ENCLOSURE

FINAL PERFORMANCE ASSESSMENT RESULTS - SALEM

Report Nos. 50-272/94-201 and 50-311/94-201

Licensee: Public Service Electric and Gas Company
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Facility Name: Salem Nuclear Generating Station Units 1 and 2

Assessment Conducted: July 11, 1994 - August 25, 1994

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EXECUTIVE SUMMARY

Between July 11 and August 25, 1994, a special team under the direction of the Special Inspection Branch of the Office of Nuclear Reactor Regulation conducted a comprehensive assessment of performance at the Salem Nuclear Generating Station. The team comprised six NRC inspectors, a team leader, and a team manager, all whom were independent of the normal oversight of the Salem site. The purpose of the assessment was to develop a comprehensive evaluation of performance at the Salem Nuclear Generating Station to aid in focusing future NRC inspection resources at the Salem site. The overall assessment results are presented on a Performance Assessment/Inspection Planning Tree which is included at the end of this report. The details of the team's findings are in the assessment report.

In summary, the team determined that increased NRC inspection is warranted in the areas of licensee control systems and maintenance; normal NRC inspection is warranted in the areas of operations and engineering; and reduced NRC inspection is warranted in the area of plant support. In the area of licensee control systems the team determined that, although the framework for effective control systems is in place, management and implementation of control systems have been ineffective. Management oversight of corrective action program activities has been weak, adequate root cause evaluations have not been consistently performed, and effective corrective action performance indicators do not currently exist. In addition, key positions within the quality oversight organization remain unfilled, and key personnel in other organizations involved with corrective action system implementation are new to their positions and lack clear guidance with regard to their corrective action enhancement responsibilities.

The team noted that recent improvements have been made in the area of operations, specifically in the conduct of operations in the unit control rooms. Control room demeanor, sensitivity to equipment anomalies, and communications all seem to have improved significantly from the period covered by the team's in-office documentation review. Weaknesses were, however, identified in management oversight of operational enhancements and resolution of operational workarounds and bypasses. The team noted that the large number of operational enhancements recently instituted to improve performance, combined with a recent increase in emergent work activities presented a challenge to some operations personnel. Operational workarounds, which require operators to take nonroutine actions to compensate for degraded equipment conditions, have only recently begun receiving appropriate attention.

Overall, current engineering work, programs, and procedures appear to be acceptable, but engineering has not demonstrated the ability to proactively seek out and correct system and component deficiencies before they lead to increasingly challenging plant events. For example, longstanding problems associated with the circulating water system, rod position indication, and excessive reactor cooldown transients are only recently being resolved. In addition, engineering work priorities do not seem to be driven by the needs of the plant, and errors made during the original plant design and during recent vendor-engineered design modifications continue to challenge plant operations.

Significant weaknesses were found in both maintenance programs and in maintenance program implementation. These weaknesses included an overreliance on the use of generic troubleshooting procedures, ineffective use of the procedure feedback process, inadequacies in the post-maintenance testing program, the inexperience of backshift personnel, and procedural adequacy and adherence concerns. The team also expressed some concern regarding the control and oversight of the numerous groups and organizations that perform maintenance and modification type work on site. The maintenance organization performed well in prioritizing work, disseminating operating experience feedback information, identifying equipment problems, and general plant housekeeping.

The plant support areas of emergency preparedness, fire protection, security, and health physics continue to perform strongly. During the team's in-office review, few concerns were raised about the plant support area and, as a result, only limited time was spent onsite evaluating these activities. Management and communications within the various plant support organizations were noted to be effective. Problem identification was proactive and effective, and programs and procedures were good. Performance indicators in the health physics area continue to show good ALARA results and good contamination control. Security, in spite of some incidents, has aggressively pursued identified issues. A team review of the emergency preparedness facilities was favorable. Response to Appendix R fire protection issues was also acceptable.

PURPOSE AND SCOPE

The purpose of the assessment was to develop a comprehensive evaluation of performance at the Salem Nuclear Generating Station to aid in focusing future NRC inspection resources at the Salem site. The assessment was based on an in-office, integrated review of documentation, followed by a broad-scope onsite performance-based review.

The in-office portion of the assessment consisted of a 3-week review of NRC inspection reports, licensee event reports, performance indicators, event investigations, licensee self-assessments, and other documentation. The documentation review covered the period between January 1, 1992, and July 31, 1994. Upon completion of the in-office assessment, the team issued a preliminary assessment report by letter dated August 4, 1994, which detailed the team's findings. A 2-week onsite assessment was then conducted between August 15 and August 25, 1994. The onsite assessment focused on programmatic areas determined to be weak during the in-office review, as well as on those areas that were indeterminate.

The assessment team was comprised of six NRC inspectors, a team leader, and a team manager, all whom were independent of the normal oversight of the Salem site.

After the completion of the onsite assessment, the team performed a comprehensive evaluation using the findings of both the in-office review and the onsite assessment. The results of this evaluation are presented on a Performance Assessment/Inspection Planning Tree, which is attached to this report. The tree is divided into five individual performance areas: licensee control systems, operations, engineering, maintenance, and plant support. These individual performance areas have been subdivided into individual elements. Each performance area, as well as each individual element, has been assigned a rating based upon the assessment results. Areas and elements where reduced, normal, and increased NRC inspection appear to be warranted have been assigned green, yellow, and red ratings, respectively. The bases for the individual ratings are given in the following report.

1.0 LICENSEE CONTROL SYSTEMS

The licensee has not demonstrated the ability to identify, evaluate, and correct plant problems before they result in significant plant events. Although senior licensee management recognizes this deficiency and has implemented a corrective action enhancement program to improve performance in each of the licensee control system areas (e.g., problem identification, root-cause evaluation, trending, and corrective action tracking), these measures have not yet been fully implemented or had sufficient time to take effect, and significant plant problems continue to recur.

Key positions within the licensee's quality oversight organization remain unfilled, and many people in other organizations involved with corrective action system implementation are new to their positions and lack clear guidance with regard to their specific corrective action enhancement responsibilities. As a result, the licensee's approach to implementation of its corrective action enhancement program has been fragmentary and uncoordinated, and the various program elements have not been properly integrated into an effective corrective action system.

Quality oversight of corrective action program activities has been weak, appropriate root-cause evaluations have not been consistently implemented, and effective corrective action performance indicators do not currently exist. As a result, implementation of effective corrective action for routine problems remains inconsistent, with continuing examples of significant or recurring plant problems. Senior licensee management has recognized this problem and has made commitments to correct it. Better definition and prioritization of the involved tasks, clearer assignment of individual responsibilities, and more effective use of corrective action performance indicators are needed to ensure more timely and effective completion of this effort.

1.1 Problem Identification

The licensee's systems for identifying plant problems were well defined with good procedures and problem-reporting tools within each of the several organizations involved in site activities. Although in the past, personnel have been reluctant to fully utilize available problem reporting tools, the team noted that license management has recognized this reluctance and is addressing the concern.

Weaknesses were, however, identified in oversight, evaluation, and management of quality oversight activities. The weaknesses were indicated by repetitive, significant plant problems and were confirmed by the assessment, which determined that recent quality oversight audits and surveillance activities have not been effective in identifying existing plant problems. For example:

- The Salem quality assurance (QA) organization has not audited the licensee's significant event response team (SERT) process, and the nuclear safety review (NSR) organization has audited the SERT process at Salem only once, in September 1993. This audit addressed only whether corrective actions recommended in the SERT report had been satisfactorily completed. The audit was not sufficiently performance-based or probing of the SERT implementation process to identify problems similar to those noted during this assessment and described in Section 1.2 of this report.

- The site QA organization observes ongoing plant activities using a QA surveillance checklist. The checklist does not include a specific requirement to verify that deficiencies or problems encountered during observed work activities are appropriately documented and reported. The absence of such a requirement is significant considering the history of problems described in recent licensee event root-cause evaluations.

