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REGION I

Report No.: 50-387, 388/90-81

License No.: NPF-14, NPF-22

Licensee: Pennsylvania Power & Light Company
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Allentown, Pennsylvania

Facility: Susquehanna Steam Electric Station

Inspection at: Berwick, Pennsylvania

Inspection conducted: October 9 - 19 and November 5 - 9, 1990

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Inspection Summary: A special, announced maintenance team inspection was performed at the Susquehanna Steam Electric Station on October 9-19, 1990 and November 5-9, 1990 (50-387, 388/90-81).

Areas Inspected: The maintenance program at the Susquehanna Steam Electric Station and its implementation were inspected in depth. The team reviewed maintenance documents, interviewed responsible personnel, and observed maintenance work being performed. The inspectors used the NRC Maintenance Inspection Guidance, dated September 1988, and Temporary Instruction 2515/97, dated September 22, 1989.

Results: The maintenance program for the Susquehanna Steam Electric Station was, for the most part, functioning well. Strengths and weaknesses identified are discussed in detail in this report. Five violations and five unresolved items were identified. A violation concerning failure to complete 10 CFR 50.59 safety evaluations is described in Sections 1.2 and 5.1. Violations for failure to follow procedures, failure to preplan work, and failure to maintain the environmental qualification of equipment are described in Section 5.1. A fifth violation concerning the inadequacy of procedure reviews is addressed in section 5.8. Unresolved items concerning the bend radius of battery cable, high temperatures in the HPCI and RCIC rooms, and the possible hazard posed when fuel tankers are parked next to the emergency diesel generator buildings are described in Section 1.2. An unresolved item concerning the EQ requirements of a temperature detector is addressed in Section 5.1. A fifth unresolved item concerning a technical specification change for the torque setting on the containment isolation valve in the reactor water cleanup suction line is described in Section 5.5.

In addition, weaknesses identified which need to be addressed by the licensee, are listed in Appendix 2.

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EXECUTIVE SUMMARY

Background

The Nuclear Regulatory Commission (NRC) considers effective maintenance of equipment and components a major aspect of ensuring safe nuclear plant operations and has made this objective one of its highest priorities. On March 23, 1988, the Commission issued a policy statement that states, "It is the objective of the Commission that all components, systems, and structures of nuclear power plants be maintained so that plant equipment will perform its intended function when required. To accomplish this objective, each licensee should develop and implement a maintenance program which provides for the periodic evaluation and prompt repair of plant components, systems, and structures to ensure their availability."

To ensure effective implementation of the Commission's maintenance policy, the NRC staff is undertaking a major program to inspect and evaluate the effectiveness of licensee maintenance activities. This inspection was one of this program of inspections to evaluate effectiveness of maintenance activities. The inspection was conducted in accordance with guidance provided in NRC Temporary Instruction 2515/97, dated September 22, 1989, and the NRC Maintenance Guidance, Volumes 1 and 2, dated September 1988. The temporary instruction includes a "maintenance inspection tree" that identifies for inspection the major elements associated with effective maintenance.

Scope of Inspection

The inspection team evaluated three major areas: (1) overall plant performance as affected by maintenance; (2) management support of maintenance; and (3) maintenance implementation. Under each of these major areas, elements considered important for proper functioning of the area were inspected. For each element, the inspectors evaluated both the program and the effectiveness of program implementation.

The inspection at the Susquehanna Steam Electric Station (SSES) was initiated with a site meeting on September 12 - 13, 1990, where the scope of the inspection, including the maintenance inspection tree, was discussed with licensee management. A list of requested site-specific information had been provided previously to the licensee by letter dated August 20, 1990. A comprehensive pre-inspection submittal of information based on this request was provided to the team leader by SSES personnel at the Region I offices on September 24, 1990.

The NRC inspection team spent September 24 to October 5, 1990, at the NRC Region I office preparing for the inspection and examining the information submitted by the licensee. The team received site-specific training, badging, and a briefing by licensee staff on September 27, 1990. The team conducted an onsite inspection at the SSES from October 9 to October 19, 1990. The team leader and two other inspectors conducted an additional onsite followup inspection from November 5 to November 9, 1990.

SSES was in a planned Unit 1 refueling outage during the course of the entire inspection; Unit 2 was operating at a high power level but at less than 100 percent power. The inspection was directed at observation of maintenance work in progress and licensee activities supporting this work, including engineering, training, and management. Maintenance activities selected for detailed review included equipment identified by application of the Probabilistic Safety Study (i.e., probabilistic risk assessment (PRA)) as having the potential for contributing significantly to core damage accident sequences or reduction of the risk associated with plant operation. Other components and maintenance activities were selected for inspection based on work in progress during the inspection, recent malfunctions of safety-related equipment, special interest items, and NRC inspection experience.

The NRC team leader held daily meetings with plant management to summarize the inspection team findings and to identify areas where additional information was required. The team members also apprised the maintenance staff of their findings daily. On October 18, 1990, a meeting was held with cognizant licensee management for each NRC inspector to present significant findings. The summary of the inspection team findings, including the team's evaluated maintenance inspection tree, was discussed during an exit meeting with licensee representatives from management, supervisory, and engineering staff on October 19, 1990. See Appendix 1 for attendees.

In addition to the primary purpose of this maintenance team inspection, a PRA team was integrated into the inspection for the purpose of evaluating a generic BWR PRA methodology that is being developed by the NRC for site-specific applications. This draft methodology uses risk insights from the available BWR PRAs to develop representative accident sequences and to prioritize systems and components based on risk. This effort was integrated into the MTI by providing the team with a generic risk-based prioritization of BWR systems and components for inspection purposes. In addition, the SSES individual plant evaluation (IPE), which was not a part of the generic methodology's database, was reviewed. The SSES dominant accident sequences were somewhat different from the draft methodology's list of representative accident sequences. This is primarily attributable to the licensee's concerted efforts to reduce its exposure to the accident sequences such as station blackout and anticipated transients without scram (ATWS) that typically are a major fraction of the core damage frequency in other BWR PRAs. The results of this PRA effort will be reported elsewhere.

Results

The inspection results for each of the major areas evaluated are summarized in the following paragraphs. Weaknesses are listed in Appendix 2.

I. OVERALL PLANT PERFORMANCE RELATED TO MAINTENANCE

Susquehanna Steam Electric Station (SESS) availability and operability was functioning well as related to the maintenance process. The team found the overall material condition of the plant to be well maintained, although in walkdown inspections the team noted some exceptions.

II. MANAGEMENT SUPPORT OF MAINTENANCE

Management support of maintenance was functioning well. Licensee plant and corporate management are actively involved in the maintenance process. Corporate managers displayed strong support of maintenance activities, including active onsite presence.

A Maintenance Function Five Year Plan identifies, prioritizes and schedules improvement activities. Management support is evident by financial commitment and the progress being made. Currently, a preventive maintenance improvement program (PMIP) is being developed which uses some reliability-centered maintenance initiatives. Some predictive maintenance programs are in place and more are being planned. PP&L has actively supported industry groups and initiatives including INPO, NUMARC, and EPRI.

III. MAINTENANCE IMPLEMENTATION

Overall maintenance work implementation was adequate in both program and execution. The team found most work to be well planned and implemented; however, a few incidents were observed where improvement was needed in planning and execution. Maintenance facilities support the maintenance process well and additional improvements are planned. Personnel controls were in place and functioning well.

The licensee has a work control program that functions adequately. The team observed that work was scheduled appropriately and was performed by well trained and qualified maintenance personnel. Radiological and radiation exposure ALARA (as low as reasonably achievable) controls were implemented effectively. Meetings to plan, coordinate, and schedule tasks ensured good communication and cooperation among work groups.

Overall, the team concluded that the maintenance process implementation was described and executed adequately. The plant's organization of maintenance into functional areas strengthened the maintenance process.

The Maintenance Inspection Tree

The inspection team's conclusions on the maintenance program are indicated by colors (green, yellow, red or blue) on the Maintenance Inspection Tree (Figure 1). For parts II and III of the tree, the upper-left portion of each block indicates how well the topic of the block is described and

documented, including the adequacy of procedures. The lower-right portion of each block indicates the effectiveness of implementation. Green indicates that the program is well documented or that the program implementation is effective. Even for blocks shaded green, however, some areas for improvement may be indicated. Yellow indicates adequacy, but the element could be strengthened, and red indicates the topic is missing or the intent is not being met. Blue indicates the item was not or could not be evaluated because of insufficient data. There were no blue colored blocks on the SSES tree.

Overall Conclusions

The maintenance process is well documented at SSES. The significant attributes of the maintenance are performing well. The implementation of the maintenance process is adequate but could be improved. Individual weaknesses are discussed in the appropriate areas of the report and are summarized in Appendix 2. Five violations were identified. A violation concerning failure to complete 10 CFR 50.59 safety evaluations is described in Sections 1.2 and 5.1. Violations for failure to follow procedures, failure to preplan work, and failure to maintain the environmental qualification of equipment are described in Section 5.1. A fifth violation concerning the inadequacy of procedure reviews is addressed in section 5.8. Unresolved items concerning the bend radius of battery cable, high temperatures in the HPCI and RCIC rooms, and the possible hazard posed when fuel tankers are parked next to the emergency diesel generator buildings are described in Section 1.2.

The violations and weaknesses identified indicated to the team that for several areas, management attention was warranted. However, these did not distract measurably from the overall excellent direction of the maintenance process at SSES. The team was impressed by the existing excellent overall material condition of the plant including management's involvement and support of the maintenance process. Also, additional plant improvements are planned or underway. Overall implementation of the maintenance process was found by the team to be good; however, the evaluation was tempered by performance inadequacies for several safety-related activities witnessed by the team.

INSPECTION FINDINGS*

I. OVERALL PLANT PERFORMANCE RELATED TO MAINTENANCE

1.0 DIRECT MEASURES

Scope

The team reviewed the availability, operability, and material condition of the plant relative to effective maintenance. Plant equipment and systems were inspected to determine the general plant condition and to identify deficiencies, safety precautions, and tagouts of equipment. Maintenance activities were observed.

1.1 Historical Data

Scope

The team reviewed historical data from Units 1 and 2 that would reflect the possible effects of maintenance on plant operation. Some of the indicators used in this evaluation were: capacity factor (CF), unplanned reactor trips, engineered safety feature (ESF) actuations, systematic assessment of licensee performance (SALP) ratings, licensee event reports (LERs) attributed to maintenance, and radiation exposure. The following list summarizes a portion of the data evaluated.

Findings

- CF (most recently completed fuel cycle)
  - Unit 1 had a 75 percent CF for fuel cycle 4, a 5 percent increase over the previous fuel cycle, and ranked fourth among U.S. boiling-water reactors (BWRs) rated above 1000 MWe.
  - Unit 2 had a 79 percent CF for fuel cycle 3, also a 5 percent increase in CF over the previous cycle, placing it second among large U.S. BWRs.
  - The station performed very well in comparison with the U.S. industry average CF of sixty-three percent.
- Automatic scrams while critical (reported by AEOD)
  - Unit 1 had one scram in the last 18 months (period ending September 1990) and it was not attributed to maintenance.

*Note: Acronyms and abbreviations used in this report are defined in Appendix 5

- Unit 2 had two scrams in the last 18 months (period ending September 1990), one of which was related to maintenance.

- Indicators based on LERs show both units improving in the area of maintenance problems, over the last six months evaluated (period ending June 1990).

- Unscheduled maintenance during last completed fuel cycle

  - Unit 1 mid-cycle shutdowns or reductions from 100 percent power accounted for 13 percent of the total fuel cycle period.

  - Unit 2 mid-cycle shutdowns or power reductions accounted for only 7 percent of the total fuel cycle.

  - SSES units required less mid-cycle maintenance than the average U.S. BWR which spent 18 percent of its fuel cycle period on unscheduled maintenance.

- ESF actuations in 1990

  - Unit 1 had five ESF actuations as of October 15, 1990, and was below its 1990 goal of nine.

  - Unit 2 had three ESF actuations as of October 15, 1990, and was below its 1990 goal of five actuations.

  - Unit 2 has historically been a better performer since start-up. This accounts for the difference in the goals set for ESF actuations.

The licensee's performance in the area of cumulative radiation exposure for the past four years was as follows:

YEAR	COLLECTIVE DOSE PER REACTOR (man-rem)
1986	414
1987	311
1988	258
3-year average ('86-'88)	328*
1989	352
3-year average ('87-'89)	307*

* Indicates 3-year average was within best quartile performance for all BWRs.

Conclusion

Overall, performance indicators for both units exceeded industry averages, reflecting well on the maintenance process. SSES has increased its availability, reducing the time lost to unscheduled maintenance, through good maintenance practices. Availability data also show that safety-related equipment has been maintained at a high enough level to ensure operability and dependable performance. The cumulative radiation exposure performance data indicate that the licensee has been aggressive in maintaining cumulative occupational radiation exposure low at the station.

1.2 Plant Walkdown Inspection

Scope

By conducting walkdown inspections of the general plant in addition to spot inspections of selected systems and components, the team assessed the material condition of the plant and determined the effectiveness of the licensee's general housekeeping, deficiency reporting, and walkdown inspections. Overall, the material condition and general housekeeping of each unit were adequate. However, a few deficiencies were identified. Details concerning the following deficiencies and other findings with less safety significance are listed in Appendix 6.

Findings

The inspection team noted several modifications that were installed on safety-related and non-safety-related systems without documented 10 CFR 50.59 safety evaluations. These are examples of a violation and are discussed in detail in the following paragraphs.

On October 14, 1990, the inspector noted temporary lighting strings for the Unit 1 and 2 control rod drive (CRD) hydraulic control units (HCUs) on the 719-foot elevation. The lighting strings appeared to be temporary modifications. Upon review, the inspector found that the condition had been identified on March 26, 1984, by a nonconformance report (NCR). The lack of adequate corrective action to date suggests the modification had become permanent. There was no 10 CFR 50.59 safety evaluation.

On October 9, 1990, the inspector noted that the Unit 2 standby liquid control (SBLC) accumulator, 2T207B, charging connection cap had a hole drilled through the cap to accommodate a replacement Shrader valve too large to fit under an unmodified cap. The licensee could not produce a 10 CFR 50.59 safety evaluation for the modification. Subsequently, the licensee found a similar modification on the Unit 1 SBLC accumulator, 1T207A, charging connection cap, indicating that the problem was generic.

On October 10, 1990, the inspector noted a "temporary protection" structure on top of and attached to the Unit 2 main steam flow panel A and B, 2C041, on the 719-foot elevation. The structure consisted of unistrut, galvanized metal, and universal angle. The structure was positioned on top of the safety related instrument rack and connected to both the rack and containment wall-mounted instrument tubing supports. During a subsequent investigation, the licensee found that drawings and documentation for the panel did not indicate any design modification, analysis, or written safety evaluation for this temporary structure.

The above items are examples of a violation of the NRC requirements for failure to perform and document 10 CFR 50.59 safety evaluations (Violation 50-387, 388/90-81-01).

The team noted several deficiencies involving seismic mounting of gas bottles within the plant. Deficiencies included missing structural members on a bottle rack, improper thread engagement, and loose seismic restraints. Because of the generic nature and number of the deficiencies involving bottle racks, the licensee issued Significant Operating Occurrence Report (SOOR) 1-90-322 to address the generic issue. The action was appropriate.

Several large scaffolds in safety-related areas did not meet the requirements of the Plant Construction Technical Specifications for erection of scaffolding or scaffold inspection. After reviewing the issue, the inspector concluded that weaknesses exist in construction and inspection of scaffolds. These scaffolds pose a potential hazard and their adequacy during a seismic event is questionable. This issue was previously documented by Unresolved Item 50-387,388/89-81-02. The licensee responded by reviewing the program and committing to revise Construction Technical Specification (TS) C-1056, Revision 1, "Construction Technical Specification for Erection of Scaffolding in Safety Related Areas." Quality Assurance (QA) had planned to increase surveillance frequency upon implementing the revised TS, but, in response to the concerns raised, is reviewing the problem with the intention of increasing surveillance frequency immediately. This unresolved item will remain open.

A long standing NRC observation at SSES has been storage of unsecured materials and equipment in various locations in the plant that could become missile hazards in a seismic event. The NRC has expressed concerns about this for several years (e.g., NRC Inspection Reports 50-387, 388/87-12 (Open Item 87-12-004) and 50-387, 388/89-81 (Open Item 89-81-002)). The team also noted a number of similar deficiencies concerning materials storage in safety-related areas of the plant. The team observed unsecured items including large wheeled tool boxes, 55-gallon drums, wheeled circuit breaker test units, and large portable pumps on wheels. The team considered the items potential missile hazards which should be removed or restrained. The licensee has known about the problem and plans to issue a new procedure by November 15, 1990 that will address the problem in general. Management and staff appeared to be waiting for the procedure to be issued rather than taking short-term corrective action. In response to inspector concerns, the licensee removed or stored identified items. During the onsite followup inspection, the inspector found other transient equipment which presented potential missile hazards. Unsecured storage of equipment having seismic missile potential in safety related areas is considered a long standing weakness.

During walkdowns of the 250-V vital battery rooms, the inspector noted a tight bend radius on an intercell jumper for the Unit 1, division 2, battery. The licensee's response indicated that CD Power Systems, Inc., the battery vendor, did not see any problem with the bend radius from a battery qualification standpoint. During the onsite followup inspection, the licensee informed the inspector that the cable in question was a Belden welding cable and, according to Belden, no minimum radius is specified. SSES has agreed to perform an engineering evaluation; this item is considered unresolved pending its completion and inspection (Unresolved Item 50-387, 388/90-81-01).

During walkdowns of the Unit 2 high-pressure coolant injection (HPCI) and reactor core isolation cooling (RCIC) pump rooms on October 9, 1990, the inspector noted that the ambient room temperature was high. Subsequent inspection revealed that the RCIC pump room temperature had peaked at 107°F on September 14, 1990, exceeding the maximum design temperature for the room. SSES Final Safety Analysis Report (FSAR) Section 3.11 and Table 3.11-6 specified that the maximum design temperatures in the RCIC and HPCI pump rooms are 104°F and 100°F, respectively, for normal operations. This item is unresolved pending an SSES evaluation of possible consequences (Unresolved Item 50-387, 388/90-81-02).

On October 15-19, 1990, the inspectors observed the maintenance refueling of the A, B, C, and D emergency diesel generator (EDG) fuel oil storage tanks by means of two tanker trailers parked adjacent to the EDG building underneath the combustion air intake structure for the four EDG units. A fire in these oil tankers has the hazard potential to feed hot combustion gases directly into the engine air intakes. The engine vacuum has the potential to draft the flames and gases into the engines. This could cause the engines to fail to start or to shut down due to lack of oxygen. This is a potential common-mode failure of the diesels. The licensee moved the tankers in response to the inspector's concern. This item is unresolved pending an NRC review of SSES's evaluation of fuel tankers parked adjacent to the EDG building (Unresolved Item 50-387, 388/90-81-03).

During walkdowns the inspectors, for the most part, noted that radiological controls were well implemented. The controls were also well implemented into the maintenance process for work observed.

Conclusions, Section 1.0

The historical performance data and assessment of walkdown inspections indicate that the overall maintenance process at SSES as related to direct measures is functioning well. In general, the material condition and housekeeping throughout both units was superior. For the most part, the team observed that radiological controls were well integrated into the maintenance process. Violations and weaknesses identified by the team indicated to the team areas for increased licensee attention and improvement.

