U.S. NUCLEAR REGULATORY COMMISSION

REGION I

SYSTEMATIC ASSESSMENT OF LICENSEE PERFORMANCE

INSPECTION REPORT 50-272/84-37 AND 50-311/84-36

PUBLIC SERVICE ELECTRIC AND GAS COMPANY

SALEM NUCLEAR GENERATING STATION

ASSESSMENT PERIOD: OCTOBER 1, 1983 - AUGUST 31, 1984

BOARD MEETING: October 15, 1984

PRESENTATION TO LICENSEE: NOVEMBER 15, 1984

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I. INTRODUCTION

1. Purpose and Overview

The Systematic Assessment of Licensee Performance (SALP) is an integrated NRC staff effort to collect observations on an annual basis and evaluate licensee performance based on those observations with the objectives of improving the NRC Regulatory Program and licensee performance.

The assessment period for this report is October 1, 1983 through August 31, 1984. This assessment also contains references to significant information which occurred prior to the assessment period as appropriate.

The prior SALP assessment period was October 1, 1982 through September 30, 1983. Significant findings of the assessment for the previous period are provided in Section IV below.

Evaluation criteria used during this assessment are discussed in Section III. Each criterion was applied using the Attributes for Assessment of Licensee Performance contained in NRC Manual Chapter 0516.

2. SALP Attendees:

Board Members:
- R. W. Starostecki, Director, Division of Project and Resident Programs
- T. T. Martin, Director, Division of Engineering and Technical Programs (Part-time)
- S. D. Ebneter, Chief, Engineering Programs Branch, DETP
- D. Fischer, Licensing Project Manager, ORB 1, NRR
- H. Kister, Chief, Projects Branch No. 2, DPRP
- L. Norrholm, Chief, Reactor Project Section 2B, DPRP
- J. Linville, SRI, Salem Generating Station

Others:
- R. Summers, Resident Inspector, Salem Generating Station
- D. F. Limroth, Project Engineer, Projects Branch 2
- H. R. Booher, Chief, Licensee Qualifications Branch, NRR
- E. M. Podolak, Chief, Program and Administrative Services Branch, RES

3. BACKGROUND

3.1 Licensee Activities

Unit 1

From October 1, 1983 until February 24, 1984, the unit operated at power except for two brief outages to repair leaks in containment and four trips due to steam generator level control problems.

On February 24 the unit tripped on main generator neutral ground protection. The unit began its fifth refueling and maintenance outage as a result of the extensive repairs necessary for the main generator.

Due to the extensive repairs to the generator and the early start date, resulting in insufficient lead time for many modifications, the outage continued through the end of the assessment period. The major outage activities included: refueling, rewind of the main generator, modification of No. 11 Component Cooling Heat Exchanger to replace the 90/10 copper-nickel tubes with titanium tubes, eddy current exams of Nos. 12 and 14 steam generator tubes and a visual examination of both primary and secondary sides of all steam generators, modification of the spent fuel pool cooling system for both units to install a permanent cross-tie capability, replacement of the control rod guide tube split pins, local leak rate and containment integrated leak rate testing, hydraulic and mechanical snubber functional testing, primary code safety valve testing, and modification of the reactor protection system to require both the undervoltage and shunt trip attachments to trip the reactor trip breakers on any automatic protection signal.

During the outage a number of activities comprised additional outage work but had only minor impact on the overall outage schedule. These activities included replacement of all of the service water piping to the No. 12 Component Cooling Heat Exchanger; replacement of all 20 RTD loop bypass isolation valves; repair of a bent core exit thermocouple column, including replacement of 11 core exit thermocouples; repair of the reactor vessel flange, head flange and stud holes; and inspection and repairs to the No. 1A Diesel Generator as a result of overheating due to a loss of cooling water. In addition to the added workload identified above, much of the licensee's resources was devoted to maintaining continued power operations of Unit 2 which had frequent problems throughout the Unit 1 outage.

Unit 2

The unit began the assessment period at 100% power. At the end of the last SALP period, the unit had just completed an unscheduled, five week maintenance outage to repair the leaking main generator stator water cooling system, and to modify the low temperature Pressurizer Overpressure Protection System (POPS) due to frequent failure of the associated valve position indication system. At the time of the modification, a decision was made not to cut out the old POPS valves due to the necessity to conduct system hydro tests of the new pressure boundaries if the valves (2PR47 and 2PR48) were removed. On October 7, 1983, the unit was shutdown due to additional leakage of hydrogen into the stator water cooling system. At that time the decision was made to modify the cooling water headers to eliminate the connections which appeared to be subject to a vibrational induced fatigue. The unit remained out of service until it was synchronized on March 4. During the maintenance outage additional work was completed, including replacement of five generator coils due to internal leaks in their conductors; repair of four containment fan coil unit motors; repair and/or replacement of leaking safety injection system check valves (SJ56s and SJ144s), which are reactor coolant system pressure boundary isolation valves; and repair of leaking secondary side code safety valves. The unit operated throughout the remainder of March and the beginning of April.

On April 6, 1984, the unit tripped due to personnel error while troubleshooting a problem with the condenser vacuum indication. On the same day, a water hammer occurred on the No. 23 feedwater line during inservice testing of the main feedwater regulating valve (23BF19). This occurred because the No. 23 steam generator stop check valve (23BF22) failed to close. However, the event was compounded by operator error since a feedwater isolation valve (23BF13) was not closed at the time as required by another procedure. An investigation was conducted to assess the resultant damage, and repairs were made to three hangers, three mechanical snubbers and two pipe whip restraints. Also, the block valve (2PR6) for the pressurizer power operated relief valve (2PR1) was repaired due to a problem unrelated to the water hammer. Following these repairs, attempts were made to restart the unit beginning on April 23, 1984. Unit trips occurred on April 23, 24 and 27. The trips on April 23 and 27 were a result of high levels in the No. 23 steam generator. The April 24 trip was due to a sticking pilot valve on a turbine stop valve while latching the turbine. On April 28, 1984 the unit was shut down during a restart following the April 27 trip, due to a suspected error in the feedwater flow signal for the No. 23 feedwater line. Subsequent testing proved that the flow venturi in the feed line had broken free from the pipe and moved over two feet up the line as a result of the April 6 water hammer event in that line. Following repairs, the unit was restarted on May 5.

On May 11, a trip occurred as a result of personnel error while troubleshooting a steam generator level recorder. The unit was restarted the same day and remained at full power until May 30, when a controlled shutdown was initiated because of suspected inoperability of two ECCS throttle valves, 21SJ16 and 22SJ16. The valves were Rockwell valves similar to those that had been replaced during the Unit 1 refueling outage (20 RTD loop bypass isolation valves), and, as a result of radiography, the proper throttling positions could not be verified because the plug was partially unthreaded from the stem. During the shutdown the unit tripped on Intermediate Range High Flux due to conservative instrument setpoint and a large reset deadband. The unit remained shutdown to replace the safety injection throttle valves. Unit heatup began on June 5; however, another cooldown was initiated on June 7 to repair the No. 23 containment fan coil unit, which had failed to start. The apparent cause was an improper rotor to stator air gap. Following repairs, the unit was restarted on June 13.

On July 5 the unit was shut down due to discovery of a through wall crack in the 8-inch O.D. charging pump suction line near vent valve 2CV372. On July 14, while the unit was shutdown for repairs to the charging pump suction line, the primary side code safety valves were inspected at Wyle laboratory. All three valves had cracked eductors. Following the repairs to the safety valves and the suction line header, the unit was restarted on July 24.

