U. S. NUCLEAR REGULATORY COMMISSION

REGION I

Report No. 50-272/89-22
50-311/89-20

License DPR-70
DPR-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: September 5, 1989 - October 16, 1989

Inspectors: Kathy Halvey Gibson, Senior Resident Inspector
Stephen M. Pindale, Resident Inspector

Approved: James C. Stone 11/7/89
For P. D. Swetland, Chief, Reactor Projects Section 2A Date

Inspection Summary:
Inspection 50-272/89-22; 311/89-20 on September 5, 1989 - October 16, 1989

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

Results: Several instances of prompt licensee response to incidents and good attention to detail were noted during this inspection. Three unresolved items were identified concerning the improper implementation of a Technical Specification required action (Section 2.2.3.A), the import of motor operated valves with heaters energized (Section 5.2.C), and overdue calibration of various security computer system meters (Section 7.2.B).

Details

1. SUMMARY OF OPERATIONS

At the beginning of the inspection period, Unit 1 was operating at 55% power due to a feedwater system valve failure and Unit 2 was operating at 100% power. Unit 1 returned to full power operation on September 10, and continued until September 18, when power was once again reduced to 55% due to feedwater system problems. The unit was returned to full power on September 25 and continued until the end of the inspection.

Unit 2 reduced power to 90% on October 5 due to a main transformer problem, and on October 13, a controlled shutdown was initiated to replace the degraded phase B transformer. At the end of the inspection, Unit 2 was in Mode 5 (Cold Shutdown) for an approximate two week outage.

2. OPERATIONS (71707, 71710)

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 included 278 inspection hours including weekend and deep backshift inspections on September 17 (4:25 p.m. - 10:00 p.m.), September 20 (2:15 a.m. - 5:00 a.m.), and October 11, 1989 (4:00 a.m. - 5:00 a.m.).

2.2 Inspection Findings and Significant Plant Events

2.2.1 Unit 1

A. On September 18, Unit 1 reduced power from 100% to about 55% to remove No. 12 steam generator feedwater pump (12SGFP) from service due to high vibrations. A plant operator noted an abnormal operating sound at the pump, and followup vibration monitoring by an offsite vendor indicated higher than normal values, although installed vibration equipment indicated normal values. The licensee identified a wiped bearing upon pump disassembly. Additionally, the 12SGFP turbine had experienced about a 30 mil upward growth. The licensee attributed the pump and turbine problems to a possible shaft misalignment. The licensee stated that the pump/turbine unit, which is connected to the large diameter feedwater piping, is very sensitive to minor misalignments. The pump was subsequently repaired and properly aligned, and the unit was returned to full power on September 25. No similar problems occurred upon startup and subsequent operation. The licensee used more precise vibration monitoring to measure component growth during startup to detect problems in a timely manner. In this case, prompt identification by station personnel assisted in early detection of the problem and possibly prevented an operational transient. The inspector had no further questions.

2.2.2 Unit 2

A. On September 21, a system engineer recognized that a phase B MPT local instrument indicated a high total combustible gas (TCG) concentration. The system engineer immediately requested that a transformer oil sample be drawn and analyzed. The results yielded a TCG concentration of 2400 ppm, as compared to the previous weekly sample result of 907 ppm. No acetylene was detected in the analysis. Daily samples were taken and the TCG concentration reached approximately 3100 ppm on September 26. The licensee then began taking three samples daily to monitor TCG trends. Additionally, unit load was reduced to 90% reactor power on October 5 to reduce the heat load on the main power transformer. TCG concentration peaked at about 4500 ppm, which is indicative of an internal hot spot in excess of 700 degrees F.

Licensee review of the TCG concentration trend charts revealed a significant amount of fluctuation between samples. Therefore, the licensee concluded that the appropriate and most prudent action would be to take the unit off-line and repair the transformer before conditions seriously degraded.

On October 13, a Unit 2 controlled shutdown was initiated to replace the phase B main power transformer (MPT). Licensee management elected to shutdown the unit to Mode 5 (Cold Shutdown) so that additional shutdown work activities could be performed, such as solid state protection system wire pull testing, control rod drive mechanism ventilation repair work and a main steam isolation valve circuitry modification. An outage duration of about two weeks was anticipated. Mode 5 was reached just prior to the end of the inspection period on October 15.

