U. S. NUCLEAR REGULATORY COMMISSION

REGION I

Report No. 50-272/89-11
50-311/89-10

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: May 1, 1989 To June 5, 1989

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

Approved: G. W. Meyer for P. D. Swetland, Chief, Projects Section 2B — 7-5-89 Date

Inspection Summary:
Inspection 50-272/89-11; 311/89-10 on May 1, 1989 - June 5, 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: One violation was identified during this inspection. The violation involved the failure to properly evaluate a temporary facility modification with respect to its impact on adjacent seismically qualified safety related equipment (Section 8.2.D). Seven Unresolved Items were identified regarding a potentially generic issue concerning leakage of a certain design safety valve (Section 2.2.2.B), inservice testing techniques (Section 4.2.B), the acceptability of previous testing on the safety injection system (Section 4.2.C), the adequacy of the licensee's programs to report events required by federal regulations (Section 6.2.B), resolution of security computer problems (Secion 7.2.C), T-mod status reporting and duration (Section 8.2.D), and the effectiveness of Salem nonconformance reporting and corrective action programs (Section 9.1.A). Five previously open NRC items were closed.

DETAILS

1. SUMMARY OF OPERATIONS

Unit 1 was in Mode 6 at the start of the inspection period. Reactor reassembly, design modifications, system restoration and testing were completed. A loss of shutdown cooling event occurred on May 20, 1989 during accumulator check valve testing. The unit was in Mode 3 at the end of the period with preparations for reactor startup in progress.

Unit 2 operated at 100% power until May 27, 1989, when the unit was shutdown to Mode 4 due to inadequate Technical Specification response time testing of steam generator main and bypass feedwater regulating valves. The unit returned to power operation on May 31, 1989.

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 were conducted in accordance with the NRC inspection procedures listed above. The inspectors performed 241 hours of normal and backshift inspection including deep backshift and weekend tours of the facility on May 5 (4:15 a.m. - 5:00 a.m.), May 6 (12:30 a.m. - 4:30 a.m.), May 11 (2:00 a.m. - 5:00 a.m.), May 22 (3:30 a.m. - 5:00 a.m.), and May 30 (3:15 a.m. - 5:00 a.m.).

2.2 Inspection Findings and Significant Plant Events

2.2.1 Unit 1

A. On May 11, while in Mode 6 (Refueling), the licensee was draining the reactor coolant system (RCS) to a mid-loop condition. During a backshift inspection, the inspector observed the associated draindown activities from the control room. The residual heat removal (RHR) system was in operation as required. The inspector reviewed the procedure in use, II-1.3.6, "Draining the RCS", and identified the following:

- Technical Specification (TS) 3/4.9.8 required that at least one RHR loop shall be in operation while in Mode 6 at a flow rate of at least 3000 gpm.

- A pump vortex curve was part of the procedure. At elevations 97'6" to 98'0", RHR flow must be between 1000 and 3000 gpm, inclusive. Note: 97'0" corresponds to RCS loop centerline level.

Due to the above RHR flow requirements, an exact system flow of 3000 gpm (with zero tolerance) was required. The inspector brought this concern to shift supervision's attention, who ordered that draindown activities be stopped when the 99'0" loop elevation was reached and that RHR flow be maintained at greater than 3000 gpm. The licensee then informed the inspector that they would maintain RHR flow at 3000 gpm, however, that since having flow on the low side of 3000 gpm was conservative from a RHR pump vortexing perspective, their efforts would be towards maintaining flow less than or equal to 3000 gpm. Therefore, entry into the TS 3.9.8 Action Statement would possibly be necessary, whose action required closing all containment penetrations providing direct access from the containment to the outside atmosphere within four hours. The containment personnel hatch was open at the time, providing a path for several hoses used inside containment for steam generator sludge lancing activities.

The inspector returned to the control room about two hours later and questioned the operators as to what RHR system flow was. The operators responded that the flow was 3000 gpm. The inspector then reviewed control room instrumentation and found that the indicators have a logarithmic scale and were subject to reading interpretation of about plus or minus 200 gpm. Control room supervision was consulted on obtaining more precise RHR flow readings. A safety parameter display system (SPDS) screen was called up which displayed an RHR flow trend. The totalized RHR flow at that time was 3256 gpm. Operators immediately reduced flow to 3000 gpm and then maintained system flow using the more accurate SPDS display.

During the day shift, licensee management was informed of the inspection findings. Specifically, that plant operators were controlling the plant in a mid-loop condition and were provided with a zero flow tolerance per procedure. Additionally, plant operators and supervision did not proactively use a very useful tool in the SPDS to monitor and trend critical plant parameters. Rather, only the control board instrumentation was used which was subject to large errors in reading the flow rates.

The licensee subsequently implemented a procedure change and safety evaluation which provided an enhanced operational band for the vortex curve (1000 to 3500 gpm). Therefore, a 500 gpm tolerance was provided between the TS minimum 3000 gpm flow requirement and the 3500 gpm maximum vortex concern value.

On the following day, May 12, the inspector reviewed a related Abnormal Operating Procedure, AOP-RHR-2, "Loss of RHR Cooling - RCS Level Below the Pressurizer - Elevation 104", and found that the same vortex curve was included in the AOP (1000-3000 gpm). The inspector brought this to the licensee's attention, who subsequently revised that curve to reflect the recently developed numbers. This appears to be an example of the licensee fixing a specific problem without fully reviewing the issue on a broader spectrum to determine whether other documents or systems were similarly affected.

During a followup review of this issue, the inspector identified that the first initial condition in the procedure II-1.3.6 specified that the RCS be in Cold Shutdown. Per Technical Specifications, Cold Shutdown is defined as Mode 5. However, the plant was in Mode 6 at the time of entering the procedure. That initial condition was initialed by a reactor operator as being completed or satisfied. The licensee informed the inspector that using the term Cold Shutdown has not always been interpreted as Mode 5, rather as having the plant at least shutdown to those conditions (including Mode 6). The licensee agreed, however, that the procedure step is misleading. The licensee also stated that including specific Mode requirements for procedure entry is not a standard practice, however, procedures will be reviewed to determine whether additional action is necessary.

In summary, there were several procedural problems associated with Operating Procedure II-1.3.6. The procedure was reviewed and approved by the Station Operations Review Committee (SORC) on March 29, 1989. Procedure reviews may not be providing the appropriate level of attention with respect to procedure adequacy since several inadequacies continued to exist. Further, there have been several recent examples of inadequate procedures and failure to properly implement procedures. The licensee informed the inspector that they recognize that procedures need improvement, and that their current plan to enhance procedure quality will be reviewed to provide better short term results. The inspector will continue to assess the effectiveness of the licensee's actions in this area during future routine inspections.

B. On March 20, while in Mode 5 (Cold Shutdown), a total loss of shutdown cooling event occurred at Unit 1 while performing a surveillance test on the safety injection accumulators. See Special Inspection Report 50-272/89-17 for additional details.

2.2.2 Unit 2

A. On May 27, 1989, a Unit 2 shutdown was commenced after the licensee determined that the surveillance tests for isolation time response of

the main and bypass feedwater regulating valves historically have not tested each of the two reactor protection system trains independently as required by Technical Specifications. Similar problems were also identified for Unit 1. See Special Inspection Report 50-272/89-16 and 50-311/89-15 for details.

B. On May 31, during a Unit 2 startup with the reactor critical (Mode 2 - "Startup"), one main steam safety valve (23MS15) lifted prematurely. The design lift setpoint is 1070 psig, however, this valve lifted at 1033 psig. No unusual activities were in process at the time of the lift. The valve lifted and then properly reseated. Technical Specification (TS) 3.7.1.1 requires that the Power Range Neutron Flux High reactor trip setpoint be reduced to 87% when one safety valve on any steam generator becomes inoperable. The licensee mechanically blocked the safety valve closed and reduced the trip setpoints to comply with TSs.

