U. S. NUCLEAR REGULATORY COMMISSION

REGION I

Report: 50-354/96-80

License: DPR-57

Licensee: Public Service Electric and Gas Company

Facility: Hope Creek Nuclear Generating Station

Location: Hancocks Bridge, New Jersey

Inspection Period: February 12 - 28, 1996

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Areas Inspected: Review of the following areas: Management Programs, Independent Oversight, Self-Assessment, Operations, Maintenance and Surveillance, Engineering and Technical Support, prior to Hope Creek restart from the sixth refueling outage.

Results: Inspection results are summarized in the attached executive summary.

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EXECUTIVE SUMMARY

Readiness Assessment Team Inspection
Hope Creek Nuclear Generating Station

NRC Inspection Report No. 50-354/96-80

BACKGROUND

Recent Systematic Assessment of Licensee Performance(SALP) results for the Hope Creek station (June 20, 1993 to April 22, 1995) indicated a decline in performance from the Category 1 to Category 2 in Operations and Maintenance. This reflected increasing NRC awareness of, and concern with, degrading performance. Operators frequently had to cope with challenges to plant systems caused by repetitive equipment problems and personnel errors.

NRC concern was heightened because these conditions appeared similar to those observed at Salem. The effect of efforts to improve performance (i.e., significant changes in management and supervision, personnel evaluation, upgraded procedures and training, modification of plant systems and design, and organizational restructuring) had not yet resulted in observed positive performance improvement.

INSPECTION OBJECTIVE AND SCOPE

The NRC conducted the Readiness Assessment Team Inspection (RATI) with the objective of evaluating the readiness of the plant operators, hardware, and management programs to support a safe restart and continued operation of the Hope Creek Nuclear Generating Station. At the conclusion of the inspection the team provided NRC management their findings as to the readiness of the plant for restart.

The RATI consisted of eight inspectors from NRC Region I and NRC Headquarters. A State of New Jersey representative accompanied the team through portions of its activities. The majority of onsite inspection activities took place between February 12 and 28, 1996. The team conducted inspection activities during all shifts and weekends for a total of over 1000 hours of direct inspection.

OVERALL TEAM RESTART CONCLUSION

Overall, the team concluded based on the inspection findings that the licensee had adequate measures in place to ensure that issues that needed to be addressed prior to unit restart were identified and addressed and that adequate corrective action had been taken to address previously known problems.

IDENTIFIED RESTART ISSUES

The RATI identified three restart issues that required licensee resolution prior to plant restart. The issues identified were:

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- In the management program area - physical verification of primary containment penetration closure in lieu of previously performed administrative verification - identified during NRC review of the Technical Specification Surveillance Improvement Program (TSSIP). (Section 3.2.2)

- In the maintenance planning area - root cause determination and implementation of corrective actions for safety-related service water system (SWS) strainer failures - identified during NRC review of strainer maintenance. (Section 3.4.6)

- In the engineering area - improper installation of high energy line break isolation dampers needed to be corrected or analyzed to ensure that an unreviewed safety condition did not exist - identified during NRC review of engineering design change packages. (Section 3.5.2.1)

These issues collectively were an unresolved item and needed resolution prior to plant restart. Although the RATI did not subsequently impact the adequacy of your response to and closure of this item, the resident inspectors did so prior to the restart of the unit. Thus, closure of this item will be documented in a separate NRC inspection report. **(UNRESOLVED ITEM 96-80-01)**

MANAGEMENT PROGRAMS, INDEPENDENT OVERSIGHT, SELF-ASSESSMENT

The team concluded that an effective management team, corrective action program, and oversight function were in place to support a safe plant restart. The team based their conclusion on the following:

- The licensee satisfied the commitments outlined in the outage completion plan (OCP) and sufficient assurance of station readiness existed for a safe restart.

- The OCP was detailed, thorough, and provided appropriate oversight for activities necessary to support plant startup. The outage review committee (ORC) provided excellent oversight of outage activities.

- The corrective action program (CAP) was sufficiently established to identify and resolve plant deficiencies in a timely manner and was functioning acceptably. Personnel understood how to use the program and management expectations for its use. The program provided sufficient tracking of required actions for identified problems. Appropriate requirements were in place for the classification and timeliness of resolutions.

- The team noted several minor issues with the CAP regarding lack of feedback to the initiators and supervision, differing significance level guidance, and misunderstanding of the 30 day evaluation completion time. The team did not consider these significant from a restart viewpoint since the adequacy of corrective actions was not adversely affected.

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- Plant management and independent oversight staffing and qualification met the Technical Specification (TS) and Updated Final Safety Analysis Report (UFSAR) requirements. The team found minor organization and qualification discrepancies when comparing the actual organization with that described in UFSAR Chapters 13 and 17; however these discrepancies were not significant.

- Excessive overtime was not being used. The increased outage scope caused material receipt to be a resource constraint.

- QA provided an independent assessment of restart readiness to the station, which basically agreed with the departmental self-assessment conclusions, but also provided more detailed observations to support the conclusions.

OPERATIONS

The team concluded that operations programs, procedures and processes were in place and were adequate to implement and support a safe and controlled restart of the Hope Creek facility. The team based this conclusion on the following:

- Plant operators conducted operations safely, with an appropriate level of professionalism and knowledge, during the time that the team was on site and during continuous control room observations.

- By identifying a questionable standby liquid control (SLC) pump operability determination, the team confirmed the licensee's self-identified weakness in performing operability determinations. However, the licensee has put in place sufficient measures to ensure that more conservative operability determinations will be made with an increased level of management involvement in the future.

- The licensee's program for self-identification of plant deficiencies has improved substantially over the last year, but continued to evolve. Not performing detailed tracking and trending of the results of apparent causes of human performance and equipment degradation was a weakness in the program because performance trends could be missed.

- The licensee demonstrated adequate processes for configuration control of plant systems. There were no deficiencies in configuration control identified during walkdowns of several plant systems important to safety. Operations personnel were aware of system status that required entry into Limiting Conditions for Operation (LCOs) and effectively tracked systems that were in a degraded, but operable condition.

- Operations personnel were knowledgeable of operator workarounds, temporary modifications, and control room instrument deficiencies (DL-10) and had identified those items important to safe plant operations and restart considerations to upper levels of management through the

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weekly Wednesday night meetings and the ORC departmental readiness meetings.

- Operations department procedures were technically adequate to support plant restart and power operations, although there were a large number of minor revision requests for procedure upgrades outstanding at the time of restart.

- Operator requalification training was up to date with all crews undergoing upgraded recertification training. Adequate operator training had been, or was scheduled to be, conducted on plant modifications implemented during the refueling outage prior to plant restart. Specialized plant restart training for each operating crew was also scheduled to be conducted on the plant specific simulator prior to plant restart.

- The team identified the possibility that the SLC pumps had been inoperable because of air binding following inservice test (IST) performance. The team noted that since 1992 the SLC pumps, on several occasions, failed to develop their TS required flow during IST. The licensee changed the IST procedure to prevent the possibility of air binding. However, the team considered the possibility that the SLC pumps previously may not have been able to supply their TS required flowrate an unresolved item. **(UNRESOLVED ITEM 96-80-02)**

MAINTENANCE AND PLANNING

The team concluded overall that the planning and maintenance programs and processes were adequate to support safe restart and continued operation, based on the following:

- Safety-related maintenance observed, other than that completed on service water strainers, was completed properly, using approved procedures. The team did note several minor issues dealing with configuration control following maintenance and documentation of satisfactory completion of a TS required surveillance test when the recorded results did not satisfy the acceptance criteria.

- The maintenance and planning department functions were organized in an efficient manner providing for good planning and conduct of safety-related work. The work control process and the accompanying planning meeting functioned adequately to ensure that the station personnel were focusing on appropriate maintenance activities.

- The licensee planned changes in the planning and maintenance organization, after the completion of the outage, to address issues raised in the self-assessments to improve future work coordination and control. Review of the new process showed improvements in the prework review of work activities, possible reduction in backlog of non-safety

(EXECUTIVE SUMMARY CONTINUED)

significant items, and enhanced planning and scheduling process for normal work and LCO maintenance activities.

- Self-assessments conducted prior to startup indicated some areas for improvement and generally adequate corrective actions were taken.

- Through the self-assessment process, PSE&G identified problems with tracking of preventive maintenance(PM) task completion dates. The maintenance department adequately reviewed the backlogged PM tasks and selected appropriate completion times for safety-related Environmentally Qualified (EQ) and Non-EQ tasks.

- The team found that the controls in place for safety-related maintenance activities on the service water(SW) strainers were inadequate. In two examples the team identified that safety-related maintenance procedures were not used or did not provide adequate information for component assembly. The team considered that failure to follow the maintenance procedure for disassembly of the "A" SW strainer and failure of the procedure to provide instructions for installing the backwash arm to stub shaft pins constituted a violation of TS 6.8.1, which required that procedures be developed and implemented for safety-related maintenance activities. (VIOLATION 96-80-03) The failures to follow procedures during safety related work on the service water strainers and the lack of management knowledge that it was ongoing were significant, particularly in light of the significant actions taken to improve the plant staff's understanding of the expectations for procedure use.

ENGINEERING

The team concluded that the engineering staff, procedures, programs and processes were adequate to support a safe startup and continued operation. The team's conclusions were based on the following:

- Design Change Packages (DCPs) were of good quality, with sufficient documentation and justifications, and adequate installation instructions. The instance noted of difficulties related to installation instructions dated from a period in which PSE&G had identified that there were problems with the generation of DCPs.

- System readiness affirmations ensured that plant systems would be ready to support plant startup when the outage ended.

- The Nuclear Engineering Department was appropriately configured to meet the needs of completing the refueling outage and was effectively tracking, evaluating, and resolving the material deficiencies of plant equipment.

- Administrative procedures provided appropriate guidance for conducting engineering activities. In those cases where process changes were being implemented, revisions to the governing procedures were being made.

(EXECUTIVE SUMMARY CONTINUED)

- The Quality Assurance department was conducting well-focused reviews of engineering activities. The findings and conclusions were well developed and documented, and recommendations were included for enhancing the performance of the Nuclear Engineering Department.

- The team identified discrepancies in safety related battery electrolyte temperatures requirements between the UFSAR, the TS and design load calculations. Based on a review of surveillance procedure changes and an engineering evaluation the team did not have an operability or a restart concern. However, the team considered the resolution of this discrepancy an unresolved item. **(UNRESOLVED ITEM 96-80-04)**

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ATTACHMENTS

DETAILS

1.0 BACKGROUND

During the last systematic assessment of licensee performance (SALP) period (June 20, 1993 to April 22, 1995) the NRC rated the Public Service Electric And Gas (PSE&G) performance at Hope Creek as Category 2 for Operations, Maintenance and Engineering, and Category 1 for Plant Support. The SALP report indicated a decline in performance from the Category 1 level in both Operations and Maintenance areas and weaker performance in the Engineering area considering the expected trend described in the previous SALP report.

At the end of the last SALP period, an NRC special team inspection reviewed an April 5, 1995, accidental radioactive release, concluding that additional problems existed in engineering support of operations, as well as some previously unknown weaknesses in the plant support area. Since then, another NRC special team inspection reviewed a July 9, 1995, operational bypass of the shutdown cooling system. This inspection revealed some fundamental operator knowledge deficiencies regarding shutdown cooling operation, operator performance deficiencies regarding procedure adherence, and management oversight weaknesses regarding procedure adherence expectations and both internal and external communications of significant issues.

During the three months of operation prior to the sixth refueling outage (RFO 6), operators frequently coped with plant system challenges caused by repetitive equipment problems and personnel errors. The similarity of these conditions to those previously observed at the PSE&G's Salem station heightened NRC concerns about Hope Creek performance.

To address internal management and NRC concerns PSE&G developed the Hope Creek IMPACT plan in late 1995. The IMPACT plan, along with significant changes in plant management and supervision were designed to improve performance (i.e., personnel evaluation, upgraded procedures and training, modification of plant systems and design, and organizational restructuring). As RFO6 approached the NRC realized that the Hope Creek IMPACT plan, had not had significant time to cause performance improvements and that many of the expected improvements would not be effected until after restart.

During management meetings held between PSE&G and NRC at the beginning, and again, about halfway through RFO 6, Hope Creek management articulated their expectations for conducting a safe refueling outage through: additional management oversight of control room activities, especially during sensitive evolutions; screening of outstanding material deficiencies for possible repair during the outage; correction of procedural deficiencies, especially for operating procedures; continuation of the review of technical specification (TS) surveillance requirements (SRs) through the technical specification surveillance improvement program (TSSIP), as a result of frequent failures to implement SRs documented in 1995; implementation of improved operator training; and, verification and validation of the station systems and personnel readiness for safe return to power operations. The elements for these improvements were contained in the Hope Creek Outage Completion Plan, which was approved and forwarded to the NRC in January 1996.

The licensee submitted the Outage Completion Plan (OCP) to the NRC by letter dated January 12, 1996. As described in that letter, the outage completion plan consisted of a number of activities to ensure: (1) successful completion of refueling operations and other critical outage work, (2) identification and completion of the physical and programmatic work necessary to achieve a safe and reliable post-refueling outage number six (RFO 6) operating cycle, and (3) a safe and uneventful unit startup and power ascension to 100 percent power. The major activities in the outage completion plan included: (1) a work scope validation, (2) an operational readiness self-assessment, (3) an integrated ORC review of outage completion plan implementation, and (4) the startup and power ascension program. Each of these major elements is addressed in this report.

2.0 INSPECTION OBJECTIVE AND SCOPE

Region I performed a Readiness Assessment Team Inspection, using inspection module 93802, Operational Safety Team Inspection and others referenced therein, at Hope Creek since:

- No substantial change in plant performance had been demonstrated and effectiveness of the IMPACT plan changes remained to be seen.

- Hope Creek implemented a series of personnel and organizational changes in an effort to resolve a recent history of declining performance.

The RATI was performed to assess and confirm:

- PSE&G's ability to develop and implement effective corrective actions to improve Hope Creek performance and operate the facility in a safe manner.

- The adequacy of actions to correct a number of plant deficiencies by expanding the scope of RFO 6 and assure that all activities have been completed to support a safe restart of the plant.

The RATI reviewed the IMPACT plan and the OCP to develop screening criteria for the selection of appropriate areas for inspection.

The team assessed plant performance in the areas of Management Programs, Independent Oversight and Self-assessment; Operations; Maintenance and Planning; and Engineering.

3.0 INSPECTION FINDINGS

3.1 RESTART ISSUES

The RATI identified three issues, that the team concluded required resolution prior to plant restart. A brief description of each item is provided below, detailed findings regarding each restart issue are provided in the section of this report noted in parentheses.

- Physical verification of primary containment penetration closure in lieu previous administrative verification - identified during review of the TSSIP. (Section 3.2.2)

- Root cause determination and implementation of corrective actions for safety-related service water system (SWS) strainer failures - identified during review of strainer maintenance. (Section 3.4.6)

- The team found that improper installation of high energy line break isolation dampers needed to be corrected or analyzed to ensure that an unreviewed safety condition did not exist - identified during review of engineering design change packages. (Section 3.5.2.1)

Collectively, the team considered these restart issues represented an unresolved item. The NRC will review PSE&G corrective actions for these issues prior to restart. **(UNRESOLVED ITEM 96-80-01)**

3.2 MANAGEMENT PROGRAMS, INDEPENDENT OVERSIGHT, AND SELF-ASSESSMENT

3.2.1 Scope of Review

The team reviewed the licensee's management programs, and independent oversight and self-assessment activities to ensure that measures were in place to monitor, control, and oversee plant performance before, during, and after plant startup. The team reviewed licensee management use of these measures to ensure that:

- Adequate corrective actions had been taken addressing the root causes of previous problems at Hope Creek.

- The plant and personnel were prepared to conduct a safe and controlled reactor startup from the sixth refueling outage (RFO6).

The team reviewed: management direction, teamwork, and communications; independent oversight; the corrective action program; and the outage completion plan review - including the system readiness affirmations, departmental self-assessments, and department readiness affirmations.

3.2.2 Management Direction, Teamwork, and Communications

a. Scope

In the area of management goals and expectations, the team assessed the following: (1) the qualification of important management and oversight personnel and the use of and control of resources (human and equipment) during the outage; (2) the ability of the plant management team to effectively set priorities and direct the plant staff through meetings and interdepartmental teamwork; (3) the effectiveness of organizational communication at promoting plant staff understanding and implementation of management expectations, particularly in the area of procedural adherence; and (4) the effectiveness of the OCP at addressing issues and the transition to new work control processes based on the Impact Plan.