- The team reviewed approximately 20 recent QA surveillance reports, involving approximately 250 hours of site QA surveillance activities, and noted that this effort revealed only two deficiencies (one related to a turbine part number documentation discrepancy and one related to clearance tagging discrepancies). These site QA surveillance results appear inconsistent with the number of problems identified by the licensee during recurring plant events and with the types of problems observed during this NRC assessment.

- Although currently being addressed by management, significant operations department weaknesses were not identified during QA surveillances.

The team determined that normal NRC inspection effort is warranted in this area. The team recommends that the inspection effort focus on how effectively licensee quality oversight activities identify significant performance weaknesses, and how well licensee management evaluates the effectiveness of quality oversight activities.

1.2 Root-Cause Analysis

The licensee has developed a good-root cause analysis capability, which, when properly implemented, was considered to be effective in establishing the root causes of problems associated with significant plant events and important equipment failures. The licensee has trained site personnel on root-cause methods and applications and solicits outside expert help for complex component failure analyses. The licensee has also implemented the root-cause process for some human performance problems.

Nevertheless, the licensee has not taken full advantage of this capability. For example, the significant event response team (SERT) is the highest level tool used at Salem to independently assess significant plant events. As described by the licensee's administrative procedure (NAP-0061), the SERT is intended to be independent of other investigative processes at Salem and to produce a "stand alone" document which gives an "accurate and comprehensive" report of the root causes of concerns contributing to or complicating an event, as well as associated corrective actions to preclude recurrence.

The team concluded that Salem is not realizing the full potential benefit of the SERT process. Corrective action system deficiencies are allowing uncorrected plant problems to escalate into significant plant events, and the SERT process is not identifying deficiencies in the corrective action systems.

The team identified the following generic problems affecting the licensee's implementation of the SERT process:

- Some SERT reports have incorrectly identified the root cause of events (i.e., identified the wrong root cause or identified only a symptom).

- Some SERT reports have not addressed any root cause or corrective action for significant contributing or complicating problems identified by the SERT report.

- Some SERT reports have identified precursors to significant events (i.e., the same problem occurred before with less significant results); however, the SERT reports did not identify why existing corrective action systems failed to previously identify and correct the earlier problem.

- The corrective actions recommended by some SERT reports have not been tracked or completed as required.

- The team leader and several members of one of the SERT teams had no documented training on how to perform root-cause evaluation.

- The SERT implementing procedure was deficient in not (1) clearly defining SERT membership qualification requirements, (2) specifying that the SERT report should clearly describe the SERT charter or objectives, and (3) clearly requiring that the SERT report should specifically describe the root cause and needed corrective actions for all problems which were identified as resulting in, contributing to, or complicating an event.

Two SERT reports illustrate the concerns noted above:

<u>SERT 94-01 (Reactor Trip on Low Steam Generator Level - 1/27/94)</u>

- The SERT report noted that the #14 steam generator (SG) level control loop had experienced control problems on January 27, 1994, causing the 14BF19 feedwater (FW) regulating valve to close rapidly when placed in automatic. (The same problem occurred on May 25, 1993, but was not severe enough to trip the reactor.) However, the SERT report did not address the root cause of why an adequate root-cause and corrective-action evaluation had not been performed after the May 25, 1993, problem. During an interview with the system engineer, the team discovered that, although a troubleshooting work order (WO) (WO 930527169) had recommended K2 relay replacement, the relay was not replaced. The vendor evaluated the SG level error controller after the January 27, 1994, trip and found that the controller had failed because of a defective K2 relay. These details were not discussed in the SERT report.

- The team reviewed previous problems with BF19 FW regulating valves and identified several problems which indicated that the root causes of recurring or potentially generic problems were not properly evaluated when the problems first occurred. These failures to effectively identify and correct the root causes of routine problems before they resulted in significant events were not addressed by the SERT report. In particular:

(1) Incident Report (IR) 92-367, dated June 6, 1992, stated that valve 24BF19 had failed to control in automatic; however, referenced WOs described no troubleshooting, and the IR was closed without any root cause being identified.

(2) IR 93-195, dated March 11, 1993, stated that valve 13BF19 failed full open in automatic and that a control board was replaced (4111194-001). A similar control board (4111194-002) had to be replaced after the failure of valve 14BF19, which resulted in the reactor trip addressed by SERT 94-01.

(3) When valve 14BF19 failed to control on May 23, 1993, no IR was written, and WO 930525090 failed to identify any apparent reason or root cause for the problem. The licensee's administrative procedure (NAP-0006) requires an IR for component malfunctions involving potential design or maintenance deficiencies.

(4) WO 930720171 replaced a bad summator (1FM500H) on valve 14BF19, which had failed to properly control in automatic; however, no IR was written to address the root cause.

(5) IR 94-044, dated February 9, 1994, stated that valve 13BF19 failed to control in automatic and that control board 4111194-002 was replaced. However, the root-cause evaluation did not address why similar control boards had to be replaced in the past.

(6) The reactor tripped again on June 6, 1994, valve 21BF19 failed to control in automatic (IR 94-182 and SERT 94-06).

- The SERT report stated that the root cause of the January 1, 1994, reactor trip was failure of the #14 steam generator level error controller, which was replaced. However, the SERT report did not address the root cause of the controller failure or prescribe corrective action to prevent recurrence.

- The SERT report noted that SERTs 92-01 and 92-03 had recommended corrective actions involving steam generator level control system preventative maintenance (PM), but these were not implemented before the January 27, 1994, event. The SERT report neither addressed the cause of the failure to implement the earlier SERT report recommendations nor identified corrective actions to prevent recurrence. The team noted that, as of August 23, 1994, the recommended PMs had still not been implemented as issued procedures.

- The SERT report incorrectly determined that the failure to perform the Pms recommended by SERTs 92-01 and 92-03 did not contribute to the reactor trip on January 27, 1994. In fact, the team determined that a recommended PM to monitor steam generator level control system components for AC noise on the DC analog signals was designed to detect capacitor failure similar to that which contributed to the January 27, 1994, event.

- The SERT report stated that steam generator feedwater flow transmitter sensing line blockages (air pockets and sediment) resulted in sluggish auto level control and contributed to the January 27, 1994, event. The report recommended periodic blowdown to prevent recurrence, but did not address the root cause of why appropriate blowdowns had not been required before the trip. The team noted that Salem had experienced prior instances of sluggish steam generator auto level control.

- The SERT report noted that the Hagan 7100 system installed at Salem was recognized as being unreliable. Although the SERT report stated that eventually the licensee would replace the system, the SERT did not ask the other utilities having the Hagan 7100 system whether or how they had been able to avoid problems similar to those affecting Salem.

SERT 94-05 (Reactor Trip Due to Generator Transformer Failure - 6/10/94)

- The SERT report stated that nos. 11 and 12 AF21 valves failed to open because the pressure transmitter in the pressure override defeat circuit failed. However, the SERT report did not address the root cause of the failure of the pressure transmitter.

- The SERT report identified several potential contributors to the problem of excessive plant cooldown after the reactor trip (steam dump control system overshoot, failure of the moisture separator reheater purge valves to close, steam losses). However, the SERT report did not address the root cause or correction of these individual problems.

- The SERT report identified numerous recurring equipment problems (13MS10 setpoint adjustment problems; nos. 11, 13 and 14 MS167 valves drifting off their open limit after a turbine trip; unreliable event times from the P-250 computer; 11HV3 FW heater channel head relief valve lifting and staying open after turbine trip). However, the SERT report did not address the root cause or correction of these recurring problems.

- The SERT report stated that breaker 1EPX for the #12 pressurizer backup heater failed to close because of spring charging failure; however, the SERT report did not address the root cause of this problem or discuss why plant operators did not detect the problem earlier.

- The SERT report identified apparent inadequacies in design change packages (DCPs) 1EC-3326 and 1EC-3327 to correct problems associated with reactor coolant system (RCS) overcooling after reactor trips; however, the SERT report did not follow through with any assessment or root-cause analysis of the DCP inadequacies, merely noting that main steam isolation valve closure is still required after trips.

- The SERT report stated that the root-cause evaluation of the potential transformer failure which caused the reactor trip had not been completed; however, the SERT report did not appear to list this as an action to be tracked in the action tracking system.

