRP-70 DRP-75
Licensee:	Public Service Electric and Gas Company P. O. Box 236 Hancocks Bridge, New Jersey 08038
Facility:	Salem Nuclear Generating Station - Units 1 and 2
Dates:	November 8, 1988 - December 12, 1988
Inspectors:	Kathy Halvey Gibson, Resident Inspector Noel F. Dudley, Project Engineer Chris G. Miller, Reactor Engineer James M. Trapp, Reactor Engineer

Approved: P. D. Swetland, Chief, Projects Section 2B   1/24/89 Date

Inspection Summary:
Inspection 50-272/88-22 and 311/88-24 on November 8, 1988 - December 12, 1988

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

Results: Weaknesses in performance, documentation and/or control of maintenance and surveillance activities indicate that increased management, supervisory and QA attention is warranted in these areas. Corrective actions for assuring that protective clothing is worn in accordance with radiation work permits have either not yet been implemented or are not effective. NRC assessment of licensee upgrades to the gauge calibration program and 2 year procedure review program is continuing. Aggressive System Engineering involvement and conservative technical guidance relative to the resolution of equipment deficiencies during the report period was noted.

DETAILS

1. Summary of Operations

1.1 Unit 1 operated at 100% power throughout the inspection period.

1.2 Unit 2 was in Mode 5 and nearing completion of the fourth refueling outage at the beginning of the inspection period. No. 2A diesel generator was returned to service on November 11, 1988 following maintenance and testing performed as a result of the generator being synchronized out-of-phase with the grid during the previous inspection period. Unit heatup was commenced and after 4 days in Mode 3, on November 18, 1988 the unit was cooled back down to Mode 5 to affect repairs to No. 23 Reactor Coolant Pump (RCP) seal which exhibited abnormally high leakoff during the heatup. Following the RCP seal repair, heatup was recommenced on November 24, 1988 and the reactor taken critical on November 26, 1988. On November 28, 1988, with the unit at 25% power, the reactor tripped as a result of low level in No. 22 Steam Generator (SG) following a SG level transient due to the failure of feedwater regulating valve 23BF19. On November 29, 1988 the reactor was taken critical and the unit synchronized to the grid on December 1, 1988. The unit reached 100% power on December 5, 1988. On December 9, 1988, Salem Unit 2 was removed from service and cooled down to Mode 4 due to high combustible gas concentration in the main power transformer.

2. Operations (71707)

2.1 Inspection Activities

On a daily basis throughout the report period, the inspectors verified that the facility was 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 facility, interviews and discussions with personnel, independent verification of safety system status and Limiting Conditions for Operation, and review of facility records. These inspection activities were conducted in accordance with NRC inspection procedure 71707 and included weekend and backshift inspection.

2.2 Inspection Findings and Significant Plant Events

2.2.1 Unit 1

On December 12, 1988, during calibration of the 1C diesel generator (DG) day tank level instrumentation, 1A DG day tank (located above the 1A DG room ceiling) overflowed diesel fuel oil to the day tank dike which then leaked fuel oil down through a hatch in the 1A DG room ceiling and into the diesel room. The inspector discussed the incident with operations personnel, reviewed the operations fact finding package, and reviewed related procedures M3I "Auxiliary Control Switches Calibration" and SP(O)4.8.1.1.3A "Electric Power Systems - Diesel Fuel Oil".

Electrical maintenance procedure M3I is a generic procedure which in part provides instructions for performing calibrations of level devices. This procedure, along with work order No. 880224213, was being used by maintenance to verify and/or calibrate the 1C DG day tank low level (33") start signal for the primary fuel oil transfer pump and the low-low level (18") start signal for the backup fuel oil transfer pump. The operations shift supervisor directed an equipment operator (EO) to close 1C DG day tank inlet valves and open the drain valve to lower level in the tank to support the maintenance effort. The day tank level was lowered to 33" upon which the primary fuel oil transfer pump start was verified. The EO then shut off the pump and placed the control switch in auto. Level was again reduced, approaching the 18" setpoint, when the fuel oil spill was discovered and the surveillance test terminated.

The inspector determined that the actions performed by the EO were consistent with operations surveillance procedure SP(O)4.8.1.1.3A (verifies proper fuel oil transfer pump operation), however it appears that this procedure was not being used by operations for the evolution described above. Further there does not appear to be a procedure that provides operator actions for the low-low level (18") part of the calibration procedure.

Licensee investigation into the cause of the 1C DG day tank overflowing is continuing, however several factors appear to have contributed to the problem. It appears that the backup fuel oil transfer pump was running prior to the day tank level reaching the 18" level, which means both primary and backup pumps were running together for a period of time (twice as much fuel oil being transferred as expected). The two inservice day tanks should have been able to handle this flow. However, the licensee had noted on November 28, 1988 during performance of the operations surveillance SP(O)4.8.1.1.3A on No. 11 fuel oil transfer pump that it took twice as long as normal to fill the 1B day tank indicating an apparent blockage in the supply line to the 1B day tank (and a corresponding increase in flow to the 1A and 1 C day tanks). Work order 881128116 (A priority) was written to investigate this problem, but had not yet been worked. In addition, it is not known at this time why the dike surrounding the 1A DG day tank leaked.