The acceptable range for the lift setpoint for 23MS15 is 1070 psig $\pm$ 1% (1059 - 1081 psig). The valve was last tested satisfactorily in place in February, 1989. The licensee identified that the same valve had lifted prematurely on at least two other occasions in the past (November, 1988 and February, 1989). Both times, the valve lifted at about 1030 psig.

The inspector reviewed the event and interviewed licensee personnel to determine the cause for the repeated premature safety valve lifts. The licensee stated that the primary reason was that 23MS15 had periodically experienced some amount of leakage, and through discussions with the valve manufacturer (Crosby), the licensee determined that the safety valve actual lift setpoint becomes lower when there is leakage. Further licensee discussions with the vendor identified that the valve's "flexidisc" design characteristically reseats tighter following a lift. This phenomenon possibly explains why the safety valve setpoint verification tests following the previous premature lifts were satisfactory.

On June 2, with the unit operating at about 70% power, the licensee tested the main steam safety valve in place. The average setpoint for the three valve lifts was 1066 psig and therefore met the test acceptance criterion. The unit was subsequently returned to full power. This safety valve testing was the first time the licensee had tested those valves while operating at power. The test procedure was properly reviewed and approved by the Station Operations Review Committee on June 1, 1989. The inspector reviewed the test procedure and its associated safety evaluation and observed portions of the test performance. No significant deficiencies were identified.

The inspector questioned whether the licensee (and the valve manufacturer) could calculate the impact on safety valve setpoint based upon specific valve leakage values. The licensee stated that no such calculations had or could be performed. The inspector was concerned that this is potentially a generic concern with this type design of safety valves and its impact on valve performance and therefore, its effect on postulated accident analyses should be addressed. Licensee review of this potentially generic issue is an unresolved item (311/89-10-01).

2.2.3 Both Units

A. On May 3, 1989, the licensee declared an Unusual Event due to a helicopter hovering low over several locations within the protected area of the plants. A passenger in the helicopter appeared to be taking pictures of the plants. Several attempts by members of the security force to motion the helicopter to land for identification purposes were apparently ignored and a security alert was initiated. The local law enforcement agency was notified and a local office of the Federal Aviation Administration (FAA) was contacted for assistance. The FAA identified the helicopter as being chartered by the licensee. It was determined that the helicopter had been chartered by the licensee's training department to make a public information film, but plant personnel had not been informed. Subsequently, the Unusual Event was terminated.

Licensee investigation into the cause of the communication breakdown identified that the licensee's transportation department, which made the arrangements for the helicopter, was also responsible for notifying the site of the date and time that the aircraft would be at the site. This communication did not take place. Site management has reconfirmed with the transportation department their responsibility to provide notification to site personnel for similar future occurrences. The inspector had no further questions concerning this event.

B. On May 15, 1989, during Unit 1 protection system modifications, the licensee identified loose clip wire connections on circuit boards in the solid state protection system (SSPS). The loose connections were apparently due to improper installation of the clips during the manufacturing process. The circuit board units were supplied by Westinghouse. The licensee has submitted a 10 CFR Part 21 report on this issue.

Since Unit 1 was in a refueling outage, the licensee performed pull tests on all of the clip connections associated with the Unit 1 SSPS. Of the 2,644 connections per train, 119 clips failed the pull test for Train A, and 103 failed for Train B. The licensee replaced the deficient clip connections.

A visual inspection was performed by the licensee on the Unit 2 SSPS connections and no loose wires or connections were observed. Unit 2 was operating at 100% power. Modifications were made to the Unit 2 SSPS during its fourth refueling outage in October, 1988, and no similar discrepancies were identified at that time. The licensee documented a Justification for Continued Operation (JCO) for Unit 2 as related to this issue. The licensee plans further Unit 2 inspection the next time the unit is placed in Mode 5.

Licensee review of historical operating records has not identified any unexplained actuations that could be attributed to loose wire connections in the SSPS.

The inspectors reviewed the licensee's pull test procedures and results, the clip connection replacement procedure, the Unit 2 JCO and the Part 21 report. The inspectors had no further questions on this issue and will follow licensee inspection and results related to Unit 2 when performed.

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

A. The inspectors routinely toured the Unit 1 and Unit 2 radiological controlled areas, including the Unit 1 containment building. The overall condition and contamination controls in the Auxiliary Building had improved over the last inspection period. Individual deficiencies were brought to the licensee's attention for resolution.

B. On May 13, the licensee identified that a contractor employee received a whole body radiation dose above the administrative quarterly limit of 1000 mRem. The dose received (1365 mRem) did not exceed the maximum quarterly occupational dose specified in 10 CFR Part 20 of 3000 mRem.

The individual reported to Salem on April 19, and properly completed Form NRC-4 (Form 4), documenting that he had received an estimated prior occupational exposure during the current quarter of 583 mRem (self-reading dosimeter). That data was then transferred to a data sheet for input into the licensee's computerized dose control system (Alnor). The transfer to the data sheet was subject to a peer review to ensure that the proper information was transferred; these actions were properly performed. However, due to an administrative error, a zero was input into the licensee's computer system, and an administrative limit of 1000 mRem (vs. 417 mrem) was allowed.

Upon exiting the RCA, the computerized Alnor reader alarmed because the individual's exposure was approaching the 1000 mRem administrative limit. Upon performing a records review to authorize a dose extension to 2000 mRem, the licensee identified that the 583 mRem was not input to the system. Licensee supervision was immediately notified, and the individual's film badge was processed. The licensee also performed a review of all high dose contractors within 24 hours to verify the integrity of the computer control system. No additional errors were identified.

The licensee subsequently received the accurate film badge reading obtained previously during the current quarter, 508 mRem. He received 857 mRem from Salem, totalling 1365 mRem. Additional corrective actions implemented by the licensee included providing a second verification for all computer inputs, and instructing workers of the necessity to maintain data input integrity and the seriousness in errors of that type. Procedure changes are also planned by the licensee.

The licensee had provided the appropriate attention in addressing this event and implementing actions to prevent recurrence. The inspector will monitor the effectiveness of the licensee actions during routine resident inspections.

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:

Unit 1

- SP(O)4.0.5-P-CV(11) Inservice Testing - Charging Pump
- SP(O)4.5.2H Throttling Valve Flow Balance Test
- OP-TEMP-8913-1 Charging Pump Flow Test

Unit 2

- SP(O)4.0.5-P-AF(23) IST - Auxiliary Feed Pump
- SP(O)4.0.5-V-AF-3A IST - Valves - Auxiliary Feedwater
- T-252 Main Steam Safety In Place Testing

4.2 Inspection Findings

A. During a review of surveillance test procedure SP(O)4.0.5-P-AF-3A, "IST - Valves - Auxiliary Feedwater", the inspector noted that there were no procedure steps which required initials of the performer, including action steps. This is a poor practice in that the potential to perform steps out of sequence or missing steps entirely is unnecessarily created. This was brought to licensee management's attention, who acknowledged the inspector's concern.

