U. S. NUCLEAR REGULATORY COMMISSION
REGION I

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LICENSEE:	Public Service Electric and Gas Company
FACILITY:	Salem Nuclear Generating Station, Units 1 and 2 Hancocks Bridge, N.J.
DATES:	January 12-20, 1995

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2/22/95
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EXECUTIVE SUMMARY

The purpose of this inspection was to evaluate the effectiveness of the PSE&G engineering organization in supporting the safe operation of the Salem Units 1 and 2. The primary focus of this inspection was the Salem Technical Department routine and reactive activities, including their performance in the identification and resolution of technical issues and problems.

The inspectors found that communications between the technical department and other station departments were generally good. Although the experience level of the system engineers varied, the inspectors found the system engineers to be knowledgeable in their technical area and familiar with the regulatory requirements associated with their duties. However, one example was noted where the system engineer knowledge of plant technical specifications was incomplete.

The engineering staffs, both in the technical department and the nuclear engineering department, appeared to recognize the importance of determining the root cause of equipment failures and other problems. However, the quality of problem resolutions was variable. In some cases, the root causes of problems were not identified and in other examples unexpected system responses were not fully understood and resolved prior to returning equipment to service.

The inspectors noted that a list of operator "work arounds" had been established to document component and system problems encountered by plant operators. Many of these were longstanding, some of which have existed since initial plant startup. The inspectors found that some of the problems have been resolved recently and other initiatives are being implemented in an effort to improve plant safety and reliability. Examples included the implementation of a preventive maintenance program for process control system control modules and improvements in the emergency diesel generator surveillance test program.

The inspectors found that the quality of operability determinations performed by the technical department was inconsistent. In some cases, the implications of technical specification bases and accident analyses results were not documented in the operability determinations. The documented bases for operability determinations were found to often rely solely on the results of technical specification required surveillance testing.

DETAILS

1.0 INTRODUCTION (IP 37550)

The purpose of this inspection was to evaluate the effectiveness of the PSE&G's engineering organization in supporting the safe operation of the Salem Units 1 and 2. The inspection focused primarily on the Salem technical department routine and reactive activities, including their performance in the identification and resolution of technical issues and problems.

2.0 SALEM STATION TECHNICAL DEPARTMENT

Organization and Responsibilities

The Salem Technical Department organization is comprised of a technical manager, six technical engineers (supervisory level engineers), 68 system engineers (SEs), and an administrative support staff. The function of the technical department is to provide technical support to station personnel through the system engineers who serve as system experts. The system engineer responsibilities are described in the "Salem Technical Department Engineer's Handbook," and involve the system engineer in all activities associated with their systems. These activities include system performance evaluation, procedure development and review, initiation of corrective actions, project team members for modifications, development of temporary modifications, and the performance of root cause analyses and safety evaluations. The SEs also provide assistance to operations department on equipment and system operability determinations.

Staffing

At the time of the inspection, all administrative and all but five of the engineering positions were staffed. These five positions included two technical engineer positions that were filled with personnel in an acting capacity.

Training

The SEs receive approximately six months of initial training as described in Training Procedure NC.TO-TC.ZZ-0905(Z), "Engineering Support Personnel Training." Beginning January 1, 1995, the training was divided into several modules, and the engineers divide their time between the plant and the training such that the six months of training is accomplished in about 18 months. Mandatory annual continuing training requirements are also included in the program, as well as quarterly operating experience feedback training sessions. The inspectors found that many of the SEs have received specialized system or component-specific training provided by the equipment vendors.

3.0 COMMUNICATIONS

3.1 Nuclear Engineering Interactions with Technical Engineering Department

The inspectors reviewed selected engineering documents and conducted interviews with the nuclear engineering department (NED) management and staff engineers to evaluate the effectiveness of their interface with the station technical, operations, and maintenance departments in the resolution of technical issues. Typically, the role of NED is to complete major engineering efforts, such as plant modifications, design bases reconstitution, and provide specialized technical assistance to the plant. The station Technical Department is responsible to provide day-to-day engineering support in the areas of plant operations, maintenance, testing, and temporary plant modifications.

The inspectors noted that each morning a phone call is held between nuclear engineering and the station departments to discuss any emergent plant operating problems, ongoing work, and upcoming licensing activities. Following this call with the station, a NED management meeting is held to determine what engineering support may be required to support any plant problems.