On July 25, a reactor trip and safety injection occurred when 2PR47 failed open. At the time of the event, the PORV block valve had just been opened by the operator following surveillance testing of the pressurizer overpressure protection (POPS) instrumentation, which involved cycling open and closed the PORV (2PR1). When the operator initiated a closure of the block valve, it did not close within the expected 10 seconds but took approximately 5 minutes to close. The reactor coolant system depressurized and subsequent to the reactor trip and safety injection, valve 2PR6 closed, terminating the loss of coolant. Through their investigation of the event, the licensee determined that the electrically disabled POPS valve (2PR47) had apparently opened during the venting and repressurization of the common line with the PORV (2PR1) during the surveillance test. A piece of magnetic material had jammed open the internal pilot valve, causing the valve to remain open, resulting in the reactor coolant system blowdown. The licensee removed both of the old POPS valves and conducted the required hydro tests satisfactorily. The licensee determined two possible explanations for the unexpected behavior of block valve, 2PR6. First, a broken lead to the operator was found during troubleshooting and second, the Limitorque operator, which had been replaced earlier in the year, was not as designed, such that, its torque output may not have been sufficient to close the valve under these conditions. The second possible cause was determined after the unit had been restarted; however, corrective actions taken prior to restart would preclude future occurrence of this failure mechanism also. The unit was restarted on August 7 and operated until August 26 when the unit tripped as a result of a main feedwater pump trip due to an instrument failure. The unit was restarted on August 27 and operated at power for the remainder of the assessment period.

Site

A full scale emergency exercise was conducted on October 26, 1983.

The Institute for Nuclear Power Operations conducted an onsite evaluation in March 1984.

A Nuclear Department reorganization was announced on July 18, 1984, which created, effective August 27, 1984, two new Assistant Vice President positions to improve coordination of Nuclear Department functions.

The licensee's Corrective Action Program implementation has continued throughout the assessment period. To date, 5 of 29 action items are complete. The licensee continues to complete the actions within the committed time frames.

3.2 Inspection Activities

Two resident inspectors were assigned to the site for the entire assessment period.

Total NRC inspection hours: 3920 (Resident and Region-based). Distribution of man-hours is shown in Table 2. Inspection activities included a special team inspection and 3 other special inspections to review licensee actions required by the May 6, 1983 Order Modifying the License which resulted from the ATWS events discussed in the last assessment period. In addition, there were special team inspections of the implementation of Appendix R requirements for Unit 1 and followup on several IE Bulletins.

Routine bi-monthly management meetings were held with the licensee to periodically assess the status of program improvements and to discuss indicators of performance. In addition, one Enforcement Conference was held pertaining to a Technical Specification LCO violation.

II. SUMMARY OF RESULTS

SALEM NUCLEAR GENERATING STATION

	CATEGORY LAST PERIOD (10/1/82-9/30/83)	CATEGORY THIS PERIOD (10/1/83-8/31/84)	TREND
FUNCTIONAL AREAS			
1. Plant Operations	3	3	Improved
2. Radiological Controls . Radiation Protection . Radioactive Waste Management . Transportation . Effluent Control and Monitoring	2	2	Improved
3. Maintenance	2	2	Improved
4. Surveillance (Including Inservice and Pre-operational Testing)	2	2	Improved
5. Fire Protection	2	3	Declined
6. Emergency Preparedness	1	2	Declined
7. Security and Safeguards	2	1	Improved
8. Refueling	1	2	Declined
9. Licensing Activities	2	2	Same

OVERALL SUMMARY

While significant resources have been dedicated toward correcting the programmatic deficiencies identified during the ATWS investigations, few of the action plans developed to address these deficiencies have been completed to date. The Nuclear Department has recently been reorganized to shorten the span of control of senior management and thus provided more time for problem resolution and followup, but several new key positions remain unfilled. Extensive preventive maintenance and post maintenance test programs have been developed, but backlogs are increasing because of extended scheduled and frequent forced outages. Efforts have been made to reduce reliance on contractor support, but these have been hampered by frequent outages. Lack of aggressive management involvement in resolving long standing problems such as the restoration of fire barrier integrity and the installation of sump pumps in safety related areas is clearly evident. Lack of direct licensee supervisory and quality assurance involvement in many outage activities seems to have led to extensive rework. On the other hand, marked organizational, staffing, and equipment improvements in the security area over the past two assessments indicate that the licensee is capable of developing an excellent operation given sufficient time and motivation.

III. CRITERIA

The following evaluation criteria were applied to each functional area:

1. Management involvement and control in assuring quality.

2. Approach to resolution of technical issues from a safety standpoint.

3. Responsiveness to NRC initiatives.

4. Enforcement history.

5. Reporting and analysis of reportable events.

6. Staffing (including management).

7. Training effectiveness and qualification.

To provide consistent evaluation of licensee performance, attributes associated with each criterion and describing the characteristics applicable to Category 1, 2, and 3 performance were applied as discussed in NRC Manual Chapter 0516, Part II and Table 1.

The SALP Board conclusions were categorized as follows:

Category 1: Reduced NRC attention may be appropriate. Licensee management attention and involvement are aggressive and oriented toward nuclear safety; licensee resources are ample and effectively used such that a high level of performance with respect to operational safety or construction is being achieved.

Category 2: NRC attention should be maintained at normal levels. Licensee management attention and involvement are evident and are concerned with nuclear safety; licensee resources are adequate and are reasonably effective such that satisfactory performance with respect to operational safety or construction is being achieved.

Category 3: Both NRC and licensee attention should be increased. Licensee management attention or involvement is acceptable and considers nuclear safety, but weaknesses are evident; licensee resources appeared strained or not effectively used such that minimally satisfactory performance with respect to operational safety or construction is being achieved.

The SALP Board has also categorized the performance trend over the course of the SALP assessment period. The categorization describes the general or prevailing tendency (the performance gradient) during the SALP period. The performance trends are defined as follows:

Improved: Licensee performance has generally improved over the course of the SALP assessment period.

Same: Licensee performance has remained essentially constant over the course of the SALP assessment period.

Declined: Licensee performance has generally declined over the course of the SALP assessment period.

IV. PERFORMANCE ANALYSIS

1. Plant Operations (37.7%)

This analysis includes both routine plant operations and support activities of the Nuclear Department. The area was under continual review by resident and region-based inspectors and regional management during the assessment period. In addition, one team inspection and two special inspections were conducted to verify actions taken by the licensee pertaining to the May 6, 1983, Order Modifying the License and one team inspection was conducted related to the actions taken pertaining to Generic Letter 83-28. Another team inspection was conducted in the area of design analysis and modifications of pipe supports associated with IE Bulletins. As previously stated, routine bimonthly management meetings also were held during the assessment period.

During the previous assessment, a number of management deficiencies were identified in the Nuclear Department, which severely impacted the overall support for plant operations. That assessment focused on the events leading up to, and the licensee's short-term response to, the two ATWS events that occurred in February 1983.

During this assessment period the licensee has spent considerable time and resources to effect long-term corrective actions to upgrade the Nuclear Department. As a result of the licensee's Corrective Action Plan, PSE&G has improved its efforts to assure quality and to maintain a good operating safety perspective. However, it is not clear that this remains foremost when the licensee is responding to events that have removed, or have the potential for removing, the unit(s) from service. The licensee has not been consistent in this area. On occasion, during the assessment period, the plant management, advised by SORC, has made sound, conservative decisions that have sometimes resulted in shutdowns of the units, for example, when the safety injection throttle valves were found degraded. However, on another occasion, the post trip review process failed to identify a problem with the feed flow venturi which was inoperable due to the water hammer event. This oversight of the flow nozzle appeared to be an exception to what was a very thorough investigation of the water hammer event. But when the unit subsequently experienced two trips due to feedwater control difficulties on the same line that had the water hammer, insufficient review of these events required another startup to identify the cause of the trips. Both of these occurrences, the decision not to investigate the flow nozzle during the water hammer investigation and the inadequate post trip review, indicate that decision making was not at a level sufficient to ensure adequate management review. During the assessment period another event occurred which supports this conclusion. On July 4, 1984, a leak was found on the Charging/Safety Injection pump(s) common suction header. The operating shift noted the problem and initiated a work order to make repairs within 48 hours. However, not until July 5, 1984, when a senior maintenance supervisor inspected the leak and brought it to the attention of station management did management immediately order a unit shutdown due to the potential loss of all charging and high head safety injection. The shift discovering the leak did not thoroughly evaluate the problem and did not bring it to the attention of management for their review.

