Public Service
Electric and Gas
Company

Steven E. Miltenberger Public Service Electric and Gas Company P.O. Box 236, Hancocks Bridge, NJ 08038 609-339-1100

Vice President and Chief Nuclear Officer

FEB 1 0 1992 NLR-N92015

United States Nuclear Regulatory Commission
Document Control Desk
Washington, DC 20555

Gentlemen:

REQUEST FOR ADDITIONAL INFORMATION
INSPECTION REPORT NO. 50-311/91-81
SALEM UNIT 2 TURBINE GENERATOR OVERSPEED
SALEM GENERATING STATION
UNIT NO. 2
DOCKET NO. 50-311

Public Service Electric and Gas (PSE&G) hereby transmits its response to the findings as described in Inspection Report No. 50-311/91-81 dated January 7, 1992. As requested this response is submitted within thirty days of receipt of the aforementioned report.

Attachment 1 to this letter contains PSE&G's assessment of the NRC findings and identifies the actions taken or planned. Attachment 2 contains the final results and recommendations of the PSE&G investigation into the Salem 2 Turbine Generator Overspeed Event, as contained in the Significant Event Response Team (SERT) report.

Should you have any questions in regard to this transmittal, do not hesitate to call.

Sincerely,

Steven E Miltenberger

C Mr. T. T. Martin, Administrator - Region I
U. S. Nuclear Regulatory Commission
475 Allendale Road
King of Prussia, PA 19406

Mr. J. C. Stone, Licensing Project Manager - Salem
U. S. Nuclear Regulatory Commission
One White Flint North
11555 Rockville Pike
Rockville, MD 20852

Mr. T. P. Johnson (S09)
USNRC Senior Resident Inspector

Mr. K. Tosch, Chief
NJ Department of Environmental Protection
Division of Environmental Quality
Bureau of Nuclear Engineering
CN 415
Trenton, NJ 08625

FEB 10 1992 REF: NLR-N92015

STATE OF NEW JERSEY)
) SS.
COUNTY OF SALEM)

Steven E. Miltenberger, being duly sworn according to law deposes and says:

I am Vice President and Chief Nuclear Officer of Public Service Electric and Gas Company, and as such, I find the matters set forth in our letter dated, FEB 10 1992, concerning the Salem Generating Station, Unit No. 2, are true to the best of my knowledge, information and belief.

Steven E Miltenberger

Subscribed and Sworn to before me
this 10th day of February, 1992

Notary Public of New Jersey

My Commission expires 4/10/1995

PSE&G's extensive investigative effort by the Significant Event Response Team (SERT) has independently identified all of the same causal factors as the NRC Augmented Inspection Team. The fact that both teams have independently reached the same conclusions regarding the contributing causal factors is a positive indication that PSE&G has undertaken a thorough assessment of the event.

Because of the close relationship of these contributing causal factors, it is difficult to separate and discuss them individually. Consequently, PSE&G has, where appropriate, grouped the NRC's Contributing Causal Factor statements and answered them collectively.

PSE&G has issued an Operating Experience report to INPO, relative to this event, for further dissemination with the industry. Additionally, this event has been discussed with all appropriate Nuclear Department personnel. The event, the contributing causal factors and lessons learned from them, have been rolled-down from the Vice President - Nuclear Operations to all General Managers, and from the General Managers down to all appropriate employees via documented meetings.

In conclusion, PSE&G agrees with the NRC statements and their characterization of contributing causal factors and provides its response below.

NRC STATEMENTS

A. Management communication and personnel understanding of the policy and expectation relative to conduct of operations involving procedure adherence, resolution of procedural and equipment problems, and quality of operations appears to be deficient in the specific case of the turbine startup on October 20, 1991. Five licensed personnel, including operators and supervisors, failed to adequately resolve a test discrepancy, involving the overspeed protection control system prior to returning the turbine to full power operation. Consequently, an opportunity to prevent this event was missed. (Contributing Causal Factor)

B. On October 20, 1991, certain licensed operators and supervisors did not sufficiently adhere to the specifications of IOP-3, "Integrated Operating Procedure-Hot Standby to Minimum Load", Step 5.33, which required the turbine to be operated in accordance with OP-III-1.3.1., "Turbine Generator Operation". OP-III-1.3.1., Step 5.1.13 specifies testing of the OPC by verifying that the Intercept Valves close when the OPC test switch is in the TEST position. When tested, the Intercept Valves did not close as was expected. Regardless, turbine-generator startup was permitted without resolving this test discrepancy. (Contributing Causal Factor)

PSE&G RESPONSE

PSE&G agrees with the NRC statements of causal factors.

The two NRC Contributing Causal Factors, above, have been grouped together since they both deal with the October 20 startup issues.