The technical department management or system engineers may directly request the NED to provide technical assistance to resolve more complex or resource intensive engineering issues. The inspectors noted during discussions with the engineering staff that several such requests were recently initiated by the technical department. For example, NED support to the station engineering staff was evident in the resolution of emergency diesel generator problems and the chemical and volume control (CVC) system solenoid valve replacements. NED was also actively involved in the resolution of battery cell copper contamination concerns and supported the upgrading of the 125 volt battery chargers to improve the reliability of the system at the request of the system engineers. In some cases, NED engineers accompanied the system engineers to vendor manufacturing and test facilities to ensure component selection and testing requirements were appropriately implemented.

In addition, the inspectors noted that the nuclear engineering department had assigned a project manager to oversee the completion and closeout of work-around items identified by operations personnel. All responsible departments, including the operations department, meet weekly to review the status of the outstanding issues on the list. The inspectors noted that any change in the item completion schedule or priority required the written concurrence of the operations department. Based on discussions with other department staff managers and a review of the current list that was updated on January 9, 1995, the inspector found that engineering was playing an active role in providing the engineering expertise and project oversight necessary to resolve old operational issues. The effectiveness of NED in this role could not be assessed at this time because many of these issues were in the early stages of resolution.

Based on the above observations and review of the applicable documentation, the inspectors concluded that the PSE&G nuclear engineering organizations were adequately engaged in the resolution of emergent technical concerns and that there was high level management involvement on a day-to-day basis to address the station issues. Good communications were observed between the NED and other departments. The station staff and system engineers frequently seek technical expertise from their NED counterparts and receive good support from NED.

3.2 Operations Interactions with the Technical Department

Operations department personnel primarily interact with system engineers (SEs) in the Salem technical department. The SE serves as the primary contact for technical support; and, NED support, if needed, is usually arranged by the SE. Key operations managers and operators were interviewed on their interactions with SEs. These interviews confirmed that SEs were frequently observed in the field and in the control room. The inspector independently confirmed SE presence in the field by reviewing deficiency (EMIS) tags on system components. The inspector found that the SEs had authored a majority of the tags sampled by the inspectors during system walkdowns discussed in Section 4.0 of this report. These tags indicated that SEs demonstrated responsibility for the material condition of their system. The engineering-operations interface was good.

During interviews, the inspector determined that some SEs used both formal and informal means to update the operations management on system problems. Although management recognized that these informal communications did not replace the need for formal documentation, they considered these updates to be good initiatives by the SEs.

Nuclear engineering visibility was noted to have improved. Both operators and SEs confirmed a recent increase in the presence of design engineers from the NED in the field and in the control room. NED engineers have demonstrated an increased willingness to resolve day-to-day issues by initiating phone contact with SEs when problems arose. During interviews, the inspector found that the improvement in support began within months after the April 7, 1994, grass intrusion event and has continued through this report period.

3.3 Maintenance Interactions with Technical Engineering Department

The inspectors interviewed members of the technical and maintenance department to assess the interface between the maintenance and technical department. The technical department had identified that a significant portion of the reactive engineering work was related to the support of maintenance issues. To reduce the reactive workload on the system engineers, the system engineer support group was established within the technical department. This multi-disciplinary group is responsible for resolving day-to-day issues and specific component problems. The individual system engineers are involved as necessary to ensure the proper resolution of overall system performance issues. The system engineer support group was formed in July 1994, and its effectiveness in assuming a significant portion of the reactive engineering workload could not yet be assessed.

4.0 SYSTEM ENGINEER INTERVIEWS/SYSTEM WALKDOWNS

The inspectors interviewed approximately 10 system engineers, and jointly performed walkdowns of portions of several systems, to assess their system knowledge and to evaluate the material conditions. During accompaniment walkdowns, the inspectors found that most SEs walk down their systems on frequent intervals. The inspectors also observed that SEs were knowledgeable on current system status and problems. Deficiency (EMIS) tags were present to document system problems. The inspectors confirmed that EMIS tag discrepancies were routinely entered in the computerized action request (AR) system.

One inspector observed the material condition of the charging, safety injection, and auxiliary feedwater during system walkdowns. Deficiency (EMIS) tags were present to document oil leaks from the running charging pump speed changers. Minor boron leaks from system valves were well documented on boron removal forms. No standing water was observed in any areas. Areas were well lit and free of unnecessary debris or clutter. Observed material condition of these three significant safety systems was excellent.