II. MANAGEMENT SUPPORT OF MAINTENANCE

2.0 MANAGEMENT COMMITMENT AND INVOLVEMENT

2.1 Application of Industry Initiatives

Scope

The team assessed through interviews, program and procedure reviews the extent that management (Corporate and Plant) supports and addresses industry initiatives regarding maintenance.

Findings

SSES's active involvement with industry organizations such as the Institute of Nuclear Power Operations (INPO), the Electric Power Research Institute (EPRI), and the Nuclear Utility Management and Resources Council (NUMARC) was evident in several areas examined. SSES provided input to draft Regulatory Guide 1.9, Revision 3, "Selection, Design, Qualification, Testing, and Reliability of EDG Units Used as Class 1E Onsite Electric Power Systems at Nuclear Power Plants." The revisions of initiative 5 and Appendix D from NUMARC-8700 were used in developing the regulatory guide. EPRI and INPO also support the program. SSES is involved in the EPRI motor operated valve (MOV) performance prediction program and is represented on its technical advisory group. It also has a member on the MOV subcommittee with the American Society of Mechanical Engineers (ASME). SSES provided input to INPO for INPO Good Practice MA-319, "Methodology for Preventive Maintenance (PM) Program Enhancement."

Pennsylvania Power and Light (PP&L) subscribes to the EPRI Non-Destructive Examination (NDE) Center and the EPRI Nuclear Maintenance Applications Center. These centers provide technical training and applications-oriented information to participating utilities. Some of the technical documents used by PP&L include "Technical Repair Guidelines for Limitorque Valve Operators," "Lube Notes," "Circuit Breaker Guide," and others. Although SSES does not have a problem at this time, PP&L was actively involved in the three EPRI reactor coolant pump and reactor recirculation pump shaft cracking workshops held to date. PP&L was also one of the first members of the Nuclear Industry Check Valve Group.

SSES supports employee involvement in industry code and standards groups such as ASME and the Vibration Institute. Many of the procedures and much of the equipment used in developing the predictive maintenance program were discussed during meetings, in professional periodicals, or at predictive maintenance conferences that employees have attended.

In addition to the aforementioned involvement, SSES originated the Cooper-Bessemer EDG User's Group and is involved in the Snubber User's Group. SSES is involved with another utility in researching the automated EDG predictive maintenance program which the other utility has

installed and is actively pursuing vibration monitoring of equipment including offering advanced vibration training at SSES.

Conclusion

SSES management takes a proactive approach to the use of industry resources. The level of involvement is very good and is an asset to the maintenance process.

2.2 Management Vigor and Example

Scope

The team determined through interviews and inspection assessments the extent to which management vigor (Corporate and Plant) affects the maintenance process.

Findings

Management vigor is shown in many of SSES's responses to industry and internal mechanical problems. PP&L responses to Generic Letters 88-14 and 89-13 are examples of this vigor. Generic Letter 88-14 required that instrument air be tested and the design verified. The facility complied with the letter, but in addition to actions required by the letter, local high-efficiency filters are being installed at critical components, the silica gel desiccant was replaced with activated alumina in the dryers, float-type drain traps were replaced with solenoid-operated drain valves, dryer pre- and after- filters were replaced with higher efficiency filters, an additional dryer skid was installed, and constant dewpoint monitoring was installed in Unit 1 and is scheduled to be installed in Unit 2. The SSES heat exchanger preventive maintenance (PM) and life extension program was one response to Generic Letter 89-13. This program provides comprehensive coverage for the maintenance of heat exchangers, including methods of cleaning and eddy current testing.

Although most observations indicated a high degree of vigor on the part of management, several contrary examples in this area were noted. Frequent failure of the Reactor Water Cleanup (RWCU) pump seals have been an ongoing problem industry wide. A replacement RWCU pump was identified by the industry several years ago, but SSES does not plan to install it until 1992. In the meantime, an average of 12 or more failures occur each year at the cost of two man-rem each. In addition, EDG negative Volt Amperes Reactive (VAR) overload trips have been acknowledged as an old problem. The short-term overloading of the EDG units while in the test mode is a problem that was first reported in SOOR 1-86-303. Although the root cause has been identified, no solution to the problem has been found yet.

Lack of contingency planning to handle the heat load potential in the drywell for the current outage was evidenced by the high-temperature condition in the drywell. The removal of service water (SW) from service was planned, so the loss of the ability to cool the drywell was a known

problem. The weather during the outage was not a known factor, but higher temperatures were a possibility. No preparation was made for hotter weather prior to the outage. No action was taken during the outage to correct the situation even though drywell stay times dropped to as low as 20 minutes from heat exhaustion considerations. The hot drywell temperatures created a stress factor on workers which could have been reduced had adequate contingency planning handled the heat load conditions.

The Nuclear Safety Assessment Group (NSAG) conducts a maintenance surveillance annually at the request of the Senior Vice President -Nuclear. This review monitors maintenance practices with regard to nuclear safety, to identify good practices, and to identify areas in need of improvement. In addition to this review, the Safety Review Committee (SRC) recently assumed the task of completing in-depth reviews of major department programs: maintenance and instrument and controls/computer (I&C/C) were two of the programs scheduled for review.

The maintenance department's evolving organization is one of its most recent and dynamic changes made in response to self-assessment. The organization now contains technical teams to deal with different problem areas in the plant. These groups include valve, nuclear steam supply system (NSSS), EDG, testing, electrical, and balance-of-plant (BOP) maintenance. Each of these teams has its own scheduling and engineering support departments. Mechanical Repairs and E&S Construction have assistant foremen and the necessary manpower to do the actual maintenance work in the plant. This organization gives the maintenance department a better handle on the different types of jobs because of this team specialization.

The document "SSES Maintenance Improvement Program," dated July 25, 1989, describes additional program improvements currently in development. The PM program outlined in the subject document is comprehensive and will change the way the maintenance department operates, once it is fully implemented. Implementation of the improvements are laid out in the "PP&L SSES Maintenance Function Five Year Plan," Revision 1. This document identifies those items to be funded in 1991 and the projected funding. The vibration, lube oil analysis, valve operation test and evaluation system (VOTES), and thermography programs are just getting started or are pilot programs.

Maintenance training is INPO accredited and applies to all levels of management, staff, and craft. In addition, specialized training is provided as needed. For example, when a vibration course being taught by a contractor was found to be too elementary, an advanced vibration course was scheduled.

Conclusion

Management vigor is evident in its support of predictive maintenance and involvement in industry.

Conclusions, Section 2.0

Licensee management is visibly involved in maintenance. Programs for self-assessment of the maintenance process are in place and functioning. This is evidenced by reorganization of the maintenance department resulting from a concern regarding support engineering for the maintenance process. Management vigor is evident in its support of predictive maintenance and involvement in industry. The predictive maintenance programs being developed are based on advanced technology currently being discussed by different industry groups including ASME and the Vibration Institute. Implementation of these programs will require future management support to further shape the maintenance program. This support is evidenced by both the current status of the pilot programs and the financial commitment in the past and that projected in the five year plan. Although weaknesses were found, e.g., failure to promptly correct the RWCU pump problem, examples of management vigor far outweighed the number of weaknesses identified.

3.0 MANAGEMENT ORGANIZATION AND ADMINISTRATION (CORPORATE AND PLANT)

Scope

The team assessed the effectiveness of the organization and administration of the maintenance functions and program. To provide a broad perspective of maintenance activities, the inspection included: the existence, availability, and scope of a formal maintenance program; maintenance policy, goals, and objectives; allocation of resources; identification and definition of maintenance requirements; maintenance performance measurements; the documentation control system for maintenance; and the maintenance decision process.

3.1 Program Coverage for Maintenance

Scope

The team evaluated the means by which corporate and plant management direction for the maintenance program is expressed by approved maintenance program documentation.

Findings

Maintenance activities are divided into two categories - Instrument and Control/Computer (I&C/C) and mechanical/electrical. Procedure AD-QA-500, Revision 11, "Conduct of Maintenance," defines the current mechanical/electrical maintenance program. This program is headed by the supervisor of maintenance who is responsible for the overall administration and control of the plant maintenance department including people assigned to the E&S Construction organization and other subgroups and contractors. Procedure AD-QA-600, Revision 4, "Conduct of I&C/C Section,"

defines the current I&C/C maintenance program. This program is headed by the I&C/C supervisor who is responsible for the overall administration and control of the department, including any contract personnel and clerical support.

Conclusions

These top-level maintenance program procedures provide the scope and definitions needed for the program, define its organization, assign responsibilities, and provide the guidance required for implementing detailed maintenance procedures. The program was functioning well.

3.2 Policy, Goals, and Objectives

Scope

The team evaluated the means by which corporate and plant management policy, goals, and objectives are expressed for factoring into the maintenance program.

Findings

Both short- and long-range maintenance goals and objectives are clearly stated in the "SSES Maintenance Function Five Year Plan." This plan was developed as a part of the licensee's managing for excellence action plan. Some of the goals in this plan include: reduction of corrective maintenance by more effective preventive, predictive, and planned maintenance; development and effective use of a computer database to enhance maintenance activities; establishment of a predictive maintenance group; optimization of predictive techniques; development of lubricating oil, thermography and VOTES performance analyses and trending programs; and effective utilization of maintenance improvement program (MIP) technologies including PRA and root-cause analysis. The 1991 maintenance budget funds the licensee's goals.

Conclusions

The policy goals and objectives for maintaining and improving the maintenance program at SSES are clearly stated in the five-year plan. Emphasis for achieving these goals is demonstrated by the 1991 maintenance budget funding commitments to accomplish these goals.

3.3 Resource Allocation

Scope

The team evaluated the adequacy of the allocation of resources to accomplish maintenance in a timely manner by conducting a review of maintenance in progress and making an assessment of the backlog.

Findings

Maintenance staffing appeared to be adequate based upon a review of some of the ongoing and completed maintenance activities and a review of the maintenance backlog. Activities observed included the refurbishment and postmaintenance testing of EDG D, HPCI turbine overhaul, RWCU pump replacement, functional testing of reactor vessel pressure channels, lubrication and maintenance of a 4-kV circuit breaker, and the discharge tests of a safety-related battery. Although the backlog of maintenance appeared to be large, it was found to be relatively small for priority jobs, which were scheduled and completed in a timely manner. The large backlog number was in part due to the licensee's programmatic inability to close open WAs that no longer require action. The licensee plans administrative actions to address the issue of the backlog.

A review of the "SSES 1991 Operating Budget," dated September 28, 1990, shows that the maintenance activity for 1991 has been base funded. In addition, an amount approximately 8 percent above the baseline maintenance budget has been earmarked for improving the program.

Conclusions

The licensee's resource allocations to accomplish baseline maintenance and to implement maintenance enhancements were deemed to be functioning well.

3.4 Maintenance Requirements

Scope

The team evaluated through interviews and procedure reviews the methods the licensee used to establish maintenance requirements.

Findings

The maintenance program is established through a series of administrative and implementing procedures. The top level procedures are AD-QA-500 and AD-QA-600. The sub-tier documents below these top level procedures provide the details required to perform specific maintenance activities. These documents also reference higher tier documents including 10 CFR Part 50 Appendix B, ANSI N18.7-1976, applicable NRC regulatory guides, and the SSES FSAR. The licensee has a proceduralized system to ensure the updating of vendor manuals and industry events review, for example.

Conclusions

The licensee's system for establishing, maintaining, and updating maintenance requirements was in place and functioning well.

3.5 Performance Measurements

Scope

Determine management oversight of maintenance activities, maintenance programs and their implementation. Emphasis is placed on the plant performance, the provisions for feedback to the maintenance processes, and root-cause analysis. Among the documents reviewed were plant procedures and maintenance records.

Findings

The provisions for management oversight through walkdowns are established by Administrative Instruction (AI) 90-003, Revision 0, "Management Inspection of Facilities." The instruction promotes management review of station activities and enhances effective communication between management and staff. The 10 on-call duty managers are required to perform a general inspection of station facilities and activities at least once a week during off hours. Each inspection is documented by the inspecting manager with copies to the superintendent of the plant, the assistant superintendent of the plant, the assistant superintendent - outages, and the applicable section heads when the inspection relates to activities within their scope of responsibility.

The backshift inspection report log for the most recent six months revealed that fewer than 50 percent of the inspection reports have been submitted. The licensee stated that written backshift reports are not required and reports can be verbally communicated. The inspector reviewed the written inspection reports and noted evidence of upper management review in the form of questions, comments, and requests for additional information directed to the report author, as well as to the responsible section heads. No objective evidence of management cognizance was identified on the verbal inspection reports.

The inspector reviewed the root-cause analysis program. SOORs and NCRs are the primary mechanisms to initiate root-cause analyses. Procedure AD-QA-424, Revision 8, "SOORs," defines the SOOR priority levels:

Priority 1 - SOORs which identify events of significant plant or safety impact. These include multiple limiting conditions for operation (LCOs) affecting more than one system, a reduction of plant capacity, or the unavailability of a single-train safety system.

Priority 2 - SOORs which identify events of "nominal" plant or safety impact. A priority 2 SOOR would document a single-system LCO entry or the unavailability of a single train of a multiple train safety system.

Priority 3 - SOORs which identify events that are of no plant or safety impact and consist of non-safety-related equipment or system failures not included in the previous categories.

Step 6.6 of the procedure requires a detailed, documented root-cause analysis for priority 1 SOORs including a timeline, a review of past similar events and an assessment of generic implications. Each priority 1 SOOR that was reviewed had a well-documented, comprehensive, root-cause analysis. However, most of the safety-related component failures involve multiple train systems and are priority 2 SOORs.

Priority 2 SOORs do not procedurally require a documented root-cause analysis, a review of past similar events, or any assessment of generic implications. The NCRs receive a root-cause analysis that is the equivalent of a priority 2 SOOR. For example, SOOR 1-90-131, "River Intake Transformer Deluge System," documents multiple actuations of the fire suppression system for a river intake pumphouse transformer. As a priority 2 SOOR, the cause of failure was identified (failed heat detector modules due to water intrusion), but there was no assessment of applicability to similar suppression systems throughout the plant.

The inspector reviewed SOORs 1-86-303, 1-89-090, 1-90-057 and 1-90-144 which reported occasions when an EDG tripped off the line and shut itself down during the monthly loading and testing when synchronized with the grid. Review with responsible licensee engineering personnel disclosed that a proper root-cause analysis of these events had not been made. Upon proper evaluation, the licensee discovered a "race circuit" between the tap changer on the engineered safety system (ESS) transformer output to the 4.16-kV bus and the EDG voltage regulator output to the same 4.16-kV bus. When the tap changer switches, there are large momentary (approximately 10 seconds) transients in EDG current. Under these circumstances, the EDG is tripped off by the generator loss of field alarm/trip circuit. Since this problem only occurs when an EDG unit is synchronized with the grid, there is no immediate safety concern. However, repeated short-term overloading of both the engine and generator may have long-term deleterious effects.

Priority 3 SOORs and other mechanisms which report failures, such as Nuclear Plant Records Data System (NPRDS), are not addressed by the SSES root-cause analysis process. For example, a September 10, 1989, NPRDS entry documents the Unit 1 reactor feedwater (RFW) pump discharge valve HV-10603B that could not be opened electrically due to thermal binding and the disc had to be jacked off the valve seat. This occurrence did not generate a SOOR and no root cause analysis was performed. Thermal binding of MOVs does, however, have potential safety system implications because of possible similar valve types and applications.

Multiple failures of RFW pump discharge air-operated check valves (NPRDS entries of January 31, June 1, and December 26, 1989), attributed to the aging of the piston seals on the air operator, were not addressed by the root cause analysis program. Spring action will partially close the valve and reduce feedwater flow.

The March 1, 1989, NPRDS entry documented a failure of the HCU nitrogen accumulator for control rod 46-51. Water leaked past the accumulator seal, completely displacing the nitrogen. The seal failure was attributed to wear and was replaced. The NPRDS entry noted that this failure would have prevented the accumulator from contributing to scramming the control rod upon loss of normal CRD system pressure, normally provided by one of two CRD pumps. The next NPRDS entry (March 2, 1989) documented a high vibration of the CRD pump. Further investigation was deferred approximately one month until the Unit 1 refueling outage. At that time, the pump shaft was found to be jammed. The cause was attributed to a small piece of foreign metal in the middle bearing. These two NPRDS entries documented potential degradations of the scram function and were not required to be addressed nor were addressed by the root-cause analysis program. The team also noted that incipient failures are not programmatically addressed.

The priority level initially assigned to each SOOR by shift supervision is not always consistent with the requirements of AD-QA-424 Step 5.9. These discrepancies include safety system failures and were generally recognized during the review process and resulted in a priority upgrade. However, this process was observed to occur in an untimely manner (one month later in some cases).

The licensee has reviewed the NRC findings and recognizes that the present program does not require root-cause analysis for component failures unless they result in relatively significant plant transients or a complete loss of system operability. Upon reviewing the previous revision of AD-QA-424, the licensee found that the requirement to review similar past events and assess generic implications for priority 2 SOORs had been accidently deleted. This error is being corrected. The licensee also recognized the need to evaluate these individual failures better, and, where prudent, perform a formal analysis before a subsequent component failed which could cause a more significant event. The licensee stated that the WA would be revised to add a review requirement for the evaluation of the adequacy of cause determination and corrective measures before the final closeout. The closeout review will determine the need for a formal root-cause analysis. With regard to the SOOR prioritization process, the licensee is reevaluating the current method of assigning SOOR priority levels. The licensee recently instituted root-cause analysis training and has trained approximately 75 plant personnel thus far. The licensee ultimately intends to train all personnel involved in the maintenance process, including the mechanics and technicians. It is expected that the increased sensitivity to root-cause determination will also help identify future significant failures for root-cause analysis review. However, on the basis of the team's findings, it was concluded that a weakness existed in the licensee's program for determining matters that require root-cause analysis.

The inspector examined the licensee's program for review and disposition of proposed licensee improvements to the maintenance program. SSES Instruction MI-AD-020, Revision 1, "Employee Feedback," is the formal mechanism by which maintenance personnel make suggestions for improving maintenance procedures, instructions, and work plans and provides feedback to the originator. The procedure provides a performance improvement form (PIF) which an employee fills out and forwards to a central location. It is then distributed to the departments responsible for

the area needing improvement. Sixty-five of approximately eighty-two PIFs submitted during 1989 are still outstanding. The inspector noted that procedural deficiencies identified by a PIF are integrated into the affected procedure through a procedure change approval form (PCAF). The current PIF backlog is mostly due to the failure to incorporate PCAFS into the procedures in a timely manner.

The team reviewed the performance indicators used to assess maintenance performance. SSES tracks and reports INPO performance indicators. In addition, SSES tracks NCRs, SOORs, nuclear quality audit findings, NRC items, and NSAG recommendations. Maintenance WAs are tracked to ensure resources are sufficient to perform the required work. Periodic maintenance overdue is trended in the monthly periodic indicator report. The trend for the maintenance department shows a steady decline since April 1990 and is currently about 7 percent higher than the INPO median. The downward trend reflects increased management attention. The I&C periodic maintenance overdue indicator is consistently below the INPO median. In October 1989, the total number of open NCRs numbered 412. In October 1990, total open NCRs numbered 277. The reduction is considered a constructive management action. The largest reduction occurred in the last quarter of 1989 and has remained steady during 1990 at about 275 open NCRs. SSES has implemented a program that adequately uses performance indicators to assess maintenance performance and make changes to correct unacceptable conditions.