On the evening of October 20, 1991, a turbine generator startup was in progress on Unit 2, following a two day shut down for steam generator secondary side chemistry cleanup. In accordance with Integrated Operating Procedure No. 3 (IOP-3), the turbine is put on line utilizing Operating Procedure III-1.3.1 (OP III-1.3.1) "Turbine Generator Normal Operation." Step 5.1.13 of the Operating Procedure requires the functional testing of the Overspeed Protection Controller (OPC) actuation circuitry by inserting a key into the OPC keyswitch, and turning it to the TEST position. The test was performed twice, once by each control room operator, and each time the expected indication was not received. A discussion of the test results ensued between the control room operators and the Nuclear Shift Supervisor (NSS), with later participation by the Operating Engineer, and subsequently, the Senior Nuclear Shift Supervisor (SNSS).

Communication errors concerning the test results and the test procedure, coupled with insufficient supervisory oversight, lack of attention to detail, and procedural compliance, resulted in all control room personnel involved misunderstanding that the test had been performed properly and had failed. Since no licensed personnel, involved in the discussion, understood the OPC function to be inoperable, the test was not performed again and the turbine startup was continued. The turbine roll-up and subsequent synchronization were uneventful. A review of the control room narrative log (OD-21) revealed no entries documenting the test failure or the subsequent decision to continue with the turbine startup without rectifying the apparent failure.

CORRECTIVE ACTIONS

1. Operations management has reviewed this incident with the individuals involved and appropriate disciplinary actions have been taken. This included development of personal corrective action plans, as well as shift supervision developing and presenting training topics to cover lessons learned from the event. Topics covered include: procedural compliance, attention to detail, communications, and the role and responsibility of the Operations Manager and Operating Engineers in the control room. This training is complete.

2. The Operations Manager is conducting half day discussions with all operating personnel regarding the practical and philosophical aspects of procedural compliance and the mechanisms available to change procedures. These discussions will take place during the current annual requalification training cycle and, will be completed in March 1992.

3. The Operations Manager is conducting one-on-one meetings with all Senior Nuclear Shift Supervisors (SNSS) to discuss their role and responsibilities and to re-emphasize management expectations.

4. The Operations Manager has directed the simulator training staff to reinforce Operations Management policy on procedure compliance and communications, and to ensure that these expectations are upheld at all times during simulator training. Operations management observes and evaluates the performance of the licensed operators during their simulator training sessions, every two weeks. In addition, INPO style Team Training will be conducted during the 1992 requalification training cycle.

5. The Vice President - Nuclear Operation and the General Manager - Salem Operations met with each operating shift during the first week of December. During these meetings, both team and individual performance were stressed. The October 20th startup was also reviewed with specific discussions of the failed barriers, procedural compliance, lessons learned, positive disciplinary actions taken as a result of the event, and refocusing the organization on future expectations and capabilities. Additionally, the role and responsibility of the operations management personnel in the control room during plant startup, along with their position in the chain of command, was reviewed.

6. The Vice President - Nuclear Operation and the General Manager - Salem Operations will hold quarterly meetings, through the remainder of 1992, with all operating shift and maintenance personnel. These meetings will provide an open forum of communication to discuss operating issues and management expectations.

7. Concurrent with the turbine testing procedure review and upgrade as a result of the November 9 Turbine Generator event, the procedures used during the October 20 startup (which contributed to the apparent confusion on the test), will be reviewed and upgraded by the Procedure Upgrade Project (PUP) prior to the Units restart from their scheduled refueling outages.

8. The operation of the EHC/Auto Stop Oil system and the role that the OPC plays in turbine generator overspeed protection is being re-emphasized with all shift licensed personnel during the current annual requalification training cycle which will be completed by the end of March 1992.

9. A thorough review of the various documents describing the "Conduct of Operations" for the NSS is being incorporated into the annual requalification training program. Some of these documents include: Standing Night Orders, Operations Directive-19, NC.NA-AP.ZZ-0005(Q), proper log taking in accordance with operating directives, and The Salem Work Standards Handbook. These topics are being incorporated into the requalification training.

10. An Information Directive #91-052, entitled "Conduct of Operations", has been issued to all Operations Department personnel stressing that strict procedural compliance is the only allowed behavior within the Operations Department.

11. A Night Order Book entry was made and discussed, on November 22, 1991, stressing the importance of the requirements for proper and thorough log keeping.

12. INPO Personnel Awareness Training is being conducted. Two new lessons, Resource Management, and Supervisory and Management Effectiveness, which had already been developed, are being rolled down to all station employees.

13. Lessons learned from this event, as well as the SERT recommendations, have been reviewed by Hope Creek for technical design applicability.

14. A Human Performance Evaluation (HPES) has been initiated. Any additional HPES corrective actions will be evaluated for implementation as appropriate.

NRC STATEMENT

C. The licensee failed to react in a timely manner to the Salem Unit 1 solenoid failures by effectively verifying the operability of, or replacing the devices in Salem Unit 2 in accordance with an LER commitment. (Contributing Causal Factor)

PSE&G RESPONSE

PSE&G agrees with the NRC statement of causal factor.