Salem has experienced similar transformer problems in the past. The deficiencies have been attributed to a susceptible transformer design, aggravated by environmental geomagnetic induced currents.

The presence of such induced currents were confirmed on September 19 by the electrical system load dispatcher. The Unit 1 transformers have been replaced with a less susceptible design, and the same change is planned for Unit 2 during the next refueling outage (April, 1990). The degraded phase B transformer will be replaced with a rebuilt spare. The licensee plans to develop preventive action recommendations for plant operators in the event that further reports are received of geomagnetic solar flares. Such actions include immediate power reductions of predetermined values and duration. The inspector concluded that the licensee's actions with respect to identifying, trending and addressing this issue were appropriate. The licensee's early detection and prompt outage scheduling/planning, and subsequent decision to shutdown the unit to prevent either an unexpected forced shutdown or ultimate transformer failure were particularly noteworthy.

2.2.3 Both Units

A. On September 9, the licensee identified that a Technical Specification (TS) required action had not been properly implemented. Unit 1 TS 3.3.2.1, Table 3.3-3 requires that when one channel of the auxiliary feedwater (AFW) system automatic start function from an emergency trip of the steam generator feedwater pumps (SGFP) is expected to be inoperable for more than 72 hours, the affected channel is to be jumpered to start of the motor driven AFW pumps upon the loss of the other SGFP. On September 4, 12SGFP was removed from service to perform check valve maintenance and was returned to service on September 9, without installing the necessary jumper.

Both motor driven AFW pumps are designed to automatically start when both main SGFPs emergency trip (two out of two logic). The circuitry prevents the automatic start of the auxiliary feedwater pumps when the SGFP trip is due to a steam generator high water level or when they are tripped manually from the control room console. TS 3.3.2.1 requires that a jumper be installed for a SGFP taken out of service so that an emergency trip of the operating SGFP will satisfy the actuation logic and automatically start the motor driven AFW pumps as per design (one out of one logic).

Licensee review of this event identified that during a routine tagout process for a SGFP, a normal evolution was to shut the associated suction valve. With the suction valve shut, the licensee stated that a SGFP low suction pressure trip is generated, which is equivalant to a jumper for the associated train of the AFW pump automatic start circuitry . Therefore, upon an emergency trip of the operating SGFP, the AFW actuation function would have been available. Based on this review, the licensee concluded that this event was not a TS non-compliance issue.

The licensee also conducted a review of Unit 2 TSs to determine whether a similar concern existed. It was found that the Unit 2 TSs were incorrect in that Table 3.3-3 listed two actuation channels per SGFP when in reality there is one per pump. Additionally, the Unit 2 TSs do not provide any similar requirement to install a jumper when one SGFP is taken out of service, although system and actuation design necessitates such action. The licensee stated that they would administratively implement the appropriate actions on both units and that TS change requests were in process for both units.

Although not specifically covered during this inspection period, the licensee identified on October 17, that contrary to the previous position, closing the SGFP suction valve would not provide the appropriate AFW pump start logic actuation. The system engineer identified that the standard tagout process included the removal of the 125 VDC power supply for the associated circuitry, which de-energizes the trip signal from the out of service SGFP. The licensee was continuing a review of this event at the close of the inspection, including permanent corrective actions, TS and procedure changes and a 10CFR50.73, "Licensee Event Report", applicability determination. Pending resolution of the issue, this item is unresolved (UNR 50-272/89-22-01).

B. ESF System Walkdown

The inspector independently verified the status of engineered safety feature (ESF) systems by performing system walkdowns. System components and support systems were verified to be operable, such as hangers and supports, electrical cabinets, insulation, area ventilation, valves and pumps, and component lubrication and cooling subsystems. Proper calibration status for installed instrumentation and proper housekeeping were also verified. The inspector performed detailed walkdowns of the auxiliary feedwater (AFW) systems. The overall status and condition of these systems was acceptable. Individual deficiencies were brought to the licensee's attention for resolution, including examples of materials (e.g. gloves, tools, lubricants) found in normally locked closed AFW instrument panels and missing lock wires associated with Bailey valve positioners.

