U. S. NUCLEAR REGULATORY COMMISSION

REGION I

Report No. 50-272/89-15
50-311/89-14

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: June 6, 1989 - July 24, 1989

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

Approved: Kathy Halvey Gibson for P.D. Swetland 8-3-89
P. D. Swetland, Chief, Reactor Projects Section 2A — Date

Inspection Summary:
Inspection 50-272/89-15; 311/89-14 on June 6, 1989 - July 24, 1989

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, and review of licensee event reports.

Results: Two violations relative to missed Technical Specification (T.S.) surveillance tests and three examples of failure to follow procedures are discussed in Section 9. These violations were licensee identified, however since corrective actions for previous similar occurrences did not prevent these instances from occurring, a violation is cited. Other examples of licensee inadequate corrective actions to prevent recurrence of previously identified problems are discussed in paragraph 10.0. Five unresolved items were identified concerning material control (Section 2.2.1B), engineering evaluations of surveillance test data (Sections 2.2.2B and 8.2B), unauthorized installation of a main steam drain valve (Section 8.2A), adequacy of correction actions to control oxygen concentration in the waste gas system (Section 9.0), and adequacy of T.S. amendment implementation (Section 9.0).

Details

1. SUMMARY OF OPERATIONS

Unit 1 was in Mode 3 (Hot Standby) at the start of the inspection period with preparations for startup from the eighth refueling outage in progress. On June 9, an automatic safety injection and reactor trip occurred from Mode 3 when a main steam safety valve opened prematurely. The reactor was taken critical on June 13. On June 18, a unit shutdown was initiated per Technical Specifications from about 20% power due to an inoperable Safeguards Equipment Control train. Mode 3 was reached before repairs could be completed. On June 19, when restart activities were in progress, an automatic reactor trip occurred from 45% power during post maintenance testing activities when a main steam isolation valve inadvertently closed. The following day, a safety injection check valve bonnet leak was identified inside containment, and a shutdown to Mode 5 (Cold Shutdown) was initiated for repairs. Valve repairs were completed on June 23, however, the licensee identified the presence of sodium in the reactor coolant system (due to improper boric acid batching). The sodium was subsequently removed and the reactor was made critical on June 27. Full power was reached on July 2. Power operation continued for the remainder of the inspection period.

Unit 2 operated at 100% power until June 10, when plant operators manually tripped the reactor after all six condenser circulators automatically tripped due to an instantaneous heavy grass buildup at the circulating water intake. The unit was returned to service on June 14, and power operation continued for the remainder of the inspection period.

2. OPERATIONS (71707, 71710, 93702)

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 169 inspection hours including weekend and backshift inspections on July 16 (9:30 a.m. - 1:30 p.m.) and July 19 (3:00 a.m. - 5:00 a.m.).

2.2 Inspection Findings and Significant Plant Events

2.2.1 Unit 1

A. On June 9, while in Mode 3 (Hot Standby), a Unit 1 safety injection (SI) and reactor trip occurred due to a high steam line differential pressure condition. That condition was created by the No. 13MS15 main steam safety valve (MSSV) lifting twice. Licensee review of this event concluded that saturated water inside the No. 13 steam line underwent an oscillating wave phenomenon, thereby changing to steam and back to water and creating localized pressure spikes within the steam line. The pressure oscillations apparently resulted in lifting 13MS15 twice and caused the differential pressure SI signal. The unit was stabilized in Mode 3 per station emergency procedures. In accordance with the licensee's Emergency Plan an Unusual Event was declared due to high head SI injection into the vessel. This event was reported to the NRC in accordance with 10 CFR 50.72 reporting requirements.

Further licensee root cause determination identified that operating procedures did not require placing the steam trap system in service in Modes 3 or 4 to drain the condensate from the main steam lines upstream of the main steam isolation valves. The failure to properly use this system apparently resulted in condensate buildup inside the steam lines. Licensee corrective actions for this event included revising operating procedures to direct placing the steam trap system in service when the plant enters Mode 4 (Hot Shutdown) during startup. In addition the licensee has requested Westinghouse to perform a review and analysis of the events to confirm the licensee's root cause determination.