On May 11, 1991, Salem Unit 2 shut down for a planned maintenance outage. This outage was scheduled for ten days, and was focused on repairing plant equipment in order to ensure reliable plant operation through the summer period. The work scope for this mini-outage was assembled from the Salem Forced Outage Work List. Items on this list cannot be performed with the unit at power and are separated into various categories. The following is a summary of the categories:

"Must Do" Items	Work which has to be performed prior to the Units returning to service. This include surveillances, commitments, and management priority items.
"1 - 2 Day List" "4 - 5 Day List"	Work which can be completed if the unit is off or expected to be off for 1-2 or 4-5 days.
"Break Vac. List"	Work which requires condenser vacuum to be broken.
"Mode 5 List"	Work which requires the unit to be placed in mode 5.

Prior to the May outage a work order was planned on the 1-2 day list, and issued to change out the 20-ET and 20 OPC-1/2 solenoids valves. In PSE&G's Licensee Event Report (LER) response, PSE&G identified that these solenoids would be changed in Unit 2 by the next "outage of sufficient duration." This commitment was entered into the Action Tracking System (ATS). A work order (WO) (900918221) was written to replace both solenoids. The work order identified this activity, the solenoids replacement, as a "LER commitment to be completed by the Unit 2 6th refueling outage". This commitment was closed on ATS on October 25, 1990, based upon the the following response:

"Work order (WO) 900918221 was written to replace both solenoids. WO is on forced outage list if condenser vacuum is broken. Otherwise, it will be completed during the unit 2 sixth refueling outage. LER commitment has been noted on the WO."

At the time of the response, the solenoid valves were not considered a "Must Do" item because the required surveillance testing procedures had been completed satisfactorily after the Unit 2 restart from the 5th refueling outage. Accordingly, these solenoids were considered "operable." Consequently, the solenoid replacement was not included in the mini-outage schedule, and was deferred to the scheduled refueling outage, based upon the following:

1. The required surveillance testing procedures had been satisfactorily completed following the 5th refueling outage. Consequently, the solenoids were considered operable.

2. The work order did not clearly identify the commitment as a "Must Do" item, on the forced outage list.

3. The solenoids would be tested, in accordance with the established procedures at that time, prior to the Unit restart from the mini-outage.

The Mini-Outage was a discretionary management shutdown to complete safety and reliability maintenance work of known broken equipment. The solenoids were replaced during the 6th refueling outage.

CORRECTIVE ACTIONS

1. A new Nuclear Administrative Procedure (NC.NA-AP.ZZ-0030(Q), Commitment Management) has been approved and issued. This procedure provides clear guidance on the tracking of regulatory commitments and will not allow a commitment to be closed until the commitment (work) has been fully implemented. For example; the ATS item regarding the replacement of the Unit 2 solenoids would not have been closed on the initiation of the work order. Closure would occur only when the task has been completed.

2. Previous LERs (1990 to 1991) have been reviewed for other forced outage commitments. Specifically, the LERs were reviewed for any commitment activity which contained the words "forced outage" or "outage of sufficient duration." No other forced outage commitments were identified.

3. NC.NA-AP.ZZ-0055(Q), Outage Management Program, will be revised to require multi-disciplinary reviews of work not completed or deferred during outages. This revision will be completed by April 30, 1992.

4. Procedure SC.OM-AP.ZZ-0001(Q) Rev. 0, Outage Scheduling, which was approved on December 6, 1991, provides clear and concise guidance to the outage schedulers on how to schedule regulatory commitments.

5. Because of the miscommunications between departments, Outage planning and System Engineers, the General Manager - Salem Operations issued a letter to all management employees stressing the need for clear and concise communications.

NRC STATEMENT

D. Though not conclusive, the information available indicates that the initial transient, i.e., low AST pressure indication to the RPS was most likely due to clogging of the supply pressure reducing orifice by foreign material (similar to the Unit I event reported in LER 50-272/88-015). However, the possibility remains that the operator at the Front standard may have inadvertently moved the test lever to momentarily Perturb the AST oil pressure. (Contributing Causal Factor)

PSE&G RESPONSE

PSE&G agrees with the NRC statement of causal factor.

PSE&G investigation into this event has determined that the initiating event of the Reactor Trip/Turbine Trip was (most probably due to) a momentary blockage of the Auto Stop Oil System inlet pressure reducing orifice by identified foreign material.

However, PSE&G has not ruled out the possibility that the operator at the Front Standard, (who was holding the trip bypass test lever during the test), unintentionally may have allowed the tests lever to move away from its test position.

CORRECTIVE ACTIONS

1. PSE&G inspected the orifices on Unit 1, during the January 21-28, 1992 shutdown to verify cleanliness of both the lines and orifice, and to maintain them in the proper condition.

2. A recurring task for inspection of the orifices, every refueling outage, has been initiated.

3. The Front Standard Test procedure (OP III-1.3.7) is being reviewed from a human factors standpoint, and will be upgraded by the Procedure Upgrade Program. The upgrade will be completed prior to the Units restart from their respective refueling outages.