During the period, the licensee has initiated QA/QC reviews of system alignments for operation. These have resulted in some improvements to the tagging system data base. However, the area needs further improvement, especially for returning systems to operation following repairs. The licensee's second verification program only applies to realignment of tagged devices, not verification of equipment alignment prior to restoration to service. On occasion, equipment such as an emergency diesel generator and fire protection equipment have been restored to service without reestablishing proper system alignment. This has resulted in unnecessarily degraded equipment. In addition, the NRC raised a concern that the verification process had not been applied to the use of jumpers and lifted leads. The licensee's application only included system lineups and tagging operations. Finally, the repair of the previously mentioned flow venturi was not adequately controlled. This was a result of improperly classifying the work activity as non-safety related such that no QA/QC verification of the work was required. This apparently was a result of inadequate training.

On several occasions the licensee has used on-the-spot-changes for procedures inappropriately. On-the-spot-changes are not permitted in cases where the intent of the procedure is changed because prior SORC review is then required. However, in one case the residual heat removal flow path was altered using an on-the-spot-change such that the forced reactor coolant flow did not pass through the reactor core and in another case the technical specification for monitoring and isolation of the containment on high radiation was violated by the use of an inappropriate on-the-spot-change. In addition, the licensee had a number of occurrences in which followup review of these on-the-spot-changes by SORC was late due to oversight. These items indicate insufficient review and control of procedures.

Station procedures, in general, do not reference commitments, license conditions, technical specifications, etc. Therefore procedure changes require a thorough review to determine if deletions will result in any violations or deviations from commitments. In addition, the licensee's commitment tracking system is weak in this area. The tracking system indicates whether the required actions are complete but not if completed actions are being maintained. The station Operations Department has recognized this deficiency and corrective actions are being assessed.

The licensee has experienced a problem in the review of records to determine operability of required systems prior to mode change. An example of this problem involves verification of "off normal" reports which the licensee has not yet reduced in size or changed in format to make it easier to determine required system operability status. In addition, operating procedure improvements are under development to account for items not yet in the tagging system data base, to improve the review process.

Corporate management involvement has improved since the last assessment. Engineering support together with Operations and Instrumentation and Control input have developed measures to reduce the number of startup or low power trips that result from feedwater control difficulties. Although the corrective actions are not yet complete due to an outstanding design change for the main steam dump valves to the condenser, the actions taken to date have already improved operator control during low power operations. However, the total number of reactor trips remains high as indicated in Table 5 and the majority of these trips (9 of 14) continue to be associated with feedwater and condensate system problems. In addition, the support provided during the investigations of significant transients such as the water hammer event and the failure of the PORV block valve to close as designed was generally thorough. However, some long standing equipment issues still have not been resolved such as failures of the steam supply check valves to the turbine driven auxiliary feedwater pump, poor availability of containment fan coil units, and repeated problems with safety related area sump pumps.

The licensee has been inconsistent in its approach to problems from a safety standpoint. Generally, they have a clear understanding of the issues, however the resolutions are not always thorough. For example, a repair to a cracked Boron injection tank (BIT) vent line, an inappropriate on-the-spot-change to the containment ventilation procedure, and an inappropriate isolation of the BIT recirculation flow to repair a valve, were accomplished without thorough evaluation of systems operability. Reviews are also not always timely as indicated by a late safety evaluation for the abnormal alignment of the RHR systems, the slow evaluation of other systems affected by the valve failures experienced on the RTD loop isolation valves, the long duration of Reactor Coolant System leak detection difficulties, and the slow response to the charging/safety injection pump suction line leak.

The licensee has made efforts to be responsive to NRC concerns. The licensee's Action Plan is an example of this. The bulk of the Action Plan implementation will be completed during the next assessment period and at that time the effectiveness of the licensee's actions can be reviewed. It would appear that questions posed by the NRC are sometime the sole stimuli for the licensee to seek further information and to perform more in-depth caused analyses of events, possibly indicative of a weak process of self-evaluation. Another concern in this area has been the licensee's responses to Notices of Violation. Frequently, additional responses are required to either explain the corrective action taken or to increase the scope of the corrective action. The licensee sometimes provides a long detailed reason for the cause of the event. If the same degree of detail were applied to the corrective actions the NRC effort to obtain acceptable resolutions could be reduced.

With respect to LERs, while events have generally been reported in a timely manner, information necessary to complete the analysis is frequently not available at the time the LER is submitted and supplemental reports are frequently developed very slowly. The nine causally linked groups of LERs in the Supporting Data and Summaries section on page 31 indicated that events are frequently repetitive and appear to be indicative of a lack of thoroughness in developing effective corrective action in some cases.

The licensee's enforcement history has improved since the last assessment. However, several violations pertaining to procedure adherence indicate a lack of regard for procedures. In addition, on a few occasions during this assessment period, the licensee did not implement corrective actions required by the May 6, 1983, Order Modifying the License within the specified periods. These resulted in violations that were repetitive to those discussed during the previous assessment, which included improper training on the use of the MEL and implementation of vendor supplied information. These items indicate that corrective measures have not been completely effective.

The licensee recently reorganized the Nuclear Department and a number of key positions have been added to the staff. A key element in the organization's ability to provide safe, reliable operation will involve quickly filling these positions with quality individuals. The use of excessive overtime for both licensed and non-licensed operators has been controlled within the station operating department. However, due to unforeseen problems, the senior shift supervisors have had to exceed NRC guidelines in this area. The Operations Department is addressing this issue and plans are being made to add another senior shift supervisor to the department.

The training program makes a positive contribution to the station operations. The program is well defined and implemented and applied to nearly all of the station operating staff. The licensee has also implemented a series of supervisor/technical staff training programs in accordance with the May 6, 1983 Order. These programs have not yet been applied to a large portion of the staff and therefore, the expected results, including better interdepartmental communication and attention to detail, have not yet been achieved. In addition, it was apparent through discussions with licensed operators that no training had been developed to explain the responsibilities of holding a license. This training deficiency is being corrected to enhance operator response and attention.

In summary, although some improvements have been made, the licensee has not yet completed the longer term initiatives developed in response to the identified ATWS deficiencies. Implementation should be completed during the next assessment period and improvements to operations should then be realized. The licensee has not demonstrated a firm commitment to ensure that deadlines are met and the desired results achieved. PSE&G has not fully implemented a sound safety oriented operating attitude. As stated in the last assessment, effective communications, thorough investigations and corrective actions, and the verification process must still be improved.

Conclusion

Category 3, improved. Licensee action plans to improve institutional deficiencies identified during previous assessment period are in progress but results generally remain to be seen.

Board Recommendation

Licensee: Complete key action plans including the staffing of important vacancies in new organization, improving and integrating management of safety reviews, monitoring compliance with technical specifications, improving coordination between Operations and Engineering, improving control of commitment tracking, and improving means for the qualitative assessment and effective monitoring of action plans.

NRC: Continue current inspection program with greater attendance of off-site Safety Review Committee meetings, monitor licensee progress in Action Plan, conduct team inspection to verify implementation of all action plans except 2.73 Information Systems.

2. Radiological Controls (9.4%)

This area was under continual review by the resident inspectors. There was one management meeting held in February 1984 at the licensee's request to discuss progress of ALARA program implementation. There were six routine inspections by regional radiation specialists; three inspections reviewed the in-plant health physics and radioactive waste programs, while the remaining three inspections reviewed the radiochemistry laboratory and environmental monitoring programs.

The radiological controls organization is generally staffed by very experienced, long service, dedicated personnel. However, contractor personnel continue to be used for certain key positions and a degree of understaffing is indicated. Areas potentially impacted by understaffing include training programs, ALARA implementation, on-site chemistry analysis, environmental analysis reporting, and procedure review and revision. Although management has identified several areas for program improvement, progress has been slow, possibly hindered by frequent unanticipated outages during the assessment period and lack of management follow-up.

Oversight by corporate management has been effective in the radiochemistry programs but somewhat less effective in the health physics programs. This may be due to lack of formal relationships and procedures which apparently are under development. The corporate staff's involvement with the Hope Creek programs appears to be diluting the effectiveness of corporate oversight activities.