The team determined that increased NRC inspection effort is warranted in this area. The team recommends that the inspection effort focus on ensuring that the licensee has appropriately identified and corrected the root causes of recurring problems.

1.3 Trending and Evaluation

The licensee has not done a good job in the past of trending and evaluating data from the many problem identification systems at Salem. The licensee has recognized this weakness and has established a comprehensive corrective action enhancement program. However, it is too soon to conclude whether this program will fully correct past problems. Some of the licensee's enhancement ideas, such as the computerized QA data base, are insightful and if promptly implemented might help reduce the high volume of recurring problems at Salem. Although the corrective action enhancement program is set forth in the licensee's Nuclear Department Tactical Plan (business plan), the overall effort is behind schedule, and the licensee has not clearly implemented a useful detailed plan for identifying, prioritizing and tracking the key steps in the program implementation. Senior management guidance of this type is viewed as being especially important at this time, since several of the people tasked with this program are newly appointed to their current positions.

The licensee has not defined useful performance indicators to gauge the effectiveness of corrective action programs. Although the licensee has currently defined an indicator for recurring equipment problems and these programs have improved, the licensee may also need to establish other indicators to highlight recurring problems within each of the major plant organizations. In addition, since several recent SERT reports and IRs indicate continued repeat equipment problems, the current indicator for recurring equipment problems may need to be validated.

The team determined that increased NRC inspection effort is warranted in this area. The team recommends that the inspection effort focus on assessing the effectiveness of the licensee's implementation of the new QA data base, validating selected corrective action system performance indicators, and ensuring the new QA data base is coordinated with other trending and evaluation efforts within other site organizations.

1.4 Corrective Action Tracking Systems

The licensee has established procedures for ensuring that corrective actions are completed for items captured within the corrective action systems. However, the team noted that tracking and carrying out commitments and corrective actions has been a problem in the past and continues to be one, as some recent SERT reports show. The primary reasons for these problems are a lack of consistency in the manner in which some action tracking system items are closed and insufficient commitment by cognizant managers to ensure that all identified items are completed. Senior management has recognized this problem and is working to correct it. The team reviewed the findings of several licensee self-assessment reports, NRC reports, vendor bulletins, and QA audits, and noted that appropriate corrective actions were captured by the licensee's action tracking system and appeared to have been completed in a timely manner or were being appropriately tracked.

The team determined that normal NRC inspection effort is warranted in this area. The team recommends that the inspection effort focus on verifying that the licensee has implemented an effective followup process to ensure that the corrective actions not only have been tracked and signed off as complete, but have actually corrected the original problems.

2.0 OPERATIONS

Historically, the operations department at Salem has been challenged by longstanding equipment and design concerns, organization and management changes, and unanticipated transients and events. As a result, operations management informally initiated numerous enhancements and modifications to operations programs. The team's onsite assessment of Salem operations noted marked improvement in control room activities, compared to the recent historical record. Facility operation was generally satisfactory. However, based on team's review, weaknesses were identified in the site management's oversight of operations, the QA assessments of operations activities, and the resolution of the operations workaround and bypass list.

2.1 Safety Focus and Management Involvement

The team's historical review indicated that the licensee's performance in outage planning and consideration of shutdown risk (i.e., outage risk management) appeared adequate. However, certain past activities indicated weaknesses in safety focus and management involvement. Examples are (1) the decision to restart Unit 2 after four aborted reactor startups due to rod control failures, (2) the intentional entry into Technical Specification (TS) 3.0.3 by repeatedly closing containment isolation valves and for troubleshooting rod position indication system failures, and (3) the failure to recognize temporary modifications associated with providing temporary power to the No. 12 auxilliary building fan and installing a blank flange in the service water system as changes to the updated final safety analysis report.

During the site visit the team reviewed portions of Salem's program for outage risk management and the licensee's process for equipment and system operability determinations. The team also reviewed a representative sample of justifications for continued operations (JCOs), Salem technical specification interpretations (TSIs), and operations personnel overtime records.

The team determined that the licensee's implementation of JCOs and TSIs was adequate. The JCOs and TSIs were clear, concise, and appropriately documented. Overtime usage, except as discussed below, was not excessive.

Based on the historical information and the site observations, the team determined that site management needs to improve its general oversight of operations activities. This determination was based in part on the following:

- There was evidence that a large amount of emergent work coupled with implementation of programmatic improvements into operations was being performed without a well-defined systematic process. During the assessment, the licensee developed a list of improvements and modifications planned or being considered. The licensee had not ensured that these programmatic improvements were being implemented in an orderly, deliberate manner and that measures were in place to assess their effectiveness.

- There was a lack of clear guidance for operability determinations. As a result, Salem management recently issued an operator aid via the standing night order process. This aid should assist operations personnel in making standardized operability determinations. Operations management encouraged feedback from the operating crews on the use of and effectiveness of this aid. These comments had not yet been incorporated into a revision of the operator aid, or put in a procedure.

- A large amount of emergent work in addition to normal operations activities resulted in a saturated workload for the operating crews. Because of the workload, shift supervisors needed longer than 1 hour to turn their shifts over and effectively worked greater-than-13-hour shifts.

- The outage risk management program was in its initial stages of development and was undergoing refinement. The team noted that the licensee had trained only two of the five operating crews on outage risk before the last planned outage.

The team determined that normal NRC inspection effort is warranted in this area. The team recommends that the inspection effort focus on management oversight of programmatic improvements, implementation and use of the operability flowchart, and implementation of the outage risk management program.

2.2 Problem Identification and Resolution

The team's historical review indicated that operations responded adequately to event-identified issues. However, weaknesses in the licensee's resolution of longstanding concerns and the inadequate pursuit of problem resolution have apparently contributed to the overreliance on operator "workarounds." The terms "workarounds" and "bypasses" are defined in this report as nonroutine actions performed by the operating crews due to equipment not functioning as designed. Examples of longstanding concerns are (1) the excessive RCS cooldown events that have made operator transient response activities unnecessarily complex, (2) rod control problems, (3) radiation- monitoring system anomalies, and (4) grass intrusion in the circulating water (CW) system. The last two concerns have contributed to operating events.

During the site visit, the team reviewed portions of the licensee's process for identifying and formally tracking operator workarounds and bypasses. In addition, the team evaluated a representative sample of recent QA assessments of operations activities, reviewed the operations department self-assessment process called the operator observation program, and conducted numerous plant tours.

Based on the historical information and the site observations, the team determined that there appeared to be an increased sensitivity in identifying problems at Salem. This increased sensitivity was shown in two ways:

- The licensee had instituted plant tours to identify deficient plant conditions. This effort increased the number of work requests issued and in turn increased the amount of emergent work and the need for increased planning and preparation.

- In a questionnaire Salem management asked the operating crews about the number of operator workarounds and bypasses at both Salem units. The results of the questionnaire revealed more than 50 operator workarounds. Operations management determined that the workarounds had been previously identified and documented by operations personnel, but until recently, had not received appropriate attention.

Because in the past responses to identified concerns had not been adequately addressed, the licensee decided that additional interdepartmental coordination was warranted, and had begun to implement a program to consolidate and prioritize all outstanding work requests, design change requests, and operator workarounds and bypasses.

The operations department recently implemented a revised operator observation program, governed by AD-01, "Operator Observation Program." The program sensitizes operations personnel to the importance of being self-critical and of documenting weaknesses and strengths in performance. Operations management was assembling this performance information into a database for trending and analysis.

The team noted that quality assurance surveillance of operations had not been performance based and that the surveillances had been ineffective at identifying significant previously existing operations department weaknesses.

Plant tours by the team revealed the plant housekeeping to be generally acceptable. However, in low-traffic areas, the licensee's attention was occasionally warranted.

The team determined that normal NRC inspection effort is warranted in this area. The team recommends that the inspection effort focus on operations self-assessment activities and resolution of the operator workaround and bypass list.