4. A design change for installation of filters on the AST oil lines to the orifices is being developed, and is intended to be completed during the current outage, or provisions will be made so it can be readily installed after the outage.

NRC STATEMENT

E. While ET-20, OPC-20-1, and OPC-20-2 were energized in accordance with design, none of the solenoids functioned hydraulically. The AST-20 solenoid was confirmed to be operable, but was by-passed during the period of the event. (Contributing Causal Factor)

PSE&G RESPONSE

PSE&G agrees with the NRC statement of causal factor.

Following the reactor trip/turbine trip, a turbine-generator failure occurred due to mechanical binding of the three solenoids referenced above (20-ET, 20-1 and 20-2 OPCs). PSE&G's investigation indicates that the solenoids were mechanically bound at the pilot valve assembly due to corrosion products and/or "O" ring debris. Concurrently, the 20-AST electrical turbine trip solenoid and the mechanical overspeed protection systems (both of which were confirmed operable) were bypassed during the performance of the test.

PSE&G believes this causal factor to be a significant contributor. Because of procedure inadequacies (failing to independently test these solenoids), PSE&G was not able to detect the failure. PSE&G's investigation revealed at least 6 contributing causal factors associated with the failure of these solenoids. Many of these were also identified by the NRC and are responded to in different sections of this attachment. The following is a list of those causal factors identified by PSE&G investigation:

1. Lack of vendor recommendation or requirement for preventive maintenance of these solenoids.

2. Failure to recognize similar industry events.

3. Failure to adequately implement a commitment to replace the 20-ET and OPCs solenoids in May 1991.

4. Failure to independently test the 20-1&2 OPCs and the 20-ET and 20-AST.

5. Failure to adequately address the October 20 apparent test failure.

6. Technical Specification Limiting Condition for Operation 3.3.4 (T.S. L.C.O 3.3.4) not sufficiently clear.

CORRECTIVE ACTIONS

1. See response to NRC statements F, G and H (Pg. 12)

2. See response to NRC statement J (Pg. 15)

3. The 20-ET and 20 OPCs solenoids valves have been replaced during the current Unit 2 refueling outage (2R6).
   See response to NRC statement C (Pg. 6)

4. These solenoid valves will be independently and hydraulically tested prior to the Unit 2 restart from the current refueling outage. The Unit 1 valves have been satisfactorily and independently tested during the January 21-28, 1992 shutdown.

5. See response to NRC statements A and B (Pg. 2)

6. See response to NRC statement O (Pg. 21)

NRC STATEMENTS

F. All of the AST pressure switches affecting the RPS logic operated as designed, but the 63-3 AST pressure switch (which is not part of the RPS) did not function as expected. The 63-3 AST pressure switch was set at 39 psig (approximately 10 to 15 psig less than the AST pressure switches affecting RPS). The 63-3 AST pressure switch is responsible to for re-referencing of the Governor valve controller from full-load to no-load when the turbine is expected to trip. Consequently, when the initial turbine trip signal occurred, the Governor Valve was not re-referenced to a no-load situation. Instead of closing the Governor Valves for the no-load condition, the valves re-opened when hydraulic trip fluid repressurized in the EHC system. (Contributing Causal Factor)

G. None of the solenoid valves were subjected to any PM program. The vendor did not prescribe any PM for the devices; consequently, a PM program was not initiated. (Contributing Causal Factor)

H. The 63-3 AST switch was not subjected to any recurring calibration program. (Contributing Causal Factor)

PSE&G RESPONSE

PSE&G agrees with the NRC statements of causal factors.

The three NRC Contributing Causal Factors above have been grouped together since they deal with preventive maintenance issues.

As a result of the 1990 Unit 1 solenoid failure, preventive maintenance tasks were developed. These tasks were scheduled to be implemented during the refueling outage, after the solenoids replacement.

Historically, planned preventive maintenance at Salem has been based upon vendor manual recommendations. Recently, a Reliability Centered Maintenance (RCM) program has been established. One of the reasons for the establishment of the RCM program was the awareness that preventive maintenance based solely upon vendor recommendations was not adequate. A program based on vendor recommendations may result in insufficient or excessive maintenance. RCM preventive maintenance procedures include plant and industry experience as documents for inspection and testing.

The RCM program has completed a number of RCM analysis for plant systems. This program was prioritized to analyze those systems that would provide the greatest increase in nuclear safety first. The RCM analysis for the Turbine-EHC system was not yet performed.

CORRECTIVE ACTIONS

1. PSE&G is presently evaluating the need (as a long term solution) and feasibility of providing a "2 out of 3" logic change to the AEH Controller input (63-3AST) signal, for Auto Stop Oil Pressure, similar to the "2 out of 3" logic to the Reactor Protection System.