Other walkdown inspections were performed on portions of the 4.16kV, 480 Vac, and 125 Vdc safety-related electrical systems. These systems were also found to be in good material condition.

During the dc system walkdown, the inspector noted that the responsible system engineers were aware of the weaknesses in their assigned systems. For example, the existing Exide battery charges were more than 17 years old, and the system engineer had identified that many of the spare parts necessary to maintain these units were difficult to obtain or were not available. In addition, the original battery charger manufacturer (Exide) had dropped their safety-related equipment qualification program. Due to these concerns and to ensure system reliability, the battery charger units were being upgraded with newer, more reliable units.

The inspectors concluded that the system engineers were knowledgeable of their assigned systems and performed frequent walkdowns to ensure the systems were maintained in a good condition.

5.0 ROOT CAUSE ANALYSES

Incident Report Reviews

Incident reports (IRs) document degradations and anomalous responses of plant systems and equipment. They are used by the licensee to investigate and resolve these and other types of problems. Procedure NC.NA-AP.ZZ-0006(Q), "Incident Report/Reportable Event Program and Quality/Safety Concerns Reporting System," specifies the requirements for incident report (IR) initiation, documentation, and resolution. IR resolution requires the use of a predefined root cause methodology. Specifically, Step 5.2.2 of this procedure requires the use of one type of root cause methodology, causal factor, and barrier analysis or change analysis for every IR. The inspectors reviewed selected open and closed IRs to assess the quality and effectiveness of the licensee's root cause methodology for both in-process and completed IRs. This review also encompassed the adequacy of Procedure NC.NA-AP.ZZ-0006(Q). The following findings were identified:

5.1 Copper Contamination of the 125 Vdc Battery

Incident Report 94-404, issued on September 15, 1994, identified copper contamination on some safety-related battery cells during regularly performed inspections. The system engineer observed that copper contamination may have been present on two negative plates of cells Nos. 13 and 36 of the 2B safety-related battery. Further examination of the battery condition with a NED engineer validated this concern. Based on this adverse condition, the engineering staff ensured that individual cell voltages, specific gravities and service test results were acceptable. Based on the visual inspection, the licensee, in consultation with the vendor, determined that any cell voltage reduction would be slow over time and concluded that the dc system was operable. In addition, the system engineer specified routine monitoring of the battery condition until the two cells had been replaced with new cells. To ensure the that no further copper contamination was in progress, the licensee inspected all safety-related batteries, with vendor assistance, to ensure no additional copper contamination was present on any other cells.

The inspectors noted that the licensee was knowledgeable of NRC Information Notice 89-17, that had identified similar concerns at other facilities. The inspector concluded that the licensee had taken appropriate corrective actions to resolve this concern by engaging all available engineering expertise within NED and the vendor to address the technical concern.

5.2 Emergency Diesel Generator 2C Slow Voltage Buildup

Incident Report 94-516, issued on December 17, 1994, identified a concern that during surveillance testing of the 2C emergency diesel generator (EDG), the generator voltage did not achieve rated voltage within 10 seconds. The Updated Final Safety Analysis Report (UFSAR) states that the diesel generators have the capability to attain rated speed and voltage within 10 seconds after the receipt of a start signal. However, rated voltage was achieved within 13 seconds as required by plant technical specifications.

The slow voltage rise resulted in the EDG output breaker closing at approximately 2900 volts during the loss of offsite power (LOOP) test and at 2200 volts during a loss of offsite power condition coincident with a loss of coolant accident (LOCA) test. All loads that were connected to the bus at the time of the output circuit breaker closing operated as expected and bus voltage continued to increase to the nominal setpoint during both tests. The SE also identified that the output circuit breaker has electrical interlocks that are designed to prevent the breaker from closing unless voltage is at 90% of rated voltage and speed has increased to 850 rpm. The interlock associated with the voltage level failed to prevent breaker closure.

The voltage regulator was subsequently replaced and returned to the vendor to determine the cause of the slow response. During subsequent EDG testing, a high voltage spike was experienced with the newly-installed voltage regulator. This regulator was also removed and returned to the manufacturer to determine the cause of the malfunction. The system engineer observed the vendor investigation, during which the vendor determined that solder joints had been damaged resulting in an intermittent open circuit condition. The connections were repaired, and the regulator was reinstalled and performed satisfactorily during the remaining testing.