Following the event, the licensee lift tested 13MS15, and found that it had lifted about 6 psig below its allowable setpoint. All the MSSVs were new and just installed during the recent refueling outage. All lift setpoints were factory set. Based on the 13MS15 result, the licensee elected to test the other MSSVs. The licensee speculated that some other MSSV setpoints may also be lower than the manufacturer set value due to the installed valves being exposed to high ambient temperatures from main steam piping which increases the spring temperature and lowers the valve setpoint. The MSSVs were tested and adjusted, as necessary. The licensee's engineering organization is continuing their investigation to confirm the cause of the MSSV setpoint discrepancies.

The inspectors review of this event is complete.

B. On June 18, 1989, the unit was shutdown to Mode 3 in accordance with T.S. due to the 1A Safeguards Equipment Controller (SEC) being inoperable during maintenance in excess of T.S. action statement

time limits. The licensee replaced two failed circuit boards and reset a sequence timing switch. The SEC was then tested satisfactorily and returned to service. The unit was returned to service on June 19, 1989.

C. On June 19, Unit 1 automatically tripped from 45% power due to low-low water level on the No. 13 steam generator (SG). The plant was ascending in reactor power following completion of repairs to the 1A SEC. The low SG level condition resulted when No. 13MS167 main steam isolation valve (MSIV) inadvertently closed during post-maintenance testing of an MSIV bypass valve on an adjacent steam line. The plant responded as per design and was stabilized in Mode 3 (Hot Standby). The licensee notified the NRC of the event in accordance with 10 CFR 50.72 reporting requirements.

The test procedure, SP(O)4.0.5-V, results in the closure of the bypass valve while checking the continuity of the closure circuit for all four MSIVs. A similar event occurred at Unit 2 on April 11, 1989, and as a result a failed reset relay was replaced. The licensee attributed the root cause of the Unit 1 event to be inadequate design of the test circuit. Further investigation revealed that due to the test circuit design, a degraded reset relay will permit inadvertent closure of the MSIVs. The licensee's initial efforts were to investigate a possible problem with the same relay which caused the Unit 2 reactor trip. During troubleshooting the Unit 1 circuit to determine the condition of the reset relay, the licensee recorded one inadvertent MSIV closure (under simulated conditions) out of 33 tests on the circuit. The relay operated satisfactorily 32 times. The licensee elected to send the relay offsite for evaluation to determine whether a defect or intermittent failure exists.

Licensee corrective actions include implementing a Unit 1 design change to improve the circuit design by providing an additional contact to prevent the relay from resetting during the MSIV bypass valve test. The modification will not prevent the MSIVs from actuating in the event a valid fast closure signal is generated. The licensee plans to similarly modify the Unit 2 circuitry during the next outage of sufficient duration. For the interim, the appropriate Unit 2 surveillance test procedure will be revised so that the circuit will not challenge the MSIVs.

The inspector will review the Unit 2 surveillance test procedures and the modification during a future inspection. The results of the vendor evaluation of the reset relay will also be reviewed by the inspector.

While in Mode 3 on June 20, the day following the reactor trip, the licensee identified that a safety injection check valve inside

containment was leaking at its bonnet connection. Licensee management decided to cool the plant down to Mode 5 (Cold Shutdown) to affect valve repairs. The repairs were completed on June 23. Subsequently, the licensee identified the presence of sodium in the reactor coolant system (RCS). Followup investigation identified that an improper mix of boric acid compounds had been inadvertently used in the batching process and subsequently injected into the RCS. The sodium was subsequently removed from the RCS by use of demineralizers and the unit was returned to service on June 27. The licensee was conducting an evaluation to determine the root cause for the wrong boric acid mix. Of particular concern is whether broader problems exist with respect to storage, labeling, and retrieval of material from the warehouse. This item is unresolved pending completion of this evaluation and review by the inspector. (UNR 272/89-15-01)

2.2.2 Unit 2

A. On June 10, plant operators manually tripped the Unit 2 reactor from about 15% reactor power following the loss of five (out of six total) circulating water (CW) pumps. Prior to losing the five circulators, the plant was operating at full power. Control room annunciators and indicators revealed high differential pressures across several CW screens, and operators immediately initiated a rapid manual power reduction. At about 49% power, the main turbine was manually tripped and the steam dump (SD) system was being used to remove heat from the primary system. However, within several minutes of the event, SD system actuation was automatically blocked due to the loss of condenser vacuum, resulting in lifting several steam generator safety valves. The control room supervisor directed plant operators to manually trip the reactor. The plant was subsequently stabilized in Mode 3 (Hot Standby) in accordance with station procedures. The plant responded to the trip as per design, however, two equipment problems occurred and are discussed below. The licensee reported this event to the NRC in accordance with 10 CFR 50.72 reporting requirements.