2. PSE&G is presently evaluating the 63-3 AST pressure switches set point. These pressures switches will be calibrated in accordance with recent Westinghouse recommendations, and will be completed prior to the Unit restart. The pressure switches associated with the RPS system (arranged in a 2 out of 3 logic) are calibrated, and their set point established, in accordance with Technical Specifications requirements of equal to or greater than 45psig. They are set at 50psig. The pressure switch (1 of 1 logic) associated with the AEH controller was originally set at 45psig. A recurring task will be established to recalibrate the AST pressure switches using the set points established by the above set point evaluation. These recurring tasks will be developed and in place prior to the next outage.

3. The RCM analysis for the Turbine-EHC system will be completed by the end of 1992.

4. Recurring tasks for the solenoids had already been developed with a frequency of three years. The three year PM frequency is being evaluated with the analysis of the EHC system, and will be completed by the end of 1992.

5. The solenoid supplier is presently evaluating the issuance of preventive maintenance requirements for turbine solenoid valves. PSE&G will incorporate these requirements pending final RCM analysis.

NRC STATEMENT

I. The local turbine speed tachometer, which could have provided early indication to the operators at the Front Standard of an overspeed condition was not maintained operable since 1987. (Contributing Causal Factor)

PSE&G RESPONSE

PSE&G agrees with the NRC statement of causal factor.

This item was identified by PSE&G to be an additional causal factor that may have contributed to the event. However it was determined to be a minor causal factor because of the location of the indication. It is doubtful that the front standard operators, performing this test, could have seen the tachometer from their location.

The tachometer and the recorder in the Control Room (RP7 Panel) had been disconnected and abandoned with an Information Tag Out of Service by 2EC-2019 since 1986. Design Change Package (DCP) 2EC-2019 installed the Hope Creek generator at Salem in 1986. Disconnecting the recorder, along with other adjacent equipment, broke the instrument current loop to the front standard tachometer. There were six additional turbine instruments abandoned during the installation of the Hope Creek Generator DCP, none of which would have played a role in this event.

Review of the above DCP showed no installation instructions, modification document or change document, to remove the RP7 recorder. PSE&G investigation results indicates that this was an error by the design change team at the time.

CORRECTIVE ACTIONS

1. A design change is being developed to reconnect these instruments. Modifications, if deemed necessary, will be implemented during the present Unit 2 refueling outage.

NRC STATEMENT

J. Information (from internal and external experience) concerning previous component failures of turbine solenoid valves does not appear to have been generally regarded by the licensee as significant or of sufficient importance to warrant priority attention and corrective action. (Contributing Causal Factor)

PSE&G RESPONSE

PSE&G agrees with the NRC statement as a causal factor.

There are a number of information sources available to PSE&G for its external operating experience reviews. PSE&G Operating Experience Feedback (OEF) program requires screening of certain documents to determine applicability and significance, for use as information only, or to require additional evaluation. The following is a list of some of the internal and external sources of information available to PSE&G:

1. NRC
   - Information Notices (*)
   - 10 CFR Part 21

2. INPO
   - Significant Operating Experience Reports (SOER)
   - Significant Event Reports (SER)
   - Operations and Maintenance Reminders (O&MR)
   - Significant by Others (SBO)
   - Operating Experience (OE)
   - Significant Early Notifications (SEN)
   - INPO Special Reports
   - Daily Nuclear Network
   - Nuclear Plant Reliability Data System (NPRDS)

3. VENDORS
   - Technical Bulletins
   - Operation Maintenance Memos
   - Availability Improvements Bulletins
   - Service information Letters
   - Technical Information Letters
   - Information Letters
   - Service Advise Letters

4. PSE&G
   - Action Tracking System (ATS)
   - Incident Reports (IR)
   - Licensee Event Reports (LER)

With the exception of the Operating Experience (OE) reports, and internal PSE&G LER, which are discussed below, no other information pertinent to this event was available to PSE&G.

Regarding the internal operating experience information, there were two LERs for which PSE&G took corrective actions. These LERs are: LER 272/88-015-00 and LER 272/90-030-00.
The 1988 LER dealt with a very similar reactor trip/turbine trip event. The root cause of that event was attributed to clogging of the Auto Stop Oil System pressure reducing orifice.

As a result of this event PSE&G committed to initiate preventive maintenance of the Auto Stop Oil system. Preventive maintenance work orders were initiated to perform oil flushes and to remove and clean the AST orifices during each refueling outage.
This was performed last in May 1989 and May 1990, for Units 1 and 2 respectively.

The 1990 LER dealt with the Unit 1 failure of the OPC solenoids. As a result of this event PSE&G committed to replace these solenoid valves in Unit 2 during an outage of sufficient duration. This issue has been discussed earlier in our response to NRC statement C. Additionally, a PM task had been developed for these solenoids. Implementation was originally scheduled for the end of the sixth refueling outage, when the solenoids were to be replaced. (See NRC statements F, G and H)

Regarding the external operating experience information, there were three related events. These events are:

1. The 1985 Ginna event (Reference O&MR 268, dated August 1985).

2. The 1985 Crystal River event (Reference OE-3729, dated December 27, 1989).

3. The 1990 Ginna event (Reference OE-4218, dated October 30, 1990).

The information available on these events emphasized a reactor trip followed by an "excessive cooldown". Although the solenoid valve failures were mentioned in the OEs, it was not readily apparent that they had been a contributing factor to the event, or what was the failure mechanism.