2.3 Quality of Operations

The team's historical review indicated that the quality of operations during event response and during outage activities appeared generally adequate. However, deficiencies in operator performance during the recent grass intrusion event, numerous examples of operators failing to comply with procedures and technical specifications during routine operations, and the reliance on operator workarounds and bypasses pointed to weaknesses in the overall quality of operations. Additionally, inadequacies in normal and emergency operating procedures, deficiencies in simulator fidelity and in operator training, and the existence of longstanding plant equipment problems contributed to weaknesses in operator performance.

During the site visit the team reviewed portions of the licensee's safety tagging program, including the computerized system "TRISS" for work control and the current unavailable equipment log. In addition, the team observed several operating crews performing normal operations, witnessed several shift turnover briefings, toured the Salem plant-reference training simulator, and discussed the operator training program with cognizant training personnel.

Based on the team's observation, the conduct of operations in the unit control rooms appeared to have improved significantly recently. This determination is based in part on the following;

- Management had emphasized to operators its expectations for the operating crews; and the team noted an increase of sensitivity to acknowledgement of annunciators, more aggressive identification of equipment anomalies, a heightened attention to crew communications, and an overall professional conduct of the operating crews.

- During shift turnovers, pertinent information was apparently relayed to responsible operators; however, in one case (a manual rod control transient), pertinent information was not relayed to the nuclear control operator (NCO).

- Multiple turnover meetings between operations supervisors and other department supervisors appeared effective. Intradepartmental communications, as during shift turnovers, were extremely well detailed.

Additionally, the team determined that operations had established effective clearance order and unavailable equipment log programs. Recent changes to these programs as a result of past performance weaknesses appeared positive, as evidenced by the following:

- Walkdowns of selected portions of systems indicated that valves, breakers, and components were appropriately positioned as indicated on the clearances. However, the team noted one exception in the fire protection area. This exception is described further in Section 4.0 of this report.

- The current unavailable or out-of-service (OOS) equipment log was being appropriately controlled by the work control center.

- The senior operations shift supervisor and the NCOs were aware of the items on the daily OOS log.

- Additional emphasis was placed on revising the process to reduce the large number of items on the OOS log.

The team determined that the operations department had recently revised the emergency operating procedures (EOPs) to meet Revision 1B of the Westinghouse Owners Group Emergency Response Guidelines (WOG ERG). During this revision, with the help of the engineering organization and the computer aided design (CAD) process, numerous set points were changed, calculations made, and appropriate modifications to the EOP flowcharts accomplished. Additionally, the licensee was using a consulting firm to develop a detailed basis document to encompass the overall EOP generation process.

The team walked down the Salem training simulator and discussed training issues with Salem training personnel. This review indicated that the simulator was being maintained in close fidelity to the actual Unit 2 control room via an annual review process. Databases of hardware and procedural fidelity issues were used to manage the program. Additionally, during crew training on the simulator, the training instructors were emphasizing managements' expectations for control room demeanor and conduct of operations. The training instructors discussed some programmatic improvements planned for the next training cycle, including the use of instructor-facilitated self-assessment techniques by the crews.

The team determined that normal NRC inspection effort is warranted in this area. The team recommends that the inspection effort focus on the EOP upgrade to incorporate the WOG ERG Revision 1B, the program for reducing equipment on the unavailable equipment log, and the program for ensuring a high standard of conduct of operations.

2.4 Programs and Procedures

The team's historical review indicated that, although the licensee's procedure upgrade program had been completed, procedural adequacy and usage may still be a concern.

During the site visit the team reviewed portions of the licensee's procedure upgrade program (PUP), interviewed procedure maintenance group (PMG) personnel, and reviewed a representative sample of normal operating procedures and their use, as well as associated administrative documents and computerized systems established to standardize the composition and content of procedures. The team determined that in general, the PUP had resulted in the removal of unnecessary information and enhanced procedure clarity from operational procedures. Most operators appeared comfortable with existing procedures, but several operators considered that certain procedures were still overly detailed.

Based on the historical information and the site observations, the team determined that the PUP was officially completed in August 1993, with a considerable backlog of requests for procedure revisions still outstanding. The PMG inherited this backlog. Because of increased requests for procedure revisions associated with emergent work activities, design changes, and an increased sensitivity to procedure quality, the licensee had not been able to achieve its performance goal of reducing the backlog to a point where new procedure revision requests can be turned around in 1 to 3 months.

The PMG did not have a formalized method for assessing the quality of the improvements to procedures resulting from the PUP and current procedure revisions. However, the team did review the quality index process that was performed at the end of the PUP and the 1994 midyear quality assessment performed by the PMG which indicated that procedure quality had improved. Based on the year-to-date efforts, the PMG had not adapted these indicators as a way of trending the quality of the operating procedures over time. The use of the computer program "PRONET" and the PMG procedure writers training program provided a positive approach to maintaining standardization of procedure upgrades and modifications after the forthcoming decentralization of the group's function to each department.

The team determined that normal NRC inspection effort is warranted in this area. The team recommends that the inspection effort focus on the effectiveness of the PMG activities and the program to ensure the high quality of operating procedures.

3.0 ENGINEERING

Current engineering design work, programs, and procedures were determined to be acceptable, but engineering has not demonstrated the ability to proactively seek out and correct system and component deficiencies before they lead to increasingly challenging plant events. For example, longstanding problems with the CW system, rod position indication, and excessive reactor cooldown transients are only recently coming to closure. In addition, engineering work priorities do not seem to be determined by the needs of the plant, and errors made during the original plant design and during recent vendor engineered design modifications continue to challenge plant operations. Although 43 configuration baseline documents (CBDs) have been issued, use and training on the CBDs within engineering was not always effective. However, the quality of recently performed design engineering work appeared to be good, as did the general engineering programs and procedures.

3.1 Safety Focus and Management Involvement

Safety focus within engineering was not always apparent, as indicated by an "Engineering Critical Issues List" which does not match the plant's critical issues list and was not prioritized by safety significance. For example, none of the items currently being tracked by the plant as operator workarounds made the critical issues list. The number one priority on the list was reducing the engineering discrepancy (DEF) backlog, mainly due to the large number of open DEFs. Additionally, there was evidence that design engineering is oftentimes not involved in early stages of problem identification and resolution. Although system engineers were routinely seen following work in the plant, they are not part of the engineering organization and often have limited contact with design engineers except for highly visible problems, such as marsh grass intrusion in the circulating water system.

Senior nuclear engineering management has communicated its expectations well, but the communication of management expectations throughout the engineering organization was not focused. For example, the number one objective for nuclear engineering in 1994 was to improve the plant safety and reliability by accurately interpreting, maintaining, and modifying plant design and licensing bases, but this objective was not mentioned within design engineering. Once again, reducing the DEF backlog was a highly placed objective for both departments.

The engineering staff appears to be stable with reliance on contractors decreasing. For example, the current 70-percent rate of contracted engineering is expected to decrease to 62 percent by 1996. Internal engineering evaluations used by the plant for operability determinations were found to be acceptable.

The team determined that normal inspection is warranted in this area. The team recommends that the inspection effort focus on evaluating design engineering work priorities and the interaction between system engineering and design engineering.

3.2 Problem Identification and Resolution

Engineering has not demonstrated the ability to identify and resolve problems at an early stage. Several significant issues have become more troublesome to plant operation, and engineering has not provided effective solutions. Although progress has recently been made on some issues, this progress was oftentimes stimulated by plant events. Additionally, many of the proposed solutions have yet to be proven. Root-cause analyses in some cases were off target. Weaknesses in the licensee's resolution of longstanding problems are identified below:

- Circulating water (CW) system - Problems with the CW system have been going on since 1991. To date, 6 of 10 projects scheduled for the CW system have been completed. In the next outage on Unit 2, the trash rakes are scheduled to be replaced with rakes better designed to clean the trash racks; the speed of the traveling screens will be doubled, doubling the area that they can protect against grass intrusion; and electrical upgrades to the switchyard and CW substations will be completed. The effectiveness of these modifications is unproven.