The inspector noted that fire protection personnel were monitoring the cleanup effort in the DG room due to fire hazard concerns. The inspector's concerns with the adequacy of procedural controls and with the performance of surveillance tests on a system with suspected deficiencies remain unresolved pending further licensee review and NRC inspection effort. (UNR 272/88-22-01)

2.2.2 Unit 2

A. On November 12, 1988, the licensee identified that the No. 23 reactor coolant pump (RCP) No. 1 seal leakoff was abnormally high at greater than 5 gpm. (RCP No. 1 seal leakoff normally runs approximately 1 gpm or less. Technical Specification 3.4.7.2 requires controlled RCS leakage to be less than 40 gpm total). The 23 RCP seal package had been replaced during the outage and because of this the licensee expected that the leakoff would reduce to normal as RCS pressure was increased and the No. 1 seal sealing surfaces came into proper alignment and seated.

The inspector observed that Abnormal Operating Procedure AOP-RCP-2 "No. 1 Seal Failure" procedural requirements were instituted by the licensee, including closely monitoring seal leakoff, seal water temperatures, and pump characteristics. In addition, system engineering provided additional guidance to the operators in the form of Technical Department Engineering Memos (No. 88-089 dated November 13, 1988 and No. 88-090 dated November 14, 1988). The inspector reviewed these documents and determined that the guidance provided initiated more conservative actions than the AOP referenced above.

The licensee determined that the No. 1 seal leakoff line could not be isolated by the operators from the control room as specified in AOP-RCP-2 for a No. 1 seal failure due to the remote isolation valve 23CV104 not being able to be fully closed. The AOP was revised to direct the operators to close the manual isolation valve CV105 if the CV104 valve does not provide isolation when required. On November 18, 1988, after determining that the seal leakoff was not improving as expected and in consideration of the degraded condition of the 23CV104 valve, the licensee placed Unit 2 in Mode 5, (cold shutdown) to replace the No. 1 seal and repair 23CV104.

The inspector observed portions of the disassembly and reassembly of the No. 23 RCP seal package and repair of 23CV104. The licensee determined that no major deficiencies were found with the seal, however the No. 1 seal was replaced. 23CV104 was found to have stem binding and was satisfactorily repaired. The unit was subsequently returned to power and no further problems have been observed with the RCP seals.

B. On November 28, 1988, with Unit 2 at approximately 25% power and preparations for main generator synchronization in progress, a reactor trip occurred due to low-low level in No. 22 Steam Generator (SG). The SG level transient occurred as a result of valve No. 23BF19 (No. 23 SG main feedwater regulating valve) jamming open causing a sudden level increase in No. 23 SG. The reactor operator (RO) took manual control of 23BF19 from the control room, but could not close it fast enough to prevent the level in No. 23 SG from reaching the high-high level (67%) setpoint upon which feedwater is isolated (BF19s close) and both steam generator feedwater pumps (SGFP) are tripped. As a result of the loss of feedwater, SG levels decreased with No. 22 SG level reaching the low-low level (8.5%) reactor trip setpoint. SG levels were subsequently returned to normal levels (33%) using the auxiliary feedwater system and the unit was stabilized in Mode 3 (hot shutdown). The inspector discussed this event with licensee operations, maintenance and engineering personnel, and reviewed operating logs, procedures and control room traces for pertinent plant parameters. The inspector's investigation of the 23BF19 problem which initiated this event is discussed in the Maintenance Section (5.0) of this report.

C. On December 9, 1988, the licensee determined that the No. 2 main transformer oil combustible gas concentration exceeded the manufacturer's guidelines and removed the unit from service to investigate. The inspector discussed the transformer problem with the system engineer, reviewed applicable licensee records and data and determined the following.

The transformer had been rebuilt and was installed during the recent outage. The licensee had also installed an on-line combustible gas monitor on the transformer during the outage and had been monitoring combustible gas concentration via the on-line system since full power operation began on December 5. The licensee noted that the data obtained was higher than normal for a new transformer and was following the parameter closely. Transformer oil grab samples obtained on December 5, 6, 7 and 8 indicated that the combustible gas concentrations were holding steady. However, on December 9, the on-line monitor indicated a significant increase in combustible gases which was later verified by a grab sample. Acetylene concentration was between 6-10 ppm from December 5 to 8 and increased to 87 ppm on December 9. IEEE limits and the manufacturers guideline for combustible gas concen-tration is 11 ppm. Fire protection personnel were notified and provided continuous coverage until the fire hazard concerns were alleviated.