Conclusions

Although the licensee has established procedures for root-cause analysis and maintenance feedback, the inspector noted that the programs and their implementation could be improved. The team noted weaknesses in the licensee's root cause analysis program, primarily in the identification of significant failures and their generic implications. The inspector noted that licensee management is using performance indicators to assess maintenance performance and address unacceptable trends.

3.6 Document Control System Scope

Scope

In this inspection, the staff evaluated through interviews, review of procedures and records the licensee's document control system to support maintenance activity.

Findings

The WA documentation flow path was found to be proceduralized and functioning well. The system sufficiently documented the progress of work packages from initiation to close out and was understood by the craftsmen using it. PMIS is considered a strength, providing a method to track open work packages and systematically transfer accountability for quality records to the document control center (DCC) computer. Permanent quality records are stored at a facility located in Iron

Mountain, New York. The DCC vault on site provides adequate short term storage and easy access to duplicate copies of quality records.

Conclusions

The team concluded that an effective document control program is in place and is functioning well.

3.7 Maintenance Decision Process

Scope

In this inspection, the staff evaluated management's involvement and awareness of maintenance decisions.

Findings

Although the decision making process to maintain, upgrade, replace, or defer maintenance work for plant equipment was not described formally, it was functioning well. PM for selected equipment is routinely scheduled. However, some safety-related equipment is not routinely scheduled for PM, including the electrical circuit breakers in service at 4.16-kV and lower voltages. The licensee is currently in the process of implementing the PM program for these breakers. Corrective maintenance is performed as required. As discussed elsewhere in this report, the licensee has begun to upgrade the maintenance program to include more predictive techniques in the maintenance decision process. Major equipment upgrades, replacements, and significant deferments of maintenance are coordinated or approved at the appropriate levels of management. Management was aware of and involved in the decision-making process.

Conclusions

Although the decision process to maintain, upgrade, replace, or defer maintenance is not formally proceduralized, no significant problems were identified from the lack of such a procedure. The team concluded that the maintenance decision process was functioning well.

Conclusions, Section 3.0

The corporate and plant organizational structure relative to the maintenance activity was clearly defined and functioning well. The overall maintenance program including both short and long range goals and objectives are documented in approved procedures and programs. The overall program is effectively implemented through a series of sub tier administrative and technical procedures. Both the physical and fiscal resources are currently allocated by the approved 1991 maintenance budget. Longer range resource allocations are included in planning documentation which reflects positive commitments to an ever improving maintenance program. Improvements in the maintenance program (as reflected by improved plant performance) are anticipated by the

licensee as more effective use is made in such areas as predictive maintenance, PRA and root cause analysis.

4.0 TECHNICAL SUPPORT

Scope

The team evaluated the extent to which engineering principles and evaluations are integrated into the maintenance process. The team reviewed maintenance work orders, activities associated with failure analyses, maintenance-related items from risk assessments, and other maintenance activities. Topics discussed included engineering support to PM, EQ of electrical equipment, radiological control, the system engineering concept, use of industry initiatives and, how the maintenance and other organizations interact on these issues.

4.1 Internal/Corporate Communication Channels

Scope

The team evaluated the licensee's organizational communication systems to ensure that corporate policies for the maintenance organization are incorporated into the SSES plant procedures and a feedback system has been established to ensure maintenance concerns are identified to management for information and corrective actions.

Findings

Plant meetings, attended by management and representatives from other departments on site, are an important and effective means for communicating maintenance activities. The meetings were held daily during the outage to discuss status and to plan, prioritize, and coordinate outage activities. The daily valve team meeting, chaired by the valve technical support engineer, was one example of maintenance meetings held to communicate and coordinate work activities.

The Nuclear Plant Engineering (NPE) group, in Allentown, Pennsylvania, and other onsite engineering organizations are made aware of maintenance concerns in meetings and through the review of engineering work requests (EWRs) and project funding requests (PFRs). EWRs and PFRs, controlled by NDI-QA-15.1.1, Revision 5, "Communication Interfaces with NPE," allow maintenance personnel to transmit concerns and modification requests to corporate engineering groups for disposition.

Conclusion

The licensee has established systems to communicate effectively between corporate and maintenance management and site organizations. The licensee's organization exhibited adequate communication in response to maintenance and outage-related issues.

4.2 Engineering Support

Scope

The team evaluated the integration of engineering principles and evaluations into the maintenance process. This was evaluated by reviewing work orders, PM, failure analyses, and other maintenance activities. Activities in the field were also reviewed to evaluate the overall effectiveness of engineering support.

Findings

Direct technical support to the maintenance effort was provided by two distinct groups of engineering staff. The first group functions in the classic sense of "system engineers" in accordance with AD-QA-400, Revision 4, "Conduct of Technical Support." The system engineers function as system experts, providing knowledge of the functional design, operation, and overall technical aspects of assigned systems. The second group of support engineers is assigned to functional groups in the maintenance department and provide support in the maintenance and modification of specific components, i.e., valves. The team observed an effective interface between the system engineers and component engineers. Both groups of engineers ultimately report to the technical supervisor of SSES. Offsite engineering personnel work with either group of engineers depending on the nature of the work task.

The team noted several strengths as well as some areas for improvement. The system engineering program has been in existence for as long as the plant has operated and the level of expertise and experience of the assigned engineers was high. The organizational alignment of the maintenance department support engineers has not been in place long, but the engineers were equally experienced. The engineers exhibited good presence in the field and had established good rapport with the operations and maintenance groups. System engineers were observed receiving copies of WAs after closure for their review, as desired. In one case, the team noted that an engineer detected inadequate postmaintenance testing (PMT) of an ASME Code component during this review. It was noted that system engineers were not required to trend component failures. The main area for improvement in both groups dealt with trending and is discussed in Section 6.4 of this report.

Conclusions

On the basis of its findings, the team concluded that, although technical support to the maintenance process was implemented well, the programs for both the system and component groups showed that trending mechanisms could be improved.

4.3 Role of Probabilistic Risk Assessment in the Maintenance Process

Scope

The team determined the extent that PRA concepts, including common mode failure, single failure criteria, safety system and component significance, are considered in the maintenance process.

Findings

PP&L is at the forefront of the industry with regard to the use of PRA techniques to assess and modify plant design and operation. Its involvement with PRA began in 1980 with a contract with Nuclear Utility Services for developing of a PRA for SSES. That effort was jointly completed in 1985. The licensee continued its PRA activities through program revision and by supporting the industry degraded-core rulemaking, individual plant evaluation (IPE) as a test plant. "PP&L IPE," Revision 1, is the basis for the licensee's risk activities. The licensee is currently revising the IPE to include modifications, procedural changes, and the plant-specific failure history.

The licensee pursues a defense in-depth strategy for all accident sequences, regardless of the calculated core-damage frequency, because of the uncertainties associated with the estimates of initiator frequencies, equipment failure rates, and the modeling of commonalities and system interactions. The licensee imposes a requirement of three stages of equipment protection to make the likelihood of a given level of damage less as the severity level of the damage increases.

The equipment-based defense-in-depth criteria are: (1) Core or containment damage shall not occur without multiple failures of redundant or diverse equipment; (2) Vessel failure shall not occur following core damage, unless additional independent equipment failures occur; and (3) Containment failure shall not occur following core damage or vessel failure, unless additional independent equipment failures occur. The licensee has used this defense-in-depth strategy to examine potential accident sequences for plant weaknesses. This has resulted in several plant and procedural modifications. Most notable are the purchase of a 100-kW portable diesel generator and the installation of a low-pressure emergency core cooling system (ECCS) permissive bypass which address two potential common-cause failures: battery depletion during a station blackout and low-pressure ECCS common mode failures, respectively.

From the maintenance perspective, the current source of risk-based input to the work prioritization process is the "Tactics for Excellence Through Accountable Management" (TEAM) Manual. This manual documents the licensee's scheduling philosophy in the form of system level rules which govern schedule development. Several examples include: only one ECCS system per unit should be scheduled out of service at one time; ECCS work window frequency shall be minimized (the work window duration should be less than 24 hours); and half main steam isolation valve (MSIV) isolations should not be scheduled at the same time the HPCI system is out of service.

The licensee is developing a risk-based component level prioritization system to augment the TEAM Manual. When completed, the licensee will have a state-of-the-art integration of PRA into the maintenance process. Two of the four priority levels have been formalized. Priority 1 comprises components whose failure alone results in a complete loss of power generation, a short allowed outage time (AOT), or the loss of a safety system function. The licensee has developed a priority 1 component list that consists of 1138 components for both units. Approximately 80 percent of these components are generation (non-safety) based, and the remainders comprise short-duration AOTs, i.e., dc power, or related to single-train safety functions such as HPCI, RCIC, and the shutdown cooling suction line.

Priority 2 is comprised of components whose failure alone results in a partial power reduction, the loss of a safety system division or a workload that is likely to exceed the AOT. The priority 2 classification, which is expected to encompass many of the risk-based components, is scheduled for completion by July 1991. The priority 3 and 4 definitions are still in draft form.

These component level priorities will be used in two areas, the preventive maintenance improvement program (PMIP) and the WA system. The priority 1 information is being incorporated into the PMIP. Thus far, six basis packages, comprising 224 components, have been drafted. PMIP basis packages will be developed for all priority 1 and 2 components by July 1, 1992, with implementation envisioned by the end of 1992. The licensee is in the process of developing a pilot program to enhance their capability to prioritize and schedule WAs. The pilot program will be available in mid-1991: the development of a full-scale program depends on the success of the pilot.

Conclusions

With regard to the use of PRA techniques to assess and modify plant design and operation, the licensee is at the forefront of the industry. Although a comprehensive risk-based prioritization system is not yet in place, PP&L is proceeding toward this goal. When completed, the licensee will have a state-of-the-art integration of PRA into the maintenance process.

4.4 Quality Control in the Maintenance Process

Scope

In this inspection, the team determined the extent of QA and quality control (QC) involvement in the SSES maintenance process. The inspector reviewed the licensee's procedures for implementing the QA surveillance and audit program, the QC inspection program, and trending of findings.

Findings

Nuclear QA Procedure (NQAP) 11.1, Revision 7, "QC Inspection Program," defines the QC inspection role. The QC department reviews all safety-related WAs to ensure that the necessary inspection hold-points have been established. Detailed inspection plans are developed before any job is performed. Their subsequent use in the field helps in the achievement of quality work and in some cases appeared to overcome weaknesses in the maintenance procedures. QC inspectors also perform sampling inspections of routine activities. The detection of defects during these inspections may result in doubling the inspection frequency until three consecutive inspections have zero defects. The need to double the frequency depends on the nature and significance of the defect. An "in-progress corrected error" program has been implemented to document problems encountered and resolved during work activities. These findings are trended quarterly to detect any conditions which are potentially detrimental to safety. NCRs are trended in a similar manner. The department is staffed with experienced personnel who are trained and certified in accordance with NQAP 11.4, Revision 4, "Training, Qualification and Certification of Inspection, Examination and Testing Personnel."

The team noted significant QC involvement in maintenance activities. It did not appear uncommon to have constant QC coverage of important tasks, e.g., HPCI turbine inspection, reactor protection system (RPS) relay inspection and adjustment, and 24-V dc panel modification. QC inspections were thorough and contributed to a better maintenance effort. Detailed inspection checklists and inspection technique guidelines prepared for the HPCI turbine were noted strengths.
Annual and semiannual audits are required per SSES Technical Specifications (TS) Section 6.5.2.8, with the exception of the audit of the fueling/refueling program which is performed once a refueling outage. The inspector reviewed the following QA audits performed during 1989 and 1990 and their responses: Audit 89-057, "Personnel Training and Qualification"; Audit 89-070, "Surveillance Test Program"; Audit 89-090, "Test Control Program"; Audit 90-005, "TS Compliance;" and Audit 90-006, "Plant Maintenance Program (Electrical Maintenance)." The audits were adequate.

The inspector reviewed QA Surveillance Reports Nos. 90-36 and 90-48 pertaining to mechanical and I&C maintenance, respectively. Both reports addressed important elements of the maintenance activities and coverage was comprehensive.

Improved guidance on the maintenance activities requiring mandatory hold-points was one area of concern identified by the team. Current procedural guidance on where to require hold-points is general and may lend itself to some inconsistencies and potentially result in less than adequate inspection coverage of some tasks; however, no specific issue was identified.

Conclusion

A well-defined program is in place and is being comprehensively implemented. The QC role in the maintenance process was determined to be a definite strength. The licensee QA surveillance program is adequate and effective in identifying deficiencies in the maintenance program and implementation.

4.5 Integration of Radiological Controls Into the Maintenance Process

Scope

The team evaluated the extent to which radiological controls were integrated into the maintenance process. The team reviewed radiological controls, involvement in the planning of and preparation to support maintenance work, corporate radiological controls support, station ALARA and operational radiation protection organizations, ALARA goals, training programs for maintenance and support personnel, external and internal dose control practices, and radioactive material and contamination control practices.

Findings

There is good organizational alignment between corporate nuclear maintenance services and corporate radiological and environmental services, both of which report to the manager of nuclear services. The corporate radiological services group has incorporated more than 220 recommendations for reducing exposure in the utility's "Managing For Excellence Action Plan." The plan schedules action items for completion over a five-year period. More than half of the 220 referenced recommendations are completed. Approved programs include control rod blade changeout, upgrade to sealless RWCU pumps, and implementation of a hot-spot reduction program. Future issues include residual heat removal (RHR) pipe source-term reduction and chemical decontamination of piping systems. These initiatives indicate good licensee efforts to reduce the general area and contact radiation exposure rates associated with radioactive systems.

At the station level, there were several notable examples of station health physics (HP) organizational integration with the maintenance department. The station ALARA group has been reorganized to closely mirror the maintenance functional groups. Consistent cooperative efforts occur between the ALARA and maintenance groups regarding valves, drywell, snubbers, inservice inspection (ISI), and BOP work groups. The HP supervisors were trained in plant operations and the radiation protection supervisor is temporarily assigned as the maintenance department drywell coordinator for 10 months. One year ago, a member of the outage scheduling group was assigned to the HP department to perform scheduling functions for the department. This integration of the work groups leads to good interdepartmental understanding of responsibilities.

The operational HP outage organization consists of 109 contract and 46 station HP technicians; station health physicists occupy all lead positions. This level of resource is considered adequate in consideration of the level of outage activities. The licensee recently staffed the position of radiological controls consultant. This individual keeps the work forces at the station informed about recent problems in industry and new techniques to minimize their exposure. Other responsibilities include reviewing contamination reports to identify areas for improvement and forwarding the information to SSES personnel through special training or the station's "Radiological Safety Notes."

The corporate group has a three-year ALARA goal of 800 man-rem per unit. Consistent with the corporate ALARA exposure goal, SSES has committed to a 1990 annual goal of 500 man-rem, which includes 337 man-rem for the current Unit 1 refueling outage. Considering the scope of work, the current outage goal, when compared to the estimated total exposure of 374 man-rem, presented a challenge. The licensee estimated that the work, which accounted for about 94 percent of the estimated exposure, had received a documented ALARA review. The actual man-rem tracking closely follows this target. If achieved, SSES will place in the INPO best quartile for BWR occupational exposures for the third consecutive year.

During a tour of the Unit 1 drywell, the inspectors found a worker performing VOTES testing on RWCU inboard isolation valve 144F001, located on the 738-foot elevation. The area was posted for high radiation with dose rates ranging from 40 to 100 mR per hour. A worker demonstrated poor ALARA awareness by remaining in the area while his partner left to obtained tools from a tool room located several elevations away. It appeared appropriate for the workers to have prestaged and inventoried their tools prior to entering the area. Low-dose-rate "wait" areas were not identified on all elevations of the drywell, but personnel in other areas knew where the low-dose-rate areas were in their work sites.

The licensee's ALARA program provides for ongoing review of work activities to ensure preplanned ALARA initiatives are being implemented. ALARA performance is discussed at daily planning meetings. Although ALARA programs are well defined through procedures, and occupational exposures are low, there is some room for improvement in some areas. For example, at every outage 12 to 16 tons of lead blankets are carried into and out of the drywell by hand resulting in several man-rem of exposure to assemble several standard drywell shield curtains. It was not apparent that hand carrying of the lead blankets resulted in the least amount of personnel exposure. The shield assemblies could be assembled outside the drywell and rigged into place.

The only radiation protection or ALARA-specific training available to maintenance workers is the normal radiation worker training and a one-day ALARA course for first-line maintenance supervisors. The latter course was developed seven years ago and needs to be revised to reflect current station practices. The licensee does provide prejob ALARA briefings for workers involved with work that has a significant potential for personnel exposure accumulation or at the discretion of the ALARA specialist. Review of the training and qualification of contracted radiological controls personnel indicated that the personnel were given training and qualification through a well-

defined contractor training and qualification program. Training in practical factors was provided by qualified instructors. Initial screening exams were used to select candidates for further training. Special training and directives were given to personnel manning radiation protection control points, e.g., the drywell.

By general observation, the station is devoid of ALARA promotional posters or other reminders. There is no ALARA incentive program in place to reward the contribution of significant ALARA suggestions from station personnel. ALARA prejob reviews are completed, as evidenced by the existence of a review for the RWCU pump seal replacement, but recommendations are not necessarily carried out. The form for the RWCU pump seal review stated that additional lighting was required. Upon further investigation of this repetitive maintenance task the inspector learned that the inadequate lighting situation has persisted for the past two years despite the maintenance department's request for adequate lighting, indicating the need for more attention to the ALARA principle.

Independent observations of ongoing work activities in radiological control areas (RCAs), review of completed radiation work permits (RWPs), and review of internal and external exposure reports indicated that the licensee maintained effective control of internal and external personnel exposures. The team did identify a need to pay more attention to the positioning of airborne radioactivity samplers. The samplers at the drywell sump and the inboard RWCU valve work on the 738-foot elevation of the drywell were not positioned to obtain representative breathing zone air samples. Once informed of the concern, the licensee immediately repositioned the samplers.

The team reviewed radiation exposure tracking and control. Current station practice utilizes the RWP sign-in sheets as the input data for processing and issuing personnel dose control reports. During this past outage, these reports were issued twice a day or once for each shift. This system appeared to work well, but was inaccurate for two reasons. First, only RWP radiation exposures are captured by the system. Work in radiation areas does not specifically require an RWP at SSES. SSES considers this exposure a small fraction of the total station exposure. Second, the reports may be fairly accurate at the beginning of a shift, but the system relies on each worker to remember and report his/her dose during the individual's shift. The licensee has established a "dose card" to provide real-time tracking of workers whose exposures are approaching the licensee's administrative limits. The licensee is aware of these problems and is developing a real-time dose control system which will provide accurate dose information on a real-time basis. Despite these limitations, the exposure tracking and control program was considered effective.

Observations of radioactive material and contamination controls indicated good overall performance, but possible areas for improvement were noted. For example, review of the contamination control boundaries at the RWCU pump cubicles indicated the cubicles were not posted as hot particle zones as required. Observations at the drywell CRD transfer area identified hoses and lines hung or strung outside of a posted hot particle zone. This could result in hot particles being inadvertently transferred out of a posted hot particle zone. Other concerns are identified in Section 5.1 of this report.