2.1 Radiation Protection and Radioactive Waste Management

Audits of radiation protection procedures by site staff and corporate personnel identified many minor technical deficiencies. These audits were commendable for their thoroughness and depth. Audits of a similar nature had not been performed in the past, making this a positive development. In addition, the audits conducted by corporate Quality Assurance as required by the Technical Specifications were reoriented in 1984 to place emphasis on the performance of the supervisory staff.

Evidence of prior planning and assignment of priorities for control of outage work is adequate due to the extensive experience of the staff. Full implementation of an ALARA program to further reduce personnel exposures has not been accomplished, possibly due to inadequate staff and unanticipated outages. The use of a temporary computer to store and manipulate exposure and other outage records allowed early identification of potential exposure problems during the outage. This allowed for management reaction and attention but was not used for advance planning. Other records were generally complete and well maintained.

The approach to resolution of technical issues is generally sound and indicative of a good understanding of the issues. In the major efforts related to procedure revisions and ALARA implementation, the proposals and plan appear technically sound. However, actual implementation is behind the schedules established by management. Although responses to NRC initiatives are generally timely, viable and technically sound, actual implementation of cnanges is slow.

In the previous assessment periods, the licensee experienced several minor violations. In this period, one violation for failure to post and control a high radiation area was identified. This was caused by inadequate supervisory review of radiological surveys.

Supervisor staffing appears adequate with authorities and responsibilities of key positions adequately defined. The organization will be changed, pending approval of a Technical Specification change, but the impact is expected to be minimal. Contractor personnel are used in supervisory positions related to administration and the ALARA program. There appears to be understaffing in these areas as indicated by a backlog of work such as revisions to existing procedures and development of new procedures for ALARA.

The training and qualification of new and existing staff personnel appears adequate. Reassignment of training responsibilities, due to a NRC initiative last year, and completion of a new licensee training facility are in progress. Licensee management has proposed various improvements in radiological training programs but appears to be hampered by lack of qualified instructors. The training of the security guard force to deal with accident conditions was reviewed and found adequate. The training programs do not appear to receive adequate review by the corporate Quality Assurance or Radiation Protection Services.

The licensee's efforts to reduce solid waste have been notable. This may be due in large measure to problems at the burial sites for low level waste. The licensee has installed new facilities to segregate clean and contaminated waste and has taken steps to minimize waste generated during outage work. These efforts have reduced waste volume by over 50%.

Overall performance in the radiation protection area has degraded slightly the past few years. Licensee management has outlined various improvements that would significantly raise the effectiveness of this program; however, management has not been effective in implementing these changes.

2.2 Effluent Monitoring and Confirmatory Measurements

Corporate management is directly involved in site activities with one supervisor designated with specific responsibilities for the Radiological Environmental Monitoring Program (REMP). The collection and analysis of REMP samples are accomplished by the corporate laboratory. Both the REMP and site chemistry laboratories are well equipped and adequately staffed. Quality control of analytical results is provided by cross-check measurements independently between the labs.

Audits by the corporate staff are generally complete and thorough; however, effectiveness is decreased somewhat due to slow response by management to certain findings. During a July 1984 inspection, it was determined that replies to a 1982 REMP audit were still not resolved. Replies to chemistry audits are generally timely and complete.

Records are generally complete, well maintained and available. Independent measurements, using the Region I mobile laboratory, verified the accuracy of the records and the analytical techniques used to obtain the data. The 1982 REMP report was submitted late relative to reporting requirements. This may be indicative of programmatic breakdown since a similar problem occurred in 1978 and 1980.

The regional inspectors noted that the licensee quantifies air flow in ventilation ducts by averaging several air velocities from a pitot tube that is traversed across the duct. This is contrary to industry practice provided in ANSI N510 which recommends measuring air velocity at one point known to be in excess of 1000 feet per minute. This occurrence indicates a need for increased management attention to the adequacy of effluent monitoring procedures.

The licensee's resolution of technical issues indicates a general understanding of the issues. During the previous assessment period, the licensee reported in a LER that the charcoal beds in the auxiliary building air cleaning system had failed the freon test. Subsequent investigation indicated that this test failure was due to high humidity in the air. However, during an inspection, region specialists determined that the licensee is not yet monitoring or attempting to control humidity in this system. Although technical resolution of problems is adequate, management followup and corrective action is weak.

Responsiveness to NRC initiatives has been thorough and timely. There are no long-standing regulatory issues attributable to the licensee. The enforcement history is significantly improved with only one minor violation this period. Major violations are rare.

Key positions within the chemistry and REMP organization have well defined authorities and responsibilities. Staffing is adequate with the exception of the technicians in the onsite chemistry laboratory. Additional technicians here would allow for increased cross-check verification of routine samples and a review and improvement in the laboratory QC program.

The training and qualification of chemistry technicians results in an adequate understanding of the work and fair adherence to procedures with a modest number of personnel errors. The quality control training of technicians will be transferred to the Nuclear Training Center in an effort to improve this area.

Overall performance in the chemistry and REMP areas has been good. Management attention is required to ensure adequate QC of on-site and contractor laboratory results.

Conclusion

Category 2, improved.

Board Recommendation

Licensee: Increase management attention to ensure timely implementation of program improvements already under development.

NRC: Continue routine program; follow up on implementation of program improvements.

3. Maintenance (11.3%)

During the assessment period, one team inspection and two followup inspections were conducted which addressed many maintenance related issues (preventative maintenance, post-maintenance testing requirements, and incorporation of vendor recommendations into maintenance procedures) that required corrective actions as a result of the reactor trip breaker problems discussed in the previous assessment. In addition, a special regional-based inspection was conducted to confirm the actions taken in response to Generic Letter 83-28, which also reviewed similar maintenance related activities. The area was also the subject of routine monthly inspections and a special maintenance history program review by the resident inspectors.

Generally, management involvement indicates prior planning of work and defined procedures for control of the activities. One possible exception to this is in the general troubleshooting procedures. Some plant trips appear to have resulted, either directly or indirectly, from troubleshooting of instrumentation. Some additional controls may be necessary to prevent future similar occurrences.

The Work Order Tracking System is a new computer based method of initiating, completing and tracking the progress of work at the station. This system does give the licensee a much better record system and should allow better control in planning and organizing the workload. During a review of maintenance history records, it appeared that equipment history trending was ineffective, although there was a formal program for review of such records, including corrective actions for any identified trends. This conclusion was based on the arbitrary way that the files are maintained and that reviews are conducted by planners rather than supervisors familiar with the equipment. The most effective trending has been through informal means by various supervisors in both the Maintenance and Instrumentation and Control Departments. Examples of this type of trending have been on the Safeguards Equipment Control Cabinets and a detailed study of valve failures in 1983. These actions have resulted in modifications and preventive maintenance activities to improve the reliability of safety equipment.

The utility has made a substantial investment to improve the preventive maintenance program at the station. However, the "managed maintenance program" (MMP) was not completed in accordance with the schedule in the May 6, 1983 Order. The licensee requested additional time, which was granted. Following completion of this item, the MMP was reviewed in July 1984 and, although some minor revisions are planned by the utility, the program has initiated additional preventive maintenance activities that are controlled by the Inspection Order System, and these activities are being completed. The utility plans to make further changes to better prioritize the workload.

Key positions in the maintenance organization have well defined responsibilities and authority. Throughout the early part of the assessment period some of these key individuals were also playing a large role in the development and initial implementation of the MMP and in the review of procedures for changes required by the vendor supplied information review. The station maintenance organization staffing appears adequate; however, due to the large number of Inspection Orders and Work Orders generated as a result of establishing a more thorough preventive maintenance program, there is a significant backlog of total work activities. The licensee is using contractor support to try to decrease the overall backlog until its size is more manageable. The station Maintenance and Technical Departments are also using excessive overtime which varies, with planned outage work being the largest contributor to both the work backlog and the high overtime rate. Overall, the staffing appears inadequate at this time to support the number of planned activities and still enable the station to respond to immediate problems without relying heavily upon contractor support or extensive overtime.