PSE&G performed a safety evaluation in accordance with 10 CFR 50.59 to assess the effects of the slow voltage buildup and to ensure that it did not constitute an unreviewed safety question. An operability determination was also performed to assess operability of the EDG until the regulator could be replaced. Based on a review of the previous refueling outage test results, that indicated that the voltage build up rate had not changed, and since the voltage and speed met the TS requirements during the testing, PSE&G concluded the system was able to perform its design function, including the time period when the voltage response was slow. The failure of the voltage sensing relay to prevent breaker closure at less than 90% voltage is believed to be due to the operating characteristics of the relay and was still under review by PSE&G. The operation of this interlock feature was not considered to be necessary to support the EDG operability since with a normally operating EDG, the voltage is normally greater than 90% by the time the speed reaches 850 rpm.

The inspectors reviewed the events with the system engineer and reviewed the safety evaluation and operability determination. The inspector noted that the ability to detect the slow voltage regulator response became possible as a result of improvements that the SEs had made in the EDG surveillance testing program. The return of the voltage regulator to the vendor for failure analysis and the identification of the root cause of the voltage spike were found to be good root cause analysis initiatives by the SEs. However, the root cause of the failure of the voltage interlock to function as designed had not been positively identified and corrected before returning the EDG to service.

5.3 Air Boost During EDG Starting

Incident Report 94-521, issued on December 19, 1994, identified a discrepancy with the operation of the 2A auxiliary air controller that functions to provide an air boost to the EDG turbocharger. Per the design, during the start of the EDG, the turbo air boost is normally provided for three seconds. In addition, once the EDG is operating the turbo air boost is designed to automatically actuate for four seconds when a large load is started on the emergency bus being supplied by the EDG. At Salem, the only load that is large enough to initiate the four second air boost is the service water pumps. However, during surveillance testing, the expected 3-second turbo air boost occurred during the EDG start and then an unexpected 4-second air boost also occurred during the EDG start. This occurred on each of the three Unit 2 EDGs but was not experienced on any of the Unit 1 EDGs during the previous Unit 1 surveillance tests. PSE&G engineers had not identified the cause for the additional air boost, but had evaluated the condition and concluded that this anomaly did not impact the operability of the EDGs. This conclusion was primarily based on the ability of the EDGs to meet the TS requirements during testing and that the expected air boost did occur when starting a service water pump. Also, during recently developed shop testing and setting of the associated relay, actuation of the relays was noted during initial energization and may explain why the relays actuate during voltage buildup of the EDG.

The inspectors reviewed this issue and found that the operability determination was based primarily on the satisfactory results of surveillance tests without the root cause of the unexpected air boost being positively identified. The inspectors concluded that without a full understanding as to why the unexpected boost occurs on all Unit 2 EDGs and not on any Unit 1 EDGs the potential implications as to the continued proper operation of the air boost could not be fully assessed. This is another example where continued operation with a degraded or unexplained condition is accepted instead of the root cause being positively identified and corrected.

The inspectors did note that PSE&G believes that the EDGs would likely perform satisfactorily without any air boost; however, at this time the air boost remains a design basis feature and must be maintained operable.

5.4 Reversed Current Transformer Leads

Incident Report 94-460, issued on December 2, 1994, identified a condition where the leads from a current transformer (CT) for the 2A EDG controls were connected reverse of the desired design configuration. The signal generated from the CT output is utilized to initiate the turbo air boost when a large load, such as a service water pump, is started on the emergency bus. Due to the reversed wiring, the air boost was not initiated during the current increase that occurs during the service water pump start. The air boost actually occurred when the service water pump motor current was decreasing from the high starting current value to the normal running current. The net result of the miswiring was that the air boost was applied approximately 1.7 seconds later than desired. The delayed air boost was discovered by the SE during a review of the test data. During the review, he noted that the bus frequency dropped slightly below the value recommended in Regulatory Guide 1.9, Revision 3, "Selection, Design, Qualification, and Testing of Emergency Diesel Generator Units Used as Class IE Onsite Electric Power Systems at Nuclear Power Plants." PSE&G utilizes the RG 1.9 criteria in their assessment of test results, however, as stated in the UFSAR, the test requirements for the EDGs are specified in the plant technical specifications. The TS do not contain acceptance criteria for bus frequency during transient loading conditions. Based on the TS requirements and the ability of the EDG to promptly restore the bus frequency to normal, the SE concluded the EDG was able to perform its intended function and was operable during the time when the CT leads were reversed. The CT lead connections were corrected and the EDG tested satisfactorily.