Conclusions

The radiological controls program with respect to maintenance activities had a strong programmatic base. The ALARA and operational radiation protection follow-through is good. Good management support of ALARA initiatives was identified with strong corporate involvement in station activities from an ALARA perspective. However, certain areas could be improved, specifically, personnel contamination control practices, positioning of air samplers to obtain breathing zone air samples, implementation of a real-time dose-tracking system, and development of stronger ALARA training for maintenance personnel.

4.6 Safety Review of Maintenance Activities

Scope

In this inspection, the team evaluated the extent to which industrial safety is integrated into the planning and performance of maintenance work.

Findings

The corporate safety program is adequately implemented in accordance with the PP&L safety policy documented in the "PP&L Safety Rule Book." The industrial safety department comprises two safety consultants and a safety supervisor. The department's direct responsibility is to guide, assist, and consult with line management to achieve safety objectives. Although the safety department administers the program, the responsibility for its implementation is clearly assigned to the job supervisors. The supervisors must ensure that safety equipment is available and that safety precautions are in place before the start of work. The industrial safety department develops a detailed accident review and analysis report for review by the Management Safety Steering Committee and for distribution to all line management.

Although inspection of maintenance work areas and maintenance in progress reflected knowledge and implementation of proper safety practices, several exceptions were noted. These isolated incidents included failure to use the proper tool (creating a missile hazard), failure to wear a hard hat in the drywell, and failure to use safety glasses in the vicinity of operating power tools.

Conclusions

The industry safety review of maintenance activities is well documented and is strengthened by involvement of management from the Chairman through the first-line supervisor. The team concluded that the PP&L industrial safety program is adequately implemented.

4.7 Integration of Regulatory Documents in Maintenance

Scope

In this inspection, the team assessed the methods used to integrate regulatory documents into the maintenance process. This includes changes to the regulatory documents resulting from periodic reviews and revisions.

Finding

Regulatory documents are processed effectively in accordance with Nuclear Department Instructions NDI-QA-3.3.1, Revision 6, "NRC Correspondence," and NDI-QA-6.2.2, Revision 12, "Industry Events Review Program." The industry events review program process includes INPO Significant Event Evaluation and Information Network, General Electric (GE) information letters, GE technical information letters, and NRC information notices. For NRC requirements, licensee commitment control involves a three-step process: (1) identification of items requiring formal responses; (2) preparation and approval of those responses; and (3) tracking and closeout of commitments by the nuclear licensing compliance tracking program associated with the responses. Items requiring formal response are identified through various administrative programs. Examples of these items include NRC audit findings, inspection findings, and licensing issues. In addition, other documents identified by department managers and supervisors can be included in the formal evaluation process.

Conclusions

The overall control of regulatory documents was considered to be effective. The level of review was adequate and sufficient information was routinely provided to document all safety issues.

Conclusions, Section 4.0

Overall, the technical support for the maintenance process was functioning well, with only a few areas for improvement noted. The licensee is in the forefront of the industry in the use of PRA techniques to assess and modify plant design and operation. System level rules have been established for work prioritization. A risk-based component level prioritization system is being developed. Quality control was determined to be a strength in the maintenance process.

III. MAINTENANCE IMPLEMENTATION

The team determined the effectiveness of maintenance controls insofar as the quality of the work performed. Four areas were evaluated: work control; the plant maintenance organization; maintenance facilities, equipment, and material controls; and personnel control.

5.0 WORK CONTROL

Scope

The work control program and its implementation were evaluated in the following areas: review of maintenance activities in progress, work order control, equipment records and history, job planning, work prioritization, work scheduling, backlog controls, maintenance procedures, post-maintenance testing (PMT), and review of completed work control documents. The team observed WAs in progress, reviewed completed WAs, reviewed administrative procedures for control of maintenance and PMT, evaluated maintenance procedures, observed material control, and interviewed various levels of maintenance personnel.

5.1 Maintenance in Progress

Scope

The review of maintenance in progress was separated for evaluation into three areas: mechanical, electrical, and I&C/C.

Findings

Mechanical

The team observed the crew complete the overhaul of auxiliary equipment and prepare for engine startup in association with the overhaul of EDG D. Work package WA S04803 was comprehensive and complete, actions taken had necessary entries and signatures. The crew's lead mechanic was knowledgeable of the work in progress and directed activities in a professional manner. The crew members adhered to procedures, and coordinated their activities well (illustrating their communication techniques were good). The foreman assigned to the work activity monitored the job well by periodic visits to the area. The team noted no concerns during this activity.

The team observed the disassembly, inspection, and repair of the Unit 1 HPCI pump discharge check valve to the condensate storage tank on October 9, 1990. The work was performed by E&S Construction mechanics with the guidance of an Anchor Darling representative. A licensee QC inspector and a technical support team participated in the work process. Work package WA S03501 utilized generic procedure MT-GM-003, Revision 9, "Valve Disassembly, Reassembly and Rework," and generic instructions from the Anchor Darling Instruction and Operating Manual as guidance to perform the work. The work activities were performed in an adequate manner.

On October 11, 1990, the team observed E&S Construction mechanics replace carbon steel butterfly valves in the Unit 1 SW system with stainless steel valves (WA S03509, "Reactor Building Closed Cooling Water Heat Exchanger SW Isolation Valves 110060, 110061 and 110062"). After the valves were installed, but before the flange bolts were torqued, emergency SW (ESW) System pumps were started to perform testing for another work activity. The ESW/SW cross-connect valve HV11024B1, a blocking point in this work package, allowed water to leak through, prematurely filling the SW system. Water then leaked through one of the loosely installed SW valves into the room. Upon discovering this, the mechanics tightened the flange bolts on SW valve 110062 to stop the flooding, overtorquing the studs and damaging the flange gaskets. As a consequence, the gasket had to be inspected and reinstalled. The team concluded that the licensee should be more aware of system status when restoring systems with an unknown ability to maintain boundary conditions, and that the licensee needed to preplan work. The team felt that there was insufficient review of inter-system connections during the planning for the two jobs. This situation is one example of a violation of the NRC requirements to preplan work (Violation 50-387,388/90-81-03).

Unit 1 SW system flow control valves 187040, 187049, and 187050 were being replaced under WA S03896. On October 12, 1990, the team observed an E&S Construction mechanic use a stud/nut assembly to pry valve 187050 away from its associated piping flange in order to insert a new gasket. While the mechanic was trying to insert the gasket, the stud popped out, permitting the flange to spring closed on the partially installed gasket (a crushing hazard). The team found that proper tools to spread the flange and valve apart were available in the turbine building tool room (TBTR), but had not been acquired before the job was begun, and were not used. The team concluded that the mechanic was taking a short cut to accomplish the task rather than taking time to obtain the proper tool and have it ready for use. The team considered this an example of poor workmanship.

The team investigated a discrepancy identified on the Unit 1 RFW pump discharge valve HV10603 while maintenance was being performed per WA S04132. The WA provided instruction for drilling a hole in the valve gate in order to prevent repetition of the thermal binding that occurred in September 1989. On October 12, 1990, after disassembling and inspecting the valve, a deformation of the upstream seat ring was discovered. After cleaning the valve and recording the deformation on video tape on October 16, 1990, the licensee reassembled the valve and prepared to place it in service. Nondestructive testing (NDT) for fractures of the ring or seal weld was not performed. This decision was predicated on the logic that the valve had safely functioned during the past year of operation without material degradation, and therefore no further degradation would occur.

The team questioned the lack of testing to ascertain the integrity of the seat ring. In response, the licensee disassembled the valve and initiated an evaluation during the nightshift on October 16, 1990. QC performed a dye penetrant test on the valve seat without success. A successful magnetic particle test (MT) was performed and the results were recorded on video

tape. The MT revealed a fracture approximately 1 inch long just off the deformed area on the seat ring. A safety evaluation that was subsequently performed by the licensee found operation with the defect acceptable.

The team observed the major PM activity of removing the casing and rotor of the Unit 1 HPCI turbine (WA P02214, PM B04691). The work package implemented MT-052-002, Revision 1, "Unit 1 and Unit 2 HPCI Turbine Maintenance," and referenced IOM 13, "Terry Steam Turbine Company Instruction Manual, Unit 1." The following findings characterize several areas that require increased licensee attention.

- The team observed the initial stages of the disassembly of the HPCI turbine and was concerned that the work was done using a work package that contained inadequate supplemental work instructions. The referenced procedure removed the throttle trip valve, throttle valve, glands, and the upper case in only nine steps. These concerns related directly to the work crew's level of experience. None of the people doing the job had previously performed or observed the activity. The job was last performed in 1982 and training for the observed job consisted of 16 hours on turbine theory. There are no on-the-job training (OJT) task-oriented requirements for journeyman-level mechanic qualification. The team concluded that, given the high complexity of the job and the low direct experience level of the worker, a comprehensive work package and procedure would be appropriate. Contrary to this conclusion, the licensee's WA implemented PM B04691, "Six Year Inspection HPCI Terry Turbine," with the following two steps: "1. Disassemble and inspect HPCI Terry Turbine per MT-052-002 and Section 6 of IOM 13" and "2. Verify proper control valve linkage travel as defined on the lever diagram in section 9 of IOM #13 (Drawing 723728)."

- Step 5.1.3 of MT-052-002 stated, "Remove the inverted oil operated stop valve." Because the clearance was inadequate, the oil-operated stop valve (throttle stop/trip valve) could not be removed as a unit. In order to overcome this problem the maintenance crew attempted to remove the oil cylinder. During this maneuver, the oil cylinder became spring-loaded against the stop valve and the fasteners had to be detensioned against a hydraulic jack. This was necessary because the stop valve had not been correctly latched with turbine lube oil pressure before starting the maintenance activity. This is a second example of the violation for failing to preplan work (Violation 50-387,388/90-81-04).

- PMT specified in the WA stated, "AD-QA-480-1," which referred to Form 480-Non-VT-2, "System Leakage Test." The team's review of IOM 13 indicated that the vendor manual was equally lacking in detail. Prerequisite 3.5 of MT-052-002 read, "Notify I&C prior to commencing for removing vibration transducers and thermocouples." The I&C group initiated support for WA S06850, which stated, "Spt. required for removal and installation of vibration transducers and thermocouples on HPCI turbine." Three I&C technicians removed approximately 18 I&C components at the direction of the maintenance technician

supervising interference removal. During this removal process, a WA addendum sheet, "Equipment Status Changes Within Blocking Points," was completed to indicate the affected instrumentation. The technicians exceeded the scope of the WA by removing speed sensor connections, limit switches, position transformers, and pressure-sensing lines in addition to the "vibration transducers and thermocouples" called for in the WA. This is an example of a violation of the NRC requirements to follow procedures (Violation 50-387, 388/90-81-05).

These and other similar problems during the performance of the activity resulted in numerous work stoppages to obtain equipment or to determine how to proceed. Although the licensee had retained a vendor representative to assist with the work because the crew was inexperienced, neither party had performed a preliminary walk through and thorough analysis of all job requirements and shared boundaries. To the licensee's credit, the numerous steps actually used to get the job done were being recorded in detail as the work progressed, which was of no help to the work in progress. Licensee maintenance management insisted that the observed problems were the exception rather than the rule, but could offer no explanation as to why this activity had so many problems.

- On October 9,1990, the HPCI lube oil cooler (WA P02837, Susquehanna Equipment Information System (SEIS) 1E213) was found open, the end bells removed, with no protective coverings on the open tube sides (a contaminated portion of the system). The open flanges (from which the cooling water piping had been removed to support the end bell removal) were also not blanked or covered. No work was in progress at the time of the observation. A subsequent check found the same condition indicating a lack of control over the work. In the same time frame, the HPCI turbine auxiliary oil pump (SEIS 1P213) was removed for overhaul. The open piping was not blanked or covered. In addition, the nuts and bolts for the flanges, which are ASME Code components, were neither bagged nor tagged.

  After being informed about these concerns, the licensee had all loose materials bagged and identified, and all open flanges were covered. The inspector noted that one flange lacked a fastener after this action was completed. During assembly of the lube oil cooler on October 14, 1990, a maintenance technician was observed to replace the missing fastener with an uncontrolled, non-Q fastener of "similar" size from his tool box. The inspector called the situation to the attention of the supervisor in the local area. The work was stopped and the condition was corrected. The team considered this an example of poor workmanship and an area which needs improvement.

- The area surrounding the HPCI turbine was established as a radiation area requiring full protective clothing (PC). The team noted on one occasion that a contractor inadvertently reached across the radiation area rope to steady himself against a structure within the radiation area. His escort did not notice the event and the contractor took no action to survey his ungloved hand.

- HP surveys were performed upon breaching the steam supply pipe to the closed turbine throttle stop valve flange, but not immediately after breaching the downstream side. HP technicians were not called until well after the flange had been parted and mechanics were working inside the valve and chest flange to loosen studs and nuts. The team noted that paragraph 4.1 of MT-052-002 included a specific precaution concerning notification of HP prior to breaking steam pipe flanges. RWP 90-583, specifically prepared for the HPCI/RCIC turbine work, included "constant HP coverage required for system breach" and "survey required every breach and weekly" under "Monitoring Required." The team was concerned that the mechanics did not notify HP and ensure HP coverage before the flange was parted. This is a second example of the citation for failing to follow procedures (Violation 50-387, 388/90-81-05).

- During removal of the HPCI turbine throttle stop/trip valve on October 13, 1990, a nylon sling was attached on one side of the valve to a short (3-inch) post on the valve body welded there for rigging purposes. The post had no lip on its end. Nothing was installed to keep the sling from slipping off the post. After the lift (3000 lb) commenced, the valve tipped slightly because it was top heavy. A C-clamp was then installed on the end of the post. The valve tipped because the top was not adequately restrained by rigging and the previously installed come-along from the top had been moved to the bottom of the valve, indicating a possible shortage of come-alongs at the job site. Personnel or equipment were not endangered during this activity, but the precautionary measure of installing the C-clamp before starting the lift would have been a safer practice.

  A nylon sling was intentionally inserted between the sharp edge of the valve flange and the mating surface of the throttle stop/trip valve when the valve tipped to keep the sharp edge from marring the mating surface. This action could have damaged the sling and endangered a subsequent user, had it gone unnoticed. The situation occurred because an expendable surface such as soft aluminum was not on hand for the purpose. This oversight was noted by onsite supervision after the fact; the job was stopped and expendable material was obtained.

- While maintenance was being performed on the HPCI turbine, a worker was observed seated on the turbine throttle stop/trip valve chest drain line, distending the snubbers to apparent full stroke. When the worker suddenly got up from the line, the spring can-type hangers rebounded to the zero extension position with considerable force. The mechanic was not sensitive to this poor work practice, i.e., standing or sitting on small equipment could cause problems. The licensee prepared NCR 90-0320 to document this potential problem.

On the basis of its findings, the team concluded that the planning procedures and work practices used to implement the HPCI turbine overhaul constitute a significant weakness.

The licensee has experienced numerous failures of RWCU pump seals, including the Unit 2 RWCU pump A repaired during this inspection (WA V03991). MT-061-001, Revision 6, "Reactor Water Cleanup and Pump Disassembly, Inspection, and Reassembly," was found to be complete and showed the detail of experience gained from performing the procedure several times a year. The semipermanently staged support equipment in Unit 2 includes a closed room with high-efficiency particulate air ventilation and air-fed hoods. This equipment is ready for maintenance technicians immediately adjacent to the RWCU pump room. A complete set of necessary tools is kept in the room. Technicians performing the work were skilled at their tasks.

RWCU pump A was placed in service on October 11, 1990, and failed again on October 13, 1990. The licensee informed the team that the pump had failed approximately 17 times in 1989 and 12 times so far in 1990. The licensee stated that the failures were a result of poor design and continuous operation of the pump at design capacity. This is an acknowledged industry wide problem; the longest period a seal had performed satisfactorily is approximately eight months. Thermal cycles induced by operational requirements tended to shorten the seal life drastically. However, during the operational period from October 11 to October 13, 1990, no adverse thermal transients occurred and no explanation was available for the short life of the pump seal. The high man-rem exposure for each seal replacement (approximately 2 man-rem) and the high excursions of reactor water conductivity during pump failures were of particular concern to the inspection team. The team concluded that the RWCU pump maintenance activity was well planned and executed. (See ALARA comment in Section 4.5.) However, an improved RWCU pump design is needed right away to reduce personnel exposure and minimize the impact on plant chemistry control.

Electrical Maintenance in Progress

The team observed several electrical maintenance activities including: 24-V battery discharge testing; battery charger load tests; replacement of capacitors in battery chargers 1D683 and 1D684; RPS channel B2 HFA relay maintenance; battery charger failure annunciator checks; replacement of the undervoltage and overvoltage alarm and trip relays in the 24-V dc distribution panel; EDG D postmaintenance retesting; and 4.16-kV ac circuit-breaker periodic maintenance. The work was well controlled and authorizations to perform the work were properly obtained. All test equipment used was within its calibration frequency and parts were obtained from the storeroom with documentation certifying them as acceptable for use in a safety system. The control of lifted leads was good, well-documented, and in all cases required a second person to verify proper restoration.

The team observed portions of work under WA P94140, "Fuel RX Recirc MG Set & Exc." The electricians stated they had previously cleaned the generator and were about to perform insulation resistance checks from the generator output breaker staves using procedure MT-GE-009, "Insulation Resistance Checks." The electricians stopped work when they found that the breaker was not blocked (tagged out) and removed from the cubicle, which was necessary to

gain access to the line side breaker staves. The inspector reviewed WA P94140 and equipment release form (ERF) R06280 and found the breaker was not listed on either document. On the following day, the inspector was told that the breaker had been added to the ERF. The generator was tested for insulation resistance; however, the initial test was unsatisfactory because there was a transformer on the bus between the generator and the output breaker. The existence of the transformer caused low resistance readings and it had to be disconnected from the bus before a satisfactory insulation test was obtained. Further investigation by the licensee indicated that resistance checks were to be performed on the motor under the referenced WA. Resistance checks on the generator were beyond the scope of the WA. This occurrence is a third example of the violation for failing to follow procedures (Violation 50-387, 388/90-81-05).

Instrumentation and Controls/Computer

The team observed performance of portions of SI-280-201, Revision 5, "Monthly Channel Functional Test of Reactor Vessel Pressure Channels PS-B21-2N021A, C, E, G and PIS-B21-2N021B, and D (Core Spray System and LPCI Permissive)." The clear, detailed procedure was followed verbatim by the technicians. Technicians were knowledgeable and kept the control room informed before performing each step affecting control room instruments. The technicians performed system alignment with appropriate verifications to ensure that the instruments were correctly valved back into use after functional testing. The inspector noted no deficiencies and considered conduct of work for this surveillance a strength.

During the review of I&C maintenance and plant walkdowns, the team identified deficiencies in the maintenance of EQ on safety-related instruments. On the basis of the hardware deficiencies identified, the team reviewed program requirements and implementing methods, and discussed deficiencies, procedures, and work practices with plant staff.

Unit 2 temperature detector TE E51-2N022B (PYCO) in the penetration room, 670-foot level, had a loose screw on the terminal cover. The licensee stated that torque requirements were being deleted for this cover. This item is unresolved pending inspection of the revised SSES detector's qualification requirements (Unresolved Item 50-387, 388/90-81-04).