One other operating experience issue, which was identified by PSE&G's investigation, is also discussed below.

NRC issued Generic Letter (GL) 91-15 on September 23, 1991, to inform licensees of a case study report of solenoids valves. The GL indicated the the NRC was providing EPRI's Nuclear Maintenance Center technical advice to assist in preparing a maintenance guide for solenoid valves. No response was required to this GL.

CORRECTIVE ACTIONS

1. Generic letters which do not require formal response, and are related to operating experience, will be sent to Reliability and Assessment to be handled as operating experience.

2. The weekly operating experience feedback meeting, initiated in 1990, have provided considerable value in upgrading the station personnel awareness of current industry events. PSE&G management considers this an important activity and will continue to support this type of operating experience feedback meeting.

3. PSE&G submitted to the INPO Nuclear NETWORK system an Operating Experience report on this event for sharing with the industry. This is being followed up with a supplemental report to properly address and communicate all aspects of the event.

4. PSE&G management presented this event at the recently held Westinghouse Owners Group Meeting, to further disseminate all appropriate information.

5. PSE&G and Westinghouse are concurrently assessing this event, in particular the solenoids and control system designs for potential Part 21 reporting.

(*) The Salem event has been documented in NRC Information Notice 91-83

NRC STATEMENTS

K. "The periodic testing of the mechanical trip function effectively isolates 17 possible trip signals or inputs while the test is being performed; prior to performing the test, there is no verification that the back-up trip and overspeed systems are functional. (Contributing Causal Factor)

L. Surveillance and operational testing of turbine trip performance and overspeed did not specifically verify the proper hydraulic functioning of each solenoid valve, independently. (Contributing Causal Factor)

M. The procedures that were established and implemented to verify the operability of the turbine overspeed control system, to meet the licensee's understanding of the requirements of TS 3.3.4, were not generally effective. Procedure SP(O) 4.3.2 adequately verified the operability of the turbine steam admission and control valves but did not sufficiently verify the operability of the overspeed control system. (Contributing Causal Factor)

N. The licensee's application of various Operating, and Instrument and Control Procedures to satisfy the channel calibration requirements of TS 3.3.4 is not well established. The procedures (OP III- 1. 3. 2, 2PD-6.1.004, and OP III- 1. 3. 1) are used to satisfy the TS requirements for the channel calibrations, but since the procedures are not dedicated TS surveillance procedures, and are considered as Category II procedures, a record of their performance is not always maintained. As a result, there is uncertainty, in some cases, as to the licensee conformance with these procedures. (Contributing Causal Factor)

PSE&G RESPONSE

PSE&G agrees with the NRC statements of causal factor.

The four NRC Contributing Causal Factors above have been grouped together since they contain and deal with procedure adequacy issues.

Concerns relative to the overall quality of the Salem implementing procedures were first identified in 1989. These concerns were identified by PSE&G as well as INPO and the NRC. The Procedure Upgrade Program (PUP) was initiated to improve the technical content, human factors, format and consistency of approximately 3700 procedures. Presently, the PUP project is approximately 53% complete with a targeted project end date of December 31, 1992.

None of the procedures related to the turbine overspeed control system had been upgraded at the time of the event. The upgrade process for these procedures has already been initiated and will be completed in support of the Units restart schedule. An element of the upgrade process is a verification that the procedures adequately test equipment and functions to assure that Technical Specification requirements are met. This involves a specific identification of Technical Specifications related steps and the delineation of acceptance criteria. Additionally, place keeping is established and record retention requirements are identified.

The PUP process includes multiple levels of technical reviews. In addition to 10 CFR 50.59 reviews, other reviews include: procedure writer, discipline supervision, station qualified review, senior shift supervisor review (Operations procedures) user's review, system engineering review, and department supervision review. As a result of the established process for the upgrade program, PSE&G believes that the probability of identifying and correcting the procedural shortcomings associated with this event was high. While it is unfortunate that these procedures were not upgraded prior to this event, PSE&G has the appropriate corrective elements within the Procedure Upgrade Project.

PSE&G has committed significant resources to the PUP project. The results to date have given us confidence that the program and process are significantly improving the quality of the Salem procedures. For these reasons, PSE&G believes that these causal factors are being properly addressed.

CORRECTIVE ACTIONS

1. Under the direction of the Technical Manager a team is being formed to develop a matrix chart to identify all turbine multi-trip testing (which are Technical Specifications Surveillance requirements) to ensure independence of each test. In addition, this matrix chart will also identify the following:

   a. Which tests are manufacturer specified tests to ensure operability.
   b. Who is responsible for each test.
   c. What are the procedures required.

   Based on the results of the matrix chart information, changes to Recurring Tasks and procedures will be initiated. These changes, if deemed necessary, will be in place prior to the restart of Unit 2 from its current scheduled refueling outage.