The inspectors reviewed this event with the SEs and found it to be an example of a thorough review of test data and identification and correction of the root cause of the problem. This is another example where PSE&G was able to identify and correct an existing problem due to the improvements that were implemented in the emergency diesel generator testing program.

5.5 Motor-Operated Valve Control Breaker Tripping

IR 94-531, dated December 21, 1994, described the unexpected tripping of two 28 Vdc motor-operated valve (MOV) control circuit breakers during testing. These control circuits were for the 21SJ44 and the 21SJ113 MOVs that respectively provide a containment sump suction for the 21 residual heat removal (RHR) pump and a flowpath from RHR to the charging pumps for "piggyback" operation. Piggyback operation is used under long-term accident conditions when reactor coolant system (RCS) pressure remains above RHR pressure. Licensee troubleshooting in response to this IR identified dc currents of 0.512 amps and 0.507 amps through the MOV control circuit breakers. In response to the breaker tripping, a design change was initiated to replace 0.5 amp breakers with 1.0 amp breakers. The DCP was approved and the new breakers were installed. Although not documented in the IR, the inspector determined through discussions with licensee personnel that previous normal current levels through these breakers were between 0.35 and 0.40 amps. No explanation was offered as to why the breaker current increased and no attempt was made to determine root cause prior to breaker replacement. A full understanding of why the control circuit changed is necessary to properly evaluate the potential impact on continued proper operation of these circuits and on other similar control circuits. In follow up discussions, the licensee agreed to address this concern prior to final IR closeout.

5.6 Battery Discharge

IR 94-410, dated November 15, 1994, describes a condition that led to the total discharge of the Unit 3 125 Vdc battery. Salem Unit 3 is a nonsafety-related gas turbine generator that may be used to supply electrical power to the site during loss of offsite power conditions. In this case, the normal electrical power supply to the Unit 3 battery charger was tagged out-of-service for 2R8 outage activities. However, the connected dc loads were not tagged, resulting in the battery being fully discharged. The inspector noted that this was the third incident where the battery was fully discharged in the last six years. This clearly indicates weakness in the corrective actions for the two earlier events. In addition, operators identified and circled the low battery voltage in their November 15, 1994 logs, but took no further action to investigate the cause. Procedure changes were proposed by PSE&G to prevent this problem in the future.

5.7 Safety Injection Relief Valve

IR 94-550, dated November 29, 1994, describes a potential missed TS LCO entry based the removal of a safety injection (SI) pump discharge relief valve (11SJ39). This maintenance activity left the only boundary as a single check valve between the pressurizer relief tank (PRT) and the work area. Specifically, the IR questioned whether either Containment Integrity (3.6.1) or Containment Isolation (3.6.3) TS applied when the relief valve was removed from the system. Of concern is the reportability evaluation that states that this condition was not reportable based on a review of Procedure NC.NA-AP.ZZ-0006(Q), "Incident Report/Reportable Event Program and Quality/Safety Concerns Reporting System." Regulation 10 CFR 50.73 requires the reporting of any condition prohibited by the plant technical specifications. Station procedures do not adequately address the basis for PSE&G's reportability decision. The inspector also noted that operations review of this IR approved not reporting based on procedure without consideration of 10 CFR reporting criteria. The inspector independently reviewed the IR and concluded that it was not reportable for the following reasons: (1) the containment isolation valve for this class "D" line is 1PR25, a check valve between the PRT and 11SJ39; (2) 1PR25 is designed to limit flow out of containment under accident conditions; and (3) recent leak rate testing replicated the piping conditions with the check valve removed and also confirmed that leakage through the valve was within specification. Thus, even if an accident were to have occurred with 11SJ39 removed, 1PR25 would have maintained containment leakage through this line within design. Based on the above, the inspector had no concerns with the overall reportability conclusion, only the manner in which it was reached. The actual reference to Procedure NC.NA-AP.ZZ-0006(Q) was insufficient to address the question later referenced in IR 94-550.