Unit 1 Rosemount flow transmitter FT-E-51-1N003, RCIC pump discharge flow, had a loose cover cap on the transmitter. The transmitter is listed on EQ Data Form (EQDF) 39-I as an EQ transmitter. EQ for the transmitter is maintained by performing the maintenance requirements prescribed by Installation, Operation, and Maintenance Manual (IOM) 532, "Model 1153B Rosemount Manual." IOM 532 required that when Rosemount cover caps are removed, the O-rings be replaced and the covers be torqued to 200 inch-pounds. After the inspector identified the loose cover, I&C personnel confirmed that the cover was loose and determined that it was torqued to 65 inch-pounds. This is an example of a violation of the NRC requirements concerning the maintenance of the EQ of instruments (Violation 50-387, 388/90-81-02).

The reactor pressure vessel (RPV) water level extended range Rosemount transmitter, Unit 2, division 2 had a loose terminal cap. Several other Unit 2 transmitters observed with loose caps were: FT-249-25120A, LT-262-24203A, LT-262-24203B, and PT-225-22649. Unit 1 junction box TB-HVE-51 for the safety-related RCIC discharge valve, MOV-149-F012, also had a loose cover. The inspector was unable to readily determine when the last maintenance was performed or to locate documented evidence verifying that any caps were torqued to the correct value after being removed for maintenance. No special forms are used to document EQ attributes after maintenance and no program controls were found requiring the update of EQ binders and EQDFs after maintenance activities. The licensee initiated SOOR 2-90-131 on October 16, 1990, in response to the NRC-identified deficiency on PT-E41-2N009. The licensee issued WAS07717 to inspect and verify all Unit 1 EQ Rosemount transmitters before startup. The licensee issued WA V06857 similarly for Unit 2 and completed the WA before the end of the inspection. Some of the EQDFs used by technicians to determine which components are EQ and what are the maintenance requirements were incomplete. As an example, EQDF-39-I for a Rosemount transmitter listed maintenance requirements as "None." EQDF-39-1 did not reference IOM 532 for 1153B Rosemount transmitters, which prescribes the required EQ maintenance requirements. Several transmitters on the EQDF are marked with an asterisk stating the qualified life of the identified transmitters was 22 years. I&C staff stated that the "understanding" was that only transmitters marked with an asterisk were required to have covers torqued; however, this was not stated clearly on the EQDF or in any approved station procedure. EQDF-40-1 for Rosemount temperature detectors had "None" under Section 12 for IOM title even though an IOM exists. It also had maintenance requirements listed as "None." Although, EQDF-40-1 was approved on August 24, 1986, more than four years ago, no periodic reviews were recorded on the form.

The inspector concluded that EQ program requirements and specific maintenance requirements on an "instrument by instrument" basis were not well defined and integrated into EQDFs or specific station procedures; this is considered a weakness. In addition, EQ instruments are not identified in the plant. The station has elected not to torque covers on non-EQ covers and therefore has a mixture of similar instruments in the plant with different maintenance requirements. The lack of specificity may have contributed to the violation of station and NRC requirements.

Inspectors identified a poor work practice during the calibration of suppression pool level transmitter LT-15776A. Technicians opened safety-related EQ junction box TB1C001-A1 on core spray instrument panel 1C001 and connected sound-powered phone alligator clips to an annunciator cable shield wire and ground. The annunciator cable shield was used as a sound-powered phone transmission path during the calibration of the level transmitter. The inspector's concerns related to the work practice included: (1) EQ safety-related terminal boxes were being opened and wires were being connected without WAs and documented configuration control; (2) open energized terminal boxes were left unattended; and (3) proper communication circuits to conduct maintenance activities were lacking. During discussions with plant staff, it was stated that the practice of using shield wires for sound-powered phone communications was

common and it appeared that supervisors knew the shield wires were used during outages and during plant operation. Supervisors stated that only Unit 1 lacked adequate sound-powered phone outlets. The licensee responded to the issue by stopping the practice.

The team observed work being performed under WA S07673, "Perform Procedure IC-178-005, Revision 0, Intermediate Range Monitor (IRM) and Average Power Range Monitor (APRM) Division B (RPS B1/B2) Half-Scram and Source Range Monitor (SRM)/IRM Block Disabling." I&C personnel conducted this WA in a professional manner. Communication between the two I&C technicians and the control room was excellent. The technicians performed the procedure in accordance with the procedure. A third I&C technician properly performed the required independent verification following circuit restoration. The documentation of work was properly completed and the control room was notified at the completion of the maintenance activity. The inspector noted no deficiencies.

The inspector observed a maintenance action to replace suppression pool resistance temperature detectors (RTDs). I&C technicians conducted a pre-job briefing (tailboard) before they left the shop. All personnel fully understood their tasks, and necessary tools and material were assembled in advance. At the entry point to the suppression pool the technicians were briefed by HP, and reviewed and signed the RWP. Tools and instruments that could fall into the pool were secured on lanyards. Personnel entering the suppression pool were briefed on heat stress symptoms and limited to a 1-hour stay. The task, soldering the RTD leads to the field wiring, was performed in accordance with procedure IC-159-001, Revision 0, "Replacement and/or Rework of the Suppression Pool Water Temperature RTDs (TE-15751 through TE-15770)." No discrepancies were noted with the performance of the work.

The inspector observed surveillance SI-283-207, Revision 5, "Monthly Functional Test of Main Steam Line Flow Channels A, B, C, & D." Communication between the reader and the worker was excellent during performance of this surveillance. Two radiological practice discrepancies were noted. Several drops of water dripped onto the floor under the test connection while the test device was being connected. The water was not cleaned up or treated as contaminated, as is required by the procedure. One worker had gloves on while manipulating test device connections and valves on the instrument rack. A second worker, who had no gloves on, risked potential contamination while verifying the position of the valves. No other concerns were noted.

Procedure IC-070-001, Revision 3, "Calibration of Standby Gas Treatment System (SGTS) Alison Fire Detection and Deluge Control System." was scheduled for October 10, 1990. This task was canceled because the procedure had not been updated. The annunciator labels associated with this procedure had been relabeled and I&C was notified of the label change on August 24, 1989. However, I&C personnel responsible for procedure changes did not update procedure IC-070-001 as required by AD-QA-324, Revision 3, "Plant Labeling Program." A significant number of proposed changes, including the correction of the annunciator wording, were noted when the procedure was performed on August 24, 1990; however, no procedure

changes were initiated. The team concluded that management oversight and timeliness of procedure changes are a weakness.

During observation of work in Unit 1 on October 13, 1990, the team noted that banana jacks were installed in safety-related panel 1C611. These jacks were installed per WA S07670 to facilitate the conduct of IC-178-005, Revision 0, "IRM and APRM Division B (RPS B1/B2) Half-Scram and SRM/IRM Rod Block Disabling." The banana jacks remained as a permanent modification to the panel. As banana jacks were noted in safety-related panels, the team questioned the practice of installing banana-jack modifications to safety-related panels under a WA and asked to see the modification package and safety analysis. SSES provided engineering analyses, EDU-ADB-0001, "Dedication Criteria for Pomona Banana Jack Adapters," and EDU-ADB-0002, "Dedication Criteria for Pomona Terminal Strip Banana Jack Adapters," that allow installation of these jacks to support surveillance and component testing. These installations do not require any specific modification configuration control or tracking. I&C is informally logging the installations; however, no guarantees exist that ensure all installations are known. Plant schematics and prints are not updated to show the location of the banana jacks, with the exception of jacks installed in support of emergency operating procedures. Banana-jack installation specifications are being developed by NPE; however, no written 10 CFR 50.59 safety analysis was provided for the existing banana jacks installed in safety-related panels. This is an additional example of the violation for failing to complete a 10 CFR 50.59 safety evaluation (Violation 50-387,388/90-81-01).

Conclusion

The team concluded that on an overall basis, mechanical maintenance was adequate. However, there were a number of program and implementation weaknesses that warrant attention. On the basis of its observations of the HPCI turbine overhaul, the team concluded that the planning procedures, and work practices used to implement the overhaul constitute a significant weakness. The team found that control of the electrical maintenance was adequate and resulted in work being accomplished within the established administrative program. With the exceptions noted above, the team concluded that I&C maintenance was functioning well.

5.2 Work Order Control

Scope

In this inspection, the team evaluated the effectiveness of the work control process. The team reviewed the administrative procedures for issuance and control of WAs, reviewed authorizations received from operations and other responsible departments, and observed activities in the field.

Findings

Although the inspection team identified programmatic weaknesses in maintenance procedures for work implementation and control, work control was adequate. Although the weaknesses did not appear to result in deficiencies in maintenance implementation, insufficient program guidance could allow deviations from standards and requirements. The implementation of work control requirements resulted in some planning deficiencies, inadequate detail in some work instructions, and maintenance-related deficiencies in installed hardware, as identified by team members and discussed in other sections of this report. The team identified the following procedural deficiencies:

- AD-QA-502, Revision 16, "Work Authorization System," Section 6.1.3 delegates the TS and operability review for plant problems to the work group supervisor rather than to the licensed senior reactor operator who has responsibility for plant operation and safety at all times. Although the procedure states important problems should be brought to the attention of the shift supervisor, the procedure has the potential for allowing TS and operability problems to be screened before shift supervision review. Although the team did not note any examples where the delegation had caused improper notification, an allowance to delegate TS and operability reviews should be evaluated. This was identified as a program weakness. Section 5.0, "Definitions," uses the terms "work group and sub-group equivalents," but does not define the terms. The definition is important, as the procedure would allow the "equivalents" the same review and approval authority as "work group supervision" and "foreman," respectively. The licensee's response indicated the terms would be replaced with titles of designated personnel. The inspector considered the action appropriate. Section 5.17 allows the use of a small "out of service" tag but does not give the reader an illustration of the tag, the information that must be on the tag, or when the tag should be used. The licensee's response indicated the tag was seldom used and reference to it would be removed from the procedure.

- AD-QA-500, Revision 11, "Conduct of Maintenance," Sections 6.9.3 and 6.9.4 were inconsistent with the requirements of ANSI N18.7-1976, Section 5.2.6, which requires that "temporary modifications such as temporary bypass lines, electrical jumpers, lifted electrical leads and temporary trip point changes shall be controlled by approved procedures which shall include a requirement for independent verification." AD-QA-500 only requires "independent verification" for activities that would affect redundant components in multiple trains. This requirement is significantly less conservative than ANSI N18.7-1976. Although the team found no cases in which the allowance was evoked, the procedural allowance is a significant program weakness.

Conclusions

The team concluded that the work control program contained a few weaknesses but implementation was adequate.

5.3 Equipment Records and History

Scope

In this inspection, the team reviewed the adequacy of the equipment records and maintenance history information. The team reviewed equipment records, maintenance history records, failure analysis reports, and classification lists for safety-related components.

Findings

The team reviewed the availability of equipment records and documentation of maintenance history for equipment important to plant safety. Information on equipment history and records existed in several plant systems and programs. The systems included SEIS, PMIS, the computer system for vibration information, the lube oil analysis program, the transformer program, the battery program, and VOTES. Although some fragmentation existed (many different programs), information on maintenance and key parameters was readily available. The two major system, PMIS and SEIS, were linked so that information retrieval on a piece of equipment was available from both systems at one location. Once in place, the management information system will reduce the fragmentation.

Conclusions

Equipment history information was readily available and the area was functioning well.

5.4 Job Planning

Scope

This section evaluated the adequacy of job planning. The team reviewed procedures and observed maintenance activities. WAs were inspected for safety concerns, coordination of work flow, completeness of each work package, special work processes, scheduling, tools and parts availability, and radiation exposure control.

Findings

Procedure MI-PS-001, Revision 13, "Work Plan Standard," details the requirements for development of work plans. The team reviewed the standard and determined that it gives enough guidance for the planners to adequately prepare a work plan to safely implement the required work activity. Work planners are required to provide for PMTs as part of the work package to ensure the repair is satisfactory. Procedures AD-QA-482, Revision 0, "PMT Program," and MI-PS-008, Revision 1, "PMT Guide," give the planners general and specific information for determining functional, operational, and performance test requirements for maintained components or systems.

The station has three separate planning departments, I&C/C, plant staff, and E&S Construction. I&C work activity is planned by the Level 1 and 2 technicians and is approved by the assistant foremen for non-safety-related work. Safety-related work activities require the additional review of the unit foremen and QC for approval. Maintenance planning for mechanical and electrical work activities at the station is divided between plant staff and E&S Construction planners. These departments have their own staff organizations and function independently. However, both work to the same instructions and procedures for development of work plans and work packages. Each department reviews and approves its own planning activities. The team noted inconsistencies in the detail of the work plans and noted that the departmental independence of plant staff and E&S contributes to different levels of detail in maintenance department work packages.

The team reviewed the technical reference material available to the planners and determined that adequate IOMs, drawings, and other information is available. A training program is established for work planners. Material specialists are assigned to each planning department to ensure parts, materials, and vendor support are available as needed to support the planned maintenance.

During its observations, the team noted deficiencies in the work plans. Additional details are provided in Section 5.1 of this report. The I&C work plan for support of the Unit 1 HPCI turbine overhaul lacked specific detail in that it only specified removal of instrumentation as necessary to support the mechanical work. No predetermination of which instruments needed to be removed was conducted or detailed in the work plan. The HPCI turbine overhaul work plan lacked adequate detail for complete disassembly and rework of this vital equipment. The work plan (S03896) for the replacement of SW valves did not specify all special tools required for the job. Lack of a flange spreader resulted in an unsafe work practice. Procedure MT-GM-003, used to disassemble HPCI pump discharge check valve, 155F009, was generic to many check valves and lacked the detail necessary for work on what is a unique valve.

Conclusions

Planning department staffing and work planning on an overall basis was adequate to support work at the station. The station relies heavily on work force training and experience for quality work. On several occasions, the team observed the need for more detailed instructions and procedures.

5.5 Work Prioritization

Scope

The team evaluated the effectiveness of the work prioritization process. Elements considered were the extent that PRA and safety influence the priority assigned to maintenance tasks. The team reviewed work schedules, work authorizations, and held discussions with the unit coordinator and work group supervisors.

Findings

The prioritization of maintenance activities is accomplished as part of the WA process. SSES Administrative Procedure AD-QA-502, as amended by PCAF 1-90-0950, September 26, 1990 lists the WA priority codes. The priority codes and their significance are as follows:

1 (Critical)	-	Risk of injury or death, health hazard to the public, work on equipment causing an LCO or a reduction in capacity. Priority 1 activities are performed immediately and continuously until the situation is rectified.
2 (Short Cycle)	-	Actions or work required to alleviate the potential of becoming critical. All planning and performance of related activities are required to be pursued aggressively until the situation is restored.
3 (Preferred)	-	Generally corresponds to work necessary to improve equipment or system rehability, which if left unperformed may jeopardize continued system availability. PM activities are included in this category.
4 (Regular)	-	Usually refers to non-impacting work which is not required for the safe continued operation of the plant. These activities can be deferred if necessary, and are supported by standard work hours.

The WA prioritization process is depicted in the TEAM Manual. With the exception of priority 1 WAs, most WA priorities are assigned by the responsible work group. The inspector selected approximately 50 WA packages including closed WAs on Units 1 and 2 and open WAs on Unit 2. The WA priority assignments were reviewed for conformance to procedural requirements. The inspector also reviewed the Unit 2 schedule with the responsible work group supervisors and schedulers. There were no outstanding priority 1 WAs for Unit 2. In general, the WA prioritization process is well implemented. The inspector found one exception: fixing the torque switch misadjustment on inboard RWCU suction line isolation valve HV244FOO1 was deferred until the Unit 2 refueling outage.

The Unit 2 RWCU inboard containment isolation valve HV244F001 torque switch was known to have been misadjusted and NCR 90-0166 was issued on August 8, 1990. SSES performed an operability review and it was determined that the valve would not close completely against full RCS pressure. However, corrective action was deferred until the Unit 2 refueling outage. Subsequent SSES staff review concluded that TS were affected by the changed torque switch and that a waiver of compliance and an emergency TS change should be sought. On the basis of the licensee's application submittal and the NRC's review, the TS change was issued on October 30, 1990. This item is unresolved pending the assurance that PP&L procedures for covering other similar cases are in place and that no other similar cases exist (Unresolved Item 50-387,388/90-81-05).

Conclusions

With the exception of the RWCU containment isolation valve torque switch misadjustment, the licensee accurately assessed the safety significance of each maintenance task and prioritized the corresponding WA accordingly. The work prioritization process is functioning well.

5.6 Maintenance Work Scheduling

Scope

This section evaluates the adequacy of maintenance work scheduling. The team reviewed schedules, work orders, and assignments to evaluate the degree to which scheduling supports and enhances maintenance activities.

Findings

The station has established an effective program for scheduling maintenance activities. The rules and goals for scheduling predictive, preventive, planned, and corrective maintenance are detailed in the station's TEAM Manual. The basis for scheduling maintenance activities is the 5-year operation cycle. An 18-month rolling schedule is generated from the 5-year cycle on the project 2 computer program. The 18-month schedule forms the basis for a 3-month rolling schedule which is broken down to monthly and weekly schedules and further into a daily work activity list. The daily list is prioritized on the basis of guidance provided in the TEAM Manual. High-priority work is worked on a round-the-clock or extended-hours base.

Risk assessment is used to assign priority work tasks; for example, HPCI and RCIC system failures are classed as 14-day LCOs per the TS. Risk assessment analysis indicated to the licensee that these systems are more important to plant safety than might be implied by the 14-day LCO. Therefore, these systems have been elevated to the highest, round-the-clock priority for return to operability.

The team attended daily scheduling meetings and determined that the meetings are effective tools for ensuring all functional work groups work on the same daily priority tasks. Meetings are conducted each week between the work group functional group leaders and the operations department to ensure coordination and resolution of conflicts between maintenance and plant operations. The philosophy of scheduling is geared to routine surveillances that operationally test safety equipment to the TS requirements. Immediately preceding the surveillance, a block of time is established for the equipment to be removed from service. All work groups work within this block of time to perform their essential maintenance and functional testing on the equipment. Operational and surveillance testing is conducted following the maintenance to return the equipment to operational status.

All identified work, including preventive, predictive, planned, corrective, and surveillance, are fed into PMIS. PMIS is then linked to the project 2 computer program which produces a work schedule. Codes in the computer system allow maintenance activities to be tracked from planning through completion. The status of each activity can be determined quickly by means of the computer system. At the functional work group level, supervisors and foremen plan work and allocate resources according to the priority assigned to activities. Support groups such as maintenance support, material procurement, HP, or technical support engineering are contacted early in the scheduling process and integrated into the schedule.

Conclusion

The maintenance scheduling process effectively supports and enhances the implementation of work activities at the station. The scheduling process and its implementation represent a strength.

5.7 Backlog Controls

Scope

The team evaluated management's control of deferred/backlogged maintenance. The team reviewed records, WAs, and schedules.

Findings

Management of backlogged maintenance work is effectively controlled and managed by weekly tracking of open WAs. Three categories are defined: scheduled work, non-impacting work, and non-scheduled work. Scheduled work is maintenance scheduled to a specific system component window of availability. Non-impacting work is work that can be accomplished by the assigned functional work group alone, no additional support is required and the maintenance does not interfere with the availability of the plant. Non-scheduled work is work that is identified but not yet assigned to a window of availability. WAs are also categorized and tracked by the maintenance department's functional work groups. Maintenance scheduled and not started or completed within the availability window is identified in a variance report. The variance report is tracked by unit coordination to ensure maintenance activities are accomplished. The team reviewed the variance report and determined that as of early October 1990 only 43 work items were identified on the variance report, a small percentage of the total work activities that met required schedules.