There are a total of 12 SD valves, which are divided into four groups of three such that each of the three valves dumps into one of the three condenser shells. Two of the blocking signals which prohibit SD valve operation are 1.) circulator not in service (two pumps per circulator), and 2.) condenser not available (low vacuum). During the event, five CW pumps had tripped within four minutes; resulting in the loss of circulators No. 22 and 23 which blocked the operation of eight SD valves. CW pump No. 21A remained running and circulator No. 21 was still available, thereby allowing four SD valves to dump steam to the No. 21 condenser. About 13 minutes following the loss of the five CW pumps, the condenser not available blocking signal had actuated, and closed the four open SD valves.

During licensee troubleshooting activities, it was identified that there was a defective coil in an interfacing relay associated with the No. 21A CW pump, causing an indication that all six CW pumps (all three circulators) were unavailable and totally blocked any SD operation at the initiation of the event.

The other potential equipment problem was the operation of the main steam atmospheric relief valves (21-24MS10), one on each of the four main steam lines. During the event, the MS10s did not automatically open when the lift setpoints were reached, resulting in main steam safety valves (MSSVs) opening. One MSSV (the lowest setpoint) per steam line opened, and then properly reseated. Plant operators subsequently opened the MS10s manually during the transient. The licensee attributed the failure of all four MS10s to a phenomenon called "reset windup", in which the valve controller "sits" at saturated conditions at about 800 psig, therefore the controller continuously attempts to seat the valve. The controller apparently cannot respond to quick transients and open the valves as the setpoint is reached (1035 psig). Operations management stated that the MS10s do open under the majority of conditions when called upon and that operators have been trained to expect either response. The licensee is conducting an evaluation to determine the acceptability of the controller application and to develop further guidance for plant operators to provide them with an increased understanding of the design response of the MS10s.

The root cause of the event was attributed to an external cause and inadequate corrective action in response to a similar prior event. The high screen differential pressure was the result of an apparent instantaneous accumulation of grass and debris on the screen. One day prior to this event, there were extreme weather conditions, including heavy rain and high winds. Those conditions resulted in significant amounts of grass to be in the river from which the CW pumps take a suction.

The CW intake structure is provided with vertically mounted trash racks. A mechanical rake serves to clean the trash racks, however, the licensee determined that the rake becomes ineffective when the trash racks are matted with large amounts of debris. The licensee also determined that the lower one-third area of the trash racks was matted and clogged the flow of water. This condition, in turn, resulted in higher flow velocities near the water surface in order to sustain normal CW pump flowrates.

A similar event occurred on Unit 1 in August, 1983. The corrective action associated with that event involved a one time cleaning of the racks but did not require any long term corrective actions or actions to prevent recurrence. Licensee actions for the recent occurrence included cleaning the trash racks and establishing a

preventive maintenance activity on an 18 month interval to periodically clean the racks.

In summary, plant operators responded well to the event. Equipment deficiencies occurred which require licensee resolution, including correcting an inaccurate LER and investigating the MS10 valve operation/ application concerns. The licensee identified that their actions for a previous similar occurrence were inadequate. The inspector questioned the licensee whether formalized increased monitoring of CW systems was appropriate following severe storms. The licensee stated that monitoring would be considered in their evaluations. The inspector concluded that the licensee actions in response to this event were acceptable.

2.2.3 Both Units

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, insulation, area ventilation, valves and pumps, and component lubrication and cooling subsystems. Calibration dates for installed instrumentation and proper housekeeping were also verified. The inspector performed detailed walkdowns of the high head safety injection and containment spray systems. The overall condition of these systems was acceptable. Individual deficiencies were brought to the licensee's attention for resolution.

3. RADIOLOGICAL CONTROLS (71707)

3.1 Inspection Activities

PSE&G's compliance with the radiological protection program was verified on a periodic basis.