The problem has been attributed to "static charge electrification", an emergent phenomenon which involves certain conditions within the transformer which cause a static charge to develop between the oil (+) and the windings (-). This results in arcing on the insulation and oil breakdown. The licensee plans to replace the transformer. The inspector concludes that licensee actions with regard to the transformer behavior was prompt in preventing further transformer degradation and possible failure which would have resulted in a turbine/reactor trip.

3. Radiological Controls (71707)

3.1 Inspection Activities

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

3.2 Inspection Findings

A. The inspector made daily tours of the radiological controlled area (RCA) on RWP 0004 and observed that the licensee has upgraded contaminated area markings and boundaries and has decontaminated and unposted several areas in the RCA (seal water heat exchanger room, sections of RHR pump rooms and the mechanical penetration areas). The inspector noted an improvement in licensee efforts with regard to control and housekeeping in and around contaminated areas.

B. The inspector witnessed maintenance activities performed on Nos. 22 and 23 Reactor Coolant Pumps under RWPs 1076 and 1094 respectively. The inspector noted that RWP 1094 specified full protective clothing, however the inspector observed inconsistencies in implementation of this requirement. Specifically, one person was not wearing a hood, four people did not tape their pant legs at the ankle and one of these did not have his sleeves taped at the wrist. The inspector brought the discrepancies to the attention of the Radiological Controls Engineer for resolution. Failure to comply with RWP requirements is a recently identified concern for which a violation was issued (50-272/88-18-01; 50-311/88-18-01). The licensee's response has not been reviewed. The inspector concluded that these instances were further examples of the same problem which will be addressed during NRC followup of the previous violation. Continued management attention may be required to resolve radiological procedure implementation concerns.

C. (Closed) Inspector Followup Item 50-272/88-09-02; 50-311/88-09-02; Update the Quality Assurance Plan Manual to reflect laboratory practices in the area of counting efficiency determinations. The licensee revised the Quality Assurance Plan Manual on May 6, 1988 to reflect current laboratory practices.

4. Surveillance Testing (61726, 61708, 61710, 72700, 72300)

4.1 Inspection Activity

During this inspection period the inspector performed detailed technical procedure reviews, witnessed in-progress surveillance testing, and reviewed completed surveillance packages. The inspector 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:

Procedure	Description
2IC-5.2.001	Rod Drop Time Measurement - Hot Full Flow
2IC-8.1.003	Rod Position Indication System Calibration
2IC-2.5.001	Reactor Coolant RTD Cross Calibration
1PD-2.6.056	Channel Functional Test - No. 14 Steam Generator Feed Flow
PLR8301RI	In-situ Response Time Testing of Installed RTD's using AMS Model ERT-1
PI/S-SW-1	Flushing of the Emergency Auxiliary Feed Supply Line

SP(O)4.4.7.2c	No. 21 - 24 Reactor Coolant Pump Controlled Leakage
SP(O)4.4.7.2.1	ECCS Subsystems - SI Check Valve Testing
SP(O)4.5.2b	ECCS Subsystems - Valve Lineup
SP(O)4.0.5V-MS-5 MS10	IST - Main Steam Valves for Valve No. 23
SP(O)4.0.5P-AF-23	IST - No. 23 Auxiliary Feedwater Pump
2IC-2.6.013 (functional test)	No. 24 Reactor Coolant Loop Delta T-Tavg Protection Channel IV
2IC-2.2.013 (calibration)	No. 24 Reactor Coolant Loop Delta T-Tavg Protection Channel IV
2PD-2.2.029	No. 21 Steam Generator Steam Flow Calibration
OP-TEMP-8808-2	2A Diesel Generator Retest
SP(O)4.8.1.1.2	Emergency Diesel Generators

Reactor Engineering Manual:

Part	Title
4	Preparation of Inverse count rate ratio
10	Post Refueling Initial Criticality
15	Boron Endpoint Determination
16	ITC Determination
20	Rod Swap Reactivity Measurement
200	Refueling Test Sequence
	Reload Safety Evaluation, Salem Nuclear Plant Unit 2, Cycle 5, Rev. 2

4.2 Inspection Findings

A. The inspector observed performance of Surveillance Procedure SP(O) 4.8.1.1.2 which checks operability of Emergency Diesel Generators. The procedure appeared adequate and the technicians had no trouble verifying the proper diesel response. However, deviation from the sequence of the procedure was noted in two separate steps. Step 5.1.6b which requires the technician to establish communications with the control room and request permission to start the diesel, and 5.1.6 which later requires the technician to request permission from the control room operator to load the diesel generator were omitted. Instead a blanket permission was given to the technician before starting the procedure to start and load the diesel. Inattention to detail in following procedures is a previously identified concern discussed in NRC inspection 50-272/88-19; 50-311/88-20. The inspectors are continuing to assess the licensee's procedure implementation.