Other backlog controls include weekly tracking of opened work documents versus closed work documents by total numbers and by functional work group. Management can quickly ascertain the growth or reduction of work activities and take necessary action to control the maintenance backlog.

SSES uses extensive, computer database-generated reports for controlling the scheduling of maintenance activities. Backlogged maintenance is routinely identified by the reports described above. Special reports identify specific information regarding delays of maintenance activities. For example, the team asked for a report showing all WAs awaiting parts; it was prepared in about 30 minutes. A total of 256 WAs were identified. The team reviewed the report and noted that a work group foreman is named to track the estimated delivery date and to coordinate the work start date with the maintenance schedule. The team noted no areas of concern.

Conclusions

SSES has implemented effective measures to control and manage the backlog of maintenance activities. This area is a strength.

5.8 Maintenance Procedures

Scope

The team assessed the development and approval process, technical content, method of control, and the periodic review process for maintenance procedures.

Findings

The team reviewed site-wide administrative procedures that directly support the maintenance program, maintenance procedures performed during observed maintenance activities, and supplemental work instructions prepared in direct support of planned maintenance activities. AD-QA-101, Revision 18, "Procedure Program," delineates responsibilities and requirements for preparation, review, approval, revision, and control of plant procedures and instructions. AD-QA-501, Revision 1, "Maintenance Procedure Program," similarly establishes requirements for maintenance department procedures format, standards for development and review, procedural adherence levels, and when procedures are required. In general, all maintenance procedures were required to be consistent with AD-QA-501. One exception is the I&C/C department which has a different organizational structure than the other departments which perform maintenance. Several areas of concern were identified.

The first area of concern related to periodic reviews. Interviews indicated that an October 1988 revision to the review process in AD-QA-101 revised Section 6.6.2 to read: "Since the preferred process for determining whether or not the procedure provides proper instructions is to perform the work using the procedure, procedures which document step-by-step implementation and which are run in their entirety at least once every two years require no additional documented review." Similarly, Section 6.7.1b of AD-QA-501 reads: "Procedures which have been used in their entirety within the review interval may take credit for this use as a review, as described in AD-QA-101." As a consequence of this relaxation of program requirements, the "exemption-from-review list" includes the following procedures:

ME-ORF-010	Reactor Vessel Head Removal
MT-199-001	Reactor Building Crane Operating Procedure
SE-024-E04	18 Month Diesel Generator E Auto Start on ECCS Actuation Test Signal
SE-024-E05	18 Month Diesel Generator E 24 Hour Run and 4000KW Load Rejection
SI-178-402	18 Month Time Response Test of APRM Channels A, B, C, D, E, F
SM-102-A03	18 Month Channel "A" 1D610 - 125 VDC Battery Electrical Parameter Test and Inspections, Battery Service Discharge and Battery Charger Capability Test
SO-152-002	Quarterly HPCI Flow Verification

AD-QA-101 was revised approximately two years prior to the time of the inspection; therefore, essentially all exempted procedures have not been reviewed in more than two years. No specific requirements to verify the procedures were placed on individuals performing the procedure. Exempted procedures became the responsibility of the section head/manager to ensure that selected routine followup review requirements were completed under the following circumstances:

- applicable procedures reviewed following plant modifications,
- applicable procedures reviewed if referenced procedures were revised,
- surveillance procedures reviewed if affected by a TS change, and
- applicable procedures reviewed that contributed to cause of an incident.

The team's review of SSES FSAR, Table 17.2-1, "Operational QA Program Compliance Matrix," determined that SSES was committed to NRC Regulatory Guide 1.33, Rev. 2, which endorsed the requirements of ANSI N18.7-1976. The table indicated that SSES was in "Full compliance except for review frequency of certain reagent preparation procedures." A review of ANSI N18.7-1976 determined that Section 5.2.15 required, "Plant procedures shall be reviewed by an individual knowledgeable in the area affected by the procedure no less frequently than every two years to determine if changes are necessary or desirable." Section 3.2 requires:

> Persons or organizations performing functions of assuring that the administrative controls and quality assurance program is established and implemented or of assuring that an activity has been correctly performed shall have sufficient authority and organizational freedom to: identify quality problems; initiate, recommend or provide solutions through designated channels; and verify implementation of solutions. The organizational structure and functional responsibility assignments shall be such that: verification of conformance to established program requirements is accomplished by a qualified person who does not have responsibility for performing or directly supervising the work. The method and extent of such verification shall be commensurate with the importance of the activity to plant safety and reliability.

The licensee stated that the decision to exempt procedures from a formal verification and validation process was based on ANSI/ANS 3.2-1982, Section 5.2.15, which added the following to ANSI N18.7-1976:

> This requirement for routine followup review can be accomplished in several ways, including (but not necessarily limited to): documented step-by-step use of the procedure (such as occurs when the procedure has a step-by-step checkoff associated with it), or detailed scrutiny of the procedure as part of a documented training program, drill, simulator, exercise, or other such activity.

However, ANSI/ANS 3.2-1982 did not change any of the requirements concerning persons performing verification activities to be independent of the activity itself, i.e., the ANSI N18.7-1976/ANS 3.2 Section 3.2 requirements. The team concluded that the licensee's program for procedural review was contrary to committed requirements because between October 1988 and October 1990, the licensee reviewed approximately 2000 procedures, including 39 maintenance procedures, surveillances, and checklists, with persons responsible for performing, or directly supervising, the procedure, surveillance, or checklist, rather that with persons not directly involved in the activity.

On the basis of findings, the team concluded that the failure to perform biannual or more-frequent reviews of procedures used to implement safety-related activities was a violation of ANSI N18.7-1976/ANS 3.2 (Violation 50-387, 388/90-81-03).

Another concern related to procedural adherence. SSES Policy Letter 89-004, "Procedural Adherence," dated May 30, 1989, addressed a new standard of expectation relative to procedures. Before the policy letter, procedures were guidance on how to do an activity. The policy letter implemented a new standard that required written procedures to be kept at the work location and to be adhered to step by step. The letter stated that an adherence category would be applied to each station procedure as follows:

> (1) Procedural steps are committed to memory; (2) The written procedure is present and followed step by step while the task is being performed; (3) The written procedure is available at the work location for reference; and (4) In the absence of clear definition, category (2) shall be assumed.

Although numerous procedures included the procedural adherence category, many did not (see, for examples, SO-149-002, Revision 10, "Quarterly RHR System Flow Verification," and MT-GM-003, Revision 9, "Valve Disassembly, Reassembly and Rework." Personnel in the maintenance department told the inspectors that the policy letter was included in maintenance department training but was not adequately understood. The workers thought that if an adherence level was not specified, the procedure was generic. AD-QA-501 does not address a procedure that has no adherence level specified.

Furthermore, Section 6.2 of AD-QA-501 addressed the subject of procedural adherence by introducing an additional concept of "generic" procedures. Section 6.2.1 of AD-QA-501 reads: "These procedures need not be taken into the field as they describe skill levels common to qualified personnel." Examples of the "generic" procedures include MT-GM-001, "Coupling Alignment (Horizontal Equipment)"; MT-GM-005, "Safety/Relief Valve Setting"; and MT-GM-010, "Pump Packing." The team found the permissive nature of AD-QA-501 inconsistent with Policy Letter 89-004 and the committed requirements of ANSI N18.7-1976 because some potentially complicated activities might be undertaken in following the cited procedures. On the basis of its findings, the team concluded that the following weaknesses needed corrective action: (1) ensure that the procedures upgrade program incorporates procedure adherence categories, (2) provide more thorough training to give the craft a thorough understanding of the importance of procedure adherence and the program changes in this area, and (3) resolve inconsistencies between SSES policy and procedural implementation policies at the lower tiers.

The team noted that at the time of inspection, the licensee had not issued a writer's guide for use in the preparation of maintenance department procedures, although a draft I&C writer's guide had been prepared and was being reviewed. AD-QA-101 does not contain substantive discussion or requirements concerning writing style, nor any guidance on verification and validation of procedures. AD-QA-501 provides more guidance on content of various procedure sections, but does not include specific guidance on verification and validation. Neither AD-QA-101 or AD-QA-501 contain guidance on acceptable vocabulary, abbreviations, acronyms, or symbols, examples of items typically found in a procedure writer's guide. The lack of guidance in this area lends itself to inconsistent procedures among the work groups. The team concluded that this is a program weakness.

MI-PS-001 provides a standard for the work planner to ensure all aspects of a work package had been considered. It also provides supplementary guidance to AD-QA-502. Section 3.5.2 of MI-PS-001 reads: "Generally, work instructions are guidelines which reference approved procedures to control the work. However, the work instructions must contain enough detail to complete the entire job." The team was concerned about the inconsistency between the MI-PS-001 procedure and the requirements of ANSI N18.7-1976. After reviewing the committed requirements, the team concluded that supplemental work instructions prepared to support maintenance had the force of procedures, and are not to be treated as "guidelines." Section 5.3.5(2) of the ANSI standard reads: "The procedures shall contain enough detail to permit the maintenance work to be performed correctly and safely, and shall include provisions for conducting and recording results of required tests and inspections." On the basis of this finding, the team concluded that inconsistency between MI-PS-001 and ANSI N18.7-1976 constitutes a program weakness.

Conclusions

The procedure program had missing elements when compared to regulatory requirements and industry standards. Implementation of the existing program was adequate, however, procedural adherence needs improving.

5.9 Post-Maintenance Testing

Scope

In this inspection, the team determined the effectiveness of the PMT program and assessed whether testing criteria were established, documented, and implemented.

Findings

The program requirements for PMT are found in AD-QA-482. From the review of completed work documents, adequate PMT was being planned and conducted. PMT in the I&C department was functioning well and was considered a strength. However, some deficiencies were found in other areas and are discussed below.

As a part of the maintenance inspection the team attempted to resolve a previous inspection's Unresolved Item (50-387/89-21-02) concerning improper PMT of the HPCI and RCIC turbine exhaust rupture discs. After discovering that the required visual exam for an ASME Code component had not been performed following disc replacement, the licensee issued NCRs (HPCI NCR 89-0453 and RCIC NCR 89-0443) and performed the required visual exam. The licensee observed the HPCI system on April 19, 1990, and the RCIC system on July 14, 1990. Additionally, operations "hot box" training (informal, on-shift) for shift supervisors took place in November 1989 to increase shift supervision awareness of the required PMT. The team noted that the PM activity (HPCI M0808-01, RCIC M0809-01) requirements sheet was also changed to clearly note that a code repair form was required for the rupture disc replacement. Because of a concern that the root cause was not addressed, the team walked through the process of determining the proper PMT to assure the system was capable of functioning correctly.

During the PMT process review, the inspector found that AD-QA-502, Section 6.3.1, assigns the functional work group the responsibility of determining the quality class and ASME Code of components being worked on. Although SEIS was noted to be the primary source of planning information for plant components and equipment, it does not include any information concerning ASME Code classifications. Thus, the planner has to refer to various design documents and drawings to determine if a component is ASME Code. A review of the SSES "Unit 1 ISI Composite Pressure Test Diagram - Functional Test HPCI System," drawing SE-152-301 clearly showed both the inner and outer rupture discs were within the ASME Code boundaries. The same was true for the rupture discs on the RCIC system as found in drawing SE-152-301. This determination was apparently not reached by the functional group planning the activity. The team

concluded that improvements in WA planning are needed to ensure that ASME Code components are identified. Licensee attention is needed to correct this weakness.

Further review of AD-QA-502 revealed that functional testing requirements, operability testing requirements, and performance testing requirements were to be identified on the WA by the functional work planning group. MI-PS-001 provides supplemental standards for work planners to follow to ensure all aspects of a work package are considered. Section 3.6 of MI-PS-001 refers the user to MI-PS-008 and includes guidance on PMT, including a logic tree for determining ASME Code component testing requirements. The team perceived this duplication as confusing since the presentation was not the same as that included in MI-PS-008. Section 3.4.7 of MI-PS-008 requires the work group planning staff to evaluate the WA for necessary PMT, seeking assistance from staff engineers where needed. Attachment D to MI-PS-008, "ASME Code Pressure Test Decision Tree," was found to be in error. The logic refers the reader to section 3.3.10.f to determine if the activity was exempted from Code-required testing, but that section does not exist in the procedure. Ultimately, the team was able to determine the proper testing for the rupture discs, but only after a laborious effort. The team concluded that the errors, inconsistencies and fragmentation in the PMT planning documents are a weakness.

The team was informed that a "Maintenance Component Matrix Data Sheet" database was complete for component level test requirements in the I&C department, was approximately 50 percent complete for mechanical components, and had not been started for electrical components. The intent of the matrix was to summarize available test procedures and identify some required testing for safety components. A review of the section of the document on mechanical components showed that the HPCI turbine discharge rupture disc was listed as requiring a visual test when performing SE-152-301. The similarly required testing for the RCIC rupture disc was not included in the document. The team also noted a problem with WA P83160, "HPCI Discs." The WA required replacement of the inner rupture disc on the steam exhaust line. The documentation on action taken indicated that both the inner and outer rupture discs were replaced without additional WA approvals or consideration for additional testing requirements. Both discs were noted to be within the ASME Code boundaries on drawing SE-150-301. The above findings indicate that the licensee had not effectively verified the correctness of component testing matrices or evaluated the adequacy of testing only the inner rupture disc on the HPCI turbine.

The team reviewed AD-QA-306, Revision 7, "System/Equipment Release," to determine the extent of shift supervision responsibility in the conduct of PMT. Specifically, Section 4.5 tasks work groups with responsibility for determining PMT requirements and Section 4.4.5 tasks the shift with "ensuring operability testing is identified to return the affected system/equipment to OPERABLE status." This division of responsibility was supported by Section 4.1.1 of AD-QA-482 which reads: [the work group] "identifies all functional, operational, and operational performance testing required for preventive or corrective maintenance performed on equipment." The team agreed that the operations group has final responsibility for approving recommended testing specified by the work group planning section. On the basis of the dispositioning of the NCRs, the team concluded that the licensee failed to recognize the role that work group planning must take in specifying all

PMT. Work group planning of required PMT for work packages was inconsistent and fragmented. Unresolved Item 50-387/89-21-02 will remain open.

Conclusions

The team concluded that the PMT program was in place but, based upon the findings, certain areas of the program need improvement.

5.10 Review of Completed Work Control Documents

Scope

In this inspection, the team assessed the process for maintenance review of completed work documents, general completeness of work documents, and feedback from the review to the maintenance process.

Findings

The team noted that AD-QA-502 controlled the closeout process of work packages. Several groups were responsible for reviewing completed work packages, starting with the functional work group foreman. Attachment G of AD-QA-502 gave guidelines for this foreman's review. The team noted that WAs which included ASME Code welding required an authorized nuclear code inspector's review of the weld traveler and that all WAs with hold-points required an independent review by Nuclear Quality Assurance (NQA)/QC. After all reviews, the WAs are returned to the shift supervisor for final determinations concerning PMT through consultation with the functional work group foreman.

The team reviewed completed work packages and noted a few minor documentation errors or omissions typical of which are the following examples. WA S94643 gave instructions for cleaning and inspecting the EDG E intercooler. End-bells were removed from this ASME Code component to replace numerous damaged studs. The WA "PMT Requirements" were listed as N/A; however, the "Action Taken" section of the work package indicated, "Performed inservice leak test (ISLT) found no leaks." The WA did not reference test data location, nor the procedure under which the test was performed. The ASME Code repair form attached to the WA indicated that "ISI NDE Requirements" included a visual test, but the test document was not a part of the work package. WA S04379 gave instructions for cleaning and inspecting the EDG jacket water pump (OP530B). Step F specifically required running the pump, collecting vibration data, and checking for proper operation. The work package contained no documented evidence that the vibration testing had been completed. These work packages failed to reference the required PMT or document completed tests. These two WAs indicate a need to improve work package documentation; this is considered a weakness.

Neither AD-QA-502 or AD-QA-500 require crew supervisors to perform a postmaintenance walkdown inspection of completed maintenance. Although the team noted that generally housekeeping was not a problem, isolated cases of insufficient clean up were noted, e.g., the area under the Unit 1 RHR A heat exchanger following cleaning (WA P02838). Because of the overall clean condition of the plant this was not considered to be a problem.

Conclusions

The program for review of completed work control documents was adequate. Several instances of incomplete documentation were found and termed a weakness.

Conclusions, Section 5.0

Work control on an overall basis was found to be adequate. Areas where improvements are needed were identified in equipment maintenance, mechanical maintenance preplanning, adherence to and reviews of procedures, assuring that commitments to standards are properly translated and delineated in implementation requirements, and postmaintenance testing. Areas that were functioning well included work prioritization, backlog controls, maintenance work scheduling, and maintenance of equipment history and records.

6.0 PLANT MAINTENANCE ORGANIZATION

Scope

In this inspection, the team determined the effectiveness and extent of control exercised by the maintenance organization on: (a) maintenance activities; (b) contract maintenance personnel; (c) deficiency identification and control; (d) maintenance trending; and (e) support interfaces. The assessment included review of maintenance controls and the implementation of those controls. Inspectors observed maintenance in progress and reviewed documentation. The areas shared with maintenance by plant and organizational departments, such as QA and engineering, are discussed in the appropriate sections.

6.1 Control of Plant Maintenance Activities

Scope

In this inspection, the team assessed programmatic and implementation controls for conducting mechanical, electrical, and I&C maintenance activities.

Findings

Two departments at SSES share responsibility for mechanical, electrical, and I&C maintenance. The maintenance department performs the electrical and mechanical maintenance, as defined in

Procedure AD-QA-500, Revision 11, "Conduct of Maintenance." I&C maintenance is performed by the I&C/C section as defined in AD-QA-600, Revision 4, "Conduct of I&C/C Section." The two department heads - the supervisor of maintenance and the I&C/C supervisor - report to the assistant superintendent of plant. These positions are on the same organizational level equal to that of the supervisor of operations, technical supervisor, HP supervisor, chemistry supervisor, and unit coordinator. The maintenance services supervisor, planning supervisor and maintenance production supervisor support the supervisor of maintenance. The work force, under the maintenance production supervisor, is organized into five functional areas: valve, NSSS, BOP, testing, and electrical.

Mechanical Maintenance

The maintenance department was divided into the following six functional areas to focus worker expertise: EDG, valve, NSSS, BOP, testing maintenance, and mechanical repairs. The functional groups' areas of responsibility are delineated in AD-QA-100, Revision 7, "Station Organization and Responsibilities." The groups function in a coordinated manner to provide resources to meet plant commitments. Maintenance actions were communicated to the functional groups via the WA packages. System work boundaries were controlled by the equipment release form (ERF) under AD-QA-306, Revision 7, "System/Equipment Release." Section 5.1 describes several instances of work outside WA boundaries, however, these were viewed as exceptions to the common practice at the site.

First-line supervisors were routinely present in the field, and supervisors actively involved themselves in maintenance activities to correct poor practices. Active supervision was needed on at least one significant job observed by the team. The HPCI turbine overhaul required active supervisor involvement (see Section 5.1) because procedures were inadequate and specific direct experience was lacking.