3.2 Inspection Findings

Tours of the radiologically controlled areas were routinely conducted by the inspectors. The overall condition and contamination controls in the Auxiliary Building were satisfactory. Individual deficiencies were brought to the licensee's attention for resolution.

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.

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

- M3Q-2	Reactor trip and reactor trip bypass air circuit breaker semi-annual inspection, lubrication and testing.
- SP(O)4.0.5-P-AF(11)	Inservice Testing - Unit 1 Auxiliary Feedwater Pump No. 11
- SP(O)4.0.5-P-AF(12)	Inservice Testing - Unit 1 Auxiliary Feedwater Pump No. 12
- SP(O)4.0.5-P-AF(23)	Inservice Testing - Unit 2 Auxiliary Feedwater Pump No. 23

4.2 Inspection Findings

A. On June 26, 1989, the licensee informed the NRC that the Unit 2 "A" reactor trip breaker undervoltage trip attachment (UVTA) failed the as-found (prior to the preventive maintenance activity) output force measurement test. This test measures the margin of force in addition to the weight of the trip bar that the UVTA is capable of overcoming. The acceptance criteria for this test is 460 grams of weight added to the trip bar. Weight is then added in 60 gram increments until the UVTA fails to trip the breaker to determine the margin. The maintenance and testing of the reactor trip breaker (RTB) and UVTA is performed as part of the above six-month preventive maintenance (PM) activity. As a result of the Salem ATWS event, the licensee is committed to report any deficiencies identified with the RTBs to the NRC.

The licensee replaces the UVTAs every refueling outage. The licensee has observed that while the UVTAs all meet the acceptance criteria (460 grams) when received from the manufacturer, the margin of force which the more recently purchased UVTAs are capable of overcoming is less than the older UVTAs. The licensee has discussed this observation with the vendor to ascertain the cause, but to this date the vendor has not concluded a reason for the difference. However, as a result of the observed reduction in margin, the licensee has experienced intermittent failures of the UVTAs to meet the PM acceptance criteria for the output force measurement.

In pursuing the cause of this particular failure, the system engineer identified two discrepancies between procedure M3Q-2 and the "Westinghouse Maintenance Program Manual for the DB-50 Reactor Trip Circuit Breakers and Associated Switchgear" dated November 20,

1986. The discrepancies are (1) M3Q-2 did not require a linear measurement from the trip lever pin to the trip bar as specified in the vendor manual and (2) M3Q-2 specified that the weights be added to the trip bar prior to closing the breaker, while the vendor manual indicates that the breaker should be closed first, then the weights added to the trip bar. The M3Q-2 procedure was revised accordingly. The licensee determined that the linear measurement discussed previously was slightly out of tolerance for the 2A RTB (18/32" vs 15/32"). Following adjustment, the output force measurement test was performed and the results were acceptable (3 trials - 580 gr., 580 gr., 700 gr.). After lubrication of the UVTA in accordance with the M3Q-2 PM requirements, the "as left" results were 760 gr., 760 gr., 760 gr. for 3 trials. The 2A RTB was returned to service following completion of the M3Q-2. The system engineer has not concluded that the difference in test methodology is the root cause of the marginal performance of certain of the UVTAs and is continuing his investigation and discussions with the vendor and other utilities. The inspector will continue to follow licensee actions in this regard.

B. The Unit 2 surveillance test performed on the turbine driven Auxiliary Feedwater pump yielded unsatisfactorily results. Two sets of data were obtained for pump differential pressure in an attempt to get acceptable data. Both sets were in the action range. The operators therefore declared the pump inoperable and entered the appropriate Technical Specification Action Statement. The Technical Department subsequently reviewed the data and determined that the pump was operable. See Section 8.2.B for details regarding the licensee's technical evaluation.

The inspector questioned operations management relative to their policy regarding obtaining more than one set of data in performing a surveillance test and how the data is used if results are not the same (i.e. one set acceptable, one set not acceptable). In the case of the AFP test, both sets of data were in the action range (unacceptable), however only one set (the less unacceptable) was used in the licensee's evaluation. The licensee stated that engineering evaluation and judgement are used in determining which data to use. However, there did not appear to be adequate documented justification for disregarding the one set of AFP differential pressure data. Further review in this area is required by the inspector to determine whether the licensee is following accepted industry testing standards. This item is unresolved. (UNR 272/89-15-02)

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 industrial codes and standards.