The team completed these assessments by performing numerous interviews and attending meetings regarding management issues. The individuals interviewed represented all levels of plant personnel, from the plant General Manager to the technicians and workers.

The team reviewed and discussed the implementation of the technical specification surveillance improvement program (TSSIP) with licensee personnel and management. Licensee management recognized that while some findings may still result after restart, the TSSIP process was charged with providing a quick review of TS surveillance requirements (SRs) required to be completed in Cold Shutdown to ensure that if continuing TSSIP reviews find an inadequately performed surveillance, that the plant would not necessarily have to be shut down to complete the test.

b. Findings

Staffing and Resources

The outage scope grew dramatically from the original plan. Originally, RFO 6 included about 5,000 activities. In excess of 7,500 activities were added to the scope of the outage. The team noted a decrease in the overall work backlog during the inspection period.

The team reviewed staffing and qualification for selected management and independent oversight positions as described in the technical specification (TS) and updated final safety analysis report (UFSAR) and found that all personnel either met the requirements or management had provided acceptable alternate means for achieving the necessary qualifications. The team identified one minor staffing issue. The onsite safety review group (SRG) engineer had resigned just prior to the inspection, leaving that group with one less than the required number of staff. The licensee selected an individual to act as the SRG engineer, until a permanent replacement could be selected.

Plant personnel did not work excessive amounts of overtime to support the refueling outage or restart. The PSE&G Nuclear Business Unit (NBU) stated expectation was that personnel should not work in excess of 60 hours per work-week. Operators maintained their normal 12-hour workday schedule. Some overtime was necessary to support critical path jobs; however, none of the personnel interviewed discussed any human resource limitations. The team reviewed a sample of maintenance personnel work schedules associated with emergent service water system (SWS) work during the inspection period and found no use of excessive overtime.

It appeared that the receipt of parts and materials was the major resource limitation during the outage. Much of this was attributed to late development of design change packages, due the increased outage scope and emergent work discovered during the outage.

Standards and Expectations

Licensee management used a variety of methods to communicate and reinforce their performance expectations to plant workers. For example: daily and weekly newsletters discussed items of current interest, prominently displayed posters outlined the management expectations, and departmental management conducted periodic tailgate meetings.

Based on interview results, the team found common understanding of management expectations in the areas of procedure adherence, problem identification, and safe restart of the plant. However, most individuals interviewed expressed that improved inter-departmental communications could have improved outage efficiency.

Through interviews and observations the team found a high degree of understanding of management expectations, especially regarding procedure adherence. However, the team identified some problems in the maintenance area regarding procedure adherence during safety-related service water system (SWS) work, as discussed in Section 3.4.6.

As part of the IMPACT plan the licensee continued to develop individual performance improvement plans including goals, as well as department and station improvement goals. The licensee expected to complete these organizational goals by April 1996.

Identification and Communication of Safety Issues

The team found that management relied on the corrective action program (CAP) as the method of identifying issues, reviewing their safety significance, prioritizing them for correction, and identifying any necessary corrective actions. (See Section 3.2.4 for additional information on this topic). Plant personnel used action requests (ARs) as the method of documenting issues/problems. ARs were graded based on significance with Level 1 being extremely significant and Level 4 being of minor concern.

The team overall found the CAP effective at identifying safety issues, communicating such information to appropriate NBU personnel for action, and tracking/trending timely completion of assigned actions.

The plant staff and management appeared to address emergent issues in a timely manner with appropriate safety focus. The work-it-now (WIN) team leader, an SRO, appropriately reviewed new action requests (ARs) for operability and the planning organization reviewed issues for appropriate scheduling of corrective maintenance or evaluation for additional analysis and corrective action.

A review of the recent NBU CAP Performance Indicator Report showed extensive trending activities. The report identified areas of weakness to senior management, including timeliness of evaluations and corrective action implementation.

Discussions with QA personnel revealed overall performance improvement with respect to problem identification and assignment of root cause evaluations. However, the CAP performance indicators showed much room for improvement as the program matured as discussed in section 3.5.6.2.

Intra- and Inter-Organizational Teamwork

The team observed communication and teamwork in several regularly scheduled interdepartmental meetings.

- Outage Review Committee

The team observed that the ORC conducted detailed meetings on issues concerning the outage scope and unit readiness for restart. Information and priorities developed in the ORC were accurately reflected to the plant staff and resulted in appropriate support for the outage completion goals. Plant management implemented the ORC as a new process during RF06 to allow the multi-disciplined review of outage scope additions, to set plant outage priorities, and to review the readiness of plant systems and departments for unit restart.

The ORC meeting attendees routinely included the plant general manager (chairman) and key members of the staff including management and staff from engineering, quality assurance, nuclear safety review, and licensing.

The team noted that system engineers were required to present a summary of their system readiness for restart to the ORC. The team found these presentations generally well done and that the ORC asked appropriately detailed probing questions to ensure the thoroughness of the engineer's review. While presenters were at times not sufficiently prepared, the committees exercised appropriate judgement, including rejecting the presentations until additional information was provided in order to support their decisions of system readiness.

The team did note one issue dealing with the ORC review of discrepancy evaluation forms (DEFs). An interview with a design engineering representative revealed the recent discovery of nine DEFs that had not been screened by the ORC to determine the possible need for additional corrective actions prior to restart. Of these nine DEFs, the team selected three for additional review. One detailed a review of design bases information and described a conflict between the battery temperatures for the 1E 125 and 250 volt batteries. (See Section 3.5.2.2 for additional discussion of the DEFs reviewed and the specifics of the battery issue). Following this, the ORC screened all of the DEFs and found no other issues warranting immediate corrective action.

- General Managers Morning/Staff Meeting

The team attended several General Manager morning meetings with department managers where the following items are discussed: operations department turnover sheet and agenda, review significance level 1 and 2 ARs and level 3

ARs requiring follow-up assessment of operability generated during the prior 24 hours, open CR Evaluations (CREV), CR Corrective Actions (CRCA), Incident Reports (IR) for the 7 day look-ahead, and LER status.

General managers staff meetings resulted in proper assignments for followup to significant plant problems that had emerged, as well as, adequate review of timeliness of any outstanding root cause evaluations and corrective action implementation. In addition, routine presentation of external operational experience feedback was also provided to senior plant management.

- Schedule and Planning Meetings

The team observed several Plan of the Day(POD) meetings and found them well run, with the necessary personnel available to make key decisions in a timely manner.

The priority and planning meetings effectively assessed progress made in the past 24 hours and established new priorities based on that progress. The planning department and plant management clearly made assignments during the meetings and frequently reinforced management expectations including stressing inter-departmental teamwork during significant efforts.

As was necessary, ad hoc planning meetings were held immediately after the routine planning meetings to discuss appropriate approaches for emerging significant issues.

Technical Specification Surveillance Improvement Program

The team concluded that to date, the TSSIP program was appropriately implementing the committed corrective action as described in LER 354/95-033. It was noted during review of the LER, that the overall program was not expected to be completed until the end of 1996. Further, additional licensee management focus to use TSSIP to assist the plant staff in assuring that technical specification surveillance requirements were met in support of startup, was determined to be a strength. The resultant findings by the TSSIP group ensured that: the technical specification procedure matrix was accurate; prior corrective actions committed to as a result of LERs, QA audits, or violation response were complete; and, that technical specification surveillance requirements that need to be performed in a shutdown condition were screened to provide further assurance that they had been implemented.

The team found that the process exceeded the requirements of Generic Letter 96-01, and as amended to support plant restart, provided adequate assurance that all surveillance requirements had a corresponding implementing procedure, and that activities needing the plant to be in Cold Shutdown were identified.

Primary Containment Closure Verification

During discussions of recent TSSIP findings, the team noted a potential problem with the method of performing the isolation verification for normally closed primary containment penetrations per TS SR 4.6.1.1.(b). The team noted that the licensee's verification program, described in Nuclear Department

Procedure NC.NA-AP.ZZ-0005 (Q) Rev. 6, "Station Operating Practices," dated February 4, 1996, allowed numerous methods of independent verification such as: hands on, or through observation of process variables or status/position indicators, as appropriate for radiation exposure savings. This procedure implied that hands on verification or at least observation of the local position indication were the preferred methods for manually operated valves. However, the procedure permitted use of status/position indication for verification, which by operations management interpretation included the frequent audit function of the TRIS data base that operations performs, including the actual performance of the containment verification TRIS review.

During this review the team identified inconsistency in the types of systems that required independent verification between Hope Creek and Salem. Attachment 11 to the verification procedure for Hope Creek did not recognize the primary containment boundary as a key system, while portions of the primary containment were listed at Salem. The team did not have a safety concern regarding this because many Hope Creek systems were part of the primary containment boundary, as opposed to a single system designation used for the key systems listed in the attachment. In addition, through discussions with operations management at Hope Creek, it was determined that Salem typically used hands on verification for containment boundary valves, which was different than the position status verification of TRIS employed at Hope Creek.

The team concluded that the verification requirements delineated in the administrative procedure ("Station Operating Practices") were appropriate. However, the team considered that the radiation exposure that would be received while verifying the closure of the penetrations inside the primary containment was minimal when compared to the additional level of assurance provided by a hands on verification. Therefore, the team considered completion of the verification a restart issue.

c. Conclusion

Plant management and independent oversight staffing and qualification met the TS and UFSAR requirements. Excessive overtime was not being used, however the increased outage length was stressful to the plant staff. The increased outage scope caused material receipt to be a resource constraint.

Licensee management established and reinforced personnel performance expectations. The plant staff generally had a common understanding of management expectations. Plant management developed a favorable atmosphere for problem identification, which provided a sound basis for restart and operations.

The ORC provided excellent oversight of committed activities per the OCP.

The team found inter-departmental communications acceptable during observation of numerous meetings such as the ORC, the General Manager's daily and staff meetings, the POD, and the planning emerging issues meetings.

The ORC and the emerging issues meeting proved very effective in reviewing and assessing the important plant issues and their significance in the aggregate, relative to system or departmental performance. During discussions with plant management, the team found that these meetings will probably be incorporated into normal station activities.

- **Restart Issue**

One restart item was identified regarding the need to complete hands-on verification of normally closed primary containment valves in lieu of the previous administrative verification. The licensee's subsequent resolution of the issue prior to restart of the unit was inspected by the resident inspectors, and will be documented in a separate NRC inspection report.

3.2.3 Independent Oversight

a. Scope

Quality Assurance/Nuclear Safety Review

The team assessed the effectiveness of the independent oversight provided by the quality assurance/nuclear safety review (QA/NSR) department through interviews, reviews of audit and surveillance reports, and observation of several QA meetings.

The team assessed the merit of the QA/NSR audit program, the ability of the QA organization to perform quality audits, and evaluated managers' actions to address these issues. Several personnel were interviewed regarding the independent oversight function implementation and conclusions.

The team reviewed the recent findings of the independent oversight groups and assessed the line organization's responsiveness to the concerns identified.

Additional special QA restart assessments and department readiness observations were reviewed by the team. These independent observations were discussed at the ORC meetings during the department readiness affirmation discussions.

Site Operation and Off-site Review Committees and the Nuclear Review Board

The team evaluated the effectiveness of the site operations review committee (SORC), the off-site safety review committee (OSR), and the nuclear review board (NRB) at conducting the TS required safety reviews.

The team assessed the effectiveness of these oversight committees by reviewing selected meeting minutes, observing several meetings, reviewing the applicable procedures, validating committee findings, and interviewing several committee members. The team evaluated the ability of these committees to concentrate on the appropriate issues, maintain an appropriate safety perspective, and to ensure these issues were addressed. Where required, the team also verified the qualifications of the committee members with respect to the applicable procedures and the TS and UFSAR.

b. Findings

Quality Assurance/Nuclear Safety Review

The qualifications of QA/NSR personnel met or exceed the TS and UFSAR requirements. QA/NSR personnel interviewed were very knowledgeable about the mission of the organization. Overall, the team assessed that communications were very good between QA and senior management and staff.

The QA/NSR organization appropriately used the CAP to identify conditions adverse to quality. In addition, to allow timely QA review of line management actions, QA findings required a separate status which ensured notification of the QA organization when line management completed evaluations and corrective actions.

The team observed generally timely line management reviews and corrective actions for QA identified CAP issues.

The team observed and/or interviewed QA/NSR personnel about their findings and management's response and determined that line management routinely asked QA/NSR to assess whether or not station personnel were meeting management expectations.

QA conducted restart surveillance observations of each plant department, which provided accurate information about outstanding department activities for both restart and for long-term performance improvements.

The team assessed that the QA restart assessments accurately reflected current departmental performance and prior QA/NSR findings including recent audit findings. However, the team noted one issue with these departmental reviews. The QA operations surveillance report noted that operability determinations (ODs) needed to be improved, however, QA did not consider this a restart restraint.

Based on previously identified NRC and QA issues with ODs, the team determined that this issue warranted additional management review/attention prior to restart. (See Section 3.3.2.2 for additional information on ODs). The team questioned whether interim corrective actions should be developed prior to implementing a change to the procedure by providing training to the operating department (currently scheduled for April 1996.)

Site Operation and Off-site Review Committee and Nuclear Review Board

The SORC and OSR adequately conducted the safety reviews required by TS. Open SORC and OSR items did not adversely affect plant restart. Team members attended several SORC meetings, verifying the required quorum and observing the proceedings.

While no offsite committee activities occurred during the inspection (neither OSR nor the Nuclear Review Board), recent committee reports and outstanding open items showed that the OSR committee accomplished its activities in accordance with TS requirements. The licensee appropriately handled committee open items for restart assessment. Based on independent reviews the team did not identify any items requiring completion prior to restart.

c. Conclusion

QA provided an independent assessment of restart readiness to the station, which basically agreed with the departmental self-assessment conclusions; however, also provided more detailed observations to support the conclusions.

The team concluded that the independent oversight activities, including both QA/NSR and various onsite and offsite review committees, were providing sufficient bases to support the licensee's decision process for activities that needed to be completed during the refueling outage, and subsequently, that the station was ready to safely restart.

3.2.4 Corrective Action Program

a. Background

Procedure NC.NA-AP.ZZ-0006(Q), "Corrective Action Program," Revision 12 (NAP-6) described the corrective action program (CAP). The procedure described the process for identifying problems, and provided for adequate management review, timely determinations of operability and reportability, and initiation of corrective actions.

The licensee changed the corrective actions program in July 1995. Before that change, the primary method to identify and correct problems at the station involved incident reports (IRs). Most significant issues at the plant requiring corrective action (beyond simple corrective maintenance) began as an IR. IRs were still referred to at the station since some were on the backlog for closeout.

After the change in July 1995, the CAP no longer used IRs; but rather, action requests (ARs), were used to identify issues or problems. The advantage of the new system was that the AR data base used the licensee's computer-based maintenance management system for tracking the activity. The old IR system was primarily a manual system that did not permit even relatively unsophisticated data manipulation.

To further clarify the terms needed in the following discussion, all identified problems generally began as ARs. ARs were classified at four different significance levels depending on safety significance, adverse trends (repeat failures), and reportability (level 1 to 4 level 1 being the most significant). After AR identification and significance level determination, the AR resulted in either a corrective maintenance (CM) activity or a condition report (CR); or both (See Section 3.4.4 for a discussion of the CM process).

The CR was used as the method of identifying that departmental review of a situation or problem was needed. The department designated had the responsibility for assigning an evaluation manager. The evaluation manager was responsible for ensuring the performance of a follow-up assessment of operability if required by the SRO who approved the AR and for conducting evaluations as required by NAP-6 based on the AR significance level.

Depending on the significance level, various evaluations for root cause determination were employed. For tracking purposes, this usually involved a condition report evaluation (CREV). Further, any required corrective actions based on the root cause analysis were tracked by a condition report corrective action (CRCA).

b. Scope

The team reviewed the CAP to determine its effectiveness in identifying, evaluating, tracking, and correcting problems. Interviews were conducted to determine personnel understanding of the process and the CAP procedure.

The team reviewed the recently implemented the Corrective Action Review Board (CARB) which provided management oversight of significant conditions adverse to quality by reviewing: completed root cause analyses, planned corrective actions and schedules, and plans to monitor the effectiveness of corrective actions for level 1 ARs.

The inspectors reviewed the CAP performance data through January 1996 and the Collective Analysis and Trending Report for the fourth quarter 1995 Nuclear Business Unit.

c. Findings

Interview results indicated a good understanding of the CAP and processing of ARs to ensure that conditions adverse to quality were promptly identified, documented, dispositioned, and corrected.