B. During observation of surveillance test SP(O)4.0.5-P-AF(23), "IST - Auxiliary Feed Pump", the inspector noted that the pump was not marked as to where the vibration probe should be placed to obtain the necessary reading. The test procedure included a pump/motor drawing and the approximate location to place the vibration probe, however, the location was subject to interpretation. ASME Section XI, IWP 4160 specifies that IST readings be taken at the same location. The licensee's procedure did not appear to be consistent with IWP 4160. The vibration data could be made more useful if the exact locations were somehow marked, to assure accurate performance monitoring and trending results. This concern was brought to the licensee's attention, who stated that they would evaluate this concern. This issue is unresolved pending NRC review of IST program commitments and licensee actions on this matter. (UNR 272/89-11-06)

C. From May 17 to May 25, the licensee performed surveillance test SP(O)4.5.2H, "ECCS Throttle Valve Flow Balance Test" several times on the No. 11 and No. 12 charging pumps. The two centrifugal charging pumps provide the high head injection portion of the emergency core cooling system. The Technical Specification designated acceptance criteria are 1) a total flow rate of less than or equal to 550 gpm, and 2) the sum of the three lowest injection line flow rates greater than or equal to 346 gpm. Several test performances failed to meet the second acceptance criterion. Additionally, the flow rates obtained from a flow indicating device located on the common charging pump discharge piping did not agree with the downstream indicated total flow rate, being the sum of the four cold leg injection flow paths. Specifically, the common line flow rates were consistently about 100 gpm higher than the total of the four injection flow rates.

The licensee investigated all feasible leakage paths, however, no leakage was identified. Flow instrument calibrations were also verified, however, the same unacceptable flow rates were obtained. The licensee then performed additional tests to determine whether there was system leakage and to investigate whether the pump performance characteristics had degraded. No performance deficiencies or leaks were identified during those tests.

Following additional full flow test failures, the licensee identified that the four orifices in the separate injection lines were installed backwards. The orifices were subsequently reversed, however, the following flow test passed on only the No. 12 charging pump. The licensee then consulted with the pump vendor and initiated a design change to install a flow orifice immediately downstream of the No. 11 charging pump. This maintenance activity is further discuseed in Section 5.2.C. The post-maintenance full flow test subsequently passed for both charging pumps.

The inspector expressed concerns as to how and when the orifices were installed backwards and as to the feasibility that the full flow test could have passed its previous performance (last refueling outage) as installed. Further licensee investigation into the details of this event is necessary to determine the above and to develop calculations to determine if it was technically possible to obtain acceptable flow rates as configured. Pending the results of the licensee review, this item is unresolved. (272/89-11-01)

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 (TS), and appropriate industrial codes and standards.

Portions of the following activities were observed by the inspector:

Activity No.	Procedure	Description
WO 871019012	M3L-1	Limitorque maintenance, surveillance and MOVATS testing of 12RH19.
WR 0082605	M3Z	Troubleshooting 12RH19 failure to close from the control room.

Activity No.	Procedure	Description
WO 890419006	M3Q-3	Reactor trip, bypass, and rod drive MG breakers and switchgear 18 month periodic inspection and maintenance.
WO 890522135	M23A	Install flow restricting orifice in No. 11 charging pump discharge line.

5.2 Inspection Findings

A. During operability retesting of the 12RH19 (12 RHR heat exchanger discharge cross connect valve) following MOVATS testing, it was determined that the valve would not close from the control room. The inspector observed the associated troubleshooting activity. Licensee technicians discovered that two wires were not reconnected following the MOVATS testing. The wires were connected and the valve tested satisfactorily. The inspector determined that the leads were not reterminated by the MOVATS crew since operability testing could not be accomplished immediately because the control room bezel for the valve was also being worked. The technicians intentionally left the leads lifted and the procedural steps were not signed-off so that the valve would not be exercised without maintenance personnel present.

Subsequently, the inspector reviewed the MOVATS procedure (M3L-1) relative to documentation and control of lifted leads. The inspector observed that on Attachment 5, Section III of the M3L-1 procedure, the documentation of the removal and restoration of several lifted leads was inadequate since the independent verification was either not performed, or performed by the same person who lifted or restored the leads. The inspector further observed that the procedural steps associated with the lifted leads did not specifically require independent verification. Station administrative procedures do not specifically require independent verification for leads repositioned as part of an established procedure. The inspector was concerned since it has been the licensee's policy to require independent verification for lifting and retermination of leads. Additional concerns with lifted leads are discussed in Section B.

B. During performance of step 9.4.3 of the M3Q-3 procedure, which tests the operation of breaker position switches, leads are lifted to prevent potential arcing across contacts and parallel paths during the testing. The inspector was in the control room during performance of this step and identified that the RP4 status lamp illuminated for

safety injection train unblock. The unit was in Mode 6 in mid-loop operation. Licensee investigation revealed that the lifting of leads resulted in the unblocking of one train of safety injection. The test was suspended as directed by operations supervision and the leads reterminated.

The inspector noted that the shift supervisor approval signature was obtained prior to performing the breaker position switch test, however the test procedure was not clear as to what the function of the lifted leads was. The inspector also noted during review of the maintenance procedure that the independent verification and QA verification signatures were specified and completed in the procedure, however, each block of leads were initialed once on the top line with an arrow through the list of signature spaces indicating completion of the verification. This is a poor practice in that verification of blocks of leads rather than individual verification and signoff may result in one or more leads being missed.

The NRC previously observed that controlled documentation of lifted leads was a strength in the licensee's maintenance program. These procedural deficiencies related to lifted leads were discussed with licensee management. Weaknesses with respect to maintenance procedures are also a previously identified concern for which the licensee has recently instituted a procedure upgrade program. However, to address these particular concerns, the maintenance manager committed to upgrade these specific procedures. The inspector verified that the procedure writers guide used for the procedure upgrade program provides for independent verification of jumpers and lifted leads.

C. The inspector reviewed the maintenance activities associated with the No. 11 charging pump discharge piping orifice installtion. The inspector determined that the affected drawing was incorrect in that a flow orifice was shown to exist for the No. 12 pump. The same print also omitted an existing flange from charging pump no. 11. The licensee plans to correctly update the drawings as part of the design change package (DCP) closeout effort.

This maintenance activity was to resolve pump flow concerns identified during surveillance testing. A DCP was developed for the maintenance. The inspector observed portions of the maintenance, and significant deficiencies were not identified. The inspector noted that Quality Assurance personnel also observed portions of the activities, and System Engineering also provided the appropriate levels of interface. Minor installation problems were experienced, however, they were properly resolved.

6. EMERGENCY PREPAREDNESS

6.1 Inspection Activity

The inspector reviewed the licensee's use of and compliance with the Event Classification Guide (ECG) and Abnormal Operating Procedures (AOPs) during events that occurred during the inspection.

6.2 Inspection Findings

A. During the March 20 total loss of shutdown cooling event at Unit 1, the licensee failed to properly classify and report the event in accordance with 10 CFR 50.72 reporting requirements. The use and adequacy of AOPs during that event is discussed in detail in NRC Special Inspection Report 50-272/89-17.

B. The licensee event reports (LERs), as listed in Section 10.1 of this report were reviewed by the inspector, and a concern was identified concerning the immediate notification required by 10 CFR 50.72. Specifically, Unit 2 LER 89-04, "Engineered Safety Feature (ESF) Actuation - Containment Ventilation Isolation", on the March 4, 1989 event was reported as a 10 CFR 50.73(a)(2)(iv) event. However, the four hour non-emergency NRC notification required by 10 CFR 50.72(b) was not made by the licensee. The licensee did not recognize that 50.72 was applicable until questioned by the inspector in June, 1989.

Discussions with licensee personnel indicated that there was confusion regarding which systems or components were ESFs. Further review in this area with respect to how ESF actuations are categorized, documented and reported is necessary to determine whether the licensee's programs properly implement NRC requirements. Pending resolution of the above concerns, this item is unresolved. (50-311/89-10-02)

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.

7.2 Inspection Findings

A. The inspector determined that security's response to the May 3, 1989 event involving an unidentified helicopter over the protected area was satisfactory and appropriate relative to the requirements specified in the licensee's safeguards contingency plan. The inspector had no further questions on this event.