B. During a tour of the Unit 1 main control room and the Unit 1 auxiliary building, the inspector identified twenty-seven gauges which had calibration stickers indicating that the instrument was out of calibration. The inspector determined that seven of these plant instruments did not require calibration and should have had a "for information only" sticker, two instruments were previously recalibrated by the Chemistry Department and had a different calibration frequency than the present sticker indicated, ten instruments had been recalibrated and the calibration stickers had not been replaced, and three instruments had gone from a three to five year calibration frequency and the calibration stickers had not been updated. The remaining instruments were left with the licensee for verification that the instruments had been calibrated at the proper frequency.

In addition, the inspector noted that control room console meters either had no sticker or had stickers indicating calibration was overdue. The inspector was informed by the licensee that instrumentation that is calibrated using a generic calibration procedure have stickers placed on them and instrumentation that is calibrated using a specific procedure for the individual instrument (such as transmitters and the control room console meters) do not have calibration stickers. The inspector observed, however, that when this policy was instituted old calibration stickers were not removed. Calibration stickers provide confidence to operators in the quality of the measurements/readings they take. They also provide management with timely assurance that the program is effective. It appears that the licensee's inconsistent use of calibration stickers is contrary to the intent of USNRC Regulatory Guide 1.30 (to which the licensee is committed in the Salem UFSAR, Appendix 3A) which states that items requiring calibration shall be labeled indicating date of calibration and identity of the person that performed the calibration.

The calibration program, which is managed through the computer based Managed Maintenance Information System (MMIS), appears to be effective for gauges that are related to Technical Specifications or that are used for operating log readings. However, the program is still evolving as indicated by the recent inclusion of chemistry department gauges, the postponement of the program's full implementation until after October 1, 1988, and the lack of any documentation or procedural guidance for the program.

The inspector will continue to monitor the licensee's progress in developing documentation for the calibration program, completing proper labeling of gauges outside the main control room and resolving the issue concerning labeling of control room console meters. The issue will be followed under unresolved inspection items 272/87-15-02 and 311/87-18-02.

C. The inspector witnessed startup physics test activities with regard to initial criticality and zero power physics testing following the Salem Unit 2, fourth refueling outage. The test procedures reviewed were acceptable and the inspector had no further questions in this regard. The inspector conducted test result verifications on the following tests.

i. Isothermal Temperature Coefficient (ITC)

The licensee measured the Isothermal Temperature Coefficient and calculated the Moderator Temperature Coefficient in accordance with Reactor Engineering Manual Part 16. The inspector independently verified the results using the reactivity computer traces. The inspector's results were consistent with those determined by the licensee. The acceptance criteria provided was consistent with the Technical Specification which requires the MTC to be less than or equal to zero. The All Rods Out (ARO) ITC was measured to be -5.666 pcm/F. The test results met the acceptance criteria and no unacceptable conditions were identified.

ii. Boron Endpoint Determination

The licensee measured the All Rods Out Critical Boron Concentration in accordance with the Reactor Engineering Manual Part 15. The inspector reviewed and noted the following results. The measured ARO Boron Endpoint was equal to 1499ppm, with an acceptance criterion of 1491±59ppm. The test results met the acceptance criteria and no unacceptable conditions were identified.

iii. Control Bank Worth Measurement

The control rod reactivity worth measurements were performed in accordance with the Reactor Engineering Manual Part 20 "Rod Swap Reactivity Measurement Method Test". The inspector independently verified the worth measurement of the reference bank using the reactivity computer traces, and witnessed the measurements of the remaining banks. The following results were noted.

Bank	Meas. Value	Calc. Value	Diff(%/pcm)	Acc.Crit.(%/pcm)
C/D	955.8	908	5.3	±10
C	873.6	876.6	-0.3	±15
B	780.0	840.0	-7.1	±15
A	406.2	406.2	0pcm	±100pcm
S/D	397.8	378.8	19pcm	±100pcm
C	400.8	375.8	25pcm	±100pcm
B	896.3	855.3	+4.6	±15
A	220.4	187.4	33pcm	±100pcm
Total	4930.9	4828.1	+2.1	±10

The inspector noted that Nuclear Supply Vendor did not supply bank worth values for rod swap as part of the vendor supplied nuclear design report. The Licensee uses rod worths generated by their Nuclear Fuels Group. The rod worths calculated by the utility are then used to normalize the measured rod worths so they can be compared with the vendor supplied Design Report values. The inspector reviewed the methodology used to compare the rod worths with the calculated values and found it to be acceptable.