The new CAP and management attention on identifying and correcting problems resulted in a large increase in ARs generated since the start of the outage in late October 1995.

The team found a common understanding of management's expectation for identifying problems. Licensee management's expectation regarding problem identification requires all site workers to be responsible for remaining alert for potential conditions adverse to quality and following the guidance of NAP-6.

In general, the team concluded that ARs were being appropriately reviewed and dispositioned, based on specific review of several significance level 2 ARs. Observations of the General Manager's morning meetings showed proper AR significance level classification, clear assignments of a designated evaluation manager for root cause determination and corrective actions, and reinforcement of management expectations.

Significance level 1 and 2 event reviews observed by the team were comprehensive and focused on finding root causes, particularly those that may have wider implications. Identified deficiencies and overdue CREV/CRCA/IRs were being properly addressed and receiving appropriate management focus.

The corrective action coordinator (CAC) had the responsibility for tracking evaluations and corrective action due dates and reporting the status to station management. In addition, the manager - corrective action & quality services was responsible for developing and distributing corrective action performance indicators and trend data to department managers for their review and action.

The team attended two emerging outage issues meetings and found them a good initiative for screening significance level 3 and 4 ARs and raising any concerns to management's attention. Attendees at these meetings included the Outage Manager, WIN team members, and planning and maintenance supervision and personnel. The purpose of the meeting was to screen ARs generated during the previous 24 hours, primarily focusing on significance level 3 and 4 corrective maintenance and condition resolutions, and their impact on planning and scheduling.

The CARB was a good initiative and increased the overall quality of significant level 1 root cause evaluations. The team observed that the CARB ensured that the assigned evaluation managers were appropriately determining the root causes. The CARB, made up of the General Manager and various department heads, held weekly meetings, where Evaluation Managers present root cause evaluations for assigned CRs. The CARB members asked good probing questions and required supporting documentation for the root cause determination and effectiveness. In addition, documentation of significant findings of the CARB were published in a weekly newsletter.

The team noted the following minor issues with respect to the CAP:

- After noting numerous instances of Level 2 ARs being downgraded to a Level 3, the team identified a weakness in the CAP, associated with the lack of feedback when management changed the significance level determination or corrective actions. According to interviews with various levels of management it was their responsibility to inform workers of any changes to ARs initiated and approved by their staff. In addition, NAP-6 required the CAC to verify significance levels and to document the resolution on the AR in the event of a disagreement.

  The team reviewed several ARs where the significance levels were changed. It appeared that the changes were being properly documented. However, the team found that there was no feedback mechanism in use to provide information about any changes made to the classification by management during review of an issue; or, to provide information about resolution of an issue, to either the initiator, the supervisor, or operations personnel, as may be necessary. Licensee management agreed with this observation and was developing a mechanism for providing feedback.

- The plant computer system provided different guidance on significance levels, from that in NAP-6. The Managed Maintenance Information System (MMIS) help screen on AR significance level did not provide adequate guidance to plant personnel. It appeared that many people used this help screen rather than guidance in NAP-6. It was also noted that the Maintenance Controls section used a paraphrased version of what NAP-6 specifies as guidance. Licensee management took appropriate corrective actions including: revising the MMIS help screen to refer the user to NAP-6, plans to discuss the changed expectation with the plant departments, and plans to provide more detailed guidance regarding significance level determinations in the next revision to NAP-6.

- There were apparent misunderstandings with the 30 day CREV completion time requirement in NAP-6 for significance level 1, 2 and 3 ARs. During interviews, the team learned of instances where CREVs were closed to avoid being overdue and CRCAs opened in order to meet the 30 day requirement. The practice of closing out CREVs prior to completion and opening CRCAs could affect performance indicator data and provide a false indication of the completed evaluations. Several Department Managers felt that the 30 day requirement did not allow enough time to complete their evaluations. NAP-6 did not contain provisions for extending the CREV time or for closing out CREVs and opening a CRCA to complete a root cause analysis, when evaluation had not been completed. There were provisions for extensions to CRCAs in NAP-6 which required varying degrees of written approval depending on the number of extensions that have been previously requested for the CRCA. This issue was documented in two ARs written by the QA Departments Corrective Action Review Committee (CARC) after reviewing a sample of CREVs generated during December 1995 and January 1996, and more recently in an AR written against guidance in a System Engineering training document.

In addition, trending data and QA and CARB reviews have identified that for significance level 2 ARs the quality of evaluations/corrective actions still require improvement and CRCA extension requests and schedules still have weaknesses. The licensee has recognized the need for overall process improvements.

d. Conclusion

The CAP was sufficiently established to identify and resolve plant deficiencies in a timely manner and was functioning acceptably. Personnel understood how to use the program and management expectations for its use. The program provided sufficient tracking of required actions for identified problems. Appropriate requirements were in place for the classification and timeliness of resolutions.

The team noted several minor issues with the program regarding: lack of feedback to the initiators and supervisors, differing significance level guidance, and misunderstanding of 30 day evaluation completion time. The team did not consider these significant from a restart viewpoint since the adequacy of corrective actions were not adversely affected.

Based on the review of performance indicators it appeared that the overall completion of CREVs, completion of CRCAs and quality of significance level 1 evaluations/corrective actions have improved and met management's expectations.

The initial development of trending data of corrective actions has recently provided additional insight to the management and staff regarding CAP findings. The CARB appeared to provide additional management oversight and levelized the expectations for evaluation quality and content.

3.2.5 Updated Final Safety Analysis Report Review

a. Scope

On a sampling basis, the team reviewed appropriate sections of the UFSAR to ensure that descriptions of the design bases, and specific commitments were being met. Other findings and conclusions associated with the UFSAR are discussed in section 3.3.4 involving Operations Procedures and Documentation, section 3.4.6 involving Maintenance Observations of battery testing and service water strainer operations and section 3.5.2.1 involving Engineering Design Change Package Discrepancy Evaluation Forms for battery temperature issues.

In the management and independent review areas the team reviewed UFSAR Chapter 13 which described the conduct of operations and Chapter 17 which discussed the operating QA program.

b. Findings/Conclusions

In Chapter 13 the team noted that on December 29, 1995 a change was made to Section 13.1.3, Qualification of Nuclear Plant Personnel, to provide consistent qualification requirements with those stated in TS 6.3. In addition most of the organizational descriptions in Section 13.1, and the resultant management qualifications, no longer reflected the current NBU organization. This section had not been updated since April 11, 1992 and therefore, did not describe the current organization.

In Chapter 17 the team noted that on December 29, 1995, this chapter was updated. Except for references to the Nuclear Department and responsibilities described for the Vice President and Chief Nuclear Officer (a position, replaced by the President and Chief Nuclear Officer of the PSE&G Nuclear Business Unit), the UFSAR description was found current and consistent with station operating procedures.

The team found that the organization and qualification discrepancies in Chapters 13 and 17 were not significant. This was based on the team determination that selected personnel were qualified as described in Section 3.2.2.

3.2.6 Outage Completion Plan Review

a. Scope

PSE&G developed several programs to ensure appropriate plant controls and oversight during RFO 6 and a safe restart as documented in the CCP. Measures were established to assess the plant readiness for restart and to evaluate performance. Some of the measures included the system readiness reviews, departmental self-assessments and departmental readiness affirmations, the operational readiness affirmation, associated hold points for scheduled power level plateaus, oversight by senior managers, and ongoing evaluations throughout the startup process.

As part of the OCP, the operational readiness self-assessment process included: operational readiness assessment and affirmation of operations shift readiness by each Senior Nuclear Shift Supervisor (SNSS).

- The individual department readiness assessments consisted of a self-assessment, implementation of corrective actions for any identified weaknesses, and an affirmation of readiness by the department manager to the ORC.

- The system readiness assessments included a review by the system managers that all outstanding work was appropriately completed for selected critical systems, a subset of which included full system walkdowns to ensure that all deficient material conditions were appropriately identified.

- The operational readiness assessment included a verification of required operator training, assurance that new operations performance expectations were effectively communicated to the operations department staff, and affirmation regarding the plant material condition being acceptable for power operations by each SNSS and operating crew.

These assessments were also provided to ORC for review and affirmation of readiness. The integrated review by SORC was to ensure that the outage completion plan had been acceptably completed and, if so, SORC would recommend to management that the plant could be safely restarted. The startup and power ascension program would include the normal startup requirements and would also be supplemented with additional management oversight and engineering support to ensure that any startup problems encountered would be addressed promptly.

b. Observations and Findings

The work scope validation process was a thorough review of all open work lists using licensee defined criteria (described in the referenced letter) to determine which items would be added to the scope of RFO 6. In addition, these same criteria were used to screen all emergent work during the outage to assess whether or not corrective actions were necessary prior to restart.

While the work scope verification process was essentially complete prior to the arrival of the team, emergent work activities and assessment for any resultant outage scope change were observed during the three week inspection period. In addition, as part of the continuing self-assessments by the departments, and the independent station readiness assessment and surveillance observations by the QA/NSR, a number of activities were identified for possible inclusion in the RFO 6 scope. Based on a review of the screening criteria and observation of its use for emerging issues, the team concluded that the licensee appropriately implemented the work scope validation part of the outage completion plan.

Based on observations, the team concluded that the system readiness assessments were appropriately implemented. (See Section 3.5.3.1 for additional information on the system readiness reviews).

Based independent reviews of department readiness, and observations of ORC activities, the team concluded that the department readiness assessments were appropriately implemented. The department readiness reviews, including the results of the department self-assessments were reviewed by the team for the engineering department, operations department and maintenance department.

In addition, the affirmation of department readiness by the respective department manager and presentation to the ORC was observed by the team.

The findings and conclusions for this area are documented in section 3.3.6 for Operations, section 3.4.2 for Maintenance and Planning, and section 3.5.7.2 for Engineering.

Although not yet completed, the team concluded that the licensee was implementing the outage completion plan. The team did not observe the final integrated SORC review; nor was the startup and power ascension process observed. These activities occurred after the onsite inspection was completed.

c. Conclusion:

Based on the activities reviewed and observed, the team concluded that the licensee satisfied the commitments outlined in the outage completion plan and that sufficient assurance of station readiness existed for a safe restart.

3.3 OPERATIONS

3.3.1 Scope of Review

The team reviewed the operations department activities to assess the ability of the operators, management, and programs to conduct and monitor a safe reactor restart and unit operation through the next fuel cycle. The team reviewed the following:

- Crew performance on shift and during simulator training.
- Adequacy of programs and their use for safety related equipment. operability determinations and the tracking of out-of-service equipment.

- Operations root cause determinations for identified issues.
- System readiness for restart and tracking of identified deficiencies.
- Control of and training on procedure changes necessitated by plant equipment changes during the outage.
- Operator training and maintenance of operator license conditions.
- Use of industry information for operations experience feedback.
- Operations department self-assessment activities.

3.3.2 Conduct of Operations

3.3.2.1 Control Room Observations

a. Scope

The team assessed and observed the conduct of operations during the inspection, including a 72-hour period of continuous control room observation. Included in these observations the team evaluated the Senior Nuclear Shift Supervisor (SNSS), Nuclear Shift Supervisor (NSS), Nuclear Controls Operator (NCO), and the Nuclear Equipment Operator (NEO) both in the control room and in the field. The team assessed the operators use of plant operating procedures. The team also observed and assessed the operations staff's ability to perform the operational functions such as shift turnover, control room access, operator communications, and operator rounds.

b. Observations and Findings

The team observed that operators conducted evolutions in a safe and controlled manner, appropriately using applicable inservice test (IST), surveillance and/or troubleshooting procedures. Although control room activities were limited during the inspection period the team observed the performance of several activities including the IST for the standby liquid control (SLC) isolation stop check valves and emergency diesel generator surveillance testing. The team verified that the SLC stop check valve test did not conflict with any requirements of the updated final safety analysis report.

The team observed troubleshooting of electrical breakers 10-C-633, and 10-C-609 on two separate shifts. As a result of this maintenance activity the control room expected the loss of a significant number of control room annunciators, due to the deenergization of these breakers. All activities were well coordinated between the operators and the plant staff involved.

The team found the individual turnovers were done in a professional manner, and the board walkdowns were sufficiently detailed. Observed turnovers included individual operators, from off-going to the on-coming crews, and from the new shift to the representatives of plant chemistry, radiological waste, and radiation protection. The shift-to-shift turnovers were concise and an appropriate level of detail was conveyed for maintenance evolutions that were being continued by the oncoming shift. The team noted during one turnover between the NEOs and the support personnel that the radiological waste representative was not present. The team was later informed that the NSS briefed the radiological waste representative separately.

The team noted good control of access to the control room operating area, and observed an NSS clear extra maintenance personnel from the area when it became crowded.

The team observed adequate communications between the operators on shift. The team noted differences among shifts in the use of formal three-point communication, however, these differences were minor in nature with overall communications meeting the requirements of department directive HC.OP-DD.ZZ-0043, "Operations Department Principles and Philosophy."

The team also reviewed several completed surveillance and IST procedures for systems that were considered fully operable finding them appropriately filled out with any deficiencies indicated. Any deficiencies indicated were subsequently retested to ensure acceptance criteria of the equipment or system were satisfied.

The team accompanied several NEOs noting that they completed their rounds in a profession manner. The NEOs appropriately used the electronic logs and communicated any discrepancies to the control room. The control room operators dispositioned these issues in a timely manner. The NEOs also communicated a few minor housekeeping issues such as water on the floor or loose materials to the control room, which were promptly resolved.

c. Conclusion

The team concluded the operators conducted themselves in a professional manner that would support the safe startup and operation of the plant. The operators use of plant operating procedures was good. Shift turnovers were detailed and appropriate. The operators maintained good control of access into the control room. Communications between operating crews had minor discrepancies, however, overall communication was in accordance with the applicable department directives. NEOs performed their rounds in a professional and efficient manner. The team concluded that the operating crews observed, maintained the appropriate levels of professionalism and knowledge to safely restart and operate the facility.

3.3.2.2 Operability Determinations

a. Scope

The team reviewed licensee reports issued in the past year that self-identified operability determinations (ODs) as an area of weakness.

As noted in Section 3.2.3, the QA surveillance report for the operations department noted that operability determinations needed to be improved, however, QA did not consider this a restart restraint.

b. Observations and Findings

The team found that operability determinations continued to be a weakness based on interviews and on review of the following licensee identified operability issues. However, the team did note that the operations department self-assessments and IMPACT plan identified operability determinations as an area for improvement.

- Hope Creek QA Surveillance Report 96-008, dated 2/26/96 identified concerns with 6 of 20 ODs. The service water system (SWS) had nine ODs mostly related to SWS screens and strainers. Also during the month, two SACS heat exchangers were fouled (degraded) due to grass. Two ODs were identified as conflicting. Further, the effect of all the deficiencies were not evaluated for their aggregate impact on system operation.

- CR No. 960116058, issued January 16, 1996, identified an operability concern on SRM "B". Corrective actions included an action for training to clarify understanding of procedure OP-AP.ZZ-0108(Q), "Technical Specification Operability Determination" for SNSS/NSS, and to emphasize that tracking and active LCOs, as the terms relate to operability and operability calls, are the responsibility of SNSS/NSS. The CR also stressed that compliance with the procedure was essential to making a correct determination (due April 1, 1996).

- QA initiated CR No. 951219239, issued December 19, 1995, documented a missed opportunity to identify an operability issue on the service water screen area vent fans. A limiting condition for operation (LCO) action statement was not entered as required.

- QA initiated CR No. 950929102, issued September 29, 1995, to document a noncompliance with the requirements of NAP 20 and GL 91-18 ODs. Nine ARs were identified on the EDGs on governor linkages and governor control circuits that should have received operability determinations but did not at the time of identification.

- LER 95-038 identified a failure to comply with required action statement upon removal of a failed snubber on the RHR shutdown cooling line.

- AR No. 950928196 was issued September 28, 1995 to identify deficiencies in ODs that did not identify technical specification (TS) surveillance and LCO requirements following an overvoltage condition.

- CR No. 950727152, issued July 27, 1995, documented that the automatic depressurization system (ADS) was inoperable due to a primary containment instrument gas (PCIG) pressure switch being out of calibration.

Through a detailed review of previous SLC IST problems the team identified a possible operability issue with the SLC system. Since making a change to the IST procedure in 1992, the licensee experienced several failures to meet the TS operability flow requirements of 41.2 gpm. Specifically, the team identified the possibility that the SLC pumps were left air bound following completion of the IST, since 1992. The team identified the following:

- Due to a dilution of the SLC sodium pentaborate storage tank in 1992 the licensee changed the procedure to drain the demineralized water used for testing from the pump suction line and to refill it with sodium pentaborate solution after each IST. Since the line did not contain any vent path, the draining and refilling operation introduced air into the suction piping and possibly the pump.