The inspector selected for review three NRC Information Notices (INs), 89-48, "Design Deficiency in the Turbine Driven Auxiliary Feedwater Pump Cooling Water System, 89-58, "Disablement of Turbine-Driven Auxiliary Feedwater Pump due to Closure of One of the Parallel Steam Supply Valves, and 89-61, "Failure of Borg-Warner Gate Valves to Close Against Differential Pressure", which were related to the AFW system. The inspector verified receipt and distribution of the INs, reviewed the licensee's internal responses and actions, and concluded that the actions taken were appropriate and timely. No concerns were identified.

3. RADIOLOGICAL CONTROLS (71707)

3.1 Inspection Activities

PSE&G's compliance 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

A. On September 17, the licensee identified a 6 Rem/hr radiation hot spot inside the Unit 2 auxiliary building. A firewatch supervisor noted that the firewatch roving personnel had received a small, but abnormal radiation dose (less than 5 mRem) following a recent tour. The supervisor then notified Radiation Protection (RP) personnel, who performed radiation surveys and identified the 6 Rem/hr hot spot on a section of piping which runs along the floor of the demineralizer alley cubicle. The cubicle is provided with two access points, neither of which can be locked. RP personnel immediately roped off the area and posted it as a high radiation area (greater than 1 Rem/hr) in accordance with station procedures. Since the access areas could not be blocked, an RP person was posted at the area to restrict personnel access. Calculations performed by RP determined that the whole body radiation dose 18 inches from the hot spot was 1.2 Rem/hr and about 125 mRem/hr in the adjacent pathway. Preparations were also made to install lead blankets to shield the hot spot in accordance with station procedures. However, the line was flushed before the lead blankets were installed.

Within about six hours, the operations department flushed the line with demineralized water and removed the hot spot. General area dose rates were then at about 2-4 mRem/hr. The portion of piping which contained the hot spot is used for resin sluicing operations. The general area had been recently surveyed (about 6 hours earlier), and no abnormalities existed. The licensee performed a review to identify whether any valves associated with the spent resin storage tank or any other lines tied to the piping were manipulated, however, none were identified. Additionally, operations verified that all lines leading to the piping section were isolated. The licensee suspected that valve leakage, allowing a hot resin particle to reach the line accounted for the high radiation source.

The licensee requested system engineering to perform an additional evaluation to determine the root cause and source of the hot spot and if any long term corrective actions are necessary. The inspector concluded that RP action in response to this event was prompt and effective and the fire protection supervisor's efforts to quickly identify and report the unexpected dose for further review were very good.

4. SURVEILLANCE TESTING (61726)

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:

-- 1IC-18.1.013 Solid State Protection System semi-annual reactor trip breaker operability test

-- M3Q-2 Reactor trip breaker semi-annual inspection, lubrication and testing

-- M3T 2B vital bus undervoltage and underfrequency trip setpoint check and time response surveillance test

-- SP(O)4.0.5-P-AF(11) Inservice testing - Unit 1 auxiliary feedwater pump No. 11

4.2 Inspection Findings

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

B. On September 21, 1989, the licensee informed the NRC that the Unit 1 "A" reactor trip bypass breaker (RTBB) undervoltage trip attachment (UVTA) failed the as-found output force measurement test with 460 grams of weight added to the trip bar. This test measures the excess margin that the RTB will overcome to trip the breaker. Preventive maintenance (PM) activities were then performed on the UVTA in accordance with procedure M3Q-2. The UVTA retested satisfactorily and the breaker was returned to service.

On October 2, 1989, the NRC was informed that the Unit 1 "B" reactor trip breaker (RTB) UVTA also failed the as-found output force measurement test. Following PM on the UVTA, the third trial of the post-maintenance output force measurement test failed. A new UVTA was installed on the breaker and tested satisfactorily. The breaker was then returned to service. Previous inspection results related to RTB UVTA test failures are discussed in combined inspections 50-272/89-20; 50-311/89-18.