Electrical Maintenance

The electrical maintenance section is a functional group which reports to the maintenance production supervisor and is responsible for the maintenance of motors, transformers, chillers, batteries, switchgear, circuit breakers, relays, and electrical tests. Work to be performed is documented via the station deficiency identification systems and PM programs. Once identified tasks are entered into the integrated station schedule, jobs are planned in detail within the electrical section.

As observed by the team, the control of electrical activities was good. Work plans and electrical maintenance procedures were sufficiently detailed to control individual tasks. Individuals who are not fully certified are required to be task certified before performing specific tasks. The control of material and calibrated equipment was good. System integrity was ensured by the use of work plans and peer and QC verification of system restoration. Work was properly released by the operations department through the use of the ERF system to ensure that overall plant integrity is

not affected by the work activities. Close supervision of maintenance activities was also an observed strength.

One area noted for potential improvement was the control of the testing of the 24-V dc charger failure alarm. Currently it is performed as a corrective maintenance task. The alarm setpoint is adjustable and potentially subject to setpoint drift. The alarm test is not performed periodically as part of the PM or surveillance test program. This alarm alerts operators to a condition that could lead to the gradual discharge of the batteries. The licensee reviewed this concern and will include the alarm test as part of the 18-month scheduled surveillance test.

Instrumentation and Controls/Computer

The I&C/C section is responsible for surveillance and maintenance of plant instrumentation, computers, and measuring and test equipment (M&TE). Procedures are implemented to control corrective, preventive, and surveillance maintenance activities. Procedure AD-QA-600 details the requirements for conducting maintenance activities for the I&C/C section. AD-QA-422, Revision 10, "Surveillance Testing Program," establishes administrative controls for implementation and maintenance of surveillance procedures and tests identified in the SSES TS. AD-QA-605, Revision 7, "Maintenance and Calibration of Installed Plant Instrumentation," controls the corrective and preventive maintenance and calibration of safety-related plant instrumentation. Surveillance and PM are tracked and scheduled by computer. Unit schedulers and coordinators provide weekly and daily schedules to the I&C/C work groups. The team reviewed these procedures, attended scheduling meetings and I&C/C department morning meetings, and determined that the control of I&C/C work activities is firmly established.

Personnel controls are established by organizational methods within the I&C department. Work crews of six Level 1 technicians and two fully certified technicians are assigned to unit assistant foremen. The assistant foremen report to a unit foreman, who reports to the assistant I&C supervisor. Overall supervision is provided by the I&C supervisor. Unit crews and unit assistant foremen are assigned responsibility for specific plant systems. The team noted that close working relationships between the Unit 1 and 2 foremen ensure general and specific knowledge of plant problems are shared within the department. The team also noted that I&C system engineers remain cognizant of ongoing work activities and actively provide support to the work crews and foremen.

The team reviewed procedure AD-QA-197, Revision 4, "Use and control of IOMs," which establishes controls for the use and implementation of vendor manuals and technical information. AD-QA-197 requires appropriate reviews and approval by technically qualified engineers before the information is used in maintenance activities. A computer database of approved IOMs is maintained. Computer searches identify plant procedures requiring review when IOM revisions are received. The team reviewed IOMs maintained in the I&C technical library and determined that these manuals are maintained in a controlled manner.

Conclusion

Mechanical maintenance programs for control of activities were good; implementation of existing programs, however, require improvement (see Section 5.1 regarding HPCI turbine overhaul). Electrical maintenance has, with the exceptions noted, a good program in place and it is being effectively implemented. The I&C maintenance program is functioning well. I&C personnel are knowledgeable and effectively implement program requirements.

6.2 Control of Contracted Maintenance

Scope

In this inspection, the team assessed controls and implementation of controls for contractors.

Findings

Instruction MI-AD-006, Revision 1, "Use and Control of Vendor/ Contractor Personnel," defines the administrative controls applied to contractors performing work for the maintenance section. The instruction requires that a responsible individual be assigned to monitor contractor activities to ensure station policies and procedures are followed. At the time of this inspection, no contractor was engaged in any major maintenance activity. The team did observe individual contractors integrated into the existing station work force. These people work under the supervision of PP&L employees and appeared to function well in this support role. Vendor representatives were also lending technical assistance for several tasks, including the HPCI turbine and EDG overhauls. The vendor representatives provided a positive contribution to the jobs they were associated with.

The E&S Construction group consists of PP&L employees who support the maintenance department. Although not under the direct control of the station, all their work is controlled by the station's maintenance program. They are trained to do the same work as station maintenance personnel and the station's QC group monitors them.

Conclusion

The use of contractors and vendor personnel to perform maintenance is limited, but where it is used, there is a good program in place to control these activities.

6.3 Deficiency Identification and Control System

Scope

The team assessed the adequacy and implementation of the deficiency identification and control system.

Findings

Identified deficiencies are documented and controlled under the following procedures: WA under AD-QA-502, Revision 16, "Work Authorization System"; NCR under AD-QA-120, Revision 6, "NCR Control and Processing"; SOOR under AD-QA-424, Revision 8, "SOORs"; and Engineering Discrepancy Report under EPM-QA-424, Revision 2, "Engineering Discrepancy Management." These procedures are available to all personnel and are a mechanism for controlling all types of deficiencies. The procedures were good and were relatively easy to follow.

The team noted deficiencies that which were not identified and documented and also noted deficiencies which were not adequately addressed. For example, vibration data on the Unit 2 main generator began to indicate transducer failure in March 1990, but the failure was not detected nor was corrective action initiated at the time of the inspection. The team also noted various safety system hardware deficiencies and various potential seismic deficiencies which had not been documented. These items are discussed in the Plant Walkdown Inspection (Section 1.2) portion of this report.

In several cases, the disposition of deficiencies was less than adequate. Several SOORs were written documenting EDG overloading during surveillance testing; however, root-cause analysis and corrective actions to prevent recurrence had not been implemented. NCR 90-0166 documented an improper torque switch setting on a containment isolation valve; however, the valve was not declared inoperable and therefore the TS actions were not taken (Section 5.5 of this report has details on the RWCU inboard isolation valve). SOOR 1-90-211 documented a toolbox on wheels hitting an EDG control panel. The resulting corrective action was to install wheel locks on the carts and gang boxes in the EDG rooms; the team; however, found wheeled items that did not have locks on the wheels. (Unsecured items are discussed in Section 1.2, Plant Walkdown Inspection)

Conclusion

Although a good deficiency identification and control program is in place, implementation of the program needs improvement.

6.4 Maintenance Trending

Scope

The team examined the methods used to trend important maintenance variables such as failure rates, excessive maintenance on similar components, recurring maintenance actions, and feedback from the trending program into the maintenance organization.

Findings

Procedure AD-QA-541, Revision 4, "Maintenance Equipment Performance and Trending Analysis," defines the responsibilities and requirement for the development of failure histories and trending of corrective maintenance on plant components. The SSES equipment performance and trending analysis report (EPTAR) is issued quarterly and trends data for the previous 18 months. The report ranks the systems by the number of corrective maintenance WAs performed and also by the total number of manhours expended on the system during the quarter. The component failure analysis report identifies cases in which components have a failure rate significantly above the industry average for similar components; it is distributed as an attachment to the EPTAR. A SOOR trending program has recently been implemented and should prove a useful tool as the database expands with time.

Several predictive maintenance programs are being developed. These include lube oil analysis, VOTES, thermography, and vibration monitoring. The work performed to date appears to have been very thorough and to place a strong emphasis on ensuring the final programs will provide meaningful predictive maintenance information. The quarterly battery surveillance data are being trended and are closely monitored to ensure any battery degradation is identified before its capacity drops below the required level that ensures operability.

The compliance section of Technical Support Engineering publishes a monthly "Deficiency and Open Item Tracking Status Report" analyzing individual activities such as NCRs, SOORs, nuclear QA audit findings, and NRC items. The inspector reviewed samples from NCRs and SOORs and found the monthly tracking/trending report adequate.

System engineers are not required to trend component failures or operating parameters. Nor is there any mechanism to ensure that adverse component failure trends are detected when a component is utilized in several systems and as such may have low failure rates in individual systems but an overall high failure rate when viewed in a plantwide context. The following are examples of a weakness in which the trending systems failed to identify adverse trends: repeated EDG overloads during surveillance testing; vibration data indicating potential Unit 2 main generator transducer failure; and repeated SBLC tank level indicator failures received no systematic fix. This is a weakness.

Conclusion

Adequate trending mechanisms are in place, but the predictive maintenance programs being developed are expected to improve the performance trending capabilities on a component level once implemented. Current component failure trending does not address adverse trends which cross system boundaries and is a weakness.

6.5 Support Interfaces

Scope

The team reviewed the working relationship between the maintenance and support organizations.

Findings

The team observed numerous instances of good information transfer, problem resolution, support, and respect within the maintenance department and between maintenance and other supporting departments, including engineering, QC, and HP. The offsite maintenance support group effectively supports the site maintenance group, particularly in the area of trending and development of new programs. Their mission and charter is contained in NDI-1.3.3, Revision 3, "Nuclear Services Charter." The maintenance support group is also supporting the maintenance department in the development and implementation of the preventative maintenance improvement program (PMIP). Instruction NSI-4.1.1, Revision 0, "PMIP," outlines this process and the work shared by maintenance support and the plant maintenance staff.

Conclusion

Areas of maintenance support are well defined and result in a good team effort approach to maintenance activities.

Conclusions, Section 6.0

The plant maintenance organization is well structured and has good programmatic controls in place to accomplish its objectives. Implementation of the program is adequate, however, weaknesses were observed in the areas of mechanical maintenance, deficiency control and component level maintenance trending.

7.0 MAINTENANCE FACILITIES, EQUIPMENT AND MATERIALS CONTROLS

Scope

In this inspection, the team assessed the maintenance facilities and controls over maintenance equipment through plant walkdowns, document reviews, and interviews conducted with supervisors and personnel in the following areas: nuclear maintenance (mechanical, electrical, and I&C); planning and support; design engineering; nuclear training; and QA. Plant operations were observed and craft personnel were interviewed. The following areas were evaluated: maintenance facilities and equipment; materials controls; maintenance tool and equipment control; and control and calibration of M&TE.

7.1 Maintenance Facilities and Equipment

Scope

In this inspection, the team examined the extent to which plant facilities and equipment enhance the maintenance process. The review included interviews with management and craft, tours of the plant, offices and shop facilities.

Findings

The maintenance facilities are well laid out; each maintenance discipline is located in a separate work area. All maintenance disciplines have direct access to the radiological control area (RCA), with the exception of certain support functions. Supervisors, foremen, and assistant foremen are located with, or in close proximity to, the craftsmen to maintain good communication and supervision. As a result of the recent reorganization, support engineering and scheduling are also co-located with the different maintenance disciplines.

The location of work shops, tool rooms, and machine shops contributes to the effectiveness of the maintenance process. There are two main tool storage areas in the facility, one inside the RCA and one outside the RCA. In addition, there are satellite tool storage locations for work areas not easily accessible from the turbine building tool room (TBTR) and for specialty jobs such as local leak rate testing (LLRT) or snubbers. Machine shops are located both inside and outside the RCA. The machine shop in the RCA is a large, well-maintained shop with the capacity to perform maintenance on contaminated or non-contaminated equipment. The decontamination facilities are located close to both the machine shop and the TBTR and serve the tool attendants well in maintaining control of contaminated tools.

The training facilities are most adequate. The training center is located outside the protected area, but in walking distance of the plant. The center is very spacious and contains nine separate classrooms for lectures and four labs for hands-on training in mechanical, electrical, I&C, and HP/chemistry areas. The training center maintains a large inventory of equipment for training. Most instruments used in the plant are available in the training labs or in storage places on site, along with motors, pumps, valves, and motor operators. Some pieces of equipment, the MOVs for example, are capable of being energized and functionally tested after being used for hands-on training in maintenance. The training program utilizes mockups for both training and step-by-step evaluations and walkthroughs preceding job performance. This program is frequently utilized for work in high-radiation areas. A fairly realistic mockup for CRD removal and an EDG simulator/trainer are two of the more impressive mockups available. The CRD mockup has significantly reduced the size of work teams, and the number of man-hours and man-rems in the actual removal/replacement of the CRD.

Staging and laydown areas are adequate in the controlled area. There are many "gang" boxes available for the mechanics to prepare and store their tools and supplies in advance of the commencement of work. Scaffolding was plentiful and was set up in many cases for storing of tools and materials for work in progress.

The communication systems used by the maintenance department are adequate. An announcing system is used for communications inside and outside the plant. Two of the five lines in the system are available for general communication within the plant. The other three lines are reserved for the two control rooms and for emergencies. A sound-powered phone system is utilized by the I&C technicians during testing and troubleshooting. A deficiency in this area is that Unit 1 lacks a sufficient number of phone jacks. This problem is discussed in detail in Section 5.1 of this report.

Conclusions

The organization of the facilities was deemed to be supportive of the maintenance process. Maintenance equipment was plentiful and work shops were well supplied and maintained. The training facilities are modern and strongly support maintenance and ALARA goals. A good communications system and adequate staging and laydown areas also contribute to the effectiveness of maintenance at SSES.

7.2 Material Controls

Scope

In this inspection, the team reviewed procedures and implementation for material controls and support of the maintenance process. Areas inspected included warehouse activities and material storage areas in the plant, as well as the procedures that govern these activities.

Findings

The materials department is divided into three groups to support the material needs of the plant. The material support services group maintains a database of all materials and supplies and is responsible for accounting, budgeting, cost analysis, requisitioning, material planning, and administrative support. The technical procurement group is responsible for the technical aspect of the procurement process. This includes completing the technical portion of procurement documents (regulatory and QA requirements, equipment specifications, etc.), classification of parts, NCRs, and vendor exceptions. The warehousing group receives all material, completes receipt inspection on material, in-storage maintenance, packaging, shipping, and material issue and return. These sections are well staffed and work well together.

The procurement program was well documented in NDI-QA-2.4.7, Revision 3, "Procurement of Quality Materials and Services"; AD-QA-210, Revision 9, "Procurement Control Activities"; AD-QA-200, Revision 11, "Material Control Activities"; and NQAP 11.2, Revision 7, "Receiving Inspection." Review of some activities in progress and review of records indicated that the procedures were being effectively implemented. The existing programs for material tracking appear to be useful, but are too time consuming and labor intensive to obtain all desired data. A planner, for example, might have to consult three different programs to get all the information needed. SSES does not employ an automated method, such as bar codes, for tracking material receipt and usage. The information is entered by hand, therefore the database information is not available on a "real time" basis.

A program currently being developed will eliminate this problem and add the advantages of being able to order and have materials staged from a terminal within the plant through a network, to find out what WA material was used in the past, and to have a "real time" inventory as items are ordered in the plant. The development of this program has coincided with meetings of representatives from maintenance, planning, and materials to facilitate the development of a program that will improve service to all areas of maintenance where material is concerned.

Material is received in a section of the warehouse outside the protected area. After an initial sort of quality and non-quality material, the material is brought into the protected area through a set of double doors under the supervision of plant security personnel. These doors are handled in the same manner as air-lock doors; only one is opened at a time to provide security. Quality material and equipment is brought to the QA receipt inspection area lockup. All other material is brought to a separate area. A program is being developed for in-house packaging to better protect equipment and material in storage. Items are inspected more closely and documentation is completed. Small items (nuts or bolts, for example) from one purchase requisition are then packaged together with a stack of tags and stored in bins in the warehouse. Larger items are tagged, packaged as required, and stored on pallets or shelves. Different areas are set aside for staging material and for non-conforming, non-quality items.

Access to the warehouse, with the exception of the consumable area discussed below, is controlled and all visitors must sign in and be badged. Storage areas are spacious and well organized. Quality items are easily differentiated from non-quality items by color-coded tags on the item and on the shelf or bin on which the item was stored. Once a location is identified, that shelf location or bin number is entered into the items record in the database and becomes the permanent storage location for that item. As items are issued, the tags are verified or, for small items, the tag is verified and attached.

Consumable fasteners are provided in an area accessible to workers for use. These items are non-quality and are inventoried on a regular basis to ensure an adequate supply. In some cases, the warehouse handles, and is only responsible for, bulk packages of consumables (whole boxes of welding rods and barrels of oil, for example). These consumables become the responsibility of the maintenance department and are issued from a tool room.

Recent improvements to the warehouse include the addition of mezzanines over shelving to make better use of overhead space, the installation of a "mall" grate-type door in place of a short collapsible gate to provide better security and safety; the installation of a separate, temperature-controlled room for storage of electrical equipment and spare parts; and the packaging area mentioned above.

The receipt inspection section is part of the QA group. It has its own space within the warehouse. The area for storage of non-conforming items and quality items in need of inspection is fenced off from the rest of the warehouse and locked. There is enough space to house most large items.

Both the material department's and the receipt inspection's processes are well documented in store's files or on microfiche in the document control area. The sample of records reviewed appeared complete and no problems were found.

Conclusions

Material controls effectively supported the maintenance process by ensuring that the wait period for parts is as short as possible; that quality, safety-related parts are ordered; and that each safety-related part is carefully inspected before it is issued. Although generation of data was time consuming, the material management programs help the material and maintenance departments meet their goals. Major strengths in the materials department include the strong organization, and the cooperation and communication between the departments.

7.3 Maintenance Tool and Equipment Control

Scope

In this inspection, the team determined the extent to which tool and equipment control has been documented and implemented and assessed its support of the maintenance process. The team interviewed personnel, reviewed documentation, and observed work and storage areas.

Findings

The methodology for tool and equipment control is well established and well implemented. MI-AD-002 Revision 4, "Tool Control Program," is the governing document for storage of tools and equipment controlled by the combo shop tool room (CSTR) and TBTR. In these rooms are stored and controlled weld filler metals, calibrated tools, non-calibrated tools and equipment, contaminated tools, rigging and lifting equipment, tool authorization forms, and shop tool assignments. Inspection of the tool rooms indicated that the standards of this procedure were being effectively implemented with the exception of several concerns noted below.

AD-QA-922 Revision 4, "Weld Filler Metal Control," and AD-QA-615 Revision 5, "Control and Calibration of Plant M&TE," provide the requirements for storage, disbursement, use, return, and maintenance for weld material and calibrated tools. Although these procedures were effectively implemented, several potential problems exist with the latter and are discussed in Section 7.4.

An inventory control system has been established and is well implemented. This construction tool system (CTS), is a computerized data system which maintains records of the daily use of all tools and equipment kept in the tool rooms.

Contaminated tools are stored in and issued from the TBTR. Control over tools issued at this point is better maintained by requiring that all tools be returned there. The tool attendant then transfers contaminated tools to the "Decon" facility. Tools that cannot be decontaminated below 1K fixed-contamination are marked with purple paint and returned to the TBTR. A weakness in this area was that fixed-contaminated and non-contaminated tools were intermixed in storage locations. The licensee's representative stated this was caused by a shortage of storage space and that there are plans to expand the TBTR after the current outage.

Procedures AD-QA-542 Revision 4, "Crane, Hoist, and Rigging Program," and MT-GM-014 Revision 5, "Rigging and Lifting Equipment Inspection," provide the requirements for rigging inspector qualification, rigging inspection frequency, lifting equipment inspection, and load test frequency. All rigging and lifting equipment is adequately maintained and controlled by the tool rooms per these requirements. One weakness noted during the inspection was that rigging equipment returned to the tool rooms was not properly tagged after the return inspection as required by the above-mentioned procedures. The licensee acknowledged the deficiency, initiated immediate corrective action and corrected the deficiency.