- Since 1992, the root causes for the failed IST did not identify any operability or reportability problems, since the licensee was able to displace the air following the IST failure and to demonstrate acceptable flow. The team noted that, immediately after acceptable flow capability was demonstrated, the drain and refill operation would again introduce air and possibly make the system inoperable.

- Although the SLC pump is a positive displacement pump, each piston compresses fluid in a volume unlike a piston in a cylinder. Because of this difference the team questioned whether the pump could self-prime (i.e., compress and clear the air left in the volume) if pumping against reactor pressure.

The licensee has developed a new procedure that will flush the suction line with sodium pentaborate, instead of draining and refilling, and should eliminate the air binding problem. The team determined that the new procedure would ensure SLC operability. The team considered the potential for past inoperability and reportability as an unresolved item pending further NRC review. **(UNRESOLVED ITEM 96-80-02)**

c. Conclusions

Based on the licensee's self-identified weaknesses, and the SLC operability issue, the team questioned the interim operations manager regarding operability determinations. In response to ORC comments, the interim operations manager issued a memorandum to the plant manager that outlined the corrective actions planned for startup. These actions included reemphasizing conservative decision making when addressing operability determinations, reviewing all outstanding action requests and work orders individually and in aggregate, as well as reviewing the TS limiting condition for operation (LCO) action tracking log prior to mode changes.

In addition, by April 1, 1996, expectations regarding the performance of operability determinations will be clarified in a revised operability determination procedure, OP-AP-06. Training will also be completed on the revised procedure by April 1, 1996. The team reviewed a draft of this procedure and concluded that many of the changes made incorporate portions of the guidance provided in NRC generic letter 91-18 as well as NRC inspection manual chapter 9900 on operability.

The team determined that sufficient measures had been implemented to ensure that the licensee would verify that necessary systems and components would be operable to support mode changes.

3.3.2.3 Tracking of Technical Specification Limiting Conditions for Operation

a. Scope

The team reviewed the listing of active and tracking TS limiting conditions for operations (LCOs) to determine status of systems and equipment for startup. Tracking LCOs were initiated when a TS system(s) was not at 100 percent capability, but still met TS operability requirements (i.e., if one pump was inoperable, in a system that has 3 pumps, but only 2 were required to be operable by TS). In such cases the licensee was not in an active LCO because the TS were satisfied, but the licensee was tracking the degraded condition.

b. Findings and Conclusions:

The team's review determined that the current list of active LCOs were scheduled to be closed prior to startup or had mode restraints assigned. In addition, the team reviewed the listing of tracking LCOs that were scheduled to remain in effect following startup and questioned whether the licensee had planned any formal assessment prior to startup.

The team concluded that the current system appeared to be effective and had no concerns related to the licensee's knowledge and control of active and tracking LCOs regarding plant startup and operation.

3.3.2.4 Operations Department Root Cause Determinations

a. Scope

The team reviewed a total of 40 condition reports (CRs) with respect to the adequacy of root cause determinations including one level 1, twenty five level 2 (nine of these had been previously reviewed by licensee QA), eight level 3 and six level 4.

The operations department had a root cause staff that consisted of two PSE&G personnel, and six contractors. The group was formally started in August 1995.

b. Observations and Findings

The threshold for reporting problems had been lowered which resulted in an increase in the number of self-identified problems reported in the past several months. The root cause analysis and corrective actions assigned for the one level 1 CR reviewed was very good. The quality, thoroughness of investigation, and corrective action recommendations for the level 2 and below CRs varied considerably. However, overall the quality improved over the last year.

The team concluded that the current inability to track and trend the results of root cause and apparent cause determinations at a level of significance below the level currently published for the site was a weakness that could miss identification of performance trends (e.g. identify and trend the specific causal factors for tagging errors).

The licensee's future plans to require the shift supervisors and operating crews to determine the level 2 and below apparent cause determinations could potentially distract them from their primary function of maintaining safe plant operations. The licensee intends to reduce this staff to 2 or 3 permanent employees by sometime in 1996, after the shift supervisors have received training in conducting root cause analysis.

The team concluded that the licensee's QA reviews of CRs were providing good constructive and independent feedback to the operations department. The feedback helped to ensure management expectations for quality of CR root and apparent causes, as well as corrective actions, were being established and maintained. The QA organization identified several problems with the CRs reviewed and rejected several initial operations responses. This required operations to provide a more detailed analysis. QA's review and rating of the 9 level two CRs (noted above) indicated, 4 were weak (rejected), 3 were good, and 2 were acceptable.

c. Conclusions

The licensee's program was still maturing very similar to the NRC 40500 inspection team findings of 1995 except that improvements have been made as noted above. Continuing oversight reviews will be necessary to ensure quality and thoroughness of root cause and corrective actions as well as verifying tracking and trending of results.

3.3.3 Operational Status of Facilities and Equipment

a. Scope

The team reviewed the administrative controls and the implementation of these controls to ensure the status of plant safety-related equipment was being adequately controlled. The teams review assessed work control activities in progress, the tagging process, configuration control, and operator challenges.

The team reviewed and assessed the administrative procedures for control of work. The procedures and computer tracking program were as follows:

- "Work Control Process", NC.NA-AP.ZZ-0009 (NAP-09) - established requirements for scheduling, planning, and review of all activities to take place at the station.

- "Safety Tagging Process", NC.NA-AP.ZZ-0015 (NAP-15) - established the requirements to maintain configuration control of plant systems and components that have activities scheduled.

- Tagging Request and Inquiry System (TRIS) - provided the control of equipment and system configuration.

The team performed a detailed review of the control room deficiencies, operator workarounds, temporary modifications, and their respective backlogs.

b. Observations and Findings

During discussions with several operations personnel it was determined the large volume of work activities and emergent outage work posed significant challenges to the Work Control Center (WCC). During the course of the inspection, delays in significant work activities were apparent. However, these delays did not adversely impact the licensee's ability to provide appropriate levels of review for ongoing work. The team reviewed several work packages in various stages of the work control process and determined that the WCC was performing in compliance with the appropriate procedures.

The tagging functions performed by the WCC were conducted well. WCC personnel were responsible for preparing tagging requests, blocking points, maintaining the TRIS worksheets, and ensuring communication with the control room staff. The team found it positive that the work control supervisor (WCS), an SRO (SNSS or NSS), reviewed and approved all tagging requests, reducing the administrative loads on the control room NSS.

The team observed the release of twelve tagouts being performed on several electrical breakers. The team noted the release of these tagouts were performed according to NAP-15. The team also walked down over 60 equipment tagouts on multiple systems such as the Reactor Core Isolation Cooling (RCIC) system, Station Service Water (SSW)system, Secondary Auxiliary Cooling System (SACS), and Reactor Auxiliary Cooling System (RACS) and verified that the tags installed were on the correct equipment, the equipment was in the correct position, and the information on the tags was correct according to the TRIS worksheet and tracking system.

The team determined that the current processes for identifying, tracking, and resolving control room deficiencies, operator workarounds, and temporary modifications were adequate. Further the team determined that there were no open items, other than those being tracked, that would be necessary to close prior to start-up. At the start of the inspection there were approximately 89 control room deficiencies, 51 temporary modifications, and 20 operator workarounds. The licensee completed these issues on a daily basis, reducing the backlog in each category. At the end of the inspection there were approximately 83 control room deficiencies, with 24 waiting for retest; 29 temporary modifications; and 20 operator workarounds, with 3 that had work in progress.

Hope Creek procedure HC.SA-AP.ZZ-0005 established appropriate criteria for SNSS to identify any current operator challenges that would adversely impact the ability of the operators in his crew to safely start and operate the unit. The team conducted walkdowns of three systems: reactor core isolation cooling

(RCIC), SLC, and SSW; verifying that the TRIS reflected the actual position of a large sampling of components and valves in the major flowpaths. The team also assessed the cleanliness and material condition of the systems.

- RCIC - The team verified approximately 30 separate component tags to be in accordance with the TRIS system lineup. Material condition and cleanliness were adequate considering the amount of work still in progress. At the time of the walkdown the system was under several WAs for various testing and repairs scheduled to be completed prior to start-up. The RCIC system walkdown was guided by the RCIC system engineer.

- SLC - The SLC system had been returned to an operable status. All components were in their proper positions and material condition was good.

- The SSW system had several work activities in progress, the most significant being the strainer work. Material conditions were not assessed, but configuration control was verified as being correct.

c. Conclusion

The team determined that the operators were appropriately informed of WAs that would impact their shift by the WCC. The team observed good communications between departments and good pre-job briefings for the WAs observed. The team concluded that there were adequate processes in place to control the configuration of the plant structures, systems, and components to support safe plant operation.

3.3.4 Operations Procedures and Documentation

a. Scope

The team selected about 35 operating procedures (OPs) with open revision requests (79 actual revision requests) that were not scheduled to be accomplished before startup, to verify that the applicable systems or components could be properly operated and not impact on safe plant operations or complicate operator response to an abnormal condition.

The licensee had a large number of revision requests outstanding for various operations department procedures. Although the actual number of revision requests varied due to the constant receipt and disposition, there were about 350 open revision requests for implementing procedures at any one time. The procedures group had processed about 575 revision requests that affected 227 procedures since the end of October 1995.

During the inspection, the procedure writers group consisted of nine people including the group lead. Only two of the procedure writers were permanent plant employees. There was one Station Qualified Reviewer (SQR) assigned full time to the operations procedure group. The procedure writers group lead, an SRO with previous senior nuclear shift supervisor (SNSS) experience, reviewed all outstanding procedure revision requests after assuming the lead position to determine which procedures needed to be revised prior to plant restart. The team also interviewed the procedure writers group lead and interfaced with several of the procedure writers.

b. Observations and Findings

Of the 35 procedures reviewed, the team asked why one procedure request concerning backwashing ECCS suction strainers should not have been incorporated prior to restart. Subsequent review indicated that the existing procedure was technically correct. However, during the review, it was identified that a part of the revision request concerning shifting of core spray suction from the torus to the condensate storage tank (CST) needed a sequence step changed. The group lead decided to incorporate the entire revision request into the procedure prior to plant startup. Other outstanding revision requests reviewed appeared to be procedure enhancements and not necessary for correct procedure implementation.

The team noted that no written criteria existed to screen the outage generated procedure change requests. The group lead stated that he had depended on his knowledge and several years experience at the plant. Subsequent to the discussions, the group lead developed written criteria for selection of procedures required (or desired) for revision prior to startup and had an independent procedure writer review of all remaining open revision requests. With the more stringent criteria, an additional number of procedures were identified as needing revision prior to startup. About 15 new procedures were identified as "required" which when added to the 10 that remained from the original selection made a total of 25 revisions required prior to startup. Fourteen of the 25 revisions were required because of design changes being made to the subject system. The actual number of revisions required was a constantly changing number due to emergent work and revision requests.

During the discussions, the group lead noted that procedure writers had, in the past, not received training on use of the writers guide and what management expected concerning procedure content and format. He stated he had submitted AR No. 00960105212, in January 1996, to address the lack of training on, and use of, the writers guide. The AR identified that UFSAR, Section 17.2.5, referenced ANS-3.2 which required that personnel be provided training for specific job related activities. He also noted that the current group of procedure writers had now received the necessary training and were using the guidance of the writers guide with a minor exception (i.e., the procedures writers currently bold the action verb in a statement, while this is not required by the writers guide).

The team did not identify any operations procedures that contained significant technical or format errors. Procedures were originally developed using a vendors writers guide and the requirements of station administrative procedures. Following the initial procedure effort, use of the writers guide was somewhat de-emphasized although the basic format of the procedures continued during incorporation of revisions.

The current writers group was using the writers guide and also referencing the UFSAR to ensure that procedure revisions accurately reflect format and administrative requirements, as well as, system operation as specified in the UFSAR. If the UFSAR is determined to be in error it is identified in an AR to initiate corrective actions.

It was also noted that training required on procedure changes had not been determined by operations management. Procedures that had been revised had been sent to training for their determination of necessary training. (See Section 3.3.5.4 for a further discussion of this training issue).

The integrated plant procedures that control plant mode changes and power operation (Mode 5 - refuel to Mode 1 - power operations), used a checklist format that provided good control. The team verified that the procedures clearly identified the systems required to be operable for mode changes.

The group lead had submitted a long term plan to operations management to upgrade all operations department procedures. The plan outlined an extensive effort spanning two to three years to fully complete. The plan if implemented would ensure that all procedures met proper format, UFSAR system operational requirements and commitments as well as management's expectations. The plan was being evaluated by operations management at the conclusion of the inspection.

c. Conclusion

The team determined that, although there was still a large operations procedure revision backlog, the significance of the requests did not appear to impact the ability of the operators to use or implement the procedures. Only one SQR in the procedure writers group presented the potential for a significant slowdown and bottleneck in the procedure change review process. The interim operations manager noted that he had several SQRs available that could be directed to review procedures if the existing group was not able to implement the desired procedure revisions in a timely manner. The team concluded that the procedures group was being effective in the implementation of technically correct and properly formatted procedure revisions. The team also noted that the licensee's training department had developed a preliminary action plan to implement the writer's guide training necessary for new or future procedure writers, to address the concerns identified in the AR submitted by the procedure writers group lead. This plan was under development and not scheduled for implementation until about August of 1996. Since the current procedure writers had received training, the August date was determined to be acceptable.

3.3.5 Operator Training and Qualification

3.3.5.1 Operator Training for Startup

a. Scope

The team reviewed the training plan for conducting startup training and observed one crew receive startup training and evaluation in the plant specific simulator.

b. Observations and Findings

The initial planned operator restart training contained a minimum number of normal evolutions (i.e., pulling of control rods to criticality with minor component malfunctions) and utilized the same simulator scenario guideline that had been used for the July 1995 startup. The licensee contended that the recertification training, together with the planned startup training, was adequate to train operators for plant startup. The individual SNSSs were also given the latitude to designate additional training for their crews if desired. This approach did not ensure a consistent minimum baseline training for each shift that was endorsed by operations management.

The team noted that more training in normal plant operations, such as establishing a reactor heatup, placing feed pumps in operation, controlling level, synchronizing the main generator and power escalation through the intermediate range, would be more appropriate given that the plant had been shutdown for 3 months.

During the inspection the licensee issued a new startup scenario guide (SG-173, dated February 20, 1996) that provided a number of options for various equipment and instrument failures that could be used to vary training among crews. This guideline was assessed as an improvement over the old guide. After some further discussions with the team, the operations engineer issued a startup training plan that outlined the minimum training requirements for startup. The team concluded that the plan was reasonable and provided a consistent minimum baseline training for each shift that was endorsed by operations management.

The team observed the startup training for one crew. The training included a normal control rod pull to criticality with several equipment and instrumentation failures. The training also included synchronizing the main generator. The inspectors concluded the training provided a useful refresher and objective feedback to the crew from the training instructor, operations engineer, and the crew's shift supervisor.

c. Conclusions

The team determined that the enhanced training plan would ensure that each crew would receive a baseline of training for normal plant startup evolutions provided by operations management. The team further concluded that the revised startup training plan should provide appropriate startup training for the licensed operators.

3.3.5.2 Operator Recertification Evaluations

a. Scope

The licensee was conducting recertification evaluations of all operating crews to verify that the performance of licensed duties would satisfy management's expectations and regulatory requirements. Crew and individual weaknesses identified would be used to develop training programs to correct the weaknesses during the normal licensed operator requalification program cycle. Any significant crew or individual weaknesses would be corrected prior to return to licensed duties. The team observed administration and evaluation of two simulator scenarios to one operating crew.

b. Observations and Findings

The team observed that crew and individual performance was satisfactory overall, however, several crew members demonstrated weaknesses in the areas of emergency operating procedure (EOP) direction, place keeping/usage; command and control; procedure compliance; and communications. Emergency classifications were generally good. The senior shift supervisor observed needed to be more proactive in his oversight role of ensuring proper EOP implementation. The licensee had determined that further training and remediation would be administered to this crew.

The licensee's evaluation team was made up of several operations department managers and training department representatives. The evaluators were generally thorough and objective. However, the evaluation team deliberated at length over performance expectations for the operators.

The licensee's QA assessment surveillance report 96-008 also identified communications and procedure usage as areas that continue to have marginal performance.

c. Conclusions

Crew and individual operator performance was generally satisfactory but needs to be improved in several areas based on the performance of the four crews that had been evaluated to date.

Although, management has attempted to upgrade operator performance and hold it to a higher standard, this standard has not yet been clearly defined and communicated to the licensed operators.