B. On May 12, 1989, a licensee senior manager's office received an anonymous telephone call, apparently from a Security organization member, expressing concerns that the guards were working excessive hours. The licensee treated this concern as an allegation, and the licensee developed an action plan to evaluate the alleger's concerns. Review of work schedules, performance monitoring and worker complaints were included in the action plan scope. Additionally, the Quality Assurance organization conducted an independent audit of Security. The inspector met with licensee representatives and reviewed portions of the investigation reports. The licensee's evaluation documented that while average work week hours had increased due to the recent Unit 1 outage, work hours were not excessive. The licensee informed the inspector that they had attempted to be proactively responsive to decrease the amount of worker overtime. The inspector also independently monitored security organization effectiveness, and no deficiencies were identified. The inspector's review of this issue is complete.

C. On May 24, 1989, a loss of all electrical power (AC and DC) to the security computer occurred. Compensatory measures were implemented by Security and a one hour report to the NRC was made. The cause of the loss of power appeared to be a design problem associated with the automatic transfer from the primary to the backup AC power sources. The inspector discussed this issue with security and licensing personnel and determined that problems with the automatic transfer have occurred intermittently since December, 1987. Since the December, 1987 occurrence, licensee security and engineering personnel have initiated an investigation into the cause of the transfer problem. However, security has not aggressively pursued resolution of this problem, nor have they instituted proactive interim actions to ensure the integrity of the security computer until the problem is resolved. As a result of discussions with the inspector, the licensee initiated an engineering work request (EWR) to implement enhancements to the system such as additional annunciators for loss of power. Until the root cause of the deficiency is identified and corrected, the licensee is taking several actions to ensure the integrity of site Security when power is lost to the security computer. Procedures are being developed to require close monitoring of the security computer and power supplies by Operations personnel, during planned transfers, to ensure prompt identification and return of a power supply if a problem occurs. In addition, Security has issued a memorandum to Security shift supervisors to implement compensatory actions upon the loss of AC power to the security computer. This will ensure that site security will be maintained if AC feed cannot be returned to service prior to the DC batteries being discharged.

This matter will remain unresolved pending completion of the licensee's short and long term corrective actions. (272/89-11-02)

8. ENGINEERING/TECHNICAL SUPPORT (71707, 92702)

8.1 Inspection Activity

The inspector held discussions with licensee personnel and the NRR project manager, and reviewed NRC and licensee documentation related to the following issues.

8.2 Inspection Findings

A. (Closed) Unresolved Item 272/87-32-01; Acceptability of alternative test method for auxiliary feed pump header. The licensee submitted an Inservice Inspection Program Relief Request dated November 28, 1988 to acquire formal approval for use of an alternate test method for pressure testing buried auxiliary feedwater piping. Licensee actions are complete and this item is closed.

B. (Closed) Unresolved Item 272/311/87-05-01; Technical adequacy of one point incore/excore calibration. The inspector reviewed NRC Safety Evaluation Report dated December 30, 1988, which concludes that the licensee's calibration method is satisfactory. This item is closed.

C. (Closed) Violations 272/87-02-02 and 272/87-02-03; Lack of procedures for piping and pipe support design activities. The inspector verified that the final draft of the consolidated pipe stress and pipe support specifications is complete. These items are closed.

D. During a routine plant tour on May 10, the inspector noted that each control room contained a tall, (about 6' high), portable reactivity computer, and whose approximate dimensions were 2' by 1.5'. Each had four wheels mounted at its bottom. Each computer was physically located adjacent to the electrical distribution and emergency diesel generator control console. The inspector expressed concern to the licensee regarding its seismic qualification or evaluation. The licensee stated that its installation was covered under the current Temporary Modification (T-Mod) Program and has been in place for both units since essentially initial plant operation (Unit 1 - 1977, Unit 2 - 1981).

The licensee's Updated Final Safety Analysis Report (UFSAR), Section 3.2, classifies the control room as a Seismic Class I (SC-I) structure. SC-I is further defined as those structures and components, including instruments and controls, whose failure might cause or increase the severity of an accident or result in an uncontrolled release of radioactivity.

The licensee's current T-Mod program is defined by Administrative Procedure No. 13 (AP-13), "Temporary Modification Control Program". The inspector reviewed the T-Mod safety evaluations associated with the reactivity computers and identified the following.

1) An April 6, 1984 engineering evaluation concluded that an unreviewed safety question was not involved and that all potential, realistic failure modes have been considered, and are not applicable.

2) A December 13, 1985 engineering evaluation determined that a technical review and not a 10 CFR 50.59 safety evaluation was required. The evaluation stated that the electrical jumper request related to the computer had previously been over-classified as being safety related. The evaluation further stated that a safety evaluation was not required because the wire terminations had been made at non-safety related terminal strips of the Hagen and NIS racks. The reactivity computer was further described as a non-safety related testing and monitoring device. The evaluation forms required that all potential, realistic failure modes and/or malfunctions must be considered and listed, including the effects on adjacent systems and structures, and protective or mitigative design features must be described. Since neither evaluation addressed the potential impact of the non-seismic computers on adjacent seismic safety related structures, the inspector determined that both safety evaluations were inadequate.

AP-13 had undergone a major revision on January 19, 1988. The inspector questioned several members of the licensee's organization as to whether more recent evaluations had been performed for the reactivity computer T-Mod. Over a two week period, none were found, and the licensee had not yet addressed the presence of the computers in the control room.

10 CFR 50.59 specifies that licensee's may modify the facility, provided the modification does not involve an unreviewed safety question. Licensee's are further required to perform and maintain written safety evaluations of those modifications which provide the bases for the determination that the modification did not involve an unreviewed safety question. The failure for the licensee to complete an adequate safety evaluation to address the impact on adjacent safety related equipment is a violation of 10 CFR 50.59. (272/89-11-03)

On May 27, the licensee informed the inspector of their intentions with respect to the reactivity computer concerns. They stated that a safety evaluation addressing the impact on adjacent equipment was not performed and that the Unit 2 computer would be removed from the control room. The Unit 1 computer was planned to remain in the control room until after restart from its refueling outage. By the end of the inspection period, the Unit 2 computer was removed. Since the licensee committed to remove the Unit 1 computer prior to any significant power operation, the inspector concluded that the computer could be controlled like other transient maintenance and test equipment used in the plant. The licensee also stated that future permanent modifications were planned as part of ongoing control room redesign efforts.

Several additional concerns were identified. One, the use of the "temporary" change may have been inappropriate. Specifically, the above Unit 1 T-Mod had been in place for about 10 years. AP-13 states that T-Mod duration should be less than 91 days. Since a permanent modification is planned and this procedure is relatively new, its effectiveness in that respect will continue to be monitored. A second concern is that AP-13 requires that the status of T-Mods shall be formally reviewed and re-presented to the Station Operations Review Committee every 91 days. The inspector found that the required review was several months past due. These concerns were brought to the licensee's attention. This item remains unresolved pending prompt, satisfactory implementation of AP-13 with regard to old T-Mods. (UNR 272/89-11-05)

E. NRC Bulletin No. 88-04, "Potential Safety-Related Pump Loss", was issued on May 5, 1988 to request all licensees to investigate two miniflow design concerns. The licensee responded to the bulletin by letter dated August 11, 1988, however, vendor evaluation of pump minimum flows was continuing. These results and the licensee's proposed actions were submitted to the NRC by letter dated April 11, 1989.

The licensee's response stated that residual heat removal (RHR) pump recirculation flows as low as 450 to 500 gpm were acceptable, however, a maximum time limitation of three hours in any 24 hour period should be established. The licensee also included in their response that the minimum required flow for continued RHR operation exceeding three hours is 2000 gpm, and that operating procedures II-6.3.2, "Initiating RHR" and II-1.3.6, "Mid-loop Operation", would be revised to include that minimum flow requirement. Cautions were also to be provided in emergency, abnormal, and normal operating procedures to avoid placing the RHR pumps on recirculation for more

than three hours in any 24 hour period. The licensee also stated where that RHR pump operation will be logged so that practical service limits and inspection frequencies could be determined.