  In addition to the modifications, Salem also completed two studies relative to CW, "Salem Detritus Characterization," dated July 29, 1994, and "Predictive Modeling of Debris Loads at Salem Generating Station," dated August 5, 1994. These studies will enable the station to predict when marsh grass accumulation will be at its highest. These studies appear to be good; however, they appear to be a direct result of the April 1994 grass intrusion event.

- Analog rod position indicator (APRI) system - Problems with the APRI system still exist. Problems with APRI drift have been the subject of numerous license event reports (LERs) and engineering has been pursuing a direct replacement for the existing system with the nuclear steam supply system (NSSS) supplier.

- Boric acid tank (BAST) - Longstanding level indication problems with the BAST were recently solved when it was discovered that filling an empty cold tank with concentrated boron was causing plugging of the tank bubbler tube. Since the tank was empty, the heaters were not on and the 12-percent boron solution crystallized and plugged the bubbler tube. Engineering had previously issued a modification to change the boron concentration to 4 percent, but the boron concentration was not the true root cause of this problem.

- Reactor coolant system - Excessive cooldown transients remain a problem pending implementation of EOP changes. The transients were originally thought to be a problem with leakage on the secondary side and two DCPs to correct leakage on the secondary side by using a block valve and time delays were implemented. These modifications quantified the leakage as minor but did not solve the problem.

  During troubleshooting on unit startup and through use of the computer program "RETRAN", developed by the nuclear fuels department to model the Salem plants, engineering has developed the theory that running auxiliary feedwater (AFW) back sooner after a plant trip would greatly reduce the cooldown transient. This solution has not been proven to date; however, recent runs of the RETRAN program show excellent results. The plant is currently pursuing a change to the EOPs relative to AFW operation after a plant trip.

Engineering exhibited good performance in its prioritization of the DEF backlog using probabilistic risk assessment (PRA) techniques. Engineering was responsive to items identified via the operating experience feedback program, and there was no backlog of operational experience items.

The team determined that increased inspection effort should be focused in this area. The team recommends that the inspection effort focus on ensuring the four issues discussed above have been adequately resolved and on the timely identification and resolution of new issues.

3.3 Understanding of Design

The large number of events, licensee event reports (LERs), and recurring problems attributed to a lack of the understanding of the plant design does not appear to be the result of any single generic engineering weakness. Rather, the problems seem to have been caused by a combination of original plant design deficiencies, design deficiencies made during plant modifications, and an occasional lack of understanding of the original design specifics. Following are examples of these problems:

- The 1992 augmented inspection team (AIT) for the loss of the control room annunciators determined that design deficiencies made by a vendor during design and installation of this modification in 1992 allowed an operator to lock up the annunciator system from a remote terminal. The design of the system was inadequate in not addressing all failure modes or the effects of the software. In addition, the licensee did not fully understand the system design because they apparently had not been adequately involved in the design of the system.

- In May of 1993 an unplanned rod motion event occurred. Contrary to the design basis in the final safety analysis report, a single failure of one slave cycler decoder card of one rod cluster control assembly (RCCA) in conjunction with a rod motion command signal caused an unplanned outward motion of a rod. The potential for this problem had existed since the plant was originally designed and built.

- An LER stated that, during the original design and construction, insufficient margin had been specified between the overvoltage protection setpoint and normal electrohydraulic control (EHC) power supply voltage, resulting in the EHC DC control power failure and turbine/reactor trip on February 10, 1994. The value used, 17.3 volts, was less than the value specified by the power supply manufacturer of 115 percent of power supply voltage plus 1 volt (>18 volts).

- During service water piping upgrade work on the Unit 2 emergency diesel generators (EDGs) in 1993, the licensee discovered that the setpoint for the differential pressure coolers which modulate service water flow to the EDG jacket water coolers and lube oil coolers was incorrect. The setpoint had mistakenly been believed to be the manufacturer's value for both coolers in series; however, the manufacturer had specified the value for each cooler, not the total pressure drop across both coolers in series. This error caused an approximate 16-percent reduction in the 700-gallon-per-minute design flow rate and resulted in the EDGs being operable only if service water temperatures remained below 60 °F.

- The electrical distribution system functional inspection (EDSFI) conducted by the NRC in 1993 found that the 30,000-gallon diesel fuel storage tank could not supply one diesel with enough fuel to run it for 7 days at full load.

- The EDSFI conducted by the NRC in 1993 found that the Unit 2 EDG combustion air exhaust pipe and intake louvers were unprotected against tornado-generated missiles and unable to withstand the effects of these missiles.

Salem currently has 43 configuration baseline documents (CBDs), and these documents are referenced as a possible design input in the DCP process. The CBDs were found to be of good quality and readily retrievable. CBD training is provided to design engineers but the training does not include recent events in which the plant's design was a factor.

During the assessment, the team reviewed an engineering collegial self-assessment of the Configuration Baseline Document Project No. SA-94-0002P. This assessment found that the CBDs were used by both design engineering and contractors, but not as much as suggested by the design engineering procedures, and that technical department personnel, in general, did not find the CBDs useful for their work. The assessment also recommended that engineers reviewing the CBDs should be held accountable for the quality and timeliness of their reviews and that this goal could be accomplished either by stronger emphasis by management or by additional training.

The team determined that normal inspection is warranted in this area. The team recommends that the inspection effort focus on the licensee's oversight of and involvement in modifications designed or installed by vendors and on the use of, and training on, the CBDs.

3.4 <u>Quality of Engineering Work</u>

During the assessment, the team reviewed portions of recently completed mechanical, electrical, and instrumentation and control design change packages (DCPs) and one in-process DCP. The DCPs chosen involved recurring and longstanding corrective action problems. The following packages were reviewed:

- 1EC-3254, "Boric Acid Concentration Reduction Modification"
- 1SC-2269, "Salem Electrical Upgrade Project"
- 2EC-3286, "Diesel Generator Combustion Air"
- 1EC-3170, "Replace Containment Isolation Valves"
- 1EC-3270, "Overhead Annunciators"

The quality of the modification packages and the 10 CFR 50.59 safety reviews was good. Work instructions for installation were generally good, and the in-process testing instructions for the annunciator upgrade modification were excellent. Drawing changes for the sample of modifications were verified to be accurate using the data management subsystem computer system, which maintains the most current drawings and is user friendly.

The design engineers and system engineers communicated well about the circulating water and analog rod position indication systems; however, except for these highly visible systems, good communication did not appear to be the norm. During a plant walkdown, the team observed contractor personnel attempting to route cables into an energized control panel. The contractors were removing the potting compound on the bottom of panels nos. 1RC-11, -13, and -14 during the implementation of DCP 1EC-3298, "Primary Water Oxygen Reduction Modification." The work description in the DCP did not adequately reflect the job, and the work details had not been communicated to the Unit 1 work control center nor to the senior operations shift supervisor, creating the potential for a reactor trip and personnel safety hazard.

There have been instances in the past of equipment being replaced without proper safety reviews or work orders. Training for new engineering personnel and retraining for existing personnel was acceptable, the one exception being the weak CBD training previously noted.

The team determined that normal inspection effort is warranted in this area. The team recommends that the inspection effort be focused on engineering's control of work activities and communication of DCP work details to the plant staff.

3.5 Programs and Procedures

The team reviewed Salem's design engineering program procedures as outlined by NC.NA-AP.ZZ-0008(Q), "Control of Design and Configuration Change, Tests and Experiments." The procedures appeared to be comprehensive and complete. The quality was judged to be good.

The team also reviewed the procedures for scoping, evaluating, and prioritizing projects. The procedures for project scope proposals, project evaluation packages, and the nuclear department resource allocation process (NDRAP) were acceptable. Prioritization of engineering projects using NDRAP was good, and the more important projects appeared to receive the correct priorities. The team verified that the performance indicator relative to the NDRAP process (60 percent or greater receiving high priority) was accurate. In addition, the team noted that NDRAP will be the subject of an upcoming engineering collegial self-assessment.

The licensee is just beginning to use PRA in the design process. The licensee plans on updating the PRA every other refueling outage. The current plan is to review all new DCPs and project requests against the PRA to determine the effect on core damage probability. If, after review, an increase in core damage frequency is found, the DCP sponsor will be notified and requested to consider another option. Results will be reported and used to update the PRA. The inservice testing and inservice inspection programs appear to be functioning adequately. Procedures were found to be thorough and accurate.