Portions of the following activities were observed by the inspector:

Work Order	Procedure	Description
890620098	Troubleshooting Guide	Troubleshoot and repair 13MS167 fast closure circuit
890724091	1IC-14.1.001	Investigate and repair control rod 2D1 - indication reading near maximum limit (low)

5.2 Inspection Findings

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

6. EMERGENCY PREPAREDNESS

6.1 Inspection Activity

PSE&G's use of and compliance with the Event Classification Guide was observed during the inspection period relative to Unusual Event declaration on June 9, 1989 and reactor trips on June 10 and June 19.

6.2 Inspection Findings

The licensee's activities in the above areas inspected were determined to be satisfactory.

7. SECURITY

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.

7.2 Inspection Findings

Implementation of the security plan was found to be adequate.

8. ENGINEERING/TECHNICAL SUPPORT

8.1 Inspection Activity

The inspectors reviewed licensee actions relative to the engineering/technical support functional areas for the following issues.

8.2 Inspection Findings

A. During licensee followup concerning the Unit 1 safety injection on June 9, 1989, it was identified that during the seventh refueling outage (1987) an unauthorized globe valve was installed on the main steam system drainline. The valve provides isolation of the common main steam line steam trap discharge header to the No. 12 condenser. The installation was unauthorized in that a design change package was not developed and approved by SORC for the installation contrary to licensee administrative procedure AP-8, "Design Change, Test and Experiment Program". The AP requires a Design Change Request for any change that involves a print revision. In addition, AP-5, "Operating Practices Program" requires independent verification of component manipulations in the main steam system. Since the design change process was not implemented, the valve was not entered into the licensee's computerized Tagging Request Information System (TRIS) and included as part of the main steam system valve lineup. The licensee's investigation regarding the unauthorized valve installation is continuing. Upon identification, the valve was numbered and entered into the TRIS system for configuration control. Failure to follow administrative procedures involving design changes and independent verification of valve lineups is unresolved (UNR 272/89-15-03) pending completion of licensee investigation and NRC review of corrective actions to prevent recurrence.

B. A July 12, 1989 performance of SP(O)4.0.5-P-AF(23) yielded unsatisfactory results with respect to pump differential pressure. The results placed the Unit 2 turbine driven auxiliary feedwater (AFW) pump in the required action range due to a high value. The licensee's System Engineering Group analyzed the results, using previous test results, pump curves and ASME Section XI. By memorandum dated July 12, the licensee concluded that the results were acceptable for that performance, and the pump was declared operable and returned to service.

The basis for the licensee's conclusion was that the baseline values for the pump differential pressure were at 96% of the pump curve, and the July 12 performance was 100.2% of the curve. The conclusion stated that ASME Section XI allows the test results to vary by 2% of the baseline value on the high end; and the combination of a baseline which was slightly low and a test result which was slightly high, have caused the pump to fall into the required action range. However, the evaluation did not address the 4.2% (vice 2% allowed) increase from the baseline value and its potential operability implications. The memorandum further stated that should the pump continue to run at the slightly higher level, additional evaluation would be performed and baseline data would be changed, as necessary.

The licensee informed the inspector that the use of a different flow gauge on a different piping location accounted for the increase in measured differential pressure since no maintenance work was performed on the pump following its previous monthly test run which would account for the change. The inspector noted that the effect of the different test methods was not included in the licensee's evaluation. Following discussion with the system engineer and review of the surveillance test and associated documentation, the inspector determined that the licensee used baseline data obtained previously using an improved gauge configuration, but performed the most recent test using a less precise measuring device and configuration since the improved gauge was offsite for calibration. The combination of the results of the two different methods yielded the unsatisfactory data. However, there was not sufficient information and analysis in the licensee's evaluation to support this conclusion. The inspector did not disagree with the licensee's conclusion that the pump could fulfill its intended safety function.