The inspector reviewed licensee procedures and determined that the majority of the changes had not been made by the end of the inspection period. Additionally, the licensee subsequently requested that the vendor support a lower minimum required flow number than 2000 gpm (1500 gpm) for continuous RHR operation. The licensee stated that their response will be revised to reflect current commitments. The inspector also identified that the licensee had not yet implemented any controls to log RHR pump operation as stated in the bulletin response.

Licensee actions to implement commitments specified in the bulletin response have not appeared to be aggressively pursued. The inspector will continue to track licensee implementation of the above actions during a subsequent inspection.

9. SAFETY ASSESSMENT/QUALITY VERIFICATION (40400, 62703, 71707, 90712)

9.1 Inspection Findings

A. On April 27, 1989, during Unit 1 control room (CR) human factors upgrade modifications, licensee quality assurance (QA) identified potential nonconforming solder connections related to Bailey control and indication relay cabinets. A work order was written for one particular wire which was completely separated from its connection. On April 28, QA's concern was discussed at the morning managers meeting at which time the licensee's engineering and plant betterment (E&PB) department agreed to address the problem since an E&PB project team had a soldering crew working in the relay cabinets in support of the CR modifications. From April 27 to May 8, licensee QA personnel performed a 100% audit of Unit 1 solder connections, identifying approximately 300 connections which did not meet inspection criteria contained in licensee field directive S-C-E000-CFD-0222-0. The deficiencies identified included loose wires, lack of solder, burnt or melted insulation, wire strands broken or outside of terminal, and cold solder joints. Approximately 70 connections were identified by QA as needing immediate disposition. In two licensee memorandums from QA to E&PB, dated May 6 and May 9, a list of the 70 connections was provided with a request to evaluate and repair the deficient solder connections.

On May 10, 1989, Operations submitted a work order for a problem with the containment sump discharge valve which resulted in the

inoperability of the containment sump pump. Troubleshooting related to this work order identified the cause as the separated wire discussed previously for which QA had already submitted a work order on April 27. QA's work order had been planned, but was not worked. However, as a result of the May 10 work order, the separated wire was resoldered on May 11.

On May 17, 1989, QA personnel became aware that no action was being taken regarding the solder connection concerns stated in their May 6 and 9 memorandums, which prompted them to submit an action request to system engineering for resolution. Again the issue was discussed at the managers meeting, and station management directed the station system engineers to resolve the concern. System engineering evaluated each of the 70 connections for disposition. By May 26, the connections were either repaired or determined to be acceptable "as is".

On May 18, the inspector was informed of the identified deficiencies and repair of the solder connections. The inspector questioned system engineering and QA as to whether the Unit 2 relay cabinets were planned to be inspected for similar deficiencies. Unit 2 was operating at 100% power. They stated that the decision to inspect Unit 2 was up to the station manager. The inspector's concerns were discussed with the station manager who directed QA to prepare and conduct a documented planned inspection of Unit 2 relay cabinets. From May 18 to May 22 the Unit 2 inspection was performed. Twelve connections were identified as needing immediate engineering evaluation. System engineers determined that one involved a safety concern while the others provided control room indication, alarms, or non-safety functions. No. 23 containment fan coil unit (CFCU) was declared inoperable and the Technical Specification Action Statement entered since a nonconforming connection was related to an auxiliary relay and interlock for a high speed breaker which allows the CFCU fan to go to low speed and positions associated service water valves for high flow under accident conditions. This connection was repaired on May 23 and the CFCU returned to operable status. By the end of the report period, the 11 deficient connections for Unit 2 were repaired. A work request has been initiated to evaluate and repair the remaining connections and is planned for future refueling outages.

The licensee has determined that the deficiencies with solder connections were due to poor workmanship during previous soldering evolutions. The licensee is in the process of evaluating the method of training and qualification of station and contractor personnel who perform soldering. QA review of solder connections made by contractor personnel during the present Unit 1 outage did not identify any deficiencies. The same outage contractor personnel repaired the deficient solder connections for both Units. The

inspector witnessed soldering activities performed under work order 890521061 and no problems were noted.

The inspector expressed concerns with regard to the slowness of attention to a potential safety problem displayed by licensee management, the informality with which QA documented their concerns and the resulting delay for a period of nearly three weeks to evaluate and resolve the discrepancies. This issue is unresolved pending NRC review of the effectiveness of the licensee's non conformance reporting and corrective action programs, and will be verified in a subsequent inspection. (UNR 272/88-11-04)

B. NRC Information Notice (IN) 89-42, "Failure of Rosemount Models 1153 and 1154 Transmitters", was issued on April 21, 1989 to alert licensees of recent transmitter failures. Specifically, the failure mechanism of several subject transmitters was the loss of oil from the transmitter's sealed sensing module. Rosemount Inc. issued a notification under 10 CFR Part 21 on February 8, 1989. The notification documented several potential characteristic symptoms that may indicate a pending transmitter failure, and provided recommendations to determine transmitter degradation.

The licensee reviewed the Part 21 report to determine whether Salem was affected. They found that only one subject transmitter was installed (Model 1154 at Unit 2). The licensee generated a safety evaluation, which concluded that the Unit 2 transmitter does not present a significant safety concern.

The bases for the licensee's conclusion are as follows. Rosemount reported that all but one of the reported failures to date have occurred during the first 30 months of service. Available data also showed that transmitters in service for more than 36 months are not expected to fail as reported. The transmitter used at Unit 2 has been in service at high pressure (reactor coolant flow) for 54 months, and during that time, has repeatedly satisfactorily passed calibration and time response surveillance testing.

The inspector reviewed the licensee's safety evaluation and found no deficiencies. The inspector review in this area is complete.

10. LICENSEE EVENT REPORT (LER) AND OPEN ITEM FOLLOWUP (92700)

10.1 Inspection Activity

The inspector reviewed the following licensee reports submitted to the NRC Region I Office. For LERs, the inspector verified 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 LERs were also reviewed with respect to the requirements of 10 CFR 50.73 and the guidance provided in NUREG 1022. The following LERs were reviewed:

- Unit 1 and 2 Monthly Operating Reports - April, 1989

- Unit 1 LER 89-018; Solid State Protection System Cabinet Connections Unsatisfactory Due to Inadequate Initial Fabrication. This event is detailed in Section 2.2.3 b of this report.

- Unit 2 LER 89-004; Engineered Safety Feature Actuation - Containment Ventilation Isolation due to System Design/Equipment Concerns. This event is detailed in Section 7.2.b of this report.

- Unit 2 LER 89-005; Reactor Trip/Safety Injection From 100% Power due to an Equipment Failure. This event was detailed in NRC Inspection Report 50-311/89-01.

- Unit 2 LER 89-006; Reactor Trip Signal After Required Shutdown - TS Action Statement 3.7.7.b. This event was detailed in NRC Inspection Report 50-311/89-03.

- Unit 2 LER 89-008; Reactor Trip from 100% Power due to an Equipment Failure. This event was detailed in NRC Inspection Report 50-311/89-03.