The UVTA must be capable of tripping the breaker with 460 grams of weight added to the trip bar three consecutive times in order to be considered operable during periodic testing. In addition, the licensee continues to add weight in 60 gram increments until the breaker fails to trip to determine the margin of force above 460 grams that the UVTA is capable of tripping. The results for the 1A RTBB and 1B RTB were as follows:

		1A RTBB	1B RTB	
			Old UVTA	New UVTA
As found	Trial 1	failed	failed	1300
	2	---	---	1300
	3	---	---	1300
As left (following PM)	Trial 1	580	460	same as "as found"
	2	580	460	
	3	580	failed	

Following notification of the as-found failures for these two breakers the inspector requested the licensee to reduce the weight incrementally from 460 grams to determine the margin of force the UVTAs were capable of tripping. The results were as follows:

1A RTBB	1B RTB
460 failed	460 failed
440 passed (breaker tripped)	390 passed
460 failed	440 failed
440 failed	420 passed
420 failed	
400 failed	
380 passed	
400 passed	
420 passed	
440 passed	
460 failed	

The inspector observed that although the UVTAs did not meet the 460 gram test acceptance criteria, the UVTAs exhibited a margin of force of at least 380 grams. The inspector concluded that based upon these results the UVTAs had considerable margin remaining to trip the breakers had they been called upon to do so.

The licensee is continuing their dialogue with Westinghouse concerning the cause of the apparent marginal lot of UVTAs received at Salem that had margin's of force in the range of 460-640 grams. The most recent UVTAs purchased appear to be consistent in quality with previous lots of UVTAs evidenced by the new one installed on the 1B RTB which exhibited a margin of force of 1300 grams. The system engineer is keeping the inspector informed with regard to continuing licensee efforts to resolve the UVTA problem and the continuing review to amend RTB commitments.

5. MAINTENANCE (62703)

5.1 Inspection Activity

During this inspection period, the inspector observed portions of selected maintenance activities to ascertain that these activities were conducted in accordance with approved procedures, Technical Specifications, and appropriate industry codes and standards. These inspections were conducted in accordance with NRC inspection procedure 62703.

Portions of the following activities were observed by the inspector:

Work Order	Procedure	Description
890918112	MP 6.1	Boric acid transfer pump-replace casing gasket
870813022	M3L-1	12SJ134, No. 12 safety injection pump to cold leg MOV; Limitorque limit switch setup and MOVATS testing
890925117	14.1.001	Investigate 23AF21 demand indicator
890306121	M3Z	Surge suppressor diodes
890913088	----	Repair service water system elbow leak

5.2 <u>Inspection Findings</u>

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

B. During preparations for casing gasket replacement of the boric acid transfer pump, the radiation protection (RP) technician assigned to this area of the RCA identified that the maintenance workers had not signed-on a Radiation Work Permit (RWP) for work involving a primary system breach. The RP technician questioned whether the workers would exit the RCA and reenter on a special RWP prior to breaching the boric acid system. The pump had not yet been disassembled, and the job was stopped until the workers signed-on an appropriate RWP and the RP technician ensured that RWP requirements were met. The inspector observed that an RWP number was not specified on the work order (WO) and noted that this discrepancy was not identified during the pre-job briefing. The inspector was concerned that adequate radiation and contamination controls may not be implemented when an incorrect RWP is utilized. This situation was discussed with the RP and maintenance engineers to ascertain whose responsibility it is to ensure maintenance is performed utilizing the correct RWP. The inspector was informed that the RWP should be specified on the WO prior to issuance. However, up to this point, because of the large number of WOs issued at times and only one RP person matrixed to planning to assign the RWPs, WOs have sometimes been issued without the RWP specified. It was assumed that the maintenance supervisor would assign the RWP on the WO before giving it to the workers. In this case, however, the supervisor left it up to the workers to choose the RWP for the job. The licensee acknowledged that several other similar discrepancies had previously occurred as a result of this practice. To correct the problem, planners and maintenance supervisors have been instructed that WOs are not to be issued or accepted without an RWP specified, if an RWP is required as noted on the WO. In addition, the inspector was informed that RP personnel will continue to monitor compliance with station procedures and RWPs. The inspector concluded that attention to detail by the RP technician was noteworthy, and the licensee's corrective actions are acceptable.