The training program for maintenance personnel, which includes both the Maintenance and Technical Departments, continues to contribute to an adequate understanding of work and generally good adherence to procedures by maintenance personnel. The training program is applied to nearly all of the PSE&G station staff. However, due to the reliance on contractor support for not only outage related, but also some routine work activities, the training program has not been applied universally. One notable training deficiency was in the area of the training provided on the proper use of the MEL for classification of Work Orders. The impact was such that safety-related maintenance activities could still have been misclassified even though corrective actions were taken to prevent it.

In summary, the licensee's maintenance programs have been improved by the expansion of the formal preventive maintenance program and the maintenance procedures have improved by incorporating many recommendations by the equipment suppliers. However, the increased workload, which has been offset by the use of contractor support and overtime, appears to have had a detrimental impact on the quality of the work completed in some cases.

Conclusion:

Category 2, Improved. Efforts to improve preventive maintenance program and maintenance procedures have been noteworthy but slow because of excessive overtime necessitated by frequent outages.

Board Recommendations

Licensee: Complete implementation of Managed Maintenance Program, reduce work order backlog, improve quality monitoring of contractor activities and training of contractor personnel.

NRC: Conduct routine program; review implementation of action plans.

4. Surveillance (9.5%)

Various aspects of the surveillance program were reviewed during four region-based inspections and during routine resident inspections.

Management control is generally evident. The Inspection Order program which covers the majority of surveillance activities provides good control for planning purposes. Procedures are generally well defined, maintained and followed. Corporate management is routinely involved in the ISI program, while other areas of the surveillance program are controlled by station personnel. Records are complete, well maintained and available. QA/QC involvement is evident; however, QA review of Technical Specification surveillance requirement changes are not timely enough to assure changes are promptly implemented. Audits are usually complete and thorough and appear to be effective in identifying problems and getting them corrected. QC reviews sometimes appear to be documentation audits only, without direct observation or of sufficient depth to identify procedural inadequacies. Finally, it does not appear that a complete QA verification has been conducted to ensure that implementing procedures have been developed for all Technical Specification surveillance requirements. This problem was indicated by missed surveillances in the fire protection program during the last assessment and, once again, during this assessment period as a violation for not having a procedure governing mechanical snubber testing.

The licensee has generally been responsive to NRC issues in this area. However, an NRC concern about RCS leak detection/measurements pertaining to the Unidentified RCS leakage which relied on "best guess" estimates of identified leakage was addressed by the licensee so that collection measurements will be used to quantify any identified leakage. The licensee had considerable difficulty and was very slow in resolving RCS leak detection methods as indicated by Unit 1 LER 83-065. The licensee finally decided that the best method for calculating RCS leakage is by a water inventory balance and this method is being used to quantify unidentified leakage.

During the assessment period, five surveillance tests were missed. Three resulted in LERs, one of which, failure to establish containment integrity with less than the required number of operable electrical power trains, had previously resulted in enforcement action. After frequent NRC reminders, the licensee revised their response to account for this additional event. Another occasion involved a missed surveillance test on emergency diesel generators. This was attributed to a lack of adequate procedures for events like the loss of a vital bus. In addition, due to another inadequate operating department surveillance procedure, which did not list the Control Bank "B" rods, the surveillance to verify operable control rods, was not documented as completed on six occasions. One violation was identified for failure to establish a procedure for mechanical snubber testing. Although the tests were being conducted, an approved procedure listing all of the Technical Specification requirements was not in use. Generally, these problems do not appear to be indicative of major program weakness in completing required surveillance testing. The errors that have occurred are a result of personnel oversight.

The surveillance test program has identified many equipment failures. Prompt corrective actions have resulted and reporting, when appropriate, has been timely. However, the licensee has identified repeated problems with the lift set point drifting on both the primary and secondary code safety valves. Resolution of these occurrences is under review and the corrective actions have not yet been determined. The number of reportable events in this area has decreased since the last assessment period. However, this is mainly due to the changes in the reporting requirements.

Since required tests are performed on time, staffing levels appear adequate. However, as a result of the licensee's Action Plan, there has been a significant increase in the outage related Inspection Orders for the Technical Department. Since this department also conducts much of the Technical Specification surveillance testing, it appears that staffing may become inadequate to support both programs without significant use of overtime or reliance upon contractor support. Training programs established for technicians and equipment operators appear to be quite good.

In summary, while the Inspection Order system provides good control over the implementation of that portion of the surveillance program to which it applies, there needs to be more management involvement to assure the adequacy of procedures and to reduce the number of missed surveillances.

Conclusion

Category 2, Improved. Although inspection order system is generally effective, added management attention is necessary to reduce missed tests and correct program weaknesses like that found in the area of snubber testing.

Board Recommendation

Licensee: Increase management attention in order to reduce the number of missed surveillances; QA verification of adequacy of program.

NRC: Continue routine inspection program.

5. Fire Protection (10.4%)

This analysis is based on continual review by the resident inspectors and one region based team inspection during the assessment period. The team inspection focused on the requirements of Section III.G, Fire Protection of Safe Shutdown capability.

There was substantial evidence of management attention to the fire protecion program. This included in-depth fire hazard analysis (except that the containment analysis was not formally documented); licensee responsiveness to NRC requests and correspondence including Generic Letter 83-33 (clarification of certain Appendix R requirements); an Appendix R "Lessons Learned" meeting conducted on December 14, 1983 (20 new exemption requests were submitted promptly); generally good safe shutdown procedures; and licensee's efforts to quickly resolve deficiencies identified during the inspection.

Protection for redundant safe shutdown components was generally provided as required by Appendix R, Section III.G. Two findings were identified during the inspection. The first involved an apparent failure to comply with the rule in certain areas of the plant. The second involved a failure to submit exemption requests in accordance with the schedular requirements of 50.48(c). In addition, several other deficiencies were also identified.

Alternate shutdown provisions as required by Section III.G.3 were generally adequate with no major difficulties noted. The alternate shutdown procedures were generally good.

Both units have been in the Technical Specification action statement for degraded fire barrier penetrations for almost three years. In the LER which reported this problem, the licensee indicated that a supplemental report would be submitted when modifications to fire doors were completed. Although a schedule for completion of the modifications and termination of the action statement was required to be included in the LER by the Technical Specification, the licensee has never provided one in spite of recent reminders by the resident inspectors. While the modification was scheduled to be completed in June 1984, numerous fire doors remain impaired because of ventilation imbalances and hoses or cables running through the doorway. This situation was further aggravated during the Unit 1 outage by the impairment of many fire barriers in the operating unit and the staging of combustible materials for outage activities in the operating unit to support outage work. Although there are roving fire watches, plant tours for unauthorized impairments, and periodic housekeeping inspections, degradation was so extensive during the outage that it would have been quite difficult to restore fire barriers to contain a fire. The plant staff is so accustomed to these conditions that they see little hope for ever terminating the action statement and have, in fact, permanently typed it in on their blank logs.

In an effort to improve the fire protection program the licensee is in the process of establishing a site fire department which will eventually assume most of the responsibility for fire protection activities now borne by the Operations Department including surveillance testing, fire brigade manning, inspections, etc. This department is under the direction of the Site Protection Manager and is only partially staffed as of the end of the assessment period.

Strong management attention is needed in this area to restore fire barrier integrity and to improve the attitude of station and contractor personnel toward this important aspect of fire protection.

Conclusion

Category 3, Declined. Aggressive management attention is necessary to correct the long standing degradation of fire barriers and the complacent attitude which accompanies it.

Board Recommendations

NRC: Conduct routine inspection program; include specialist follow-up on fire barrier integrity.

6. Emergency Preparedness (7.9%)

During the assessment period there were two routine inspections of emergency preparedness activities, one of which was unannounced routine and the other an observation of the annual exercise.

One violation was identified during the assessment period for failure to distribute protective response information to the public within the emergency planning zone during calendar years 1982 and 1983. Actions have been taken to correct the violation.

Part of the scope of the routine inspection included a review of the emergency plan against the NUREG-0654 planning standards. This review disclosed an excessive number of items (23) requiring additions or changes to the emergency plan in order to fully meet the emergency preparedness standards. In addition, a review of the overall meteorological program indicated that the licensee has not yet fully conformed to NRC published guidance. The licensee's present program has no means for determining the complex flow regime associated with a coastal site and therefore cannot adequately represent meteorological conditions in the vicinity of the site.