The interim operations manager acknowledged that additional improvement in operator performance is needed. This was also identified as an item in the licensee's IMPACT plan which requires further training based on the generic weaknesses identified during the crew recertification process.

3.3.5.3 Remediation of Operator Training Weaknesses

a. Scope

Remediation (special training) of licensed operators is performed to correct weaknesses identified during requalification testing, simulator exercises or observation of a weakness during performance of routine duties. Remediation packages for two individuals and one crew in 1995 and for three individuals and one crew in 1996 were reviewed by the team.

b. Observations and Findings

The remediation packages reviewed by the team focused only on remediation of the weaknesses identified on the particular examination failed and did not attempt to remediate any previous weaknesses identified throughout the 2 year training cycle. The remediation packages satisfactorily addressed the weaknesses identified on the exam.

The team also noted that the two individual and one crew failure in 1995 were all assigned to the same crew. It was further noted that the licensee had taken action to strengthen the crew by reassigning personnel to change the crew composition.

There were three documented remediation packages for the entire year of 1995. This appeared to be a low number of remediations. However, the team noted that the number of remediations identified already in 1996 have exceeded the total number identified in 1995 which appeared to indicate that the licensee has established a lower threshold for documentation and formal remediation of identified weaknesses. The interim operations manager and several training instructors acknowledged that the formal documentation and remediation of training weaknesses may have been a past program weakness.

c. Conclusions

The team concluded that this was an area that had been identified by the licensee as an area that could be improved by increasing the scope of remediation training of operators. There appears to be an increase in management's expectations concerning operator performance as well as a willingness to initiate remediation of identified weaknesses.

3.3.5.4 Training on Procedure Revisions, Design Change Packages and Industry Events

a. Scope

The team reviewed recent procedure revisions implemented since September 1995 and the process used to determine on which procedure changes operators would receive training. The team also reviewed the listing of design change packages (DCPs) implemented during this outage and reviewed a sample of three on which operators had been trained recently. The team also verified that operators were routinely trained on industry events that were applicable to the Hope Creek facility as part of the requalification training process.

b. Observations and Findings

The team reviewed a sample of procedure changes on which the training department had decided not to provide operator training and identified one procedure(HC.OP.SO.SP-001, revision 2, "Radiation Monitoring System Operation", added attachment 9, "Operability Determination Information for Filtration, Recirculation and Vent Monitoring System Low Range TS Table 4.3.7.11-1," issued July 19, 1995) on which operators should have been trained. The team questioned the training instructor responsible for training on procedures. The instructor agreed that operators should have been trained on the change. The operations training supervisor planned to add this procedure to the control room book of procedure changes for the operators to review prior to startup and to conduct operator training on this procedure during the next training cycle.

The team questioned one of the operations training supervisors concerning the process used to screen on which procedures the operators will receive formal training. The inspectors concluded that the process was informal and based on the training individuals experience. Operations management in most cases had not provided the training department guidance on which procedures they desired the operators to be trained. The exception was when a condition report had been initiated that requested operator training as part of the resolution.

Training on RF06 plant modification DCPs had not been completed yet since it was scheduled to be performed as "just in time" training prior to restart. Licensee quality assurance (QA) assessment surveillance report 96-008 indicated that thirteen RF06 DCPs were still in the initiation phase and had not been assessed by QA for their potential to impact restart. However, the training department had planned to conduct training on these DCPs prior to startup. No concerns were identified, however, the inspectors again noted a lack of formal controls and direction from operations management in selecting on which DCPs the operators should be trained.

QA Surveillance Report No. 96-008 identified that training on DCPs and procedure changes occurred after the changes had been implemented. This was not in accordance with NC.NA-AP.ZZ-0001(Q), Nuclear Procedure System, which required the user department to evaluate the need for training prior to procedure approval (AR NO. 960223254).

c. Conclusions

The team concluded that the process used to determine on which procedure revisions and DCPs the operators should be trained was informal and based on the training department individuals experience without operations management input. The team further concluded the current practices demonstrated weak operations management oversight in this area. The team noted that operators were trained on industry events as part of the routine requalification program training. The team also noted that the licensee now requires that all levels of procedures be taken into the field and used by operations personnel. Previous practice allowed operators to perform evolutions in the field without level 3 procedures. The new policy reduces the importance of training on procedure revisions not related to DCPs. The interim operations management acknowledged that more operations management involvement was necessary in this area.

3.3.5.5 <u>Conformance with Operator License Conditions</u>

a. Scope

The team reviewed the attendance records, test grades, operator time on watch (requirements 56/60 hours/quarter), and operator license reactivation from inactive status for the current 2 year licensed operator requalification training (LORT) cycle.

b. Observations and Findings

One weakness was identified by the team in that no one single point of contact was assigned the overall responsibility for ensuring that all license requirements were met for the licensed operators prior to assignment to licensed operator duties. The team noted that the last issued operations department personnel roster dated November 13, 1995 was not accurate at the time of issue for staff licensed operators. The team noted 12 staff licensed operators that were listed on the roster as having active licenses. All 12 actually had inactive licenses at the time the roster was published. The team did not identify any instances where operators were assigned to licensed operator watchstanding responsibilities on shift without first meeting license conditions.

The interim operations manager agreed with the teams finding regarding a need for more management oversight to ensure operators met all license conditions prior to assignment. Two action requests (ARs) 960224111 and 960224114 were written to ensure a single point of contact would be assigned to monitor the status of operator qualifications and to ensure that an operator would not be returned to licensed operator duties without meeting the requirements or completing the required documentation.

The team noted that the program controls, training procedure, SH.TO-TC.ZZ-0305(Z), "NRC Licensed Operator Requalification Program" for missed cyclic simulator training and evaluated scenarios did not require makeup of missed training as long as minimum annual and biennial manipulation requirements were met. Although, the program controls did not specifically require makeup of missed scenario training and evaluations, training attendance in the LORT program for the past year was reviewed by the team and determined to be good.

c. Conclusions

The team concluded that management oversight and controls for ensuring operators met all license conditions prior to assignment to licensed duties was an area for improvement. However, there were no examples of inactive licensed operators being returned to licensed duties identified. Training attendance was found to be good although the requalification program did not specify makeup for missed scenarios.

3.3.6 Operating Experience Review

a. Scope

The team reviewed the licensee's process for review and evaluation of industry events such as, various Institute of Nuclear Power Operation (INPO) notifications, NRC information notices and bulletins, General Electric service information letters, and other information pertinent to the facility. Members of the team attended two of the daily meetings held by the licensee during the inspection.

The Operating Experience Feedback (OEF) Program was detailed in procedure NC.NA-AP.ZZ-0054, Revision 2, at the beginning of the inspection, but was under revision to better describe the current means of operation of the OEF program. Revision 3 was in the process of being issued at the close of the inspection. There were minor changes updating responsibilities of individuals and incorporating 10 CFR Part 21 requirements, as well as other minor changes.

b. Observations and Findings

The team noted that the licensee discussed current status of backlog items assigned to each facility, Salem and Hope Creek, during each OEF meeting. The licensee also discussed new items and events that occurred or were reported during the previous 24 hours and determined if the item was applicable and what priority it should be assigned for review, if applicable.

The team noted some hesitancy of the OEF members to distribute items to the responsible division if applicability was questionable or of low significance. These items were usually forwarded as "information only" to the responsible division.

The team also noted that assigned items were being tracked by the OEF group through the completion of action by the assigned responsible division. Corrective actions were being evaluated for technical as well as administrative requirements for closure.

c. Conclusions

The team concluded that the licensee was conducting effective reviews of industry experience and that applicable information was being forwarded to the responsible division for corrective action and training of department personnel, as appropriate.

3.3.7 Management Oversight and Self-Assessment Observations

Hope Creek procedure HC.OP-DD.ZZ-0004(Z), "Operations Standards" was extensively revised in November 1995 to require, among other things, that assessments be performed at least once per week by all operations supervisors. The purpose of the required assessments was to ensure that operations personnel were adhering to established standards.

The team reviewed a random sample of completed self-assessment check sheets that had been completed over the past several months in the areas of training, procedure usage/adherence, safety tagging, and equipment deficiencies.

The licensee conducted meetings every Wednesday night for the Senior Nuclear Shift Supervisors (SNSS) and every other Wednesday for both the SNSSs and the Nuclear Shift Supervisors (NSS). The team observed both Wednesday night meetings. The team also attended the Outage Review Committee (ORC) meeting conducted during the inspection to assess the operations department readiness for restart.

The team also discussed several issues with operations department management during the period. The interim operation manager documented additional action to address these issues in a February 28, 1996 internal memo.

b. Observations and Findings

The assessments reviewed by the team were objective and comprehensive, and provided significant self-assessment and management feedback to the licensed as well as non-licensed operators.

The team concluded this was a good initiative by the licensee. The assessments pointed out many areas for improvement and provided on the spot feedback from management to the operations department staff.

The team members noted that discussions about operations personnel concerns during the Wednesday meetings were open and frank. Operations management provided direction and discussed their expectations of the operations department. Management clearly expected the operations department to be the lead in directing the operations and control of the facility. First line supervisors expressed concern about the open items such as operator workarounds and the inoperable control room instrument list (DL-10 list) as well as other items that would have an impact on plant restart. The supervisors noted that these items were being worked off but indicated that a high priority to clear the open items must be maintained to ensure corrective actions were complete before startup.

The ORC meeting concerning operations department readiness for restart, observed by the team, somewhat mirrored the Wednesday night meeting with more specifics about items that had to be corrected prior to restart and what actions the operations department had to take to ensure that all requirements for system operation were met before making operational mode changes. This concern was similar to the inspection team's concern discussed in Section 3.3.2.2, Operability Determinations.

c. Conclusions:

The team concluded that licensee was well aware of the items and operator concerns needing to be addressed prior to restart. The licensee held open and frank discussions, and implemented necessary corrective or compensatory action to eliminate operations department personnel concerns and plant deficiencies.

Some actions, although scheduled, were not fully implemented at the conclusion of the inspection.

The team concluded that the licensee's self-assessment activities were effective and had identified the equipment problems and operator concerns that needed to be addressed prior to startup. The licensee management at the meeting implemented corrective and/or compensatory action to correct plant deficiencies and address operator's concerns.

The mode change procedures in conjunction with the LCO and Tracking LCO log, TRIS, and additional reviews required by the interim operations manager's internal memo dated February 28, 1996, provided adequate assurance that all systems required to support mode changes will be identified.

3.4 MAINTENANCE AND PLANNING

3.4.1 Scope of Review

The team conducted detailed reviews of the maintenance and planning organizations and functions to determine that each department could support a safe unit restart. The team reviewed the following:

- departmental organizational effectiveness.
- self-assessments conducted as part of the readiness for restart and the affirmation for restart readiness conducted by the department managers before the outage review committee.
- QA involvement including the developed plan and surveillance report generated by this independent organization.
- the current work control process including the identification of problems and the new work control process that will be fully implemented following the outage.
- the corrective maintenance and preventive maintenance planning and scheduling processes.

The team spent a majority of its time reviewing activities and observing work in the field.

3.4.2 Organizational Restart Review

a. Scope

The team reviewed the planning and maintenance department organizational charts and conducted over 15 interviews with a cross section of personnel in each department. The team also reviewed the self-assessments conducted and attended portions of the outage review committee meeting where departmental readiness for restart was discussed. The team also reviewed the planning and results of an independent QA surveillance of departmental restart readiness.

b. Findings and Observations

Interviews:

Through discussions with workers, as previously assumed, the major challenges during the outage were the increase in outage work scope and the feedback to problem identifiers as to what would be corrected or not and why not as appropriate. The concerns identified in the maintenance and planning self-assessments appeared to mimic the concerns discussed by workers and supervisors.

Self-Assessment and Outage Restart Readiness Affirmation:

The team found that the self-assessment activities conducted by the planning and maintenance organizations identified performance issues of concern. The issues and actions taken by planning centered around the planning and coordination of work activities to ensure the identification and correction of the most significant issue in a timely manner. The maintenance department assessment focused on areas of preventive maintenance, corrective action effectiveness, reduction of backlogged corrective maintenance items, and the work process.

The outage readiness committee and departmental readiness affirmations for planning and maintenance departments appeared appropriate. The planning affirmation was completed on February 27, with several trackable open items. The maintenance department affirmation began on February 28. There were several issues including the completion and review of open work activities that still needed review, prior to startup.

The QA Maintenance and Planning restart assessment surveillance report, dated February 26, provided a good overall summary review of the issues discussed in the departmental self-assessments. QA concluded that there were no startup restraints. The team reviewed the surveillance plan and preparation check list, dated February 7, 1996, and the completed surveillance report, dated February 26 finding the overall plan and documentation of conclusions well justified. The surveillance report and plan covered areas important to safe operation following the restart.

c. Conclusions:

The maintenance and planning department functions were organized in an efficient manner providing for good planning and conduct of safety-related work. Changes in the planning and maintenance organization were planned for after the completion of the outage to address issues raised in the self assessments to improve future work coordination and control. Self-assessments conducted prior to startup indicated some areas for improvement and generally adequate corrective actions were taken.

3.4.3 Work Control Process

a. Scope

The team reviewed administrative procedures for the control of work and attended numerous plant outage meetings. The team also reviewed the implementation of a new work control process including detained on-line maintenance planning and implementation of a work it now team (WIN). The team discussed the current and new work control process during interviews with plant personnel.

b. Observations and Findings

Outage Work Control

The current work control process during the outage, including planning, scheduling, release, and closure were effective. The work control process was noted in both the maintenance and planning self-assessments as needing improvement, particularly in the areas of holding personnel accountable for schedule adherence and interface with operations and engineering. While schedule adherence is not specifically a regulatory issue, differing from the approved plan to conduct work or not being aware of work status can lead to changing plant conditions when not desired.

The team found that the outage schedule and the accompanying meetings provided sufficient information to set daily priorities. The meeting also provided a forum for planning, maintenance, engineering, and operations to hear a common message and to ask appropriate questions about priorities and schedule. The meeting format was open with plant conditions being discussed followed by discussions of important topics, and then a discussion of schedule exceptions. Management appeared to generally provide adequate definition of their expectations for the meeting.

New Work Control Process

PSE&G plans to implement a new work control process, following the outage, to address previous concerns. The concerns included developing a detailed method of screening work activities and then correcting the issue or scheduling and planning it for a future period, as appropriate to ensure reactor safety and unit operation. The WIN team will screen out the easily corrected emergent issues, while issues that require more detailed planning will be reviewed by the Unit Coordinator and placed in the schedule and planned as part of the new process.

Initially the planning process will be using a six week look ahead for scheduled corrective and preventive maintenance, system outages and surveillance testing. Each week will be assigned to a planning department work week manager, who will be responsible for coordinating the overall schedule, and planning and tracking issues from assignment through completion. The planning for these processes appeared to be well developed and thought-out.

The WIN team currently in place reduced the backlog of non-safety significant issues through a process of screening current ARs. In the future, PSE&G plans to focus the WIN on emergent work issues that do not require in-depth detailed planning. The expectation is that the maintenance department will then focus on corrective maintenance activities that have been planned in the normal scheduled work process. PSE&G management recognized the need to get individuals with good work skills and supervisory ability involved in this program since this will be a significant part of corrective maintenance activities completed on site.

The work week managers have been selected and generally appear to have the skills needed to conduct the process. The team discussed the work week manager functions with the Unit Coordinator and with individual work week managers. These individuals were very knowledgeable about the expectations and the problems that the new process is intended to address. Each manager comes with specific previous qualifications that when taken together should provide a very diverse knowledge base.

The unit coordinator (UC) will be the common planning person needed to provide constant oversight of the work scheduling process. The UC will review the ARs that have not been picked up by the WIN team on a daily basis and will then select an appropriate future outage where the work will be scheduled and then transmitted to planning for development of the package. The unit coordinator had a good vision of the new process and the capabilities of the individual work week managers, and should be able to provide the needed consistency in the process.

The team found a well developed new process for preparing an LCO maintenance plan for safety related on-line maintenance outages. A sample plan used to conduct work on a control room emergency ventilation chiller (BK400) provided very detailed statements of TS requirements, outage scope, a justification for performing the activity, prerequisites, a detailed item by item schedule and associated duration estimates, contingency and compensatory measures, and a risk assessment. Also in the plan was a discussion of personnel contacts and briefing of the operating crew that need to be conducted. The briefing material provided a detailed list of components and systems affected by the maintenance activity.

c. Conclusions:

The work control process and the accompanying planning meeting were appropriate to ensure that the station personnel were focusing on important maintenance activities. PSE&G plans implementation of a new work control process after completion of the outage. Review of the new process and observation of a pilot activity on a control room chiller discussed in section 3.1.6 demonstrated improvements in the prework review of work activities, and an enhanced planning and scheduling process for normal work and LCO maintenance activities.