During the control rod worth measurement, the inspector observed that the two groups of a control bank became separated by two steps. The operators immediately stopped rod movement. With the assistance of the plant staff, a method of realigning the groups and preventing further group misalignment was devised. Technical Specification (T.S.) 3.1.3.2.1(b) requires Group demand counters to be within ±2 steps of the pulsed output of the Slave Cycler Circuit over the withdrawal range of 0-228 steps. Upon further investigation by the inspector, it was determined that this T.S. requirement is verified by performance of IC 5.1.003, page 8 step 8.66. This is an I&C surveillance which is performed on a 18 month cycle. Neither the test procedure, nor the operators' understanding of T.S. 3.1.3.2.1 provided technical guidance on avoiding rod misalignment while moving the control banks in the individual bank select mode during the rod swap measurement. However, the inspector concluded that licensee's actions during the group separation were conservative with regard to T.S. 3.1.3.2.1(b).

The startup physics testing was conducted in accordance with licensee procedures and NRC requirements. All measured values of test parameters were within the acceptance criteria. The engineering personnel involved were knowledgeable in the startup physics test procedural requirements. However, it appears that procedure upgrades may be warranted to provide clarification and assistance to the operators relative to the rod position problems encountered during the rod swap measurements test.

5. Maintenance (62703)

5.1 Inspection Activity

During this inspection period, the inspector 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.

Portions of the following activites were observed by the inspector:

Work Order	Procedure	Description
880221001	Technical Manual 97-0675	Lubricate Governor Drive Gear No. 23 Auxiliary Feed Pump
881121222	2IC-2.6.013 2IC-2.2.013 2IC-2.6.009 2IC-2.2.009	Swap leads for No. 24 Hot Leg RTD (2TE-431A-B) to installed spare
881116089	M11E	No. 22 Reactor Coolant Pump (RCP) - add balance weight (472 grams) to No. 4 coupling bolt
941017001	M6A	No. 23 Reactor Coolant Pump seal disassembly, inspection and repair
881114108	MP7.8 M14A-2	Valve No. 23 CV104, 23 RCP No. 1 seal leakoff, inspect and repair
A0090067		Valve No. 23BF19, 23 steam generator feed regulating valve, troubleshoot and repair
A0090982	M3Z	Valve No. 21MS171, 21 Main steamline isolation valve (MSIV) vent valve air vent, troubleshoot and repair
Not available	M3Z	Valve Nos. 21 and 22MS169, 21 and 22 MSIV vent valve air vent, troubleshoot and repair

5.2 Inspection Findings

A. The inspector observed the removal of oil from the gear box of the governor for No. 23 auxiliary feedwater pump. The inspector observed that the work order included diagrams of the auxiliary feedwater pump highlighting the bottom plate of the gear box to be removed to affect the lubrication, a page from the Lube Oil Manual (LOM-1) which specified the type oil to be used, and a reference to the applicable technical manual (97-0675). Although there were no apparent problems identified in performing this maintenance activity, the inspector noted that the work order did not provide specific directions on how to perform the lubrication and that neither a separate procedure or the technical manual was present at the work location. In addition, the inspector noted that the specified oil was not available to refill the gear box and had to be requisitioned from the warehouse on an expedited basis, which delayed exiting the Technical Specification action statement indicating that prior planning for scheduled maintenance on safety related equipment may need enhancement. The inspector will continue to assess procedure and planning issues with regard to their impact on availability of safety related equipment.

B. The inspector observed maintenance activities performed on the steam generator feed regulating valves (21-24BF19) and discussed with licensee engineering and maintenance personnel issues surrounding the failure of 23BF19 which resulted in a Unit 2 reactor trip during this inspection period. Licensee investigation concluded that the failure of the valve resulted from the air supply regulator to the valve positioner being set too high (90-92 psig vs 85 psig) which caused the cam to overshoot on a high demand signal, bending the positioner linkage which resulted in the valve jamming open. The licensee determined that the regulators for 3 of the 4 feed regulating valves were set too high during outage maintenance due to personnel error. The Instrument Calibration Data (ICD) cards indicated that the regulator be set at 85 psig, however the licensee stated that an accepted rule of thumb is to set air regulators approximately 5 psig higher than what the valve actually needs and apparently the personnel setting the regulators did not know that the 5 psig was taken into account in the ICD value of 85 psig. Hence, in three of the four cases the regulators were set approximately 5 psig too high. The licensee repaired 23BF19 and reset the air regulators to the correct value.