NOTE

In addition to the Solid State Protection System (SSPS) inputs, SSPS train B inputs to 20-ET and SSPS train A inputs to 20-AST, these solenoids receive a number of electrical generator protection trip signals. These signals are divided into Regular and Backup. The need to independently test each of these signals will be determined by the results of the matrix chart.

2. The existing Unit 1 procedures (1IC-18.1.006 and 1IC-18.1.007) have been revised. The revision independently tested solenoid valves 20-ET and 20-AST during the Unit 1 startup of January 1992. The upgraded version, through the PUP process, will be issued prior to the Units restart from their respective refueling outages.

3. Other Instrument & Control (I&C) and Operations procedures, related to this event, will be revised and issued prior to the Units restart from their respective refueling outages.

4. A design change to upgrade the turbine protection circuitry by adding a back-up 20-AST is being developed, and will be incorporated during the present refueling outage. This back-up solenoid would not be isolated during testing. Other logic changes are being evaluated, and any changes deemed necessary, will be implemented prior to the re-start of Unit 2 from its current scheduled refueling outage.

5. Long term, a design change to upgrade the turbine protection circuitry by adding an electrical overspeed channel, is being evaluated.

NRC STATEMENT

O. The NRC Standard Review Plan, upon which Unit 2 was evaluated, generally assumes the availability of three diverse and redundant overspeed protection devices (OPC, mechanical, and emergency trip). In the case of Unit 2, two of those three (mechanical overspeed and electrical input to AST-20) are prevented from functioning whenever the AST system is under test. (Contributing Causal Factor)

PSE&G RESPONSE

PSE&G agrees with the NRC statement of causal factor.

Technical Specifications (T.S) Limiting Condition for Operations (LCO) 3/4.3.4, Turbine Overspeed Protection states "At least one turbine overspeed protection system shall be operable." There are two actions statements associated with this LCO:

1. Addresses inoperable steam supply valves.

2. Addresses the failure to have the required overspeed protection system operable.

A clear definition of what constitutes a required Turbine Overspeed Protection System is not provided in the UFSAR or Technical Specifications.

Amendment 115/97 to Technical Specifications reduced the Turbine Valve Testing frequency. This amendment was based on the results of a Westinghouse Owners Group (WOG) study, published in WCAP-11525. This WCAP was written to address all plants that participated in the study, including Salem Units 1 and 2. WCAP-11525 has been reviewed for possible input into determining the required Overspeed Protection System identified in this LCO. The WCAP identified the types of overspeed protection for each of the participating utilities. Salem was classified as having a system No.2 Trip System. A System No.2 Trip System is described in the WCAP as follows:

> System No.2 has mechanical overspeed trip valve and a 20-AST solenoid valve either of which will dump the autostop oil. The dump of the autostop oil causes an oil operated interface valve and a 20/ET solenoid to open, either of which dumps the emergency electro-hydraulic trip fluid. System No.2 also includes two overspeed protection control solenoid dump valves (20-1 OPC and 20-2 OPC), either of which will dump the control electro-hydraulic trip fluid.

Thus, there are four solenoid valves and one mechanical trip which can be grouped into three independent overspeed protection circuitry. These are:

1. Mechanical Overspeed.

2. OPC (20-1 and 20-2 solenoids).

3. 20-AST/20-ET solenoids.

The mechanical overspeed protection system and 20-AST are prevented from functioning whenever the AST system is under test. However, 20-ET and the 20 OPCs would remain available to provide the necessary protection.

CORRECTIVE ACTIONS

1. After reviewing the Technical Specifications, the UFSAR and the Westinghouse WCAP, PSE&G will change the Technical Specifications Bases to clarify and list the overspeed protection systems that need to be considered when determining if at least one system is operable. This change will be performed under 10 CFR 50.59 and it will be submitted to NRR for review by the end of 1992.

FINAL RESULTS OF ROOT CAUSE ASSESSMENT

As noted in your report a Significant Event Response Team (SERT) was established on November 9, 1991. The team was tasked with providing an independent assessment of the event including root cause(s), and corrective action recommendations. The SERT process is proceduralized in a Nuclear Department Administrative Procedure, which clearly defines its responsibilities and scope.

The General Manager - Nuclear Operations Support was assigned as the SERT manager. The SERT membership was made up of trained and qualified personnel having the necessary general and specific knowledge required for this investigation. The eleven individuals selected represented several departments including: Engineering and Plant Betterment, Nuclear Training Center, Emergency Preparedness, Safety Review, Quality Assurance, and Technical Department.

INITIAL REACTOR/TURBINE TRIP

Investigation has shown that the AST System Oil pressure decreased to below the trip setpoint for a duration of 1.5 seconds and then returned to above the reset pressure setpoint. This pressure drop was most probably caused by the primary AST oil supply pressure reducing orifice becoming momentarily clogged.