ASME Section XI allows for analyses to be performed to demonstrate that the required action range condition does not impair pump operability and that the pump will fulfill its function, provided a new set of reference values is then established after such an analysis. At the end of the inspection period, the licensee agreed that a new baseline should be developed, and committed to perform that task. Further review of this and similar evaluations is necessary to determine whether the licensee is in compliance with ASME requirements regarding corrective actions for data beyond acceptance criteria, and development of new reference values when required. This item is unresolved.(UNR 272/89-15-04)

9. LICENSEE EVENT REPORT AND OPEN ITEM FOLLOWUP (90712, 92700)

9.1 The inspector reviewed routine operating and licensee event reports submitted to the NRC Region I Office to verify that the details of the event were clearly reported, including accuracy of the description of

cause and adequacy of corrective action. The inspector determined whether further information was required from the licensee, whether generic implications were indicated, and whether the event warranted onsite followup. The following reports were reviewed:

- Unit 1 and 2 Monthly Operating Reports - May, 1989
- Unit 1 and 2 Monthly Operating Reports - June, 1989

Unit 1

- LER 89-009; Inadequate sampling of plant vent effluent due to a procedure deficiency; Corrective actions included revising the procedure and installing a redundant sampling alignment. Failure to obtain plant vent composite samples is a licensee identified violation of Technical Specification 3.3.3.9 Table 3.3-13 Action 36. The inspector has determined that the discretion criteria of 10 CFR 2, Appendix C have been satisfied and concluded that a violation will not be cited. (NCV 272/89-15-05)

- LER 89-010; Due to the failure of a common air sample pump, both actuation trains of the Containment Purge/Pressure - Vacuum Relief System became inoperable. The equipment was repaired within the action requirements of Technical Specifications.

- LER 89-013; LER 89-017; Failure to perform surveillance tests within the required time in accordance with T.S. 4.0.5 (1A diesel generator service water valve and prelube oil pump) and T.S. 4.3.3.3.1 (Triaxial time - history accelographs) due to inadequate administrative controls. Surveillance scheduling has been a weakness in the licensee's program for which a previous violation has been issued (VIO 272/88-14-01). Although these missed surveillances were licensee identified, the licensee's corrective actions for the previous similar violation did not prevent these recurrences. Therefore, the discretion criteria of 10 CFR 2, Appendix C have not been met and a violation is proposed. (VIO 272/89-15-06) This item closes violation 272/88-14-01.

- LER 89-014; An ESF actuation, containment ventilation isolation, occurred due to a failed channel scalar which caused a high channel spike. The channel scalar was subsequently replaced, and the channel was calibrated and functionally tested satisfactorily.

- LER 89-015; Historical failure to compare snubber drag force surveillance results in accordance with T.S. 4.7.9e.1 due to misinterpretation of the requirement. Field Directive No. S-C-MPOO-MFD-1, "Functional Testing of Mechanical Snubbers" had been revised to require the comparison check pending NRR approval of a license changed request (LCR) to delete this requirement. The LCR was subsequently approved by NRR on July 20, 1989. The inspector has determined that this

failure to comply with T.S. constitutes a licensee identified violation which will not be cited since the discretion criteria of 10 CFR 2, Appendix C have been met. (NCV 272/89-15-07)

- LER 89-016; Oxygen concentration in the waste gas decay tank exceeded T.S. limits and were not reduced within the required time. The LER documents similar previous occurrences in April, 1986 and December, 1987. The root cause of the oxygen ingress has been attributed by the licensee to system design and procedure problems. Corrective actions for the three occurrences involved procedure revision. This item will be unresolved pending the inspector's review of the licensee's corrective actions to prevent further recurrence of this problem. (UNR 272/89-15-08)

- LER 89-018; SSPS Cabinet Connections Unsatisfactory Due to Inadequate Initial Fabrication; This event is discussed in NRC Inspection Report Nos. 50-272/89-11; 50-311/89-10.

- LER 89-019; Loss of Decay Heat Removal Capability Due to Personnel Error; This event is discussed in NRC Special Inspection Report No. 50-272/89-17.

- LER 89-020; T.S. Surveillance 4.5.2h Non-Compliance; Maximum Charging Pump Safety Injection Flow Rate Exceeded; This event is discussed in NRC Inspection Report Nos. 50-272/89-11; 50-311/89-10.