C. During performance of limitorque preventive maintenance (PM) and surveillance activities associated with motor operated valve (MOV) 12SJ134, the maintenance crew identified burn damage to wire insulation internal to the motor operator, apparently due to their close proximity to an energized limit switch compartment heater. An action request (AR) was submitted for engineering disposition. Licensee immediate corrective actions included repairing the wires and tagging open all MOV heater power supply breakers. Valve 12SJ134 was subsequently tested with satisfactory results. The licensee inspected 11SJ134 and identified that a limit switch compartment heater was present but was not wired and therefore not energized. No wiring damage was identified.

The inspector discussed the wire damage issue with station management and engineering personnel with regard to valve operability, applic-ability to other MOVs, and actions taken in 1986 in response to Information Notice (IN) 86-71, "Recent Identified Problems With Limitorque Motor Operators", which discussed MOV wiring damage due to internal heaters. The licensee informed the inspector that the 12SJ134 insulation damage was not severe enough to prevent the valve from performing its intended function. However, the inspector was informed that since the licensee thought that the heaters had been removed in 1986 as a result of the IN, licensee management elected to perform a sample inspection of Unit 2 valves since it was in an outage to determine the extent of the problem. The Unit 2 MOV inspections were in progress at the end of the inspection period. Further, the licensee was attempting to verify what other MOV related actions were taken in 1986. The inspector noted the attention to detail displayed by the maintenance workers in identifying the damaged wire insulation and raising the issue to the appropriate levels for proper resolution. Pending the results of the licensee's investigation and resolution of the problem, this item is unresolved (UNR 50-272/89-22-02).

6. EMERGENCY PREPAREDNESS (71707)

6.1 Inspection Activity

The inspector reviewed the licensee's procedures for reporting and response to hurricane activity and observed several training drills performed by the licensee in preparation for the upcoming graded Emergency Plan exercise.

6.2 Inspection Findings

A. The inspector reviewed Emergency Classification Guide (ECG) Section 12, Earthquake/Severe Weather and Abnormal Operating Procedure (AOP), AOP-WIND-1 to verify licensee procedures and preparations for potential hurricane activity due to Hurricane Hugo. The inspector identified that the entry conditions for the ECG and AOP were discrepant in that the ECG required declaring an Unusual Event at 70 mph wind speed while the entry condition for the AOP was 90 mph wind speed. This discrepancy was discussed with the senior nuclear shift supervisor (SNSS) who determined that the ECG had been revised to the more restrictive wind speed value, but the AOP had not been updated. An on-the-spot change was made to the AOP to resolve this issue. The inspector questioned plant management as to whether a generic review of the ECG and related procedures to verify consistency was planned in light of this recently identified discrepancy. The inspector was informed that this type of review was previously planned to be performed as part of the Procedure Upgrade Project (PUP). The inspector was further informed that the AOP upgrade is scheduled to be completed during the first quarter of 1990. The inspector discussed this issue with the Salem General Manager (GM-SO) and expressed concern that ECG requirements for emergency response may not be implemented in the necessary time frame if similar discrepancies exist. The GM-SO acknowledged the concern, but stated that the rational, planning and priorities for the PUP were established and sound and he did not feel that redirection was necessary since the AOP's were one of the top priority groups of procedures to be processed. The inspector had no further questions.

B. With regard to inspector observation of training drills, several minor concerns were discussed with the licensee's Lead Controller who factored them into the drill critique for resolution. The inspector concluded that conduct of the training drills was effective in that performance improvements were noted.

C. (Closed) Violation 272/89-17-01; Inadequate Event Classification Guide (ECG) procedure. The ECG has been revised to clearly identify the proper reporting requirements. The appropriate sections were revised to facilitate usage. Additionally, the Emergency Preparedness Department conducted detailed training on the revised ECG for the senior shift supervisors. Licensed operators will receive similar training during their requalification cycle. The inspector reviewed the revised ECG and determined that the appropriate 10CFR50 reporting requirements were clearly identified. This item is closed.