The adequacy of the licensee's procedures and training for conducting work on the feed regulating valves is an unresolved item. (UNR 311/88-24-01)

C. The inspector observed several maintenance activities related to deficiencies identified by the licensee during operational testing of the main steam isolation valves (21-24MS167s). Each MSIV has a vent valve (MS168) which opens to bleed steam from the MSIV upper cylinder resulting in valve closure. The MS168 valves have a three way design which permits the valve to be lined up to either of two discharge valves (MS169 and MS171), or both at the same time. When the MSIV (MS167) receives an emergency closure signal from the Solid State Protection System (SSPS), the air supply to the selected discharge valve(s) (MS169 and/or MS171) is removed resulting in opening of the discharge valve(s) allowing the steam from the upper cylinder of the MSIV to vent through the MS168 valve and discharge to atmosphere via the MS169 and/or MS171 valves. During operational testing the following discrepancies were identified and corrected by the licensee. Licensee troubleshooting, repair, and testing were witnessed and verified by the inspector.

i. Discharge valve 21MS171 would not operate on signals from either SSPS train. The licensee determined that leads lifted on a timer in the circuit during outage activities had not been relanded due to personnel error. The inspector observed that the leads were landed and that the valve tested satisfactorily.

ii. Discharge valve nos. 21 and 22MS169s open limit switches did not make up. The inspector witnessed adjustment of the limit switches and observed that the valves tested satisfactorily. Licensee investigation determined that periodic environmental qualification maintenance was performed on the valves during the outage. The limit switch settings for these two valves were not verified at the completion of the maintenance activity because the valve was tagged for other maintenance activities and could not be stroked at that time. Apparently maintenance personnel did not go back after the tags were released and verify the switch settings. The licensee is assessing the root cause of this issue. The inspector is following licensee actions in this regard.

iii. The discharge valves (MS169 and 171) for each MSIV vent valve (21-24MS168) appeared to respond improperly (backwards) from that denoted on plant drawings. The switch in the control room which permits the operators to select either or both discharge valves is a three way switch labeled "Port A", "Port B", "Port A + B". According to plant drawings, Port A is MS169 and Port B is MS171. The switch is normally selected to the "Port A + B" position and the operational test is normally performed with both discharge valves selected. If the MSIV closes within the required time (5 sec) upon a signal from SSPS, the test and valves are considered satisfactory.

Due to the problems identified in 1.0 and 2.0 above and the licensee's troubleshooting efforts relative to these problems, the operational test was performed several times in the "Port A" and "Port B" switch positions. These test evolutions revealed that when "Port A" was selected, valve MS171 opened and when "Port B" was selected, valve MS169 opened. This is opposite of what should have occurred according to plant drawings. However, engineering investigation including infield wiring/piping walkdowns and drawing review and verification concluded that the installation is correct, but the control room switch was labeled incorrectly. Applicable drawings were inconsistent with regard to the Port A/Port B nomenclature. The licensee further determined that the same discrepancies were applicable to Unit 1.

The licensee plans to relabel the switches in each control room eliminating the Port A/Port B nomenclature and substituted the appropriate valve numbers (MS169 and 171). The switches currently have caution tags affixed to them requiring Operations Manager notification prior to changing switch position. Drawing upgrades to correct inconsistencies and change valve nomenclature are in progress. The inspector questioned the operability of the MSIV (ability to emergency close and perform its' intended safety function) if one of the discharge valves was to be worked at power with the conditions that one discharge valve was selected out of service using the incorrectly labeled switch and the possibility of maintenance being performed on the inservice discharge valve. The licensee determined that to perform maintenance on any discharge valve, the air supply would first be tagged which would allow the discharge valve to open and the MSIV to go closed resulting in a reactor trip. The licensee indicated that to their knowledge these valves have not been worked at power. Inspector review of this issue is complete.

The inspector observed good communication and cooperation between system engineers and I&C technicians during these troubleshooting activities. However, the inspector noted that the I&C technicians had in hand a work request for troubleshooting 21MS171 (Part 5.2.C.i) but did not have paperwork for the MS169/MS171 problem discussed in the previous paragraph. These troubleshooting activities were conducted in the same time frame and although the effort was directed by the engineer and was technically satisfactory, the inspector is concerned that working on plant equipment without having the proper work orders may result in challenges to safety systems. As a minimum, documentation of what the troubleshooting activities involved and as-found conditions may be lost. The inspector observed a similar situation with the maintenance performed on the BF19s discussed in Part B where all 4 valves were being worked on but only a work request for 23BF19 was at the job site. Discussions with the maintenance staff indicated that the work requests were being generated and were to be brought to the job site. The inspector will continue to assess the significance of this poor maintenance practice.

D. The inspector witnessed the swap of leads for one No. 24 Reactor Coolant System loop hot leg RTD to the installed spare due to its failing the RTD cross calibration. The inspector noted that the procedures used to perform the swap and post-maintenance testing were updated to indicate that the spare is in service. However, the inspector noted that the wiring diagrams were not updated to reflect the repositioning of leads. The inspector discussed this issue with the licensee and was informed that the licensee does not update drawings to reflect which installed spare is inservice and expects that in the case of installed spares, technicians should recognize and anticipate that the primary instrument or any of the installed spares could be inservice. The inspector is concerned that drawings that do not reflect actual plant conditions may be confusing to technicians and may result in errors. The licensee's technical staff is evaluating this issue and possible corrective actions. The inspector will follow licensee progress in this area.