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 272/87-32-01	Section 8.A
Closed	UNR 272/87-05-01	Section 8.B
Closed	UNR 311/87-05-01	Section 8.B
Closed	VIO 272/87-02-02	Section 8.C
Closed	VIO 272/87-02-03	Section 8.C

11. EXIT INTERVIEW (30702, 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.

On May 15, a meeting was held between the NRC and the licensee in the NRC Region I office to discuss recurrent problems associated with the Unit 1

and 2 main steam flow indications. The licensee outlined the history of problems with main steam flow instrumentation, and discussed short term and long term corrective actions taken or planned. The NRC will continue to monitor the corrective actions taken and their effect on the reliability of the main steam flow indications, as they affect reactor protection system and engineered safety features performance. Meeting attendees are listed in Attachment 1 and a meeting outline is included as Attachment 2.

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.

ATTACHMENT 1

LIST OF ATTENDEES - PUBLIC SERVICE ELECTRIC AND GAS MEETING

Main Steam Flow Indication

May 15, 1989

Nuclear Regulatory Commission

P. Swetland, Chief, Reactor Projects Section 2B, Division of Reactor Projects (DRP)
M. Conner, Project Engineer, Technical Support Section, DRP
C. Anderson, Chief, Plant Systems Section, Division of Reactor Safety (DRS)
L. Cheung, Senior Reactor Engineer, Plant Systems Section, DRS
K. Gibson, Senior Resident Inspector

Public Service Electric and Gas Company

P. White, Technical Manager - Salem Operations
J. Gueller, Operations Manager - Salem Operations
L. Miller, General Manager - Salem Operations
F. Thomson, Supervisor - Nuclear Licensing
L. Griffis, I&C System Engineer
D. Lyons, Technical Engineer - I&C
C. Williamson, Senior Staff Engineer
G. Roggio, Station Licensing Engineer - Salem
D. Martrano, Senior Staff Engineer
R. Heaton, System Engineer

AGENDA
NRC PRESENTATION
STEAM FLOW MEASUREMENT
MAY 15, 1989

▪ INTRODUCTION	L.K. MILLER
▪ HISTORY AND ACTIONS SALEM - UNIT 1	L.C. GRIFFIS
▪ LER 50-311/89-007 SALEM - UNIT 2	D.W. LYONS
▪ OPERATOR ACTIONS	J.C. GUELLER
▪ CONCLUSIONS AND SUMMARY	L.K. MILLER

STEAM FLOW CONCERNS SALEM UNIT 1

LEE C. GRIFFIS
SYSTEM ENGINEER - I&C SYSTEMS

- STATEMENT OF PROBLEM AND CONCERNS
- DESCRIPTION OF MEASURING SYSTEM AND CALIBRATION TECHNIQUE
- INFORMATION RECEIVED FROM INDUSTRY AND VENDOR CONTACTS
- ACTIONS TAKEN, THE RESULTS AND ANALYSIS OF THE RESULTS
- SAFETY SIGNIFICANCE
- SHORT TERM ACTIONS TO MINIMIZE RECURRENCE OF TECH SPEC ACTION STATEMENT ENTRIES
- LONG TERM ACTIONS TO RESOLVE STEAM FLOW MEASUREMENT CONCERNS
- SUMMARY

PROBLEM STATEMENT

- PRIOR TO THE 7TH REFUELING OUTAGE STEAM FLOW INDICATION REMAINED CONSTANT AT 100% POWER USUALLY REQUIRING SENSOR CALIBRATION ONCE DURING A CYCLE
- FOLLOWING THE 7TH REFUELING OUTAGE (3/4/88) INDICATED STEAM FLOW BEGAN TO INCREASE WITH NO INCREASE IN TURBINE POWER OR FEED FLOW
- AFTER START UP FOLLOWING A REACTOR SHUTDOWN THE INDICATED STEAM FLOW IS LOW REQUIRING SENSOR RECALIBRATION
- AFTER RECALIBRATION STEAM FLOW BEGINS TO TREND UP AGAIN REQUIRING ADDITIONAL SENSOR CALIBRATIONS
- INDICATED STEAM FLOW STOPS INCREASING AND APPEARS TO LEVEL OFF AFTER ABOUT TWO MONTHS

FLOW MEASUREMENT

SALEM DESIGN

LOW DIFFERENTIAL PRESSURE

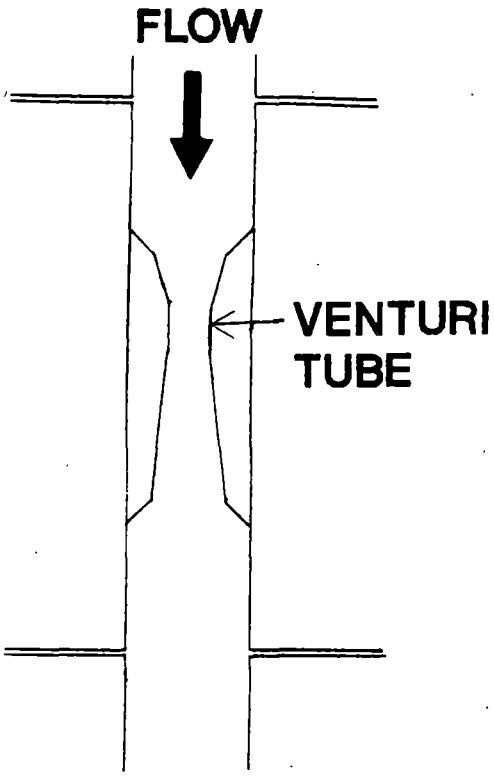
120 INCHES TO 140 INCHES OF WATER AT 100% POWER

BASICALLY A FLOW RESTRICTOR

LOW SIGNAL TO NOISE RATIO

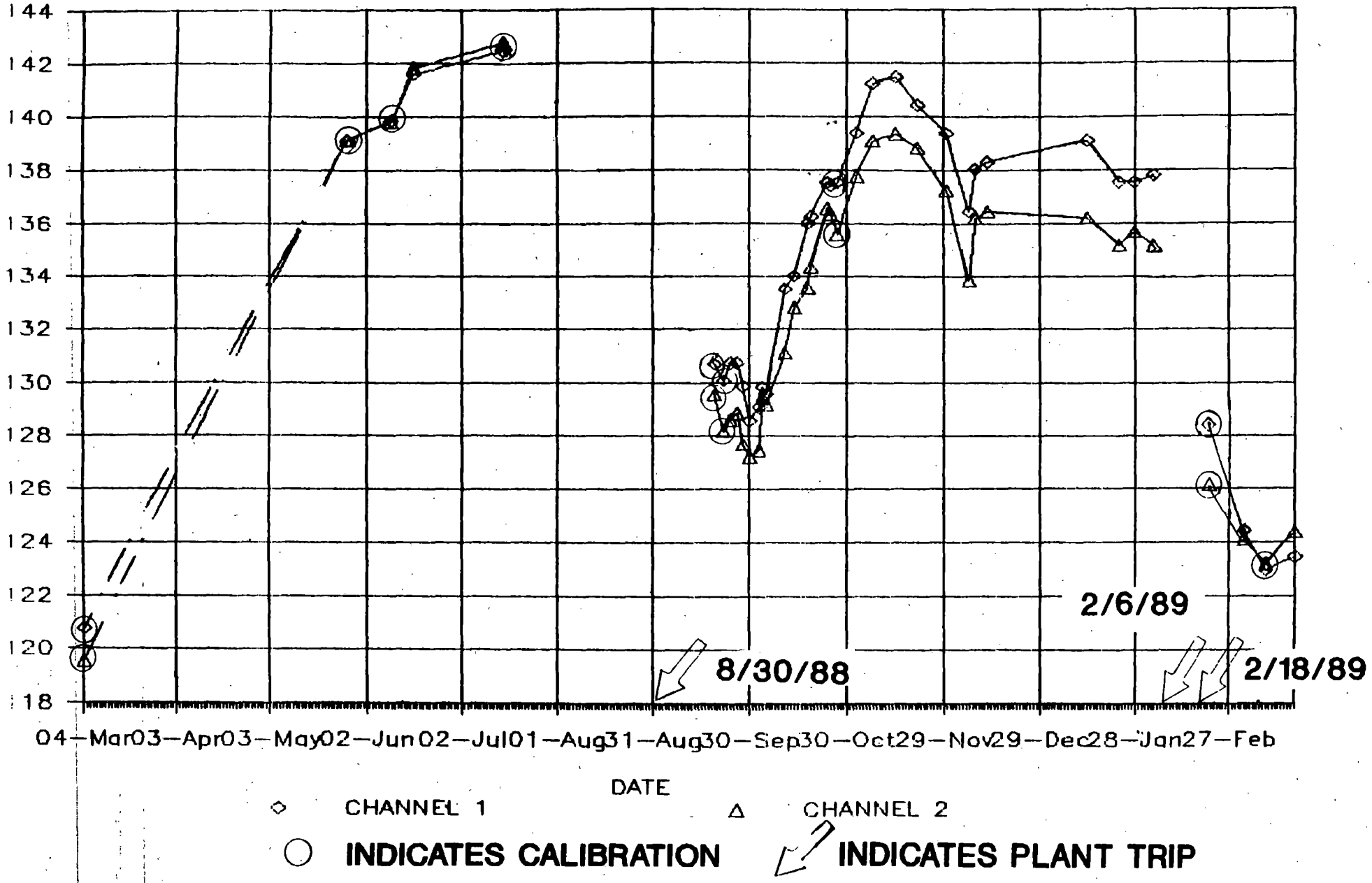
CALIBRATE BY SETTING 100% FLOW TO MEASURED VALUE