A Unit 1 1988 turbine trip/reactor trip event (reference LER 272/88-015-00) involved blockage of the orifice. However, the Unit 1 blockage was sludge. Sludge does not appear to be the cause of this Unit 2 event since sludge has not been discovered around the subject orifice. Inspections have discovered foreign material on the inlet side of the orifice. Four (4) of the twelve (12) holes were plugged. In addition, a 3/32" diameter flake was found adhering to the inlet side of the orifice. This material has been analyzed as Aluminum. Since there are no Aluminum made components in the system, the most probable source of the Aluminum is believed to be from the painted inner lining of the Lube Oil Storage Tank. PSE&G's investigation as to the source of the aluminum is continuing.

The SERT could not completely rule out a second possible cause. The operator, holding the manual test bypass lever, may have moved it unintentionally and then moved it back within 1.5 seconds. If this did occur, it would be attributed to inadequate human factors design. There is no "positive indication" whether the manual test lever is in the normal vs. test position.

This could have occurred by the operator flexing his hand. The operator had been holding the handle for approximately twenty (20) minutes when the event occurred. The amount of lever deflection needed to take the lever out of test is approximately one (1) inch, as demonstrated by post event testing (total travel is 2 inches). No "detent" feature for the test lever exists while it is held in the test position, nor any positive indication of when it is engaged. The operator does not believe he moved the lever.

A human factors study of the front standard test, points to human factors improvements, which ultimately would support making this test less of a risk for initiating a trip signal. These improvements are being discussed with Westinghouse.

<u>TURBINE/GENERATOR FAILURE</u>

Following the Reactor Trip, a Turbine/Generator failure occurred. The root cause of this event was a combination of: 1) the failure of the 20/ET backup turbine trip solenoid valve to open upon energization; 2) failure of the two (2) primary overspeed protection solenoid valves (20-1/OPC and 20-2/OPC) to open upon energization; and 3) as found setpoint inconsistencies, of the AST pressure switches, resulted in not sending a turbine unlatch signal to the Analog Electro-Hydraulic (AEH) controller of sufficient duration to drive the AEH controller "Load" reference to zero. Also, the re-establishment of AST pressure (i.e., turbine latched), with the turbine stop valves "closed" signal(s), resulted (per design) in the opening of the turbine stop valve bypass valves.

The solenoid valves were all found to be mechanically bound such that the valves could not open when the solenoid was energized. The degradation could have been detected either by routine maintenance (ie., inspection/cleaning) or by periodic hydraulic testing of the valves individually.

The solenoid valve failures were not prevented or detected prior to the event due to several contributing factors discussed previously in our response.

SERT RECOMMENDATIONS

Significant Event Response Team's (SERT) recommendations for corrective actions resulting from the event of 11/9/91 are listed below. As stated earlier in this letter, the SERT team also identified and recommended corrective actions for all fifteen NRC identified causal factors. These have been discussed in Attachment 1 of this letter. The additional corrective actions with a brief status are provided below:

a. Review Technical Specification surveillance testing methodologies to ensure no other instances of failure to test components independently exist, which could involve Technical Specification violations or reductions in protective functions redundancy.

STATUS

A review of all Technical Specification requiring a Channel Calibration has been performed. The review did not identify any other similar instances. The Procedure Upgrade Program will ensure that all Technical Specification surveillances are clearly identified. To be completed by December 1992.

b. Review the process of Technical Specification license change request to determine who LCO 3/4.3.4 was not clarified when it was last amended. Identify actions to prevent recurrence.

STATUS

In progress. To be completed by March 1992.

c. Work with Operations and Computer Engineering to implement a program to save an optimal set of SPDS and P-250 data for future use during event evaluation, separate from the AD-16 program.

STATUS

In progress. To be completed June 1, 1992.

d. Re-emphasize to all Emergency coordinators that Emergency Plan procedures and Attachments are not stand alone documents.

STATUS

A letter (NEP-92-013) addressing this concern was issued on January 1, 1992.

e. Assess AOP-Fire-1 guidance concerning operation of equipment involved in or contributing to a fire, and revise as needed.

STATUS

See H below.

f. Enhance training on de-escalating events and use of procedure EPIP 405.

STATUS

Completed February 2, 1992.

g. Revise ECG Attachments 1, 2 and 3 with recommended enhancements.

STATUS

Revision in progress. To be completed by April 1, 1992.

h. Revise AOP-FIRE-1, FRS-1-001, EPIP 202 and EGG Attachment 8 to better address offsite assistance requests.

STATUS

AOP-FIRE 1 has been superseded by Site Protection procedure M10-FRS-I-002. This procedure has been approved and issued.

i. Revise the Initial Contact Message Form Attachments 2 and 3 to enhance guidance in terminating events.

STATUS

Revision in progress. To be completed by April 1, 1992.

j. Provide refresher training on pager activation to primary and secondary communicators.

STATUS

Refresher training to completed by February 1993.

k. Finalize Engineering analysis to determine all origins of steam flow energy which resulted in the turbine overspeed event, and place final report of this analysis in the SERT file for this event.

STATUS

In progress. To be completed by March 3, 1992.