The team determined that reduced inspection effort is warranted in this area.

4.0 MAINTENANCE

Significant weaknesses were identified in both maintenance programs and in their implementation. These weaknesses included an overreliance on generic troubleshooting procedures, ineffective use of the procedure feedback process, inadequate post-maintenance testing training, the inexperience of backshift personnel, and procedural adequacy and adherence concerns. The team also expressed concern regarding the control and oversight of the numerous groups and organizations that perform maintenance and modification work on site. The maintenance organization did a good job at prioritizing work, disseminating operating experience feedback information, identifying equipment problems, and general plant housekeeping.

The team observed both emergent and ongoing maintenance activities, interviewed maintenance personnel, conducted several plant tours, attended selected meetings, and reviewed selected statistical data to determine the effectiveness of the Salem maintenance activities. The team observed the following maintenance activities:

- Replacement of the mechanical seal on the no. 13 condensate pump in accordance with Work Order (WO) 940820047, Activity 01, and Procedure SC.MD-PM.CN-0005(Q), Revision 2, "Condensate Pump Replacement, Mechanical Seal Inspection/Replacement."

- Preventive maintenance (PM) on circuit breaker 2A164 for the #21 switchgear room supply fan motor circuit breaker in accordance with WO 941014001, Activity 01, and Procedures SC.MD-ST.230-0003(Q), Revision 4, "230 and 460 volt ITE K Series Breaker PM," and SC.MD-ST.230-0001(Q), Revision 2, "230 and 460 volt ITE K Series Breaker Overload Test."

- Replacement of the motor on the no. 21 turbine auxiliary cooling pump in accordance with WO 940822167, Activity 04.

- Troubleshooting the failure on the EDG annunciator panel in accordance with WO 940819109, Activity 01, and Procedure SC.IC-GP.ZZ-0006(Q), Revision 7, "Controls Equipment - Troubleshooting."

- Troubleshooting the rod control system rod stepping anomaly in accordance with WO 940811197, Activity 01, and Procedure SC.IC-GP.ZZ-0006(Q).

- Troubleshooting and replacement of the governor on EDG 1A in accordance with WO 940816066, Activity 07; WO 940819136, Activity 01; and WO 940819111, Activity 01, and Procedures SC.IC-GP.ZZ-0006(Q), Revision 7, and SC.MD-CM.DG-0006, Revision 1, "Diesel Generator Speed/Load Control System Alignment."

- Troubleshooting and repair of an inoperable annunciator on the 2C1 125 VDC battery charger in accordance with WO 940822178, Activity 01, and Procedures SC.IC-GP.ZZ-0006(Q), Revision 7, and SC.MD-ST.125-0001(Q), Revision 7, "Preventative Maintenance and 18 Month Surveillance of 125 Volt Battery Chargers."

4.1 Safety Focus/Management Involvement

It appears that management has a proper safety focus in prioritizing maintenance activities. The team attended a plan-of-the-day (POD) meeting and a work planning meeting to assess the licensee's methods of scheduling and prioritizing maintenance activities. From these meetings and from a review of the daily and weekly planning activities, the team concluded that production needs were not taking priority over safety.

The team noted that management has made a good effort to reduce both the corrective maintenance backlog and the number of overdue PM activities. However, the licensee's efforts to identify problems in the plant have greatly increased the amount of emergent work. This increase has lengthened the time it takes to return equipment to service. The team noted that the licensee was taking positive actions (e.g., through the use of the work planning meetings) to ensure that this emergent work did not adversely impact scheduled work. The licensee considered system availability in planning maintenance activities and is currently developing a method of using PRA in scheduling and planning maintenance activities.

The team observed the pre-job briefing for testing the governor on the 1A EDG after its replacement. The team considered this briefing to be comprehensive, however, it was noted that mechanical maintenance personnel were not involved in this briefing. While they were informed of the briefing results later by their supervisors, their absence from the briefing reduced the effectiveness of the briefing.

Supervisory personnel were observed monitoring work activities; however, the oversight was not always effective, as evidenced by an incorrect procedure in the field during the mechanical seal replacement on the no. 13 condensate pump. In reviewing this work package, supervisors failed to notice the incorrect procedure. Management was involved in decision making, as evidenced by maintenance personnel conferring with their supervisors when problems were identified.

Maintenance department staffing is relatively stable, with an increase in staffing planned due to unitization of the plant organization. The team noted that maintenance personnel, supervisory maintenance personnel, and maintenance planners assigned to the back shifts were generally the least experienced personnel. The team concluded that, because the personnel and technical support available on these back shifts is limited, the staffing of the back shift with the least experienced personnel may be inappropriate. Coordination between the maintenance department and other departments was effective, especially between the maintenance department and the system engineers.

During plant tours, the team observed several temporary modifications (T-Mods) installed in the field. The team verified that these T-Mods were current and that the licensee was tracking the modifications to ensure that they were intact and would be properly dispositioned. The team noted that the T-Mods were increasing but concluded that this increase was not excessive and continued to be manageable.

The team determined that normal NRC inspection effort in this area is warranted. The team recommends that the inspection effort focus on licensee planning activities and on management oversight of maintenance activities, including the back shifts to assure that field supervision is effective and that activities are being conducted by qualified personnel.

4.2 Problem Identification/Problem Resolution

The licensee uses a process called the equipment malfunction identification system (EMIS) to identify equipment problems. The licensee recently trained its personnel to be particularly observant of such problems and to identify them through the EMIS. As a result of this activity, the team noted a large number of EMIS tags throughout the plant. The majority of these tags were hung within the last 3 months. Although the team considered the EMIS to be an effective way of identifying equipment problems, the team noticed some degraded equipment without EMIS tags. In one instance, an EMIS tag was hung on the equipment but did not get entered into the maintenance tracking system.

Another process used by maintenance personnel to identify problems is the feedback forms that are a part of the WO planning sheets. While the purpose of this feedback process is to identify problems that occur during a maintenance activity, the team found instances in which this process was not being implemented. During interviews with field maintenance personnel, the team discovered that they have a low regard for these forms and, as a result, usually do not complete them. The team also found that, when these forms were completed, the information did not always get back into the planning system to ensure that errors were corrected. In some instances, the initiator of the form did not get timely feedback as to resolution of the problem.

The maintenance department assesses its performance through supervision and use of the planning feedback process. The team considered the aggressiveness of the assessment to be lacking, especially considering the problems with implementation of the planning feedback process.

With regard to problem resolution, the licensee's performance indicators showed that the Salem station has a considerably higher recurrent equipment failure rate than that of similar plants. The team considered the continuing recurrent equipment failures to be indicative of the licensee's inability to resolve longstanding equipment and system deficiencies. Examples of these longstanding deficiencies are the problems with the radiation monitoring system, the rod control system, the analog rod position indication system, and the main feedwater controllers.

The team noted that the licensee has an excellent system to address external organization findings through the operational experience feedback (OEF) program. An OEF meeting is conducted weekly to identify the issues and assign responsibility. The team attended one of these meetings to observe implementation of the program. The team also reviewed various OEF findings and verified that these findings were tracked and properly closed.

The team determined that normal NRC inspection effort in this area is warranted. The team recommends that the inspection effort focus on the licensee's control of emergent work activities, implementation of the maintenance planning feedback process, and resolution of longstanding equipment problems.

4.3 Material Condition

Plant management realized in 1990 that the plant had material condition problems and as a result developed a Salem Material Condition Study Document. After developing this document, the licensee established the Salem Material Condition Revitalization Project. The goal of this project was to resolve the discrepancies identified in the study document. The team noted that this project is scheduled to be completed by approximately June 1995.