5.8 Feedwater Regulating Valve Control Improvement

During plant startups, the plant operators identified that the operation of the feedwater regulating valve bypass valves (BF-40 valves) were erratic in that the valves were hunting from full open to full closed position while attempting to control steam generator water level at low power levels. The system engineer found that the overall gain of the BF-19 valve control loop was higher than previously perceived. This was the result of the feedwater regulating valves (BF-19 valves) and the bypass valves (BF-40 valves) sharing the same controller but responding differently to a given controller output signal. The BF-40 valves will go full open with a one-volt output signal, while the BF-19 valves require a five-volt signal to go to the full open position. The gains necessary to achieve stable operation of the BF-19 valves at high power levels resulted in erratic operation of the BF-40 valves at low power levels. Lower flow controller gain settings were established at low power levels to achieve stable operation of the BF-40 valves and then the original gains were set in when transitioning to operation on the BF-19 valves at higher power levels.

The inspectors reviewed this issue with the SE and found that although this problem was allowed to exist for many years, once resources were devoted to its resolution a thorough problem assessment and root cause analysis was performed.

5.9 Control Module Preventive Maintenance Program

The inspectors reviewed a program developed by PSE&G to perform periodic refurbishment of the Hagan 7100 reactor protection and control system modules. The need for such a program to improve the reliability of the system was initially considered in 1988. Due to the large scope of work and limited resources, plant management decided at that time to trend performance before initiating a preventive maintenance program. Following a plant trip in 1993 that was caused by a failure in a control module, the significant event response team reviewing the trip recommended the development and implementation of a program to refurbish the modules on a periodic basis.

The inspectors reviewed the development of the Hagan system PM program with the system engineer and found that he had been a strong proponent of establishing such a program and was also instrumental in the development and implementation of the program. Since 1993, a bill of materials has been developed, parts have been procured, procedures have been written and approved, and refurbishment work has been accomplished on some of the modules.

The SE has also created new component identifiers in the computerized maintenance management system so that the modules can be tracked and trended by module serial number rather than the location in which a particular may be located.

The system engineer has also initiated actions to have the Hagan system channel calibration procedures revised to include a step to check the dc signals for any ac noise levels. This action will aid in the early identification of degrading components, capacitors in particular.

The inspectors concluded that these actions were good initiatives to improve the system reliability.

5.10 Solid State Protection System Timer Relay Failure

Incident Report 94-472 documented the failure of a time delay relay in the #23 auxiliary feed pump starting circuit. The relay had an adjustable range of 0.1 to 30 seconds and in this application was set at three seconds. During time response testing of the solid state protection system slave relays, the relay initially operated at 13.5 seconds and then operated erratically on subsequent tests. The inspector discussed this event with the solid state protection system engineer and found that the SE had reviewed the maintenance history for the relay at Salem and also reviewed the nuclear plant record data system to determine if additional failures of these relays had been experienced either at Salem or at other licensee facilities. This review did not identify any other similar problems and the failure was considered to be an isolated failure. Based on this, no additional root cause investigation was planned, although the relay was saved should additional action be necessary. The inspector concluded that the SE had appropriately reviewed and dispositioned this problem.

5.11 Additional Observations

The inspectors also noted that not all SEs were aware of the existence of a new nuclear business unit root cause analysis procedure, NC. NA-BP.ZZ-0002(Z), "Root Cause Analysis Guideline." This procedure was approved on December 15, 1994. The inspectors also noted that no continuing training was provided on root cause methodology or the application of TS and their basis to address problems with safety-related equipment.

Conclusions

The above examples provide insights into the PSE&G root cause investigation program at Salem. The inspectors noted several examples of good problem resolution, including the resolution of some of the long-standing issues. The SEs interviewed indicated a recognition of the importance of pursuing the root cause of problems, although the actual results were mixed.

The events discussed in Sections 5.2, 5.3, 5.5, and 5.6 show continued weakness in the licensee's approach to problem resolution. The inspector also noted that some completed IRs did not specifically document the root cause methodology used to investigate the IR. The SEs did not always reach a full understanding for the cause of unexpected system responses prior to concluding the system was operable and returning the systems to operation.