The accumulation of minor discrepancies identified with each of the maintenance activities discussed above indicates that increased management and supervisory attention is needed to ensure implementation of acceptable maintenance practices in the field.

6. Emergency Preparedness (82301)

6.1 Inspection Activity

On November 29, 1988, the Artificial Island Emergency Plan Annual Exercise was conducted (NRC Combined Inspection 50-272/88-23; 50-311/88-26). The inspector observed drill activities in the Salem Unit 2 control room. The inspector observed event classification and offsite notifications, operator interactions, EOP use through EOP-LOCA-5, and communication between the control room, OSC and TSC personnel.

6.2 Inspection Findings

The inspector concluded that under the constraints of the drill scenario, control room response and activities were effective in protecting the health and safety of plant personnel and the public.

7. Security (71707)

7.1 Inspection Activity

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

7.2 Inspection Findings

The inspector observed security force containment access controls during the Unit 2 outages, reviewed applicable post orders and verified consistency with procedural requirements contained in security procedures SP-9, Control of Packages and Materials and SP-7, Personnel Access Controls. The inspector determined that licensee activities inspected were effective in meeting the safety objectives of the security plan.

8. Engineering/Technical Support (71707)

A. The inspector observed aggressive system engineering involvement and technical guidance with respect to troubleshooting and correction of identified problems encountered during the inspection period. Examples include the development of a comprehensive test procedure to verify operability of the 2A Diesel Generator, providing conservative documented technical guidance to operators regarding the No. 23 Reactor Coolant Pump No. 1 seal high leakoff, thorough investigation of the various MSIV discrepancies, and prompt identification and followup of the transformer high combustible gas problem. With regard to low power physics testing observed during the inspection period, the inspector found the Reactor Engineering Staff to be qualified and familiar with the Startup Physics Test Procedures. The Reactor Engineer performing the testing kept the control room operators informed as to the intent and direction of the tests being performed. The Nuclear Fuels Group provided strong support throughout the testing by providing both personnel and analytical test criteria.

B. The inspector noted that several of the procedures reviewed during the inspection period were overdue for their two year review. The inspector discussed this observation with the licensee's Technical Department (TD) personnel responsible for procedure reviews in order to ascertain the magnitude and significance of the problem. The inspector determined that the TD had taken primary responsibility for procedure writing, reviews and revisions in January 1987 resulting from the licensee's identification of the need for upgrade in the procedure control area including timely 2 year reviews. Previously each station group was responsible for their own procedures and had different methods for documenting the 2 year reviews. The inspector observed that the TD developed the Procedure Index Control System (PICS) which is used to track procedure reviews and revisions. The inspector reviewed PICS data and determined that approximately 10% of station procedures are due or overdue for their 2 year review. The inspector selected several procedures from the list and determined they were in fact in various stages of the review and/or revision process. The inspector reviewed TD procedure TI-10 "Control of Station Procedures" which provides instructions for the control of writing, review and revision of station implementing procedures and concluded that the procedure is consistent with Technical Specification (T.S.) requirements. The licensee has assigned 4 full time procedure writers, is in the process of computerizing all procedures to aid in faster turn around for reviews and revisions.

The inspector concluded that failure to perform procedure reviews is a violation of T.S. 6.8.2, however since the problem was identified by the licensee, is being corrected, and is of low safety significance, in accordance with 10CFR2, Appendix C a notice of violation is not being issued. (272/88-22-02; 311/88-24-02)

9. <u>Safety Assessment/Quality Verification</u> (71707)

Discrepancies identified during the inspection period indicate a need for increased management, supervisory and QA oversight of routine plant activities. Examples include the apparent lack of adequate procedural controls or supervisory oversight during performance of the diesel day tank level calibration in recognition of a previously identified blockage problem in the fuel oil transfer line that had not yet been corrected.

Several instances of personnel improperly wearing PC's in accordance with the RWPs indicates that corrective actions for similar previously identified occurrences have either not been implemented or are not effective. Procedural requirements for operability testing of the diesel generators (DG) were not properly implemented with regard to control room notification prior to DG synchronization and loading which is particularly disturbing in light of the recent out-of-phase synchronization event. Improperly executed maintenance activities performed during the outage with regard to BF19s and MSIVs subsequently caused operability problems with these valves. The inspector did not detect QA involvement or witnessing of either of the Unit 2 startups or the startup physics testing despite the P-9 modification and SG feed control problems Discussions with the QA Manager indicated that the QA organization has performed surveillances on startups and physics testing during previous startups. The inspector has observed that QA has been involved with large scope projects such as the 2A Diesel Generator maintenance and testing, main steam safety testing at the vendor lab, and control room redesign implementation. Significant problems were identified and brought to resolution by QA with respect to these activities. However, it appears that QA is not as actively involved or as effective in routine plant activities. The inspector will continue to monitor the effectiveness of licensee managers, supervisors and QA personnel in ensuring the quality of plant activities.