- LER 89-021; On May 23, 1989, the Radiation Protection Engineer identified that the high radiation area (HRA) (>1000 mR/hour) including the CVCS holdup tank rooms was not being controlled in accordance with Technical Specifications in that the entrance to the HRA was not locked or guarded, for approximately a 10 minute period. A guard was posted immediately upon identification of the problem. Licensee investigation identified that a contractor technician had removed the pad lock on the door and entered the area to perform a pre-job survey and failed to either lock or guard the entrance while the survey was in progress. Licensee RP procedures require continuous surveillance of unlocked HRA doors to preclude unauthorized entries. Further, the results of surveys of the CVCS holdup tank (HUT) indicated that radiation levels near one of the three HUTs were in excess of 1000 mR/hour (maximum - 5000 mR/hour). However no one other than the RP technician entered the area during the time the door was left unlocked.

  On three previous occasions, one in March, 1987 and twice in October, 1987 a locked HRA door to the bioshield area was defeated due to a plastic shoe cover being put in the doors' self-locking mechanism. A notice of violation was issued for the October, 1987 occurrences. In addition, violations were cited in September, 1988 and January, 1989 for a number of examples of failure to follow RP procedures.

Due to the potential safety significance of this issue in that a person could have entered the HRA and receive an uncontrolled exposure, and since the corrective actions for the previous instances of loss of control of HRA doors and failure to follow procedures did not prevent the occurrence of the May 23, 1989 incident, a notice of violation is proposed. (VIO 272/89-15-09)

- LER 89-022; T.S. 3.1.3.2.2a Non-Compliance Due to Personnel Error and Inadequate Administrative Controls; During control rod shutdown bank calibrations, two banks of control rods were withdrawn together, contrary to T.S. and procedural precautions. The technicians involved failed to recognize the precautions and requested plant operators to move more than one bank while in Mode 3 (Hot Standby). Technical Specification 3.1.3.2.2 was only recently revised (effective upon completion of the eighth refueling outage). However, plant operators on shift were unaware of the amendment. The LER documented that station management has initiated a review of the process by which T.S. amendments are promulgated. Pending completion of this review and NRC evaluation, this item is unresolved. (UNR 272/89-15-10)

- LER 89-023; TS 3.0.4 Non-Compliance Due to Personnel Error; T.S. 3.0.4 requires that entry into an operational condition without satisfying the Limiting Conditions of Operation is prohibited. Contrary to procedural precautions, during unit startup activities on June 3, the licensee identified that only one source range channel was operable while in Mode 3 with the reactor trip breakers closed and the control rod drive system capable of rod withdrawal. Two channels were required for that condition. The procedural precautions specified that two source range channels be operable prior to energizing the Rod Control System and closing the reactor trip breakers.

  The failure to follow station procedures, as documented in LERs 89-021/022/023, constitute three examples of licensee identified violations of T.S. 6.8.1, which states that written procedures shall be established, implemented and maintained. Licensee corrective actions for multiple previous procedural compliance violations have not been effective in preventing further problems, and therefore, the discretion criteria of 10 CFR 2, Appendix C have not been satisfied. These three examples of failure to follow procedures constitute an apparent violation of T.S. 6.8.1. (50-272/89-15-09)

- LER 89-024; Safety Injection/Reactor Trip During Mode 3 Operation Due to Inadequate Procedures; This event is discussed in Section 2.2.1.B of this report.

- LER 89-027; Reactor Trip on No. 13 Steam Generator Low-Low Level Due to an Equipment Design Concern; This event is discussed in Section 2.2.1.B of this report. The LER noted that a Supplemental report was not expected. Inspector review of this identified that the same relay on Unit 2 apparently failed on April 11, 1989, resulting in a similar reactor trip. The LER documented that the relay was replaced and the previously installed relay will be sent to the vendor for evaluation. The purpose of supplemental reports are to provide information not available when the LER was submitted. Results of the relay evaluation may possibly support or contradict the licensee's root cause conclusion. For this case in particular, when a recent similar failure occurred on the opposite Unit, a supplemental report should be submitted. The licensee agreed to submit a supplemental report when the test results are received from the vendor.

Unit 2

- LER 89-007; T.S. 3.0.3 Entry due to - two steam flow channels for one steam line inoperable. Drifting of the measured main steam line differential pressure is a continuing concern for which licensee investigation is continuing. A management meeting was held recently on May 15, 1989 to discuss licensee actions to resolve this issue. This issue is being followed by the inspectors as unresolved. (50-272/88-17-01)

- LER 89-009 and 89-010; ESF actuations containment ventilation isolation due to design and equipment problems; These ESF actuations were caused by the failure of the same plant vent noble gas monitor (2R41C). The LER's document engineering investigations and resultant planned system modifications to upgrade the radiation monitoring system to prevent recurrence of these problems. NRC inspection 50-272/89-10 reviewed the licensee's long term corrective actions in this regard and found them to be acceptable, however timeliness in completion of the actions was stressed with the licensee.