During the observation of the annual exercise, eleven improvement items were identified which had the potential to contribute to a degraded response. During the 1983 exercise and subsequent practice drill, communications between the control room and the technical support center were average at best. While the transmission of raw data was acceptable, interpretation and analysis among the disciplines within the centers and between the centers was lacking resulting in misunderstandings and oversights.

The licensee generally has been responsive to NRC initiatives. Based upon the inspector's observations of licensee emergency preparedness management and personnel, it appears that the staff is adequate in number, management and staff are competent, response facilities are adequate and adequate resources are available to maintain an effective emergency preparedness program. The overall findings indicate an acceptable level of performance.

Conclusion

Category 2, Declined.

Board Recommendation

Licensee: Complete program improvements.

NRC: Conduct routine inspection program; provide operations expertise for drill inspection team.

7. Security and Safeguards (4.9%)

Two unannounced physical protection inspections were performed during the assessment period by region-based inspectors. Routine resident inspections continued throughout the assessment period. No violations were identified during these inspections. The licensee submitted one security event report pursuant to the requirements of 10 CFR 73.71 during the assessment period. The description of the event was clear and the corrective actions taken were adequate and prompt.

Licensee management resources were adequate and effective in administering the security program. Corporate management involvement in site activities was evidenced by a thorough and comprehensive annual corporate security audit and support for various improvements in the security program as noted below. Licensee security management involvement was evidenced by consistent reviews of daily records and activities of the contract security force, comprehensive and thorough audits of the security program, and timely and effective corrective actions on audit findings.

Management awareness and commitment to maintaining an effective security organization was evidenced by: (1) purchase of an integrated security computer system which includes new key card readers for vital area access control; (2) purchase of "walk-thru" explosives detectors for the main and auxiliary access control points and modification of the metal detectors at these points to increase their sensitivity; (3) identification and definition of duties and responsibilities of key licensee positions and staffing of these positions; and (4) purchase of new uniforms and associated garments for the guard force. Low personnel turnover, good morale and a well defined and implemented security personnel training and qualification program also contributed to a sound security program.

Conclusion

Category 1, Improved. Organizational, staffing and equipment improvements reflect exceptional management commitment to have an outstanding program.

Board Recommendations

Licensee: Complete hardware improvements.

NRC: Conduct routine program.

8. Refueling and Modification (8.9%)

The assessment of this area is based on routine resident inspections conducted during the Unit 1 fifth refueling and modification outage (February 24, 1984, through the end of the assessment period, August 31, 1984), and during numerous maintenance outages on Unit 2.

Because the outage started three months ahead of schedule due to main generator failure, mobilization and the completion of deisgn change packages was understandbly slow. Unanticipated events in both units further complicated efforts to plan and control the outage. For example, on Unit 1, a core exit thermocouple column was bent while replacing the reactor vessel head, requiring replacement of the column and the thermocouples, and more cracks in No. 12 Component Cooling Heat Exchanger service water piping required replacement with another material for the second time. Unit 2 equipment problems during operation including a feedwater flow nozzle failure, degraded safety injection flow throttle valves, failed containment fan coil unit motors, and degraded pressurizer code safety valves, required replacement with Unit 1 parts further increasing the scope of the outage and distracting management. Even after the originally scheduled start date of the outage had passed design change packages for scheduled work activities were not available. These problems, coupled with material procurement delays and manpower shortages, had an adverse effect on morale and, when combined with pressures to meet schedule commitments, appear to have led to poor quality work requiring rework and poorly controlled work in some cases. For example, check valves were installed backwards in the service water system, flow orifices were installed backwards in the safety injection system, and a post maintenance test of a 4KV infeed breaker that should not have been done under existing plant conditions initiated a loss of offsite power event that resulted in overheating an emergency diesel generator. All of these events resulted in increased workload and impacted the scheduled work.

In spite of the difficulties noted above, the modifications to the Nos. 11 and 12 Component Cooling heat exchangers and the spent fuel pool cooling cross-connect occurred with relatively few problems once pre-staging for the work was established. The refueling operation conducted by a Westinghouse team also took place without any major difficulties. During the fuel handling, no PSE&G QA/QC or reactor engineering personnel were directly involved in observing and verifying that the fuel handling was proceeding according to plan. Instead, contractor support was utilized and licensee personnel reviewed the video tapes after the fact.

During the refueling outage, the inspectors raised some concerns about the controls for temporary rigging of new equipment from "operable" components such as safety-related cable trays and piping for systems required to be in service. The licensee issued guidance to the outage staff to prevent such activities unless specific authorization from engineering is provided. Another inspector concern involved the licensee's apparent lack of control over the scaffolding that remained over equipment, such as cable trays, when the unit was being prepared for the plant heatup at the end of the outage in August 1984. The licensee had not yet developed a response to this concern at the end of the assessment period.

The licensee event reports pertaining to outage related activities were generally timely and accurate. Specifically, the proposed corrective actions for the event that resulted in a loss of service water cooling to the emergency diesel generators were good.

The licensee's staffing did not appear to be adequate to support or control the workload during the refueling outage. Although licensee efforts to control work, including the establishment of containment coordinators from the Planning Department and frequent status meetings were evident, better licensee supervisory oversight of work in progress would have provided better control. The lack of timely work packages, equipment and craft to support the activities resulted in numerous delays and interferences with major planned activities.

Conclusion

Category 2, Declined. Although frequent unscheduled outages and an early start to the scheduled refueling outage due to a generator failure have aggravated problems in this area, a lack of direct licensee involvement in many jobs seems to be contributing to excessive rework.

Board Recommendations

Licensee: Complete action plans to enhance outage management; improve monitoring of contractor activities to reduce re-work and schedule delays; provide management attention to assure timely engineering support for outage activities.

NRC: Conduct routine program; perform Operational Readiness Team inspection following Unit 2 outage if refueling occurs.

9. Licensing Activities

The basis for this appraisal was the licensee's performance in support of licensing actions that were either completed or had a significant level of activity during the current rating period. These actions, consisted of amendment requests, responses to generic letters, TMI items, and other actions, including 18 multi-plant actions (MPAs) and 24 plant-specific actions. These are tabulated on page 33, item 5.

The licensee continues to place slightly better than average management attention on routine licensing actions, MPA's and amendment requests. This has assured prompt attention to most site-specific actions. This current assessment is approximately the same as in our previous SALP evaluation. The basis for this was timeliness in addressing schedular commitments regarding specific actions which reflects effective planning and assignment of priorities. The licensee has also been cooperative with respect to our requests for technical meetings and has reacted to the Commission's schedules and priorities.

During the evaluation period, PSE&G has been implementing a corrective action program to improve its management effectiveness regarding all phases of the Salem operations. The program was initiated about one year ago following the Salem ATWS events, however, all the positive gains that were expected as a result of this program have not been realized. Since all phases of the program have not been completed, it may be presumed that insufficient time has elapsed to see strong indications in all areas. It is believed that some positive gains with respect to licensing initiatives will be made. Monitoring of this area during the forthcoming year will continue to determine whether those elements of the program affecting licensing actions have been successful.

The licensee's performance regarding the resolution of four licensing actions was judged to have demonstrated good technical expertise and understanding of the issues at hand and decisions relating to these actions exhibited conservatism with respect to safety matters. However, the licensee's performance was generally found to be average for the remainder of the licensing actions screened. For one action, implementing Appendix R requirements, the licensee's performance was judged to be marginal. Further, most of the PSE&G employees involved with the licensing reviews have had enough years of experience relating to nuclear plant operations and interfacing with the NRC to benefit them in this regard.

During this assessment period, the Salem Licensing Department has not added to its staff and its effectiveness has not improved. PSE&G plans to continue its program to expand the licensing group staff and to improve their methodology when responding to NRC initiatives. Monitoring of the licensee in this area will continue.

Conclusion

Category 2, Same.

Board Recommendations

None.