7. SECURITY (71707, 62703)

7.1 Inspection Activity

PSE&G's compliance with the security program was verified on a periodic basis, including the adequacy of staffing, entry control, alarm stations, and physical boundaries. The inspector reviewed design change package (DCP) 1SC-2156, "Modification of Security Fence Routing" and observed portions of DCP implementation.

7.2 Inspection Findings

A. The activities observed relative to the security fence modification were effective with respect to meeting the objectives of the security plan and procedures and the design change implementation process.

B. During a walkdown of the security computer power supply equipment, the inspector observed that various meters associated with the system were overdue for calibration as indicated by the calibration stickers affixed to them. The inspector had discussed this issue previously with security personnel, but noted that the problem has not yet been resolved. The inspector discussed this observation with the security engineer and was informed that a security inverter maintenance procedure is being written for this equipment which will include the calibration frequencies and procedures. A recurring task in the licensee's maintenance tracking system (MMIS) will be developed to ensure the calibrations are performed at the required frequency. The licensee has committed to complete these actions by December 31, 1989. This matter will be unresolved pending completion of the licensee's corrective actions (UNR 50-272/89-22-03).

8. ENGINEERING/TECHNICAL SUPPORT

(Closed) Unresolved Item 272/89-20-01; Failure of 12SGFP discharge check valves. The licensee manufactured a new hinge pin and repaired the check valve, and Unit 1 returned to full power on September 10. All loose parts were recovered except for the tip of the hinge pin. Inservice loose parts monitoring was performed at several potential locations in an attempt to locate the loose part, however it was not found. The licensee concluded that the failed hinge pin had been damaged for a relatively long time based on the evidence of erosion, therefore the loose part had most likely traveled and subsequently lodged itself. The system engineer contacted the valve vendor for the spring loaded check valve (mounted 45 degrees from vertical) to determine a permanent corrective action. A permanent resolution has not yet been reached, however, the licensee's efforts are continuing.

The licensee currently plans to inspect the Unit 2 swing check and spring loaded check valves during the upcoming refueling outage (April 1990). Acoustical monitoring is also under consideration for both units. Discussions with the valve vendor indicated that sustained plant operation at certain power levels can increase the likelihood of check valve bumping against its closed or open seats and therefore damaging the valve internals. The licensee stated that guidance will be provided to plant operators, restricting plant operation in the trouble zones.

Failed check valves of various types and applications had been the subject of several NRC Information Notices and other generic industry correspondence. On October 15, 1986, INPO issued Significant Operating Experience Report (SOER) 86-3, "Check Valve Failures or Degradation". The SOER addressed the various industry generic check valve concerns and provided recommendations with respect to valve maintenance and valve design. The licensee received the SOER and issued action requests to the appropriate station groups.

The licensee's valve program consists of three stages; 1) identify, 2) inspect, and 3) surveillance. A contractor performed stage 1, using EPRI NP-5479, "Application Guidelines for Check Valves in Nuclear Power Plants", as a guideline for valve selection. Ninety-eight valves per unit were identified. A procedure development program is currently in place to generate specific maintenance/surveillance procedures for the various types of check valves. The licensee is also pursuing "Non-Intrusive Inspection Techniques", to develop baseline data (acoustical monitoring) to minimize the number of those valves required to be disassembled for inspection. The licensee's program is continuing. Its effectiveness will be monitored routinely by the inspectors.

9. SAFETY ASSESSMENT/QUALITY VERIFICATION (40500)

During this inspection period, the inspectors noted several examples of good attention to detail by various levels of the licensee's organization. The licensee's recent efforts to increase station sensitivity to identifying problems, communicating them to the appropriate level of management, and performing work activities in a deliberate manner appear to have been effective thus far. The inspectors will continue to monitor the licensee's programs to resolve recent problems as identified in the latest NRC SALP report.

10. LICENSEE REPORT REVIEW AND OPEN ITEM FOLLOWUP (92700, 92702)

10.1 The inspector reviewed the following licensee reports for accuracy and timely submission.

- Unit 1 Monthly Operating Report - August 1989
- Unit 2 Monthly Operating Report - August 1989

10.2 Reference to Open Items

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

Closed	UNR 272/89-17-01	Section 6.C
Closed	UNR 272/89-20-01	Section 8.A

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.