3.4.4 Corrective Maintenance

a. Scope

The team reviewed the conduct of corrective maintenance within the existing work control process through the observations discussed in section 3.4.6 below and in discussion with plant personnel.

b. Findings and Conclusions

The corrective maintenance process appeared to be functioning well. The work packages developed by planning appeared to have sufficient detail, and specify appropriate procedures and initial retest information. Work package quality appeared good for the several packages reviewed.

Through discussions with planners and maintenance personnel and by review of packages the inspector determined that the CM adequately addressed problems.

Licensee personnel believe that the use of maintenance engineers, as component level experts, should provide added emphasis and engineering involvement.

The scheduling of specific critical path issues was conducted well and was adequately discussed at daily meetings. Schedules available to plant personnel were appropriately detailed and provided adequate sequencing of system outages and restorations needed for given plant conditions.

The startup backlog was reviewed for several systems and found to have been properly addressed by the ORC process.

3.4.5 Preventive Maintenance

a. Scope

The team reviewed the backlog of PM. The team then determined which PMs were for safety-related equipment, specifically which were for environmental qualification purposes and finally which items would be overdue at restart. The team also reviewed how the maintenance department conducted their similar review.

The maintenance and planning self-assessments identified that the tracking and scheduling of preventive maintenance tasks needed improvement.

b. Findings and Observations

To provide the needed focus the maintenance department took over the PM program and conducted a detailed review of overdue items. One major issue identified was in the previous scheduling of non-EQ PMs. They had been scheduled to the 125 % overdue date, not the 100 % date.

The team reviewed the safety-rated non-EQ and EQ PM backlog and found that all items have been properly identified and broken down into specific groups, based on completing the schedule.

The EQ PMs were acceptably scheduled for completion by the 10 year date or deferred. The inspector reviewed several of these deferrals and found them acceptable. In one case the inspector questioned the extension of the EQ PM on the Core Spray(CS) and Residual Heat Removal(RHR) pump motors. In this case PSE&G has acceptably implemented adequate action for predictive maintenance in accordance with current industry practice.

c. Conclusions

Through the self-assessment process PSE&G identified problems with tracking of PM task completion dates. The maintenance department adequately reviewed the backlogged PM tasks and selected appropriate completion times for safety related EQ and Non-EQ tasks.

3.4.6 Maintenance Observations

a. Scope

The team focused its activities on the observation of activities in the plant with respect to work control, use of procedures, control of safety-related systems and equipment, and material condition.

b. Findings and Observations

During the observations of work activities described below the team observed generally good performance of operators and maintenance personnel. Work was generally performed properly in accordance with procedures.

Secondary Containment:

There was good documentation of secondary containment in the tracking log. It appeared that the proper testing was done for operability prior to control rod movement (core alteration). Further, the 18 month surveillance tests were scheduled to be completed prior to restart.

Torus ECCS suction Strainer testing:

The team observed the conduct of the special test that was performed to determine the possibility of ECCS suction strainer clogging due to suspension of debris normally settled on the lower torus surface. The test was conducted for 6 hours, with an RHR pump and a loop of CS (2 CS pumps) in the normal IST configuration. During pump operation suction strainer clogging would be evident by a reduction of the pump suction pressure, due to the increased pressure differential of a blocked suction strainer. Based on internal torus inspections PSE&G did not expect that debris would cause strainer clogging and expected that each pump suction pressure would not change by more that 0.5 psig. The test specified that if suction pressure reduced by 2.0 psig the procedure should be terminated. The team observed the conduct of the testing in the control room and at the pumps, finding very good knowledge of personnel and very good control over the testing evolution. Review of test data indicated that there was no change in the suction pressure of the RHR pump or either CS pump during the testing. This indicated that there was no appreciable deposition of debris on the suction strainers. Further, PSE&G subsequently conducted a visual inspection of the strainers finding no deposited debris.

The team reviewed the special test procedure, and the 10 CFR 50.59 evaluation conducted for this test adequately addressed the test configuration and duration, determining that running an RHR pump and a loop of CS (2 CS pumps) in the normal IST mode for 6 hours would produce the expected turbulence and provide the best achievable method of deposition of material on the suction strainers.

Hiller/Anchor Darling Valves

The team reviewed Hiller spring to open actuators and Anchor Darling double disc flex wedge gate valves.

The team found that the failure of the actuator to be able to open these safety-related valves has been a recurring problem. PSE&G appeared to have taken significant actions to correct/address the issues. These actions included soft seating the valves (i.e., setting mechanical stops to prevent the air operator from driving the wedge into the seat), testing using the packing enforcer to trend and track valve internal and packing forces and valve refurbishing/internals modification and subsequent repetitive testing and trending to ensure operability over a fuel cycle.

Emergency Diesel Generators

- C EDG

Maintenance Activities:

The mechanic performing corrective maintenance properly identified a broken connecting rod bolting keeper cotter pin on the number 3 cylinder. Further inspection showed that other cotter pins had been damaged previously, possibly by pliers during installation. PSE&G replaced all the connecting rod cotter pins on the C EDG and then subsequently on the other EDGs.

Following this activity the maintenance department did not leave the C EDG in a condition that would allow operation, due to failure to adequately review a work order (WO) during closure. During the restoration of the C EDG prior to the maintenance run of the machine, operators identified several issues indicative of ineffective closure of a WO. In this case an operator conducting the pre-startup review identified that the air operated baring device had been left installed. Maintenance was contacted and removed the baring device, and operators continued with their pre-startup preps. The team observed that the operator properly identified that the EDG cylinder pet cocks were open when he tried to open them. This immediately raised a concern to the operator that the maintenance department had not closed the petcocks following the maintenance. At this point the EDG had been returned to service and could have, while not required to (i.e., inoperable), started in response to a loss of voltage on its associated bus. This could have caused a significant fire/smoke hazard if the EDG started. The operator placed the local control switch in the maintenance position, which would have prevented that auto start and contacted operations management.

Maintenance personnel conducted a review of the EDG condition following maintenance and determined that the root cause was a failure of a supervisor to identify that the baring device was not removed and the petcocks were not closed following the work. Following discussion of the root cause with PSE&G maintenance management, the team also noted that the supervisor should have identified that the petcocks had been left open when the barring device had been left installed (i.e., ask what else had been left in an abnormal condition following maintenance).

Testing:

PSE&G conducted post-maintenance testing on the mechanical components and subsequent weekly surveillance testing on the C EDG well. The team reviewed the surveillance testing following the maintenance and observed the next weekly surveillance test.

The surveillance test work orders properly documented the necessary retests and the individual work orders documented satisfactory completion of results including jacket water, fuel oil and lube oil leaks. These included verification that leakage had been corrected. The inspector identified that several equipment trouble tags on the C EDG local control panel were not cleared in a timely manner following completion of the retest.

Nuclear Equipment Operators were observed to have conducted very good reviews of system operating conditions when the EDG was in operation.

- <u>B EDG</u>

The team reviewed the corrective action taken for a November 26, 1995 inadvertent closure of the EDG output breaker out of phase with the associated 4 KV bus frequency, and for a December 11 condition where the A phase current indicated zero. PSE&G had completed a significance level 1 corrective action report on the November 26 issue, but had not completed the documentation of the significance level 1 issue before the December 11 issue.

The team found that the corrective action report for the out of phase closure was very well prepared, using event and causal factor and failed barrier analysis to determine the cause and documentation of a well developed troubleshooting plan. The analysis conclusions documented several poor human performance issues including: 1) inadequate review of a March 25, 1995 problem during operation of the unit syncroscope, which could have led to identification of the logic control problem that included problems with system engineering and planning response to the issue, 2) the system engineer did not properly review the possible cause for alarms received by the operators on November 26 prior to the inadvertent closure, and 3) problems with the logic card test device that could allow a failed card to be installed unknowingly. The corrective action recommendations documented in the report appeared to adequately address the problems identified in the report.

The troubleshooting plan developed as a result of the out of phase closure was well developed and helped to document several of the root cause conclusions.

The team discussed the failure of the output circuit breaker A phase with the 4 KV system manager. PSE&G had not completed the corrective action report on this issue. The team found that, based on discussions and review of a photographic report on the failure that the pin holding the circuit breaker A phase operating arm to the operating mechanism had backed out of its position. This allowed the other two phases to close and the A phase not to close. Following the failure PSE&G removed the breaker and completed an inspection. The pins for the outboard A and C phase were installed and held in place by spring clips retained in a machined slot on the end of the pins. The center B phase was pinned but the pin contained a cotter pin on each end. Initial observations showed that the spring ring was not on one end of the A phase pin, which would have allowed it to back out of the assembly. PSE&G did not find the spring clip in the cabinet and it was not found following transport of the breaker to the manufacture's shop. This led PSE&G to believe that the spring ring had not been installed during manufacturing. The licensee sent a number of both safety and non-safety related breakers to the manufacturer for PM during the outage. The manufacturer reported that there were no further instances where the spring clip had not been installed. The team reviewed the operation of the breakers with the electrical maintenance supervisor and determined that there was no way to identify the failure through normal testing.

The team reviewed several work activities on the B EDG during its outage, including repair to a combustion air leak on the No. 7 cylinder and a leak from the jacket water warming pump shaft seal. In both cases the inspector found that the proper section of approved maintenance procedures were used and that maintenance technicians properly documented as-found and as-left conditions.

Plant Tour Issues

The team found that adequate configuration control was maintained during a SACS outage on the EDG cooling water supply valves.

During a walkdown of the 4160 V electrical panels the team identified several minor problems with caution tags installed on the CS and RHR pump circuit breaker manual control switches and the positions stated on the control panels. All of the circuit breakers except the B RHR where tagged with white caution tags that stated "Switches in pull to lock (PTL) IAW IO 0005/TS 3.5.2. Do not operate without NSS approval; these switches in PTL to prevent inadvertent floodup". The team was concerned since several pump switches were not in pull to lock, because the pumps were required to be operable to inject water by TS 3.5.2, following installation of the fuel pool gate. Walkdown of the control room panel indicated that all the pumps that were in pull to lock had the appropriate white bezel cover indicating such. For the B RHR pump the control room indication showed that the switch was still caution tagged in the PTL position, but the breaker switch was in normal after stop and no tag was hung. In the case of the pump switches that had the caution tags but were in the normal after stop position there were no bezel covers showing that caution tags were still hanging. The team discussed this with the SNSS who quickly corrected this minor administrative issue.

Control Room Annunciator Troubleshooting/Preventive Maintenance

The team found that PSE&G handled several issues that affected control room annunciators well. These included the conduct of preventive maintenance on a power inverter which resulted in all CR annunciators being inoperable. The team observed very good preparation for this activity including the package and briefing of the control room operators. Proper planning for stationing equipment operators at remote panels was conducted while the annunciators were disabled. When the annunciators were repowered, 13 did not properly respond to an operable condition. PSE&G developed an appropriate troubleshooting procedure to allow the identification and correction of the control card which caused this failure.

In a separate activity several annunciators were deenergized to allow troubleshooting the possible cause for a previous partial loss of annunciators. During this troubleshooting PSE&G found that the possible cause for a low voltage condition during an annunciator test could have been a faulty diode in a power supply. The diode was replace and retested satisfactorily.

Alternate Rod Insertion Valve Modification and Preventive Maintenance

The team observed the installation of the design change package on the two alternate rod insertion solenoid valves and the implementation of the EQ PM on the valve o-rings. The team found that the o-rings were properly replaced. The team observed that initial attempts to set the limit switches were initially not successful. This included the need to insert an ARI signal and observe the valves reposition and the scram air header depressurize.

The installers had problems with setting the limit switches due to a poorly worded DCP instruction that did not specify the part of the technical manual that needed to be conducted. Subsequently, the installers identified the issue.

Control Room Chiller Maintenance

The inspector reviewed the maintenance activities on the BK 400 control room chiller and found that maintenance personnel performed very well. Procedures were appropriately followed and annotated with as-found and as-left conditions. The work supervisor appropriately N/Aed steps that did not need to be completed, leaving the mechanics and electricians with a clear path for completion.

Safety-Related and Reactor Core Isolation Cooling Battery Testing

PSE&G properly replaced two cells on the "C" 125 volt safety-related battery following performance testing. After the performance test, the two cells showed lower voltage, not outside the TS range, following equalizing charge. The team reviewed the work orders that replaced cells No. 43 and 48. The work orders included part numbers that were traceable to manufacturer purchasing certificates. Review of the purchasing certificates showed that the individual cells had been performance tested at the factory prior to installation. The associated vendor performance testing met the requirements of the Technical Specification performance test on an individual cell. Through discussions with the battery system engineer the team found that storage conditions for the cell appeared acceptable.

The team also observed the 250 volt RCIC battery 60 month TS performance testing, and found the technician knowledgeable and performing the test well. The testing was conducted using a state of the art computer controlled load bank system that allowed for continuous monitoring and control of battery discharge amperage and monitoring of individual cell voltages. The discharge rate for the performance test and the low cell voltage acceptance criteria met the assumptions in the TS and the UFSAR. Upon review of the completed procedure the inspector identified a possible problem with the recorded performance capacity of -107 %. The remarks section stated that they were actually at 110 % with a high value of 120 %. The acceptance criteria was greater than or equal to 80 %. The team could not find clear documentation of acceptability based on the criteria. The team discussed this with the electricians and found that the actual capacity was 121 % based on the computer printout and that the -107 may have been caused by computer fault after the test had been completed.

Service Water Maintenance and Testing

The team observed and conducted a detailed review of the service water stainer work performed during the inspection period. There were four strainer failures within the two weeks that the team was onsite. "C" overloaded when started. "A" strainer failed due to dropping of backwash arm. "B" failed due to backwash arm pin failure. "D" failed possibly due to debris loading.

In reviewing of these activities the team identified the following:

- Failure to Follow Maintenance Procedure:

1) Procedure not followed during "A" strainer disassembly.

Based on team observation of the condition of the "A" strainer and the associated elements and appropriate procedures, the inspector concluded that the approved procedure had not been followed (i.e., the conditions did not match the procedure and could not have been achieved using the procedure).

The specific work order documentation stated that the strainer cover had been separated from the baskets and the backwash arm removed from the baskets. Neither of these operations had been described or allowed by the procedure.

2) No procedure steps for installing backwash arm pins possibly causing "B" strainer failure.

Based on observations of the "B" strainer backwash arm pin failure, lack of procedure guidance may have caused the failure. There was no procedure guidance for installation or removal of these pins (i.e., no torque value or thread engagement requirements and no surface preparation requirements for the backwash arm surface).

- <u>Inadequate Control and Knowledge of Critical Clearances:</u>

Based on observation of strainer configuration and due to the failures the team concluded that due to a lack of procedure direction, critical clearance within the strainers were not established, documented, or maintained. This included failure to verify that components were in proper vertical alignment prior to establishing the backwash shoe vertical clearances.

- <u>Poor Supervision/Management Knowledge of Procedure Usage:</u>

Following team identification that the procedure for the "A" stainer had not been used, the team questioned maintenance and then plant management on the use of procedure and the understanding of when a procedure change was needed. Initially the maintenance department management responded that their personnel had met the expectations for procedure adherence during the "A" strainer work. The team disagreed with maintenance management. After team discussions with plant management the maintenance department fully reviewed the issue and determined that maintenance personnel had not met the station expectations for procedural use.

After several days of discussion about whether skills of the trade were appropriate in this case in lieu of a more detailed procedure and two additional strainer failures, the maintenance department management agreed with the team's conclusion. The maintenance manager found through interviews of maintenance personnel that while the words used to convey expectations relative to procedure compliance were clear, the understanding by the entire staff was not.

The team asked for information on mechanical maintenance safety-related procedure changes conducted during the outage. Based on a review of a sample of these changes, the team found that none had been initiated because of difficulty following procedures as written. There did not appear to be any specific examples, based on further discussions with maintenance management. The team considered this symptomatic of a weak understanding of procedure compliance expectations in the mechanical maintenance area.

Apparently the confusion existed in the supervisory area about substituting training for procedure guidance. Maintenance department management took action to discuss expectations on procedure compliance with department personnel including tailgate meetings to reinforce expectations. The SW strainer issues appeared to be an isolated issue based on the other observations.