During plant tours, the team noted that the plant material condition appears to be good; however, the team did find some evidence of degraded conditions. A tour of the service water intake structure revealed holes in the traveling screen fiberglass covers, corrosion on large bore piping, and some areas of poor housekeeping. The residual heat removal pump rooms were entirely roped off because previous valve and piping leaks had contaminated insulation. The team also noted that four of eight atmospheric relief valves were leaking by their seat and that balance-of-plant equipment had some minor leaks. The continuing recurrent equipment problems have also contributed to a decline in the material condition of the plant. The team noted that some of these failures have resulted in plant safety system challenges and plant transients.

The licensee has reduced the number of control room annunciators out of service. The team examined the status of out-of-service annunciators and found that the licensee's attempts at keeping this number low have been effective.

According to the NPRDS database, the Salem station has more recurrent equipment failures than the average for similar plants. However, it appears that the total equipment failure rate at the Salem station is below the average for similar peer plants in the same NPRDS data base. Plant systems and components in which degraded material conditions persist include the radiation-monitoring system and the main feedwater controllers. The team noted that these issues are being addressed either by special projects or as a part of the revitalization project.

The team determined that normal NRC inspection effort in this area is warranted. The team recommends that the inspection effort focus on the completion of the revitalization project and of other ongoing plant upgrade projects such as the service water system upgrade.

4.4 Quality of Maintenance Work

The team noted that the licensee's practice of developing multiple activities for each WO was cumbersome. For example, a single WO to perform a specific job might have an activity assigned to mechanical maintenance, another to controls maintenance, and another to post-maintenance testing and retesting. Each of these activities is distinct, and field personnel usually do not know how one activity affects or is related to another. However, the end of the work process was appropriately coordinated.

The licensee has also had a history of problems associated with troubleshooting activities. Although these problems appear to have decreased slightly, they continue to exist. The licensee's practice of using multiple copies of the troubleshooting procedure to perform a single troubleshooting activity hampered maintenance personnel in following the job progress. The licensee also appears to rely excessively on the troubleshooting procedure to perform repetitive maintenance tasks, in lieu of developing procedures to accomplish these tasks (e.g., the replacement of battery charger components that have a limited life).

While observing maintenance activities, the team noted instances of personnel errors, a failure to follow procedures, and excessive reliance upon "skill of the trade." The team noted that the control of measuring and testing equipment was adequate. The team also noted that interdepartmental communication was good; however, there was some evidence that supervisors did not communicate effectively with workers in the field. The Salem station has had a history of personnel errors, and there are indications that the error rate is not decreasing. The following examples are indicative of the above concerns:

- The licensee uses turnover sheets to ensure that oncoming shifts are aware of the status of the work on the job they will be doing. Although in general the use of these turnover sheets appeared to be effective, the team observed one instance, associated with the replacement of a condensate pump seal in accordance with WO 940820047, in which the turnover sheet gave ambiguous instructions as to which one of the three mechanical seals left at the work site was to be installed. The team discussed this observation with the field supervisor. The supervisor acknowledged the team's observation and agreed that the information given to the oncoming shift did not meet the licensee's expectations regarding turnover sheets and component control in the field.

- While observing the troubleshooting activity on the 2C1 battery charger associated with WO 940822178, the team observed that the procedure prerequisite check-off list had not been completed even though the maintenance technician was already performing subsequent sections of the troubleshooting procedure. When the team asked the technician why the prerequisites were not completed, the technician responded that the prerequisites had been completed and that he had neglected to sign off the check-off list steps as required. The technician then stopped the troubleshooting activities and completed the check-off list. Not completing the prerequisite list before beginning the rest of the procedure was considered an example of a failure to follow the procedure.

  This maintenance activity also involved the replacement of defective parts as necessary. As the maintenance technicians were preparing to install new parts, the team noted that one of these parts was designated as non-safety-related. The team questioned the technicians regarding this part. The technicians responded that the part matched the part number listed in the bill of materials (BOM) and that they were trained to install a part as long as it matched the part number in the BOM. The team discussed this observation further with senior maintenance management personnel. As the result of this discussion, the licensee determined that the installed part had not been properly qualified.

- While observing the work activity involved with disassembling, cleaning, and adjusting a circuit breaker in accordance with WO 941014001, the team noted that a maintenance technician on a back shift failed to notice that the breaker was slow in closing after the PM was performed. The day shift technician noticed the slow closing and discussed it with his supervision. As a result, it was decided that the breaker should again be disassembled. The team noted, however, that the steps that had to be reperformed were not checked off in the procedure when they were reperformed. In addition, the team noted that the controls technician had apparently not been trained on the function of the breaker pickup point and how that relates to the design function of the breaker.

- During maintenance activities associated with the no. 13 condensate pump mechanical seal replacement performed in accordance with WO 940820047, the team observed that maintenance procedure MN6, "Turbo-Star Mechanical Seals and Chesterton 123 Mechanical Seal Installation/Rebuilding," was included in the work package. The team noted that the mechanical seal being installed during this activity was a Chesterton 222 and discussed this observation with maintenance personnel to determine the reason for using procedure MN6. As the result of this discussion, the licensee determined that procedure MN6 was not the correct procedure for this job. The maintenance planner, supervisor, and technician did not recognize that the MN6 procedure was incorrect for the seal that was to be installed.

  The team later determined that a senior licensee manager had previously noticed the inclusion of the incorrect procedure, but the manager's observation apparently was not properly communicated within the maintenance organization, since the procedure was still part of the work package.

- During a walkdown to verify that the equipment clearance program was properly implemented, the team found a clearance (blocking) tag that was no longer attached to the component requiring blocking. The component, fire protection valve FP-141 (hydrant 092-117), was located inside a curb box. The blocking tag had been installed on the curb box because the valve was located approximately 5 feet below ground and was normally operated via a removable valve reach rod. Site services maintenance personnel excavated around the valve and removed the curb box to allow access to the valve. These personnel did not, however, remove the blocking tag from the curb box and replace it on valve FD-141. These personnel did not realize that removal of the curb box with a blocking tag attached was inappropriate. The licensee issued IR 94-236 as the result of this event.

The team determined that increased NRC inspection effort in this area is warranted. The team recommends that the inspection effort focus on the implementation of maintenance activities, including the maintenance planning process, with an emphasis on troubleshooting activities and procedural adherence.

4.5 Programs And Procedures

The licensee completed a procedures upgrade plan (PUP) in 1993. The PUP involved both operations and maintenance procedures. Although the PUP has been completed, the team noted that procedure adequacy continues to be a problem, apparently because a number of procedures have not been upgraded and because the PUP was not always effective. For example, although an excellent troubleshooting procedure has been developed and implemented in the controls area, a similar procedure developed for the mechanical maintenance area has not been implemented. As discussed in Section 4.4 of this report, it appears that the licensee relies too much on the troubleshooting procedure to resolve maintenance problems, especially recurrent ones. The licensee has made this procedure a type of catch-all procedure. The team found no evidence that the licensee has been developing procedures to address recurring maintenance problems. The following activities observed by the team illustrate procedure adequacy and upgrade problems:

- In reviewing the work package associated with WO 940822178 that involved troubleshooting and replacement of components in the 2C1 battery charger, the team noted that the troubleshooting procedure was being used to replace and initially test the charger. The team noted that the troubleshooting procedure referenced engineering instructions that were needed to provide the initial setup of the charger after the component replacement and before the charger load test (which was to be conducted in accordance with the PM procedure). The replacement of these components was not unique, and from discussions with licensee personnel, the team determined that this type of replacement and testing had been performed in the past. Even though similar components had failed in the past and required replacement, the licensee had not yet developed a procedure for this type of replacement and initial testing. After reviewing this issue further, the team found that procedure revision requests to incorporate these engineering instructions into approved procedures were issued twice, on July 15, 1992, and on May 6, 1994. The procedures maintenance group, the group that was responsible for processing such changes, did not process these changes because of an excessive procedure change backlog.

- After the installation of the 1A diesel generator mechanical and electrical governor, the team observed the performance of the diesel generator speed/load control system alignment procedure. While performing the procedure, the licensee had to issue an on-the-spot change (OTSC) to the procedure because the procedure steps were out of order, preventing the test from being properly performed. The OTSC was needed to allow the electronic governor to be adjusted so that it did not interfere with the adjustment of the mechanical governor. The team discussed this problem with the licensee and determined that, although this procedure had been used in the past, the procedure was apparently not corrected to allow proper adjustment of the mechanical governor.