Overall, the inspectors found that the root cause weaknesses identified in the Salem SALP (50-272/93-99) continued in that the quality of root cause evaluations continued to be inconsistent. The licensee has recognized and acknowledged these weaknesses and has agreed that continued performance improvement is necessary.

6.0 OPERABILITY DETERMINATIONS

Operations personnel are responsible for making operability decisions for degraded or nonconforming safety-related equipment. Both system engineering and design engineering may assist operations with operability determinations. Plant technical specifications (TSs) provide guidance on system and component operability. The inspectors questioned engineers to assess their knowledge of TSs associated with their assigned systems. System engineer knowledge of TS limiting conditions for operation (LCOs) and their bases for their systems was found to be variable. Some incorrect answers were given to specific questions about important system TSs during interviews. When questioned further by inspectors, SEs indicated that system TS and their bases were not emphasized during training. Their knowledge level of TS varied based on personal initiative. Thus, their ability to assist operations in making operability determinations in accordance with Generic Letter (GL) 91-18 guidance may be limited.

In addition to those operability determinations associated with the issues discussed in the previous sections of this report, operability determinations on file in the control room were also reviewed. During these reviews, the inspectors found that operability determinations performed by SEs did not consistently emphasize the safety basis of their systems. Often there was no reference to either the safety basis contained in TS Section B 3/4.0 or the FSAR Chapter 15, Accident Analysis. Specifically, the degradation was not compared nor its effect quantified against the outcomes of the applicable accident analysis. There was often a strong reference to the design basis, but no differentiation between it and the safety basis. Nuclear engineering was not routinely involved with operability determinations. When involved, the quality of these determinations was improved.

7.0 OPERATIONAL EXPERIENCE REVIEW PROGRAM

7.1 NRC Information Notice 94-85

The NRC issues information notices (IN) to inform utilities of recent operational experiences to make them aware of problems that occur at other plants so that similar problems can be avoided. PSE&G's operations assessment group reviews INs when they are received by them to determine whether they are applicable to PSE&G plants.

NRC Information Notice 94-85, "Problems With the Latching Mechanism in Potter and Brumfield R10-E3286-2 Relays," was issued on December 21, 1994. The purpose of this notice was to alert licensees that problems had been identified with relays that were utilized in battery charger control circuit boards. The inspector reviewed this potential deficiency with the system engineer and found the engineer to be knowledgeable of the problem and that the licensee had inspected their circuit boards to determine if any of the suspect relays were installed in either of the Salem Units. One suspect relay was identified and its proper operation verified in accordance with the instructions contained in the IN and in a 10 CFR Part 21 Notice on the same subject.

The inspectors concluded that the licensee had taken prompt action in response to this information notice. During interviews and discussions with system engineers, the inspectors found the SEs to be knowledgeable of industry events and experiences that may impact the operation of their assigned systems.

8.0 MANAGEMENT OVERSIGHT AND SELF-ASSESSMENT

The inspector interviewed PSE&G employees to determine the level of management involvement in engineering activities and self-assessment activities. The inspectors found that the station management has recognized the need to transition from a condition where the SEs are functioning in primarily a reactive mode to that of a proactive mode. This would enable SEs to put a greater emphasis on predicting and preventing problems rather than reacting to failures and events. The establishment of the SE support section is one initiative designed to achieve this objective.

The engineering management, both NED and STD, has taken a more active role in resolving long-standing plant equipment and system problems and in improving communications and cooperation between departments.

9.0 EXIT MEETING

An exit meeting was held on January 20, 1995, with members of the licensee's staff noted in Attachment 1. The inspector discussed the scope and findings of the inspection. The licensee had no disagreements with the findings. The inspector did not take any proprietary information off-site at the conclusion of the inspection.

Attachment: Exit Meeting Attendees

ATTACHMENT 1

EXIT MEETING ATTENDEES

Public Service Electric and Gas

L. Catalfamo, Operations Department
R. Griffith Sr., Quality Assurance
C. Lambert, Nuclear Engineering
M. Metcalf Sr., Maintenance Department
J. Morrision, Technical Department
M. Morroni, Maintenance Department
W. Schultz, Nuclear Engineering
J. Summers, General Manager - Salem Operations
E. Villar, Licensing Department

U. S. Nuclear Regulatory Commission

C. Marshall, Senior Resident Inspector

Delmarva Power

P. Duca