- Review of UFSAR-SW strainer operations:

The strainers always rotate when the associated pump is in operation. The UFSAR documented that the backwash valve bypass was open allowing continuous small backwash flow. The team observed that there was no backwash flow on the operating unit during the inspection. In a September 1995 safety evaluation, PSE&G documented a change in the operation to provide intermittent backwash. PSE&G provided the team with a UFSAR change notice dated January 26, 1996 which stated that the changes had been made as a result of DCP 70-43 modifying the strainers.

c. Conclusions:

The team concluded that most of the safety-related maintenance observed was completed using proper procedures. The team did note several minor issues:

- configuration control of an EDG where maintenance had completed work but left the engine in an abnormal condition.

- failure to clear several equipment trouble tags shortly after the condition had been corrected by maintenance action.

- the documentation of a completed RCIC battery surveillance was unclear as to its satisfactory completion.

With respect to service water strainer issues, the team concluded the following:

- It was significant that the team identified two examples where safety-related maintenance procedures were not used or did not provide adequate information for component disassembly or assembly. PSE&G maintenance personnel and supervision had not identified that procedure HC.MD-CM.EA-0003 (Q) - Rev 9, dated 12/4/95, "Service Water Strainer Overhaul and Repair" could not be or was not performed as written and therefore did not correct the issue. The team considered that failure to follow the maintenance procedure for disassembly of the "A" SW strainer and failure of the procedure to provide instruction for installing the backwash arm to stub shaft pins constituted a violation of TS 6.8.1, which required that procedures be developed and implemented for safety-related activities. **(VIOLATION 96-80-03)**

- There were weaknesses in the procedures for strainer maintenance in that they did not ensure that critical clearances were established prior to returning the equipment to service.

- Maintenance management had not identified that the procedure usage during stainer work was less than adequate and further, continued to believe that it was adequate following identification by the team. This indicated a lack of understanding of expectations for procedural usage by maintenance managers and supervisors.

- The team considered the lack of mechanical maintenance on-the-spot-changes prepared during work activities symptomatic of a weak understanding of procedure compliance expectations in the mechanical maintenance area.

- Licensee Corrective actions:

  At the end of the report period the licensee was in the process of beginning root cause determinations on the service water stainer failures and was preparing revisions to procedures so that work could be completed.

  Station management recognized the problems with procedure compliance after discussions with the team and took corrective actions to enhance the knowledge of maintenance management, supervisors, and personnel on procedural usage.

- Restart Issue

On February 26, the team expressed concern to plant management that a review of the SW strainer failures and the other SW issues needed to be completed prior to reactor startup. On February 27, the inspectors met with engineering personnel and were presented a well developed plan for assessment of SW issues, including the strainers, prior to startup. There will also be some long term corrective actions. The NRC considered that completion of a root cause determination and necessary corrective actions for the recent strainer failures constituted a restart issue. The licensee's subsequent resolution of the issue prior to restart of the unit was inspected by the resieent inspectors, and will be documented in a separate NRC inspection report.

3.5 ENGINEERING

3.5.1 Scope of Review:

The team reviewed the engineering program and the design changes that have been conducted during the outage to determine their adequacy. The team reviewed the following:

- The design changes that were implemented during the outage.

- A list of identified discrepancies to verify proper corrective actions.

- Engineering support to system readiness and overall plant material conditions.

- Engineering administrative procedures and the ability of the organization to support the outage.

- Quality assurance assessment and engineering self-assessments.

3.5.2 Conduct of Engineering

3.5.2.1 <u>Design Change Packages (DCPs)</u>

a. Scope

The inspector selected a number of DCPs for review. The review included an evaluation of the extent to which the DCP addressed the targeted condition, the adequacy of the installation instructions, appropriateness of retests, procedural update requirements, and conformance to the licensing and design basis as documented in the Updated Final Safety Analysis Report (UFSAR). The following DCPs were selected for review:

- 4HO-0896-1, Diesel 'A' Starting Air Receiver Check Valve Replacement
- 4HO-0865-1, Recirc M-G Set Voltage Regulator Xfmr. Alternate Mounting
- 4EO-03426-2, Ralph A. Hiller Filter Regulator Replacement
- 4HE-0154-1, Change Normal Operating Range on SWS Motor Ammeters
- 4HE-0124-1, EDG Jacket Water Heater 1A-E-407 orifice/spacer
- 4HE-0331-1, Replacement of No. 16 AWG Wire in Scram Solenoid Circuits
- 4HE-0237-2, Replacement of Reed Switches on SOVs 1BFSV-F160A & F160B
- 4HO-0909-BD, Reorientation of backdraft isolation dampers

The team also interviewed supervisors in Design and Project Engineering with regards to difficulties experienced with one of the DCPs.

During the review of DCP HO-0909-BD, the team became concerned with the licensee's handling of an old construction deficiency discovered in 1992 regarding the reactor building ventilation system backdraft isolation dampers. These dampers were designed to mitigate the consequences of high energy line breaks that could occur in the various rooms or compartments in the reactor building. The design function of these dampers is to limit the spread of steam and moisture through the ventilation system in the event of a high energy line break. The dampers were designed to automatically drop closed when a high energy line break event is sensed in a compartment.

b. Findings and Observations

The DCPs reviewed were generally of good quality with sufficient documentation to permit evaluation of the effect on design and licensing basis, appropriate retest instructions, necessary procedure and UFSAR change requests, and adequate installation instructions.

The one DCP with which installation difficulties were encountered involving the ARI valves discussed in section 3.7, relied on instructions supplied on vendor prints. The vendor prints used a step list to remove old parts and replace them with new upgraded parts. No reference was made in the step list to the installation instructions in the Operations and Maintenance Manual (OMM), which was included with the DCP package. Of the two crews performing similar installations, one experienced difficulties with the installation and retest. Some difficulties resulted from the lack of a pre-design walkdown (the equipment could not be opened for inspection during operation), and others resulted from failure of the technicians to refer to the installation instructions included in the vendor OMM. The field problems were adequately resolved to allow completion of the installation and satisfactory completion of the retest. This particular DCP was generated during the early part of the outage, during the time of the significant increase in outage scope, and the influx of contract designers to accommodate the increased workload.

Backdraft Dampers

In 1992, the licensee found that a number of the dampers were installed backwards. This was a concern since, if improperly oriented, the force of the high energy line break condition could be sufficient to hold the damper partially open and permit the steam and moisture to move into other, unprotected compartments. This would invalidate the expected conditions for equipment qualification and cause a potential common mode failure mechanism to exist.

After discovery of this problem in 1992, the licensee corrected the improperly oriented dampers associated with the steam tunnel ventilation. While this corrective action was appropriate, the licensee failed to correct the other sets of dampers similarly mis-oriented. The resolution for these uncorrected dampers at that time was to "use-as-is," and to ultimately restore the condition at a future unspecified time. During this refueling outage as a result of the work scope verification process, the backdraft damper issue was again reviewed and determined not to be required to be repaired at this time. However, after an independent team review this issue was discussed with plant management. Subsequently plant management concluded that corrective actions were necessary prior to restart.

c. Conclusion

The team concluded that the DCPs were of good quality, with sufficient documentation and justifications, and adequate installation instructions. The instance noted of difficulties related to installation instructions dates from a period in which PSE&G has identified that there were problems with the generation of DCPs.

- Restart Issue:

The team identified a restart issue involving the improper installation of high energy line break backdraft isolation dampers. Specifically the dampers were installed in an unanalyzed fashion (backwards). The team concluded that this condition needed to be corrected or analyzed to ensure that an unreviewed safety condition did not exist prior to restart. The licensee's subsequent resolution of the issue prior to restart of the unit was inspected by the resident inspectors, and will be documented in a separate NRC inspection report.

3.5.2.2 Discrepancy Evaluation Forms

a. Scope

The team reviewed the list of DEFs which had been presented to and reviewed by ORC, and the list of those which had not. The inspector conducted a review of several DEFs selected at random from the list of those which had not been ORC reviewed. The DEFs selected were:

- DEH-92-0031, Discrepancies between 125/250VDC battery temperatures in UFSAR, Technical Specifications, and battery sizing calculations.
- DEH-93-0031, UFSAR Table 7.1-3 calls out an erroneous General Design Criterion for Primary Containment Isolation System
- DEH-94-0025, CBD, DITS, and UFSAR design basis descriptions need clarification regarding compliance with requirements for remote shutdown system redundancy

The DEF was a method of identifying, evaluating, and correcting discrepancies between design documents which can be resolved by paperwork changes, and without the need for any equipment modifications.

b. Findings/Conclusion

The team identified one issue in the review of the three DEFs:

Battery Temperature

DEH-92-0031 identified discrepancies between the battery temperature in the UFSAR, TS, and the battery sizing calculations. UFSAR, Section 8.3.2.1.2.2, indicated that Class 1E 125 and 250 VDC battery electrolyte temperatures will be in the range of 77±5°F, based upon the ventilation controller setpoint. The Class 1E battery sizing calculations used the lowest expected temperature of 72°F. Technical Specifications Section 3/4.8.2, DC Sources, requires battery electrolyte temperatures to be above 60°F for the Class 1E batteries to be operable.

The team discussed this matter with a System Engineering supervisor, and expressed concern that it appeared as though the TS allowed operation outside the design basis. PSE&G performed the following:

- Formulated revisions to the weekly and quarterly surveillance test procedures to require notifying the supervisor if electrolyte temperature drops below 72°F, while engineering conducted an evaluation of the condition.

- PSE&G engineering determined that based on the current capacity, the batteries have sufficient capability to meet design basis load at a temperature of 60°F, assuming an approximate 10 percent margin penalty for operation below 72°F.

Based on these actions the team did not have an operability or a restart concern. However, the resolution of this discrepancy is an unresolved item. **(UNRESOLVED ITEM 96-80-04)**

3.5.3 Engineering Support of Facilities and Equipment

3.5.3.1 <u>System Readiness Affirmations</u>

a. Scope

The team interviewed several system engineers, attended a meeting of the System Engineering Review Board (SERB), and attended several meetings of the Outage Review Committee (ORC), in order to observe the system readiness affirmation process.

b. Findings and Observations

The system engineers interviewed were knowledgeable of the condition of their assigned systems, the status of work in progress, and work scheduled for the remainder of the outage.

The SERB was intended to be a preparatory step for the system engineers going to the ORC. System Readiness Affirmations were presented to the SERB, and the presentation and knowledge of the system engineer were evaluated. In those cases where the system or presentation was not thought ready for ORC, the ORC review was rescheduled, and the system engineer was requested to perform additional research and/or evaluation and return at a later date. The SERB emphasized system knowledge.

The ORC, comprised of the department directors and chaired by the Plant Manager, made the final determinations on adding work to, or removing it from, the outage scope. System engineers presented the ORC with the system readiness affirmations, including outstanding work items. The ORC members asked detailed, probing questions relating to the work remaining to be performed to make the system ready to support plant startup. In several instances, the ORC directed system engineers to go back and reevaluate issues and items, and return at a later date with better answers to the questions.

c. Conclusion

Based upon the discussions with the system managers, observations made during the system walkdowns, and the system readiness presentations made to the ORC, the team concluded that the system readiness affirmation process would ensure that plant systems would be ready to support plant startup when the outage ended.

3.5.3.2 <u>Material Condition of Facilities and Equipment</u>

a. Scope

The team toured the facility including the drywell, both in company with system managers during system walkdowns and alone, observing the material condition of the equipment, structures, and surrounding areas. In addition, the inspector reviewed the System Indexed Data System (SIDS) printouts for several systems to evaluate the effect of outstanding equipment deficiencies and work activities on restart readiness.

b. Findings and Observations

The plant areas toured were generally well preserved and the equipment appeared to be in good condition. The exception to this observation was the traveling screen room in the Service Water Intake Structure, which exhibited widespread corrosion of the structural steel, conduits, cable armor, and junction boxes. These conditions were noted during the PSE&G system walkdown conducted during the outage and were documented in the SIDS printout. The traveling screens themselves appeared to be well-maintained and in a good state of repair.

c. Conclusion

Based upon the facility tours, discussions with system managers, and reviews of the SIDS printouts, the inspector concluded that, although the systems were not then ready to support startup, the Nuclear Engineering Department was effectively tracking, evaluating, and resolving the material deficiencies of plant equipment. Appropriate consideration was being given to safety significance and effect on restart readiness.

3.5.4 Engineering Procedures and Documentation

a. Scope

The team reviewed the following administrative procedures which affect Engineering Activities:

- NC.NA-AP.ZZ-0006, Corrective Action Program
- NC.NA-AP.ZZ-0009, Work Control Process
- NC.NA-AP.ZZ-0013, Control of Temporary Modifications
- NC.NA-AP.ZZ-0008, Control of Design and Configuration Change, Tests, and Experiments
- NC.NA.ZZ-0054, Operating Experience Feedback (OEF) Program
- HC.SA-AP.ZZ-0005, Operational Readiness Self Assessment Program
- SA-SD.ZZ-0008, System Readiness Review Board and System Engineering Review Board
- HC.TE-DD.ZZ-0004, System Engineering Walkdown Program
- HC.TE-DD.ZZ-0005, Support System Readiness Review Program

b. Findings and Observations

The team noted that the procedures provided guidelines and controls for the conduct of the related activities. However, some procedures had not kept up with the rapid pace of changes in the associated programs. The most notable example was the Operating Experience Feedback Program, which was substantially revised in late 1995, and the procedure revision draft was submitted for review and approval while the team was on-site in February 1996.

c. Conclusions

The team concluded that the administrative procedures provide appropriate guidance for conducting engineering activities. In those cases where process changes are being implemented, revisions to the governing procedures were being made.

3.5.5 Nuclear Engineering Department Organization

a. Scope

The team reviewed the Nuclear Business Unit Organization Charts, dated December 1, 1995, which were provided to the team at the February 12, 1996, entrance meeting, the Impact Plan as it applies to Nuclear Engineering, and the Engineering Improvement Plan. The team also interviewed system engineers, managers and supervisors in design and project engineering, and quality assurance auditors.

b. Findings and Observations

As previously noted under the discussion of procedures, the team found that the organization charts had not kept pace with the rapid changes occurring within the organization. Based upon the information provided during the interviews, the inspector determined that the Nuclear Engineering organization had undergone several changes, in order to be able to better respond to the emergent issues which developed during the Hope Creek outage. At the time of the inspection, PSE&G planned to revise the engineering organizational structure again, after restart, in order to better match the needs of the day-to-day operation of the plant.

c. Conclusions

The team concluded that the Nuclear Engineering Department was appropriately configured to meet the needs of completing the refueling outage. In addition, due consideration appears to have been given to the need to support facility operation in the long term.

3.5.6 Quality Assurance in Engineering Activities

3.5.6.1 Quality Assessment Activities

a. Scope

The team interviewed three quality assessment auditors involved with the reviews of the Nuclear Engineering Department, and reviewed the following Quality Assessment Surveillance Reports:

- Surveillance Report 95-158, System Readiness Review
- Surveillance Report 96-005, Engineering Improvement Plan Assessment
- Surveillance Report 96-006, System Readiness Assessment

b. Findings and Observations

Quality Assurance personnel monitored the conduct of the system readiness assessments for the six systems which received full field walkdowns (Recirculation System, Emergency Diesel Generators, Control Rod Drive System, Service Water System, Filtration Recirculation and Ventilation System, and Radiation Monitoring). In addition, Quality Assurance personnel conducted their own walkdowns of five systems important to startup (Feedwater, Condensate, High pressure Coolant Injection, Reactor Core Isolation Cooling and Standby Liquid Control), and partial walkdowns of three others (Reactor Protection System, 1-E Chilled Water, and Main Turbine). The results of the QA walkdowns were compared to the results of the system engineering readiness assessments through attendance at the system readiness affirmations at ORC, or through directly questioning the system manager.

QA concluded that the system readiness assessment and ORC review process were still being worked out during the first several ORC meetings they attended. QA also determined that the process improved during the course of the affirmations, and resulted in thorough, professional, and effective reviews. At that time, QA also concluded that the systems were not ready to support restart, but that completion of the work as scheduled should ensure that the systems would be capable of supporting startup. QA also determined that appropriate controls were applied to the process for removing work items from the outage scope.

QA review of the Engineering Improvement Plan found it to be well-organized and broad-based. It was also considered a major step toward improving engineering performance, and was properly implemented. While progress and good initiatives were noted in several areas, QA was unable to verify the effectiveness of many of the assessments since they were still ongoing. Although QA identified several weaknesses, none were judged by them to prohibit restart. In addition, they noted several strengths in the plan, including a commitment to improve analysis and trending of performance, as exemplified by the development of the performance indicators on the Local Area Network(LAN).

c. Conclusions

The team concluded that Quality Assessment was conducting well-focused reviews of engineering activities. The findings and conclusions were well developed and documented, and recommendations were included for enhancing the performance of the Nuclear Engineering Department.