HAVE RECALIBRATED THE SYSTEM APPROXIMATELY ONCE PER CYCLE PRIOR TO CYCLE 8



12 STM. GEN. STEAM FLOW

(100% DELTA P VALUES)



INDUSTRY EXPERIENCE

CONTACTS:

- ISSUED NETWORK QUERY TO ALL UTILITIES THE FOLLOWING PLANTS RESPONDED:

BEAVER VALLEY	DAVIS BESSE
DIABLO CANYON	KEWAUNEE
MILLSTONE 3	PRAIRIE ISLAND
H.B. ROBINSON	SAN ONOFRE
SEABROOK	YANKEE

- ALSO, SPOKE WITH THE FOLLOWING:

SEQUOYAH	TROJAN
NORTH ANNA	ZION

RESULTS:

- MOST PLANTS USE CALIBRATION TECHNIQUE SIMILAR TO SALEM'S
- TWO PLANTS STATED THEY HAD EXPERIENCED DRIFTING PROBLEMS. ONE HAS EVEN HAD TO REPLACE TRANSMITTERS DUE TO THE AMOUNT OF DRIFT. NEITHER HAS EXPERIENCED THE "RESET" AFTER A TRIP
- MOST PLANTS HAVE STEAM FLOW MEASURING INSTRUMENTATION WHICH RESULTS IN LOW DELTA P's SIMILAR TO SALEM'S SYSTEM.
- ONE PLANT HAS A CENTER TAPPED VENTURI. THEY HAVE A LARGE DELTA P.
- INSTRUMENT TUBE AND TRANSMITTER PROBLEMS HAVE OCCURRED BUT NOT WITH SAME SYMPTOMS AS AT SALEM

VENDOR CONTACTS

WESTINGHOUSE

- BASED ON REVIEW OF OUR INFORMATION THEY OFFERED THE FOLLOWING POTENTIAL CAUSES:
  - FOULING OF INSTRUMENT LINES
  - FOULING OF VENTURI
  - CHANGE IN VENTURI GEOMETRY
- EXPLAINED THE MAIN PURPOSE OF THE VENTURI WAS A FLOW RESTRICTOR NOT A FLOW MEASURING DEVICE.

BIF, THE VENTURI MANUFACTURER

- THE MANUFACTURER OFFERED THESE CAUSES:
  - IMPROPER TAPPING OF VENTURI COUPLED WITH CONTAMINATION OF VENTURI OR INSTRUMENT TUBING
  - CHANGE IN VENTURI GEOMETRY
- THEY HAVE NOT SEEN SIMILAR OCCURRENCES

ROSEMOUNT

- THEY WERE NOT AWARE OF ANY FAILURE MODE OF TRANSMITTERS WHICH WOULD GIVE THE OBSERVED SYMPTOMS

ACTIONS TAKEN AND THE RESULTS

ACTION	RESULT
"AS FOUND" DATA COLLECTION TO MONITOR TRANSMITTER DRIFT	TRANSMITTERS CONSISTENTLY REMAIN WITHIN CALIBRATION REQUIREMENTS
CHECKED STEAM FLOW DIFFERENTIAL PRESSURE WITH TEST TRANSMITTER	TEST TRANSMITTER READ SAME VALUE AS INSTALLED INSTRUMENT
TRENDED DIFFERENTIAL PRESSURES	BOTH CHANNELS ON EACH STEAM GENERATOR HAVE SAME DIFFERENTIAL PRESSURE SHIFTS
BLED DOWN AND REFILLED INSTRUMENT LINES TO CHECK FOR BLOCKAGE	INSTRUMENT RETURNED TO SAME READING AS BEFORE (NO BLOCKAGE)
INSPECTED NOZZLE AND TAPS WITH BOROSCOPE	APPEARED CLEAN; NO WEAR OR FOULING SEEN
MODIFIED OPERATOR'S LOG SHEETS	INCREASED AWARENESS OF SITUATION & SYMPTOMS

ANALYSIS OF ACTIONS TAKEN

CONCLUSION	BASIS
THE ELECTRONIC INSTRUMENTS DO NOT APPEAR TO BE THE CAUSE	AS FOUND DATA DOES NOT SHOW DRIFTING
	TEST TRANSMITTER HAD SAME READING
INSTRUMENT TUBING DOES NOT APPEAR TO BE THE CAUSE	TRENDS ARE THE SAME ON BOTH CHANNELS. FOULING WOULD NOT BE IDENTICAL BOTH CHANNELS
	BLEEDING AND REFILLING DID NOT AFFECT READING
FOULING OR WEARING OF THE VENTURI AND/OR TAPS DOES NOT APPEAR TO BE THE CAUSE	INSPECTION DID NOT REVEAL FOULING OR WEAR

SAFETY SIGNIFICANCE

- THE PRA ANALYSIS FOR SALEM STATION ASSUMED ALL STEAM FLOW TRIPS HAVE FAILED. A CHANGE IN STEAM FLOW FAILURE RATE WOULD NOT AFFECT THE PRA RESULTS. OUR PRA PREDICTS A CORE DAMAGE RATE COMPARABLE TO OTHER PLANTS.
- THE SALEM FUELS GROUP HAS PERFORMED A SAFETY ANALYSIS OF FUEL DAMAGE WITH HAVING THE STEAM FLOW CHANNELS CALIBRATED 5% LOW (NON-CONSERVATIVE) DURING A MAJOR STEAM LINE BREAK. THE ANALYSIS SHOWED NO AFFECT ON THE FUEL.

SHORT TERM ACTIONS

- SET CONSERVATIVE CALIBRATION PRIOR TO START UP AFTER REFUELING.
- BLOWDOWN STEAM FLOW INSTRUMENT LINES DURING START UP.
- TAKE STEAM FLOW DATA AT SEVERAL POWER PLATEAUS DURING POWER ASCENSION.
- PERFORM ENGINEERING STUDY (BY CONSULTANT)TO DETERMINE ROOT CAUSE.
- TAKE WEEKLY STEAM FLOW DATA TO MONITOR CHANGES AND TRENDS.
- ENSURE A CONSERVATIVE CALIBRATION AFTER A SHUTDOWN.
- DETERMINE IF EXAMINATION OF THE REFERENCE LEGS WHILE AT POWER TO ENSURE THEY REMAIN FULL IS POSSIBLE.
- REVIEW FSAR AND DESIGN BASIS DOCUMENTS TO DETERMINE IF OUR CHANNEL CHECK CRITERIA IS TOO RESTRICTIVE.