10. <u>Licensee Event Report (LER) and Open Item Followup</u> (71707, 90712, 90713).

Upon receipt, the inspector reviewed licensee event reports (LERs) as well as other periodic and special reports submitted by the licensee. The reports were reviewed for accuracy and timely submission. Additional followup performed at the discretion of the inspector to verify corrective action implementation and adequacy is detailed with the applicable report summary. The following reports were reviewed during the inspection.

A. Unit 1 Monthly Operating Report - October, 1988
Unit 2 Monthly Operating Report - October, 1988

B. Unit 1 LER 88-003; Reactor Trip on a False Intermediate Range-High Flux Signal Due to Personnel Error

A reactor trip occurred when a maintenance I&C technician repeated a channel adjustment procedure on N35 Intermediate Range (IR) and failed to properly perform the procedural steps in sequence. As a result, the technician pulled the channel fuses prior to bypassing the output trip signal, which resulted in IR High Flux trip signals tripping the reactor. The Nuclear Training Center has incorporated the lessons learned from this trip into their maintenance training program, the procedure PD-16.4.034 NI channel adjustment has been revised, and a Human Performance Evaluation System (HPES) report has been completed.

The HPES report identified the root cause as a failure to follow procedures with complicating factors involved such as problems identified with the content of the procedure and the method of assignment of technicians to perform repetitive tasks. Inspector review of this event is complete and unresolved item 50-272/88-08-01 is closed.

C. Unit 1 LER 88-19 Technical Specification 3.7.11
Unit 2 LER 88-21 Non-Compliance - Late hourly roving firewatches

These LER's document three occasions, one each on September 26, 1988, October 10, 1988 and October 31, 1988, where firewatch personnel fell asleep resulting in the rove for several plant areas not being completed within one hour as required. Two of the three individuals involved subsequently tested positive for drug use. The individuals were relatively new hires (less than 6 weeks) and passed the pre-employment drug screening. The inspector reviewed the details of these occurrences, previous instances of late firewatches since January 1988, licensee corrective action implementation and effectiveness and held discussions of these issues with the Fire Protection Supervisor and the Site Protection Manager. The inspector concluded that the root cause (sleeping) of the events was different from previous occurrences (Unit 1 LER 88-08 dated March 1988 and Unit 2 LER 88-05 dated April 1988) both of which involved not complying with the rove sequence, and that additional corrective actions taken to prevent reoccurrence for the September 26 incident were not fully implemented by the licensee when the October 10 and October 29 instances occurred.

Corrective actions included soliciting and achieving support from the firewatch union and business agent to deter inappropriate behavior of firewatches, reiterating to the firewatches to notify their supervisor and ask for relief if not fit, and strengthening of the firewatch to supervisor periodic call in program. The inspector also determined that the licensee's corrective actions to identify and prevent potential late firewatch occurrences implemented since the earlier problems are aggressive and generally have been successful. (No deficiencies due to incorrect rove sequence since April 1988 and no sleeping firewatches since November 1988.) Since the occurrences were licensee identified, corrective actions were aggressive and appear to be effective, and safety significance is minimal since detection systems were operable in the areas in question, in accordance with 10CFR2, Appendix C no violation is being issued. (272/88-22-03; 311/88-24-03)

D. Unit 2 LER 88-20 discusses a T.S. non compliance on October 2, 1988 in which the fuel handling building (FHB) crane was operated over the fuel pool for fuel assembly insert change outs without both FHB exhaust fans operable. The root cause of the event was inadequate communication and coordination of activities between operations supervisors. The tag out for this ventilation system was authorized by operations prior to completion of the FHB activities. Corrective actions include developing a standard tagout which will ensure tagout of the FHB crane when the FHB ventilation system is inoperable. The inspector concluded that this is a licensee identified violation for which no further action is required. (311/88-24-04)

E. Unit 2 LER 88-022 provides details on the history, discovery and repair of through wall cracks on both containment spray system header isolation valves. Inspection activities related to this event are discussed in NRC Combined Inspection Report 50-272/88-19; 50-311/88-20. The inspector had no further questions following review of the LER.

F. Unit 1 LER 87-019-01; this supplement documents the results of additional investigation and corrective actions by the licensee to ensure that the oxygen concentration in the Waste Gas Holdup System is maintained below T.S. limits. The inspector had no further questions.

G. Unit 1 Supplemental Special Report 88-3-3 addresses additional degraded fire barrier penetrations discovered during the licensee's Penetration Seal Review Program. Unit 2 Supplemental Special Report 88-5-1 documents that all fire penetration impairments resulting from Unit 2 refueling outage activities have been resealed. The inspector is continuing to follow licensee actions in this area.

11. Exit Interview (30703)

The inspectors met with Mr. L. Miller 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.