3.5.6.2 <u>Engineering Self-Assessment Activities</u>

a. Scope

The team discussed reviews being conducted by the engineering department during interviews with engineering department personnel, and reviewed the Nuclear System Engineering Division Self Assessment and the Nuclear Engineering Assessment to Support Hope Creek Startup Readiness for reviews conducted and resulting actions. In addition, the inspector was briefed by

PSE&G personnel on the new performance indicators program which was being developed and being made available on the PSE&G LAN.

b. Findings and Observations

PSE&G had contracted for an independent technical review of Design Change Packages (DCPs) produced by the engineering department early in the outage. The review was to assess the conformance of the DCPs to the design basis, licensing basis, and regulatory requirements, to ensure the original issue was appropriately addressed, to ensure that adequate installation instructions were provided, and to verify that associated drawings, procedures, and materials listings were being updated. Most of the deficiencies identified occurred in packages developed during the early part of the outage, during the rapid escalation of the work scope. The deficiencies were attributed largely to the rapid turnaround required, and the large number of contractor personnel being drawn into the process who were not familiar with the PSE&G program. As a result of this effort, several changes to the DCP process were initiated, including:

- line by line check of the DCP during peer review,

- requiring conceptual and constructability walkdowns during the design phase, and installation walkdowns prior to the installation,

- review by Operations to ensure that appropriate procedures were identified for revision, that the change appropriately addressed the plant condition targeted, that the Tagging Request and Inquiry System was revised as needed to support facility operation after completion of the modification,

- review by Station Maintenance to verify that affected maintenance procedures have been addressed as part of the design change and that recurring tasks (preventive maintenance and surveillance testing) were revised as needed, and,

- review by Station Planning to ensure that necessary parts and materials have been ordered, parts made obsolete by the change were deleted from inventory, and appropriate operational spares have been ordered or an inventory analysis has been performed to ensure an adequate inventory was on hand.

At the time of the inspection, another independent contractor was conducting a continuing technical review of the quality of completed DCPs.

During the presentation on the new Engineering Performance Indicators for Hope Creek, many of the functions had to be demonstrated using the Salem performance indicators since most of the Hope Creek data had not yet been entered. The performance indicators were a graphical representation of various functional areas using color coded boxes: green for good performance, yellow for weak performance, and red for unacceptable performance. The top level areas, when selected, showed breakouts to smaller functional units on subsequent screens. The original intent was that if a subarea was shown in red (unacceptable), that red indication would carry all the way up to the top level indicator on the first screen. During the demonstration, using the Salem indicators, the inspector noted that one functional area showing yellow, broke down to a group of subareas showing green, yellow and red. This indicated the existence of a program flaw which had not yet been fully rectified.

c. Conclusions

The Nuclear Engineering department planned improvements to enhance the quality of completed engineering work. While not yet competed the team noted progress toward attaining several of the program goals, specifically in performance tracking and trending.

ATTACHMENT 1

STATE OF NEW JERSEY

DEPARTMENT OF ENVIRONMENTAL PROTECTION

BUREAU OF NUCLEAR ENGINEERING

LETTER DATED APRIL 12, 1996

State of New Jersey

Christine Todd Whitman
Governor

Department of Environmental Protection
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Robert C. Shinn, Jr.
Commissioner

April 12, 1996

Mr. Richard W. Cooper, Director
Division of Reactor Projects
U.S. Nuclear Regulatory Commission
475 Allendale Road
King of Prussia, PA 19406

Dear Mr. Cooper:

Subject: Hope Creek Readiness Team Inspection

This letter revises our April 8, 1996 letter to correct a typographical error. In accordance with the provisions of the Memorandum of Understanding between the Nuclear Regulatory Commission and the New Jersey Department of Environmental Protection, we are providing feedback regarding the Hope Creek Readiness Assessment Team Inspection (RATI). A representative of the Bureau of Nuclear Engineering observed the the RATI.

This participation was especially valuable for the DEP since it scrutinized processes, programs and personnel performance that are common to both Salem and Hope Creek.

During the three weeks, the observer consistently noticed the awareness of the corrective action system in all groups and at all levels of personnel associated with Hope Creek. This behavior is the one, single, noticeable, positive change at Hope Creek. Every problem that came up was recognized as needing to be captured as an Action Request. Sometimes multiple Action Requests were issued where multiple aspects to a problem were recognized. Even the Design Engineering Group, a group not typically connected to daily plant problems, identified the need to formally identify problems for corrective action and root cause analysis.

At this point, our confidence with PSE&G's ability to document problems and take immediate action if appropriate is significantly higher. However, the key for long term success is in their actions to prevent recurrence. It is in this area where meaningful trending, effective root cause analysis, a questioning attitude, and investigating the extent of an adverse condition become critical. It is in these areas where the NRC must continue to focus and the BNE will continue to observe.

In addition, budget cuts are inevitable at the NBU. Problems entered into a formal corrective action system cost manpower to resolve. It is important that future inspections look for any change in management direction regarding the entering of problems into a corrective action system (e.g. lowering problem thresholds or discouraging problem identification in some way). The feedback mechanism to be developed by PSE&G, to inform the originator of an Action Request of its outcome needs to be implemented. This current lack of feedback tends to be a discouragement to an originator, because he is unaware if any action was ever taken on his/her problem.

A second, noticeable, positive change is the presence and the impact of Quality Assessment personnel. Many individuals spoke highly of this group and valued their input, including the NRC. These personnel observed many of the oversight and outage related meetings and they were present in the Control Room and at training in the simulator. The Hope Creek Plant Manager toured the facility regularly with the QA Manager for Hope Creek and was extremely positive about the changes made in this area.

Two other positive aspects of change were noted. The Operating Experience Feedback Group is functioning as a more visible entity with increased management oversight than observed previously. This is an area where we would like to observe follow up inspections as part of the Salem restart review activities or the Hope Creek Integrated Performance Assessment Process Inspection. Establishing a dedicated Hope Creek engineering group with its own contracted architect-engineering firm is a sound decision that appeared to contribute to timely support by engineering. It is important that PSE&G remain committed to consistent, high standards at Hope Creek and not redirect financial and human resources to support the Salem restart. The NRC inspectors for the Salem restart activities and the Resident Inspectors need to be wary of this and raise this as an issue immediately if it is detected.

For the most part these observations were communicated directly to Mr. Jim Linville and the inspection team during the inspection. In keeping with the spirit of the agreement between the DEP and the NRC, we will not disclose these observations to the public until the NRC releases its final report. If you have any questions, please contact me.

Sincerely,

Kent W. Tosch

Kent W. Tosch, Manager
Bureau of Nuclear Engineering

cc: Dave Chawaga, NRC
Dr. Jill Lipoti, DEP
Dennis Zannoni, DEP

ATTACHMENT 2

EXIT MEETING ATTENDEES

NRC

R. Cooper
J. Linville
L. Nicholson
J. Stolz
D. Jaffe
R. Summers
S. Morris
C. Marschall
D. Screnci

PSE&G

L. Eliason
E. Simpson
G. Overbeck
M. Reddeman
J. Benjamin
C. Warren
C. Clapper
M. Trum
E. Harkness
J. Pollack
K. Maza
J. Ranalli
W. Mattingly
D. Tauber
T. Kirwin
R. Gambone
M. Pacy
C. Fricktel
R. Jackson
M. McGough
J. Flannagan
M. Marano
B. Furman
J. Polyac

Other

R. Pinney, New Jersey, Bureau Radiation Protection
K. Kille, Delaware Emergency Management Agency
J. Janocha, Atlantic Electric
E. Davis, Lower Alloways Creek
M. Gray, Today's Sunbeam
C. Satiritz, WCAU-TV
N. Brown-Washington, WCAU-TV
M. Buniy, News Journal
M. Murray, News Journal
R. Fiske, S. Dennis
M. Farschon, General Electric

ATTACHMENT 3

NRC EXIT MEETING SLIDES

MARCH 1, 1996

UNITED STATES NUCLEAR REGULATORY COMMISSION

HOPE CREEK

RESTART ASSESSMENT TEAM INSPECTION

NRC INSPECTION 50-354/96-80

EXIT MEETING

MARCH 1, 1996

INSPECTION OBJECTIVE

ASSESS THE READINESS OF THE PSE&G STAFF, PROGRAMS AND THE HOPE CREEK FACILITY FOR A SAFE STARTUP AND CONTINUED OPERATION UPON COMPLETION OF THE SIXTH REFUELING OUTAGE

INSPECTION SCOPE AND STAFFING

- EIGHT TEAM MEMBERS FROM NRC REGION I AND HEADQUARTERS AND ONE NEW JERSEY STATE OBSERVER

- ONSITE INSPECTION DATES FEBRUARY 12-28, 1996

- INSPECTORS CONDUCTED INSPECTION ACTIVITIES ON ALL SHIFTS INCLUDING NIGHTS AND A HOLIDAY

- OVER 1000 HOURS OF DIRECT INSPECTION

PERFORMANCE ASSESSMENT AREAS

- MANAGEMENT OVERSIGHT
- OPERATIONS
- ENGINEERING
- MAINTENANCE

MANAGEMENT OVERSIGHT

- MANAGEMENT EXPECTATIONS ARE CLEARLY COMMUNICATED AND PROPERLY IMPLEMENTED BY THE STAFF
- OPERATING EXPERIENCE REVIEWS ACCEPTABLE
- TECHNICAL SPECIFICATION SURVEILLANCE IMPROVEMENT PROGRAM HAS IDENTIFIED, REPORTED AND CORRECTED DEFICIENCIES IN SURVEILLANCE PROCEDURES AND GOES BEYOND THE GUIDANCE OF RECENT NRC GENERIC CORRESPONDENCE ON LOGIC CIRCUIT TESTING
- THE THRESHOLD FOR PROBLEM IDENTIFICATION HAS BEEN LOWERED AND PROBLEMS ARE BEING APPROPRIATELY IDENTIFIED
- ROOT CAUSE EVALUATIONS FOR SIGNIFICANT PROBLEMS AND CORRECTIVE ACTIONS HAVE GENERALLY BEEN APPROPRIATE
- QUALITY ASSURANCE ASSESSMENTS WERE EFFECTIVE
- STATION OPERATIONS REVIEW COMMITTEE MET TECHNICAL SPECIFICATION REQUIREMENTS.
- DEPARTMENTAL STARTUP SELF ASSESSMENTS WERE ACCEPTABLE

- THE OUTAGE REVIEW COMMITTEE ASKED PROBING QUESTIONS AND WAS A STRENGTH IN ASSESSING SYSTEM, DEPARTMENTAL AND OPERATIONAL READINESS

OVERALL CONCLUSION

MANAGEMENT PROGRAMS INCLUDING THE CORRECTIVE ACTION PROCESS, INDEPENDENT OVERSIGHT FUNCTIONS AND THE SELF ASSESSMENT PROCESS WERE SUFFICIENT TO SUPPORT A SAFE PLANT RESTART AND CONTINUED OPERATION.

OPERATIONS

- OPERATORS CONTROLLED COMPLEX ACTIVITIES SAFELY AND EFFECTIVELY
- SHIFT TURNOVERS AND PRE EVOLUTION BRIEFINGS WERE THOROUGH
- OPERATORS USED PROCEDURES APPROPRIATELY
- CONTROL ROOM OPERATIONS WERE FORMAL AND PROFESSIONAL
- SYSTEM AND EQUIPMENT CONFIGURATIONS WERE USUALLY CONSISTENT WITH ADMINISTRATIVE CONTROLS
- OPERATOR WORK AROUNDS, CONTROL ROOM DEFICIENCIES AND TEMPORARY MODIFICATIONS WERE SUBSTANTIALLY REDUCED DURING THE OUTAGE AND THOSE REMAINING SHOULD NOT SIGNIFICANTLY IMPACT OPERATOR PERFORMANCE
- STARTUP PROCEDURES WERE ADEQUATE TO SUPPORT RESTART
- PROCEDURE REVISIONS REQUIRED TO SUPPORT OPERATIONS HAVE BEEN IDENTIFIED AND WILL BE IMPLEMENTED PRIOR TO RESTART

- PROBLEMS IDENTIFIED WITH PERFORMANCE OF OPERABILITY DETERMINATIONS WILL BE ADDRESSED BY IMPROVED GUIDANCE PRIOR TO RESTART

- OPERATOR REQUALIFICATION TRAINING WAS CURRENT

- STARTUP SIMULATOR TRAINING HAS BEEN STRENGTHENED AND WILL BE COMPLETED PRIOR TO RESTART

OVERALL CONCLUSION

OPERATIONS PROGRAMS, PROCEDURES, AND STAFF ARE ADEQUATE TO SUPPORT A SAFE STARTUP AND CONTINUED OPERATION

ENGINEERING

- SYSTEM READINESS REVIEWS AND WALKDOWNS APPROPRIATELY SCREENED OUTSTANDING ISSUES FOR RESTART
- PLANT MATERIAL CONDITION WAS GENERALLY GOOD
- SYSTEM MANAGERS WERE KNOWLEDGEABLE AND UNDERSTOOD MANAGEMENT PERFORMANCE EXPECTATIONS
- THE REORGANIZATION OF NUCLEAR ENGINEERING TO INCLUDE DESIGN ENGINEERING AND SYSTEM ENGINEERING HAS IMPROVED COORDINATION AND COMMUNICATIONS
- DESIGN CHANGE PACKAGES WERE GENERALLY GOOD INCLUDING CHANGES TO DRAWINGS, PROCEDURES AND THE FSAR
- TARGETS FOR THE DISPOSITION OF TEMPORARY MODIFICATIONS WOULD BE USEFUL IN FURTHER REDUCING THE RELATIVELY SMALL BACKLOG
- THE SYSTEM READINESS REVIEW BOARD GENERALLY PREPARED SYSTEM MANAGERS WELL FOR READINESS AFFIRMATIONS BY THE OUTAGE REVIEW COMMITTEE

OVERALL CONCLUSION

THE ENGINEERING STAFF, PROCEDURES, AND PROGRAMS WERE ADEQUATE TO SUPPORT A SAFE STARTUP AND CONTINUED OPERATION

MAINTENANCE

- THE WORK CONTROL PROCESS WAS EFFECTIVE
- THE NEW WORK WEEK MANAGEMENT PROCESS WAS PILOTED DURING THE INSPECTION AND APPEARED TO BE EFFECTIVE
- THE PREVENTIVE MAINTENANCE PROGRAM WAS ADEQUATE.
- THE RELATIVELY LARGE PREVENTIVE MAINTENANCE BACKLOG WAS APPROPRIATELY SCREENED FOR RESTART AND PLANNED FOR REDUCTION
- POST MAINTENANCE RESTORATION AND TESTING WAS USUALLY EFFECTIVE
- SURVEILLANCE TESTING WAS GENERALLY CONDUCTED WELL
- THE CORRECTIVE MAINTENANCE PROCESS WAS USUALLY EFFECTIVE WITH DETAILED WORK PACKAGES, APPROPRIATE PROCEDURES AND RETEST REQUIREMENTS
- THE CORRECTIVE MAINTENANCE BACKLOG WAS APPROPRIATELY REVIEWED FOR RESTART

- MAINTENANCE ACTIVITIES WERE USUALLY ACCEPTABLE EXCEPT TWO VIOLATIONS FOR WORK PERFORMED ON SERVICE WATER STRAINERS WITHOUT AN ADEQUATE PROCEDURE

OVERALL CONCLUSION

PLANNING AND MAINTENANCE PROGRAMS AND PROCESSES WERE ADEQUATE TO SUPPORT SAFE RESTART AND CONTINUED OPERATION

RESTART ISSUES

- COMPLETE ROOT CAUSE ANALYSIS AND IMMEDIATE CORRECTIVE ACTION FOR MULTIPLE RECENT SERVICE WATER STRAINER FAILURES INCLUDING ADEQUATE SPARE PARTS TO ASSURE THE ABILITY TO RESTORE THE SERVICE WATER PUMPS TO OPERATION SHOULD FUTURE FAILURES OCCUR

- COMPLETE PHYSICAL VERIFICATION OF CONTAINMENT ISOLATION VALVES

- COMPLETE REVIEW OF BACKDRAFT DAMPERS AND ASSURE THE PLANT IS CONSISTENT WITH LICENSING BASIS OR THERE IS AN ADEQUATE ANALYSIS AND 10 CFR 50.59 EVALUATION TO CHANGE THE FSAR