- The licensee categorizes its maintenance procedures as Category 1 or 2. Category 1 procedures must be followed step-by-step at the work site, while category 2 procedures are required to be at the job site but not specifically open and followed step-by-step. While observing the performance of a PM on a non-safety-related breaker in accordance with WO 941014001, the team observed that the procedure in use was a

Category 2 procedure. The team noted that this same procedure was used to perform Pms on safety-related breakers. In addition, the team noted that there were no provisions in the procedure for quality checks for significant error-prone steps such as the breaker mechanism reassembly. The team further noted that the procedure contained no acceptance criterion for setting the long-time pickup point on the breaker. The team considered the adequacy of this procedure to be questionable because of the use of a Category 2 procedure for maintenance on safety-related equipment, the lack of appropriate acceptance criteria, and the lack of quality check points.

The team noted that the performance of maintenance activities was controlled by the maintenance planning process. In this process, maintenance planners develop the WO. The WO specified the work to be performed and included the procedures to be used, the BOM, the post-maintenance test (PMT) requirements, and the operability retest requirements. Although the planning program appeared to be developing well, the implementation of this program has been ineffective. Specifically, the team identified weaknesses in the use of the feedback process and in the specification of post-maintenance testing requirements. The team attributed these weaknesses to the inadequacy of the controlling procedures for the planning process, the inexperience of the planning staff, and poor training of planners in PMT and retesting requirements. In several instances, the team found that maintenance planners failed to specify appropriate PMT requirements, but instead gave generic instructions such as "Operations Perform Appropriate Retest." Interviews with maintenance planners and a review of the applicable PMT procedures also indicated uncertainty regarding maintenance planners' responsibility in specifying PMT requirements.

Although plant management stated the intention to improve procedure adequacy and adherence, this intention has not been effectively communicated to the working staff in the field. As a result, station management has not been effective in improving procedure adherence and in implementing the feedback process that is needed to correct deficient procedures.

The team determined that increased NRC inspection in this area is warranted. The team recommends that the inspection effort focus on procedure adequacy, the licensee's efforts to improve procedure adherence, and the use and adequacy of PMTs and retests.

5.0 PLANT SUPPORT

The initial document review phase of this assessment indicated that the licensee has implemented strong plant support programs. The strong performance was evidenced by good self assessment, lack of recurring problems, and good root cause assessment and timely correction of observed problems. Because of the absence of negative findings during the initial assessment, the team's onsite assessment of the plant support area was limited to certain specific activities. The team's observations of ongoing plant support activities did not identify any significant problems which reflected negatively on the quality of these activities.

5.1 Safety Focus and Management Involvement

The team noted that management safety focus was appropriate and that management and supervisors were involved in plant support activities. Their involvement was particularly evident for physical security activities during periods of increased personnel access processing and vehicle inspections. The team also observed that communications within the various plant support organizations were adequate.

The team determined that reduced NRC inspection effort is warranted in this area.

5.2 Problem Identification and Resolution

The emergency preparedness, fire protection, and health physics organizations appear to have implemented proactive and effective problem identification and resolution programs, as shown by a lack of recurring problems, and good root cause assessment of observed problems. The security organization has also demonstrated good problem identification through a comprehensive audit program. However, in the past, problem resolution of audit results have not been aggressively pursued. The team reviewed eight security audits that were conducted between May 12, 1993 (Audit QA 93-033), and August 5, 1994 (Audit SQA 94-0074). Of these eight audits, three had discrepancies that required corrective actions. The team's reviews noted that these discrepancies were properly addressed and resolved in a timely manner. In addition, the licensee has noted that detection and assessment aids have been deteriorating with age without timely resolution. The team noted that the deterioration was limited to certain equipment. The licensee is addressing this problem through a phased-in replacement of new equipment. The team observed that this replacement was on schedule. To verify the effectiveness of the existing assessment aids, the team observed activities at the secondary assessment station (SAS). All equipment provided appropriate surveillance capability.

The team determined that reduced NRC inspection effort is warranted in this area.

5.3 Quality of:

Emergency Preparedness

The initial document review indicated that the licensee had demonstrated a high level of competence during emergency preparedness training drills. Emergency response facilities (ERF) and equipment were effectively maintained, and ERF support and command and control were appropriately implemented. Both the document review and site observations indicated that the emergency preparedness program is of high quality and adequately maintained. The licensee demonstrated a high level of competence during the team's walkdown of the emergency facilities. The ERFs and associated equipment were effectively maintained, inventoried, and staged. However, two areas supporting the emergency operations facility exhibited poor housekeeping. Additionally, several copies of the EOP flowcharts in the technical support center were outdated. The emergency preparedness (EP) staff were observed to be very responsive in correcting identified problems and were knowledgeable of all aspects of the EP process.

The team determined that reduced NRC inspection effort is warranted in this area.

Fire Protection

Response to Appendix R issues has been acceptable. Performance of compensatory measures was good. Drill and fire protection scenario performance by the fire department was excellent. Training was very good. The team observed several fire doors held open by ventilation and a fire door propped open by a trash can; however, the team did not observe any other problems which reflected negatively on the quality of fire protection activities. The licensee is currently working on solutions to the ventilation system problems.

The team determined that reduced NRC inspection effort is warranted in this area.

Security

The team's observations of ongoing security activities indicate that the level of security was appropriate. Site security personnel performed well during personnel access and vehicle search activities. The team noted that, during high traffic periods, additional security personnel and supervision were stationed to assist with personnel access. Supervisors was also observed to be present during periods of increased vehicle search activity.

The team discussed with licensee personnel the resolution of the recent security events involving personnel access and vehicle searches. The team identified that the licensee did not consider these events to be isolated. The licensee is treating these events as a generic concern and showed evidence that their security contractor will be taking positive action in the form of additional audits and training. The team considered the actions being taken by the licensee to be responsive and conservative.

The team determined that reduced NRC inspection effort is warranted in this area.

Health Physics

The licensee has consistently performed health physics activities in a manner that demonstrates a high level of management expectation. These efforts are characterized by a good program for limiting radiation dose, good contamination controls, and good health physics training and qualification. The team's observations of ongoing site health physics activities did not identify any problems which reflected negatively on the quality of health physics activities.

The team determined that reduced NRC inspection effort is warranted in this area.

5.4 Programs and Procedures

The licensee has consistently implemented strong plant support programs characterized by good procedures. Few problems have been identified in the plant support areas, and the more significant problems have been identified and corrected by the licensee. The team's observations of ongoing plant support activities did not identify programs or procedures whose effectiveness was questionable.

The team determined that reduced NRC inspection effort is warranted in this area.

6.0 EXIT MEETING

On August 25, 1994, upon conclusion of the assessment, the team held a preliminary exit meeting with the licensee. At a final exit meeting on September 9, 1994, the team presented the final assessment results. The final exit meeting was open to the public. The following is a list of the principal attendees:

NRC

NAME	POSITION
J. White	Section Chief, Project Branch No. 2, DRP, Region I
C. Marschall	Salem Senior Resident Inspector
J. Jacobson	Inspection Team Leader, Special Inspection Branch, NRR
J. Wiggins	Deputy Director, Division of Reactor Safety, Region I
E. Wenzinger	Chief, Project Branch No. 2, DRP, Region I
R. Gallo	Chief, Special Inspection Branch, NRR

PSE&G

S. Miltenberger	Vice President & Chief Nuclear Officer
S. LaBruna	Vice President, Nuclear Engineering
J. Hagan	Vice President, Nuclear Operation & GM Salem Operations
F. Thomson	Manger, Licensing and Regulation
M. Morroni	Maintenance Manager, Controls
A. Orticelle	Maintenance Manager, Mechanical
P. Ott	Operating Engineer
T. Cellmer	Rad. Pro/Chemistry Manager
R. Griffith	Manager, Salem QA
C. Lambert	Manager, Nuclear Engineering Design

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