LONG TERM ACTIONS

- INVESTIGATE REPLACEMENT OF THE EXISTING STEAM FLOW MEASUREMENT SYSTEM WITH A CENTER TAPPED VENTURI SYSTEM.
- INVESTIGATE ENGINEERING CHANGES SUCH AS ADDITION OF A FOURTH LEVEL CHANNEL, MEDIAN SELECTOR LOGIC FOR STEAM GENERATOR LEVEL, OR ADVANCED DIGITAL FEEDWATER CONTROL TO ELIMINATE NEED FOR STEAM FLOW/ FEED FLOW MISMATCH TRIP.
- INVESTIGATE ELIMINATION OF HIGH STEAM LINE FLOW SAFETY INJECTION SIGNAL BY USING RATE OF CHANGE OF STEAM PRESSURE IN PLACE OF HIGH STEAM FLOW TRIP
- INVESTIGATE WOG SAFETY INJECTION ELIMINATION STUDY RECOMMENDATIONS.

SALEM UNIT 1
STEAM FLOW SUMMARY

- OUR MEASURING SYSTEM AND CALIBRATION TECHNIQUES ARE SIMILAR TO MOST WESTINGHOUSE PLANTS
- THE SHORT TERM ACTIONS WILL MINIMIZE RECURRENCE OF ENTRY INTO TECH SPEC ACTION STATEMENTS
- WE ARE CONTINUING TO INVESTIGATE TO DETERMINE THE ROOT CAUSE
- THERE IS NO SAFETY SIGNIFICANCE

STEAM FLOW EVENT SALEM UNIT TWO

DAVID W. LYONS
TECHNICAL ENGINEER - I&C SYSTEMS

- STEAM FLOW DRIFT IS BEING MONITORED ON UNIT TWO, THUS FAR IT SHOWS NONE OF THE INDICATIONS OF DRIFT OBSERVED ON UNIT ONE.

LER 50-311/89-007

- THREE STEAM FLOW CHANNELS WERE READING HIGH (ONLY TWO WERE OUT OF TECH SPEC LIMITS) RECALIBRATION WAS INITIATED ON THESE THREE CHANNELS.
- UNIT WAS SUBSEQUENTLY SHUTDOWN FOR AN UNRELATED PROBLEM.
- DURING THE SHUTDOWN THE DELTA T LOOPS WERE RECALIBRATED BASED ON NEW STATEPOINT DATA.
- UPON RETURNING TO POWER OPERATIONS, THE THREE STEAM FLOW CHANNELS THAT WERE RECALIBRATED DID NOT MEET THE 3% CHANNEL CHECK CRITERIA.
- T.S.A.S. 3.0.3 WAS ENTERED AT THIS TIME. THIS WAS A VERY CONSERVATIVE APPLICATION. THE PROVISIONS OF T.S.A.S. 3.0.4 COULD HAVE BEEN USED TO ALLOW RECALIBRATION OF THE STEAM FLOW CHANNELS AT THE FIRST STEADY STATE CONDITION. RECALIBRATION OF DELTA T LOOPS AFFECTS STEAM FLOW CHANNEL CALIBRATIONS. THE STEAM FLOW CHANNELS CAN ONLY BE RECALIBRATED AT POWER.
- THE THREE CHANNELS WERE RECALIBRATED AND THE ACTION STATEMENT WAS EXITED
- ON APRIL 5, 1989 WITH THE UNIT AT STEADY STATE OPERATION, STEAM FLOW DATA WAS OBTAINED FOR ALL CHANNELS.

SALEM UNIT TWO STEAM FLOW SUMMARY

- UNIT TWO DOES NOT HAVE ANY OF THE SAME SYMPTOMS AS UNIT ONE
- THE UNIT TWO EVENT WAS CAUSED BY RECALIBRATION OF DELTA T LOOPS AND A CONSERVATIVE ENTRY INTO T.S.A.S. 3.0.3
- BETTER COMMUNICATION ABOUT ACTIONS BEING PERFORMED WHICH MAY AFFECT CALIBRATIONS AND TRAINING ON APPLICATION OF T.S.A.S 3.0.4 SHOULD PREVENT RECURRENCE OF THIS TYPE OF EVENT

OPERATIONS

JAMES GUELLER

1) *Operator Monitoring*

2) *Operator Training*

PARAMETERS MONITORED

* *11-14 SG STM/FW FLOW CHANNEL CHECK*

* *11-14 SG STM FLOW CHANNEL CHECK*

* *11-14 SG STM FLOW/POWER LEVEL CHANNEL CHECK*

CONTROL CONSOLE READING

PARAMETERS	MAL %	T/S %
11-14 SG STM/FW FLOW CHANNEL CHECK	6/4	8/5

Either Stm Flow Channel shall be within MAX limit of either Feed Flow Channel, if not, contact System Engineering for corrective action.

T/S 3.3.1.1 applies for the following:

0-15% Reactor Power	6	8
15-100% Reactor Power	4	5

MANAGEMENT ACTION LEVELS (MAL) PRIOR TO THE ACTION STATEMENT LEVELS

READINGS ARE TAKEN ONCE PER EIGHT HOURS

CONTROL CONSOLE READING

PARAMETERS	T/S %
11-14 SG STM CHANNEL CHECK	3
(8 Channels) highest to lowest between any two channels	

READINGS ARE TAKEN ONCE PER EIGHT HOURS

CONTROL CONSOLE READING

PARAMETERS	MAL %	T/S %
11-14 SG STM FLOW/POWER LEVEL CHANNEL CHECK	+3 -1.5	N/A

At 100% Reactor Power check all eight STM FLOW CHANNELS to power, if any channels are greater than 103% or less than 98.5% CONTACT System Engineering IMMEDIATELY

READINGS ARE TAKEN ONCE PER EIGHT HOURS

INCREASED OPERATOR AWARENESS AND RESPONSE

By;

* Operations Management discussions with Shift Personnel
* Shift Supervisor discussions with Nuclear Control Operators
* Revised Reactor Operator Console Logs
* Monitoring of Steam Flow Indications and Trends by Station Management / System Engineering

CONTINUING TRAINING

* Pre-Startup Simulator Training on Steam Flow Sensitivity & Control

* Steam Flow Instrumentation & Control will be reviewed during the first requalification segment.

* Training is scheduled to include coverage of LER's on Steam Flow Problems in the *Industry Events* portion of Licensed Operator Requalification.

CONCLUSIONS

OPERATOR AWARENESS INCREASED

QUICKENED OPERATOR IDENTIFICATION OF STEAM FLOW TRENDS

MANAGEMENT ACTION LEVELS

SALEM STEAM FLOW SUMMARY

- OUR SHORT TERM ACTIONS ON UNIT ONE WILL MINIMIZE ENTRY INTO TECH SPEC ACTION STATEMENTS FOR STEAM FLOW PROBLEMS
- WE ARE CONTINUING TO INVESTIGATE TO DETERMINE THE ROOT CAUSE OF THE UNIT ONE STEAM FLOW CONCERNS
- THERE IS NO IDENTIFIED SAFETY SIGNIFICANCE OF HAVING THE STEAM FLOW CHANNELS SLIGHTLY NON-CONSERVATIVE
- THE EVENT ON UNIT TWO IS UNRELATED TO UNIT ONE CONCERNS
- OUR OPERATORS HAVE A HEIGHTENED AWARENESS OF THESE ISSUES

(LAST)