V. SUPPORTING DATA AND SUMMARIES

1. Licensee Event Reports

Tabular Listing

Type of Events:	Unit 1	Unit 2	Total
A. Personnel Error	11	13	24
B. Design/Man./Constr./Install	14	9	23
C. External Cause	3	1	4
D. Defective Procedures	3	2	5
E. Component Failure	14	7	21
X. Other	7	4	11
Total	52	36	88

Licensee Event Reports Reviewed

Unit 1: Reports 83-39 through 83-75, 84-01 through 84-16
Unit 2: Reports 83-49 through 83-67, 84-01 through 84-17

Causal Analysis of Salem LERs

Nine causally linked chains were identified:

a. Three LERs (all on Unit 1) involve electronic lock-up of the P-250 computer. Consequently the Reactor Coolant System subcooling margin monitor is inoperable. Design of a Safety Parameter Display System is presently underway and will be installed in late 1984. The RCS monitor will be connected to the safety related SPDS computer. The LERs in this group are: (Unit 1) 83-039, 83-043, and 84-045.

b. Six LERs (5 on Unit 1, 1 on Unit 2) detail inoperability of containment airlock doors. Most of them are due to poor sealing from improper operation of the air lock. The LERs in this group are: (Unit 1) 83-044, 83-050, 83-058, 83-059, and 83-070; (Unit 2) 83-052. This continues a chain identified in the last SALP.

c. Three LERs (2 on Unit 1, 1 on Unit 2) involve Rod Position Indication in excess of 12 steps from the group demand position. This was due to calibration drift. The LERs in this group are: (Unit 1) 83-047, and 83-074; (Unit 2) 83-054. This continues a chain identified in the last SALP.

d. Four LERs (all on Unit 1) detail leakage into containment sump in excess of technical specification limits. The leaks were caused by a variety of different component failures. Procedures were changed to redefine unidentified leakage. The LERs in this group are: (Unit 1) 83-051, 83-055, 83-065, and 84-006.

e. Six LERs (all on Unit 1) involve problems with various portions of the fire protection water systems. Most of the incidents were due to frozen components during extremely frigid conditions. Other failures were due to normal wear. Procedures for preparation for cold weather conditions were developed and implemented to prevent recurrence. The LERs in this group are: (Unit 1) 83-064, 83-066, 83-067, 83-068, 83-069, and 84-011.

f. Two LERs (both on Unit 1) involve reactor trips due to Steam Generator Feedwater Flow mismatches at low power. The problem is caused by operator error when the reactor power is increasing. The LERs in this group are: (Unit 1) 84-001 and 84-003. This problem has occurred frequently in the past, and as a result changes to operating practices and modifications to the main and bypass feedwater regulating valve control system have been implemented. There appear to be fewer of these trips as a result.

g. Seven LERs (1 on Unit 1, 6 on Unit 2) detail inoperability of Diesel Generators. Most of the failures were either due to fuel oil leaks or SEC problems. Modifications have been made to the SECs to prevent recurrence. The LERs in this group are: (Unit 1) 83-073; (Unit 2) 83-058, 83-059, 83-063, 83-065, 83-067, and 84-004.

h. Four LERs (1 on Unit 1, 3 on Unit 2) involve reactor trips due to maintenance activities, normally during troubleshooting, that have either initiated transients that have resulted in the trip or directly caused the trip itself. The LERs in this group are: (Unit 1) 84-004; (Unit 2) 84-008, 84-012, and 84-013.

i. Two LERs (on Unit 2) involve two reactor trips, one plant shutdown and inoperable Reactor Trip System instruments as a result of the No. 23 Feedwater Flow Nozzle being displaced from its normal position in the feedline as a result of the feedwater hammer event on April 6, 1984.

2. Investigative Activities

None - miscellaneous allegations were examined during routine inspections.

3. Escalated Enforcement

None

4. Management Conferences

4.1 Management Meeting on October 11, 1983 to discuss the development and implementation of the PSE&G Action Plan for improving Nuclear Department operations.

4.2 Bimonthly Management Meeting on November 18, 1983 to discuss the methods of monitoring status of the individual items of the PSE&G Action Plan.

4.3 Management Meeting on December 14, 1983 to discuss the lessons learned from previous 10 CFR 50 Appendix R Safe Shutdown inspections.

4.4 Bimonthly Management Meeting on January 5, 1984 to discuss the status of the PSE&G Action Plan.

4.5 Management Meeting on February 1, 1984 to discuss planned improvements in the licensee's ALARA program.

4.6 Bimonthly Management Meeting on March 6, 1984 to discuss the status of the PSE&G Action Plan.

4.7 Bimonthly Management Meeting on May 18, 1984 to discuss the status of the PSE&G Action Plan and performance indicators for use in monitoring expected improved operation.

4.8 Enforcement Conference on June 27, 1984 regarding activities at Salem Unit 2, principally the failure to comply with a Technical Specification on Containment Ventilation Isolation.

4.9 Bimonthly Management Meeting on July 19, 1984 to discuss the status of the PSE&G Action Plan and recent negative performance indicators including: inattention to detail; poor safety perspective; and insufficient personnel accountability or inquisitiveness.

5. <u>Licensing Activities</u>

5.1 <u>NRR/Licensee Meetings</u>

May 23, 1984, Detailed Control Room Design Review
May 24, 1984, Environmental Qualification
July 18, 1984, Appendix R

5.2 <u>NRR Site Visits</u>

Participate, in conjunction with Region I, in three Bi-Monthly Management Meetings regarding the PSE&G Corrective Action Program following the ATWS events.

Review of Q.A. Department and Charter

5.3 <u>Commission Briefings</u>

April 10, 1984, Status of Salem Corrective Action Program

5.4 Schedular Extensions Granted

One-time only extension to the reporting requirements in Appendix H, 10 CFR 50, Capsule Irradiation Sample - July 13, 1984.

5.5 Reliefs Granted

None.

5.6 Exemptions Granted

None.

5.7 License Amendments Issued

Unit 1 - Licensee request for a one-time extension for performance of Containment Integrated Leak Rate Test - October 31, 1983

Unit 1 and 2 - Licensee request to increase the maximum reload enrichment - November 22, 1983

Unit 2 - Licensee request to modify schedular requirements for performance of visual snubber inspections - January 27, 1984

Unit 1 and 2 - (1) In response to NRC request, Licensee request to add manual initiation function for the AFW and (2) Licensee request to change a Containment Air Lock surveillance test requirement - July 16, 1984

Unit 2 - In response to NRC request, Licensee request adding an Appendix R license condition - August 30, 1984

5.8 Emergency Technical Specifications Issued

None.

5.9 Orders Issued

Unit 1 and 2 - Order modifying the May 6, 1983 Order "Corrective Action Program" resulting from Salem ATWS events - January 31, 1984

Unit 1 and 2 - Order confirming Licensee commitments on Emergency Response Capability as required by Supplement 1 to NUREG-0737 - June 12, 1984

5.10 NRR/Licensee Management Conferences

None.