- LER 89-012; Controlled Shutdown, T.S. Surveillance Non-Compliance Due to Inadequate Procedure; This event is discussed in NRC Special Inspection Reports No. 50-272/89-16; 50-311/89-15.

- LER 89-013; Manual Reactor Trip - Loss of Five Circulating Water System Circulating Pumps Due to External Causes; This event is discussed in Section 2.2.2.A of this report. Inspector review of the LER identified that the licensee incorrectly stated that the SD valves were lost solely due to an increase in condenser back pressure. The LER did not address the immediate partial loss of the

SD system due to the loss of the associated circulators. Further, the LER did not address the relay failure which permitted the event to continue due to partial SD operation, and its potential safety impact. This was discussed with the licensee, who committed to resubmit the LER with the appropriate information.

The above LERs were reviewed with respect to the requirements of 10 CFR 50.73 and the guidance provided in NUREG 1022. In general, the overall quality of the LERs reviewed during this inspection was adequate. However, specific deficiencies were noted and communicated to the licensee including inaccurate and incomplete information as provided in Unit 2 LER 89-013 and not planning to submit a supplemental report when pertinent information is anticipated to be received from a vendor (Unit 1 LER 89-027). Further, the inspector identified that several LERs did not include a complete the assessment of the actual and potential safety consequences and implications of the event. Specifically, NUREG 1022 specifies that an assessment of an event under alternative conditions must be included if the incident would have been more severe under reasonable and credible alternative conditions, such as power level or operating mode. These concerns were brought to the licensee's attention, who stated that a review in this area would be performed. The inspector will continue to evaluate the adequacy of LERs during future routine inspections. For example LER 272/89-022 includes an analysis regarding withdrawal of the third most worthy rod, but does not analyze the impact of a lower boron concentration which is also reasonable and credible condition that should be analyzed. Further, LER 272/89-021 concludes that the uncontrolled HRA door posed no risk to the health and safety of the public, however the risk to plant workers was not discussed and is obviously the reason for locking HRA's.

9.2 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 VIO 272/88-14-01 Section 10.1

10. SAFETY ASSESSMENT/QUALITY VERIFICATION (40500, 92702)

10.1 Inspection Activity

The inspectors reviewed the performance of the Station Operations Review Committee (SORC) relative to T.S. 6.5.1 requirements. In addition, the inspectors reviewed the effectiveness of the licensee's corrective action program relative to 10 CFR 50, Appendix B criteria.

10.2 Inspection Findings

A. The inspector attended Station Operations Review Committee (SORC) meetings on June 11 and June 13. Technical Specification member attendance requirements were verified. In general the meetings were characterized by frank discussions on the subjects reviewed. No deficiencies were identified.

B. This report documents a number of recent licensee identified problems for which previous similar problems were noted and for which corrective actions were not adequate in preventing recurrence. For example, Section 2.0 of the report discusses unit trips attributed to grass and debris accumulation on CW trash racks and a deficient MSIV closure circuit design which recurred during this inspection period due to inadequate corrective actions for previous similar events. Section 4.0 discusses the continued marginal performance of reactor trip breaker UVTAs with respect to meeting the output force measurement acceptance criteria during semiannual preventive maintenance activities. Section 9.0 includes review of LERs which document repeat problems such as failure to follow procedures, missed T.S. surveillances, oxygen ingress to the waste gas system, and RMS design and equipment problems which continue to result in ESF actuations. The inspector has observed increased diligence with which the licensee identifies and investigates plant problems. Self assessment is considered a licensee strength. However, the licensee's program for correction of self-identified problems to prevent recurrence appears to be weak. This is indicated by the number of examples of repeat occurrences listed previously. These conclusions were discussed with station management. The inspector requested that the licensee review their corrective action program in this regard to determine whether improvements are needed, and document their conclusions along with the violation responses as indicated by the inspection report cover letter. The licensee agreed to perform the review and provide the requested response.

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.