TABLE 1

TABULAR LISTING OF LERs BY FUNCTIONAL AREA

SALEM NUCLEAR GENERATING STATION - UNITS 1 AND 2

	Area	Number/Cause Code						Total
1.	Plant Operations	17A	10B			4E	3X	34
2.	Radiological Controls							
3.	Maintenance	5A	12B	1C		5E	3X	26
4.	Surveillance	3A			4D	8E	5X	20
5.	Fire Protection			2C		4E		6
6.	Emergency Preparedness							0
7.	Security and Safeguards							0
8.	Refueling							0
9.	Licensing Activities							0
	Other (Original Design Errors and Equipment Failures not Classifiable Into Areas 1-9)		1B	1C				2

Cause Codes
- A. Personnel Error
- B. Design, Manufacturing, Construction, or Installation Error
- C. External Cause
- D. Defective Procedures
- E. Component Failure
- X. Other

TABLE 2

INSPECTION HOURS SUMMARY (10/1/83 - 8/31/84)

SALEM NUCLEAR GENERATING STATION

		Hours	% Of Time
1.	Plant Operations........................	1482	37.7
2.	Radiological Controls...................	367	9.4
3.	Maintenance.............................	444	11.3
4.	Surveillance............................	371	9.5
5.	Fire Protection.........................	407	10.4
6.	Emergency Preparedness..................	308	7.9
7.	Security and Safeguards.................	194	4.9
8.	Refueling/Outage Activities.............	347	8.9
9.	Licensing Activities....................	No Data	
	Total	3920	100%

TABLE 3

INSPECTION REPORT ACTIVITIES

SALEM NUCLEAR GENERATING STATION

REPORT UNIT 1	UNIT 2	HOURS	INSPECTOR	AREAS INSPECTED
83-15	83-12	180	Team	May 6, 1983 Order Items
83-30	----	236	Specialist	Emergency Preparedness
83-31	83-32		Resident	Management Meeting to Discuss PSE&G Action Plan
83-33	83-33	173	Resident	Routine Safety
83-34	83-34		Resident	Management Meeting to Discuss PSE&G Action Plan
83-35	83-35	44	Specialist	Radiation Safety Program
83-36	83-36	172	Resident	Routine Safety
83-37	----	350	Specialist	Fire Protection - Appendix R Review
83-38	83-37	166	Resident	Routine Safety
84-01	84-01	15	Resident	Management Meeting to Discuss PSE&G Action Plan
84-02	84-02	64	Specialist	Chemistry Control Program
84-03	84-03	35	Resident	May 6, 1983 Order Items
84-04	84-04	173	Resident	Routine
84-05	84-05	156	Specialist	IE Bulletins 79-02, 04, 07 and 14
84-06	84-06	65	Specialist	Physical Protection
84-07	84-07	77	Specialist	QA/QC Program
84-08	84-08	188	Resident	Routine

REPORT		HOURS	INSPECTOR	AREAS INSPECTED
84-09	84-09	43	Specialist	Radiation Safety Program
84-10	84-10	72	Specialist	Emergency Preparedness
84-11	84-11	10	Specialist	Management Meeting to Discuss Radiation Protection Program
84-12	84-12		Resident	Management Meeting to Discuss PSE&G Action Plan
84-13	84-13	249	Resident	Routine
84-14	84-14	72	Specialist	Surveillance Testing and Calibration Control & Design Change Controls
84-15	84-15	210	Resident	Routine
84-16	84-16	210	Specialist	Followup on Generic Letter 83-28
84-18	84-18		Specialist	Operator Licensing Examinations
84-19	84-19	162	Resident	Routine
84-20	84-20		Resident	Management Meeting to Discuss PSE&G Action Plan
84-21	84-21	36	Specialist	Radiation Protection Program
84-22	----	55	Specialist	ISI Program and Review of NDE Data
-----	84-22		Resident	Plant Operations Involving Containment Pressure Relief
84-23	84-23	178	Resident	Routine
84-24	84-24	15	Specialist	Transportation Accident of Waste Shipment
84-25	84-30		Resident	May 6, 1983 Order Items
----	84-25	16	Resident	Enforcement Conference - Containment Ventilation Isolation - Gaseous Activity Channel
84-26	----		Specialist	ILRT Inspection

REPORT		HOURS	INSPECTOR	AREAS INSPECTED
84-27	84-26		Specialist	Environmental Assessment - Non-Radiological
84-28	84-27		Resident	Routine
84-29	84-28		Specialist	Environmental Assessment - Radiological
84-30	84-29	20	Resident	Management Meeting to Discuss PSE&G Action Plan
84-31	84-31		Specialist	Physical Protection

TABLE 4

VIOLATIONS (10/1/83 - 8/31/84)

SALEM NUCLEAR GENERATING STATION

A. Number and Severity Level of Violations

Severity Level	Common	Unit 1 Only	Unit 2 Only
Deviations			
Severity Level I			
Severity Level II			
Severity Level III			
Severity Level IV	6		8
Severity Level V	1	1	1
Total	7	1	9

B. Violations vs. Functional Area

FUNCTIONAL AREAS	DEV	Severity Levels I	II	III	IV	V
1. Plant Operations					8	3
2. Radiological Controls					1	
3. Maintenance					3	
4. Surveillance					1	
5. Fire Protection						
6. Emergency Preparedness					1	
7. Security and Safeguards						
8. Refueling						
9. Licensing Activities						
Others						
Totals	0	0	0	0	14	3

Total Violations = 17

TABLE 4

VIOLATIONS

Unit 1	Unit 2	Inspection Date	Subject	Require.	Sev.	Area
83-15	83-12	9/28-10/6/83	Failure to Follow Procedures	TS	IV	3
	83-30	9/7-10/4/83	Failure to Follow Procedures	TS	IV	1
	83-30	9/7-10/4/83	Failure to Meet LCO Requirements	TS	IV	1
83-33	----	10/5-11/9/83	Failure to Submit LER	TS	V	1
83-37	----	12/5-6/83 &1/16-20/83	Failure to Provide Fire Protection	TS	*	5
83-37	----	12/5-6/83 &1/16-20/83	Failure to Submit Exemption Request	10CFR50.48	*	9
84-03	84-03	2/27-3/2/84	Failure to Perform Review	10CFR2	IV	3
84-05	84-05	1/30-2/3/84	Failure to Control Procedure	10CFR50	V	1
----	84-08	2/7-3/6/84	Failure to Follow Procedures	TS	IV	1
84-10	84-10	2/28-3/2/84	Failure to Provide Emergency Planning to Public	10CFR50. 54(g)	IV	6
----	84-13	3/7-4/11/84	Failure to Post & Control Access to Radiation Area	TS	IV	2
----	84-13	3/7-4/11/84	Failure to Take Corrective Action	10CFR50	V	1

* These findings are under NRC management review.

Unit 1	Unit 2	Inspection Date	Subject	Require.	Sev.	Area
84-14	84-14	4/2-5/84	Failure to Review, Identify & Distribute TS	TS	IV	1
-----	84-15	4/12-5/8/84	Failure to Follow Procedure	TS	IV	1
84-15	84-15	4/12-5/8/84	Failure to Follow Order	TS	IV	1
-----	84-15	4/12-5/8/84	Failure to Take Corrective Action	10CFR 50APPB	IV	3
-----	84-22	5/29-30/84	Violation of Limiting Conditon for Operation	TS	IV	1
84-23	84-23	6/9-7/6/84	Failure to Establish Surveillance Procedure	TS	IV	4
----	84-27	7/7-8/13/84	Failure to Follow Procedures	TS	IV	1

TABLE 5

SUMMARY OF REACTOR TRIPS

	DATE	UNIT	DESCRIPTION
1.	12/31/83	1	Low power reactor trip due to steam generator level generator level control problems - required improved procedure for operators.
2.	1/1/84	1	Low power reactor trip due to operator error during turbine latching.
3.	1/7/84	1	100% power reactor trip due to a combination of the No. 12 Steam Generator Feed Pump trip on low suction pressure and the closure of No. 14 main steam stop valve.
4.	1/10/84	1	Low power reactor trip due to the No. 14 main feed regulating valve failing open and overfeeding the No. 14 SG.
5.	1/21/84	1	High power reactor trip due to No. 11 SGFP trip on low suction pressure as a result of technician error during troubleshooting.
6.	2/24/84	1	100% power reactor trip due to a main generator fault.
7.	4/6/84	2	100% power reactor trip due to technician error during troubleshooting.
8.	4/23/84	2	Low power reactor trip due to feedwater control problems resulting from the damaged feed flow venturi.
9.	4/24/84	2	Low power reactor trip due to improper latching of the turbine caused by a sticking turbine stop valve pilot.
10.	4/27/84	2	Low power reactor trip due to feedwater control problems resulting from the damaged feed flow venturi.
11.	5/11/84	2	100% power reactor trip due to a technician error during troubleshooting.
12.	5/30/84	2	Low power reactor trip during shutdown due to nuclear instrumentation setpoint problems.
13.	7/25/84	2	Intermediate power reactor trip and safety injection due to a reactor coolant system depressurization as a result of a failed open relief valve.
14.	8/26/84	2	100% power reactor trip due to the No. 21 SGFP trip as a result of instrument failure.