Conclusions

Except for inadequate storage space in the TBTR, and improper tagging of slings and lifting equipment after return inspection, the tool and equipment program is well established and adequately controlled. The use of a computerized inventory system to maintain accountability and inventory control is a strength.

7.4 Control and Calibration of Measuring and Test Equipment (M&TE)

Scope

In this inspection, the team determined, through discussions with personnel, inspection of instruments and the instrument storage area, and a review of records, the extent to which M&TE is controlled and calibrated.

Findings

The team reviewed the governing procedure, AD-QA-615, and observed the functioning of the program during various work activities. All M&TE is uniquely identified, and the identification is transferred to the work document when the M&TE is employed. Traceability is also maintained through checkout documents executed by the craft withdrawing the equipment for use in the field. Several checkout points are maintained in the plant, providing the worker with easy access to the equipment. The calibration laboratory was well maintained and capable of performing approximately 90 to 95 percent of required calibrations without having to send equipment out to qualified vendors for calibration.

Distinctive markings were placed on all pieces of equipment identifying calibration due dates and any limitations associated with the equipment. Plant personnel were responsive to the recall methodology employed, and no out-of-calibration equipment was observed in the field. M&TE found to be out of calibration (non-conforming) was documented utilizing the NCR process. NCR dispositioning included an engineering evaluation of equipment on which the non-conforming M&TE had been used, and a determination of the required corrective action. An equipment history, including both calibration and maintenance history, was kept on each piece of M&TE.

Calibration due dates and recall were handled through the PMIS. This system is cumbersome for the purposes used by the M&TE program. This problem was recognized by the licensee and current plans include shifting to a database dedicated to the M&TE program by December 1990. The M&TE program does not require the formal notice be sent to the M&TE user/supervisor upon the expiration of calibration of a piece of M&TE. The weekly PMIS printout of calibration status provides an indication, however, no special notification is made when the M&TE calibration expires which would cause the user to turn the equipment in or to stop using it. The licensee stated that the program placed the responsibility on the user for ensuring that M&TE out of calibration is not used. The team considered the lack of special notification, indicating expired M&TE calibration, a weakness in the M&TE program.

Functional checks of M&TE returned to the issue point were neither required nor performed on any equipment with the exception of torque wrenches marked exclusively for snubber work. Relative to performing functional checks on M&TE for torque wrenches employed in other safety-related activities, for example, the licensee provided data that determined a non-conformance rate of 0.83 percent for the 603 calibrated torque wrenches used during the recent EDG and other Unit 1 outage activities. Although this failure rate suggests that the tools are in good repair and under statistical control, the team concluded that early identification of non-conforming conditions provided by a functional check on return after use would improve the program.

The team also learned that functional checks on the operability of equipment sent out for calibration were not performed upon return unless specifically requested on the purchase order. This is not routinely done. Although it is a matter of practice for laboratory personnel to "accompany" QC

personnel on receipt of equipment, the absence of shipping damage before field use was not verified. The team concluded that such a check would improve the program.

AD-QA-615, Section 6.2.2, permits the use of M&TE up to one-quarter of its calibration period beyond the calibration due date if approved by the I&C/C supervisor. The team noted that this practice has only been used once in the past six years and is consistent with INPO Good Practice MA-303 (INPO 84-006) of January 1984.

Three areas for improvement in storage of M&TE were noted. The CSTR does not have a controlled environment in which to store M&TE equipment with special storage requirements. At the time of the inspection, no discrepancy in M&TE storage was noted. The second problem noted was the possible mistreatment of M&TE equipment following decontamination. Several pieces of M&TE equipment were returned to the calibration lab because of rust and lack of internal lubricant following decontamination. Lastly, the team noted that segregated storage for non-conforming M&TE was not available. One digital multimeter clearly marked as inoperable was stored with calibrated equipment. Improper handling of decontaminated M&TE and improper storage of non-conforming M&TE were areas for program improvement.

The team found that I&C technicians are rotated through the laboratory every two to three years. OJT was the primary method used to train the technicians to perform sophisticated laboratory procedures. Although the experience level of the personnel rotated into the lab is relatively high, because of the short rotation periods, the direct laboratory experience was low.

The last QA audit of the M&TE program was performed in the summer of 1989. Because there were no negative findings in this and previous audits, the audit schedule has been extended to once every 2 years.

Conclusions

Although the M&TE program is functioning adequately and is being implemented in accordance with current program requirements, the team concluded that program improvements could be made enhance the overall operation.

Conclusions, Section 7.0

Maintenance facilities, equipment and material control were supportive of the maintenance process at SSES. The materials control program is well defined and implemented. There is a strong, well-implemented program for the control of maintenance tools and equipment. The M&TE program is well implemented however there are several areas where program improvement could be made. These areas deal with instrument recall, functional checks at the issue point, storage of non-conforming M&TE and experience level of technicians in the calibration lab. The program to control maintenance tools and equipment is well defined. Tool rooms are adequately stocked to

support maintenance activities. Weaknesses identified include the shortage of storage space in the TBTR and improper tagging of slings and wire ropes after inspection.

8.0 PERSONNEL CONTROL

Scope

In this inspection, the team determined the extent to which personnel are trained and qualified to perform maintenance activities. The team examined the current status of the following four areas: staffing control, training, testing and qualification, and current status. Evaluations are based on interviews, direct observations at the training facilities, observation of field activities, and reviews of documents and records.

8.1 Staffing Control

Scope

The team interviewed personnel and observed in the field the extent to which personnel control is proceduralized and implemented into the maintenance process .

Findings

Plant organization charts were readily available and current. The maintenance department reorganized approximately a year and a half ago, as described in Section 2.2, but job descriptions for the new work positions have yet to be developed. The need for full shift coverage is determined by job priority. An on-call maintenance duty team, including management, job planners, and crafts is maintained to finish high-priority work after hours or to come in and handle high-priority failures. The required response time for these people is 30 minutes. This coverage is adequate, based on the infrequent use and the craft average overtime of approximately 15 percent. The average overtime during the outage has been high (40 percent), but is within the limitations of not more than 72 hours of work in any seven day period as specified in TS 6.2.2.f.

The different craft are clearly defined and work well together. This was evidenced in the planning of work and implementation of work in the field. Communication between departments was very good. A turnover minimization policy is not required, as the total turnover in the maintenance department is very low. One contributor to the low turnover rate may be the maintenance department's policy to hire for the bottom ranks and to promote from within. In addition to the tests for training addressed below, craft must pass maintenance selection exams to advance. A person taking the mechanics exam, for example, would be required to take the training in basic mechanics, a specific exam in the specialty, and a practical exam that might consist of taking a component apart, repairing it, and reassembling it.

Conclusions

The maintenance department's staffing control is working well, aided by good communications between departments and low turnover. The limited backlog of work and low average yearly overtime indicate that shifts are well covered and that staffing is adequate. The only weakness identified in this area was the unavailability of job descriptions for the new jobs created in the reorganization.

8.2 Provide Personnel Training

Scope

In this inspection, the team determined the extent to which training is implemented, documented, certified, and addresses safety, including effective feedback in the maintenance process.

Findings

The maintenance training program was reorganized more than two years ago to provide certification programs in the mechanical, electrical, and I&C maintenance areas. One of the strengths of this new program was the decision to require all maintenance personnel to qualify, i.e., not to "grandfather". The program now consists of three phases. Phase I, the entry level, should take approximately three years to complete. It deals with basic work practices, elementary skills, and simple plant component and system theory. Phase II takes approximately two years to complete and addresses higher level skills, more complex component theory, and equipment maintenance. These two levels are required for certification. Phase III training is regarded as continuing training and training related to complex or unique in-plant equipment beyond the requirements of the first two phases.

Each phase consists of two parts. Part A is formal classroom training that must be completed. This training takes place at the training center and consists of both classroom lectures and hands-on training in labs. The lists of classes available in the different phases were very comprehensive and lesson plans were well organized and contained a good amount of detail. Part B identifies skills and tasks that are trained or evaluated by the maintenance/I&C department. Each task in part B has a list of references, and has requirements to address the safety concerns of the particular job, review the applicable procedure, receive OJT, and satisfactorily perform the task. One weakness identified in this area was that task certification was not available for complex tasks performed on an infrequent basis (HPCI turbine overhaul, for example).

The maintenance and I&C departments have temporarily transferred people to the training department for anywhere from two months to two years. One assistant foreman from mechanical maintenance was transferred as an instructor and was able to become certified in the two years he was there. He has since transferred back to mechanical maintenance and another assistant foreman was assigned to be an instructor with the same goal in mind. In addition to providing instruction,

- personnel from maintenance have greatly strengthened the training program by designing and constructing mock-ups for simulations. Two examples include the EDG simulator trainer and the CRD/under-vessel simulator.

- The feedback program in the training department was effective and functioning well. Not only did students supply feedback at the conclusion of courses, but it is requested again several weeks after completion of training to see if any further comments could be made or if the training was effective on the job. Comments received are tracked and trended, and reviewed and resolved by management, and a written reply is forwarded to the trainee to indicate the action that was or will be taken. A minimum of 96 hours is spent by instructors in the plant each year. This time can be spent assisting the maintenance department, observing the performance of maintenance recently reviewed in a lecture to provide feedback to improve lectures, or collecting data for future training.

Conclusions

The training program is complete and well documented. The certification program, the feedback program and the ability of maintenance to temporarily assign maintenance/I&C people to training were viewed as strengths.

8.3 Establish Test and Qualification Process

Scope

The team evaluated the extent to which testing and qualification of maintenance personnel is integrated into the maintenance process. The team interviewed personnel, toured the training facility, and reviewed procedures and documentation.

Findings

The training department recently procured a system called "Logic Extension Resources" to generate tests at random from a question data bank. Objective numbers and difficulty levels are assigned to each question entered. A matrix is entered into the data bank for each lesson plan number giving the number of questions for each objective and the number of questions at each difficulty level. When a test is needed, the lesson plan number is entered into the data bank and the test is produced. The test format was suggested by the NRC and all test questions are based on objectives in the lesson plans.

The training history for personnel is well documented in a computer database. These records identify all classes an employee attends and the grade received. The completion of certification tasks is documented by the maintenance department.

Conclusions

The test and qualification process is well documented and the testing format follows NRC guidance. Personnel qualifications are documented and traceable through computer records and the maintenance department training records.

8.4 Current Personnel Control Status

Scope

In this inspection, the team evaluated personnel status in the areas of testing and qualification, drug problems, work performance by unqualified personnel, and turnover rate. The team interviewed personnel and reviewed procedures and documentation.

Findings

The average experience level in the maintenance and I&C departments is approximately ten years, indicating stability. The very low turnover rate includes personnel transferred within the company. The certification levels are clearly posted for use in planning jobs, helping to prevent work from being attempted by unqualified personnel. Nineteen mechanics and thirteen electricians were certified this year, more than double the original goal.

Responsibilities for implementation of the licensee's policy on fitness for duty are established. The staff was trained several months before the program was implemented. Disciplinary action for violating the policy is based on severity of the violation and could lead to firing. Both contractors and new employees are given a drug screening before being granted unescorted access to the site. Access is only granted (escorted or unescorted) if the person is willing to complete the screening.

Conclusions

The licensee has a stable, experienced maintenance work force. The turnover rate is quite low and includes personnel transferred within the company. The licensee has a fitness-for-duty program.

Conclusions, Section 8.0

Plant organization charts were readily available and up to date. The hiring and promotion policy is being implemented according to the licensee's program. The personnel turnover rate at the plant is low, so a turnover minimization policy has not been needed. The on-call maintenance duty team handled high-priority work effectively after hours. There is not a large backlog of work and the average overtime for the craft is approximately 15 percent. On the basis of the low work backlog and the overtime figure, the inspector concluded that the maintenance department is adequately staffed for all shifts.

The training program at the plant is INPO accredited. Yearly training includes site access training and a minimum of three weeks of classroom training. In addition to this, manufacturers train plant staff on different equipment and plant staff attends offsite schools as the opportunities arise. The task certification program is run by the maintenance department and takes place as needed. Training is thoroughly documented. Personnel become qualified through a documented testing program and by satisfactorily completing task certification programs.

APPENDIX 1

INDIVIDUALS CONTACTED

Susquehanna Steam Electric Station

Meeting(s) Attended	Name	Position
	D. Artman	I&C Assistant Foreman
abc	T. Bannon	SSES Maintenance Support Team Leader
	G. Bausinger	I&C Engineer
ab	J. Blakeslee	Assistant Superintendent of Plant
b	R. Bogar	Electrical Work Group Supervisor
	B. Bogh	Training and Resource Coordinator
b	C. Boschetti	Engineer/Risk Analyst
	B. Boyer	Assistant Construction Foreman
a	G. Butler	Manager, Nuclear Design
	D. Cassel	Senior Project Engineer
b	K. Chambliss	Maintenance Production Supervisor
b	C. Coddington	Senior Project Engineer, Licensing
cd	N. Covington	Engineer
	M. Crowthers	Project Engineer, Nuclear Design
	M. Deckman	Nuclear Maintenance Training Supervisor
ab	T. Dalpiaz	Assistant Superintendent, Outages
b	M. Detamore	Supervisor, Systems Engineering
	T. Dreyfus	Assistant Foreman Mechanical Repairs
b	G. Eustice	Coordinator, NQA
	J. Fallbright	SSES MTI Support Team
	G. Farley	I&C Assistant Foreman
abcd	E. Figard	Supervisor of Maintenance
	D. Flaim	Assistant Foreman Mechanical Repairs
	M. Fogarty	Engineer, Level II
	B. Fritz	SSES MTI Support Team
b	J. Fritzen	Radiological Operations Supervisor
	D. Gandenberger	Maintenance Services Supervisor
bd	G. Glaser	I&C Production Supervisor
b	M. Golden	Plant Engineering Supervisor
b	J. Gutshall	Valve Maintenance Assistant Supervisor
b	D. Hagan	Radiation Protection Supervisor
	K. Hart	Valve Technical Support Supervisor

	M. Hiedorn	EDG Engineer
b	R. Hoopes	Valve Maintenance Supervisor
ab	T. Iorfida	I&C/C Supervisor
b	V. Kelly	Nuclear Maintenance Engineer
	P. Kester	Unit 2 I&C Coordinator
b	S. Kuhn	Diesel Generator Function Team Leader
b	G. Kuczynski	Technical Supervisor, PP&L
	J. Kulik	Supervisor, Risk Assessment
	G. Kulzynski	Plant Technical Supervisor
b	S. Laskos	Unit Coordinator
ab	L. Mahasky	Construction Superintendent
	K. Mantz	Assistant Foreman Mechanical Repairs
b	K. Mattern	NSS Maintenance Supervisor
	T. Nork	Plant Engineering Supervisor
abd	L. O'Neil	Supervising Engineer, Resident Engineer
	R. Paley	Electrical Engineer
a	H. Palmer	Supervisor of Operations
	V. Recla	Electrical Engineer
b	H. Riley	Health Physics Supervisor
b	G. Robinson	Electrical Foreman
ab	D. Roth	Senior Compliance Engineer
	J. Rowe	Unit 1 I&C Coordinator
b	S. Rozic	MSER Foreman
	N. Runge	E&S Valve Mechanical Foreman
	M. Rutkoskie	I&C Assistant Foreman Calibration
b	A. Sabol	Manager, Nuclear Quality Assurance
b	R. Sacco	Construction Supervisor
	B. Saccone	Senior Project Engineer, Resident Engineer
b	G. Scheibner	Engineer, PP&L
	R. Sgarro	Licensing Project Engineer
b	S. Shah	Maintenance Planning and Scheduling Supervisor
b	D. Sitler	Senior Resident Engineer, BOP Supervisor
abd	G. Stanley	Superintendent of Plant
b	T. Steingass	Maintenance Testing Supervisor
	D. Stevens	Construction Foreman Field Services
b	J. Sullivan	IEG Group Lead
	D. Thomas	I&C Assistant Foreman Scheduling
b	J. Toodd	Consultant, Maintenance Department
b	G. Treven	I&C Production Engineer

b	K. Tutorow	Foreman, Mechanical Repairs
bd	R. Wehry	Power Production Engineering
d	C. Whirl	Assistant Manager, Nuclear Quality Assurance
abcd	W. Williams	Licensing Engineer
	W. Wimer	E&S Valve Mechanic Assistant Foreman

United States Nuclear Regulatory Commission

abc	S. Barber, Senior Resident Inspector
b	N. Blumberg, Chief, Operational Programs Section
b	W. Hehl, Director, Division of Reactor Projects
b	P. Swetland, Chief, Reactor Projects Section 2
a	J. Stair, Resident Inspector

Other licensee personnel also contributed to this inspection

a - Attended entrance meeting held on September 12, 1990.
b - Attended exit meeting held on October 19, 1990.
c - Attended entrance meeting held on November 5, 1990.
d - Attended exit meeting held on November 9, 1990.

APPENDIX 2

SUMMARY OF WEAKNESSES

Weakness - A potential problem or condition presented to a licensee for evaluation and corrective action as appropriate.

Section	Description
1.2	Missile hazards due to unsecured material stored in safety related areas. This has been a long-standing problem based upon previous NRC inspections and needs both short-term and permanent-long term corrective action.
3.5	The root-cause analysis program and its application to failures including assurance that generic implications are addressed.
5.1	EQ instrument program requirements, specifically, distinguishing EQ instrument requirements from Non-EQ instrument requirements.
5.1	Inadequate management oversight and timeliness of procedure changes.
5.1	Inadequate preplanning of work, a lack of procedural adherence and an insufficiently detailed WA package, as observed during the HPCI turbine overhaul.
5.2	Inadequate independent verification. Procedure AD-QA-500 is less stringent than ANSI N18.7-1976.
5.8	Untimely procedure upgrades to specify procedure adherence categories, provide inadequate procedure adherence training for workers, and inconsistencies between SSES policy and lower tier procedural implementation/adherence requirements.
5.8	Inadequate requirements for maintenance procedures, e.g., lack of a writers guide. Inadequate procedure status for supplemental work instructions (reference ANSI N18.7-1976).
5.9	Inadequate postmaintenance testing planning process, e.g., ASME Code components are not being identified.
5.10	Inadequate work package documentation.
6.4	Inadequate component failure trending across system boundaries.

7.3 Inadequate separation of fixed-contaminated and non-contaminated tools in TBTR storage areas.

7.4 Inadequate notification of expired M&TE calibration.

8.1 Inadequate job descriptions for new positions created in SSES's reorganization.

8.2 Lack of task certification for complex tasks performed on an infrequent basis (HPCI turbine overhaul, for example).

Appendix 6 Inadequate controls and inspections for scaffold erection.

APPENDIX 3

SUMMARY OF UNRESOLVED ITEMS

Unresolved items are matters about which more information is required in order to determine whether they are acceptable items, deviations or violations. Unresolved items identified during this inspection are listed below:

U/I No.	Description	Ref. Section
90-81-01	Engineering evaluation of Belden battery cable bend radius	1.2
90-81-02	Evaluation of the long term effects of high temperatures in the HPCI and RCIC rooms	1.2
90-81-03	Evaluation of hazard of parking tankers adjacent to EDG building	1.2
90-81-04	Clarification of EQ requirements for temperature detector TE E51-2N022B	5.1
90-81-05	Provide assurance that PP&L procedures covering submittal of a technical specification change are in place and that no similar cases exist.	5.5

APPENDIX 4

DOCUMENTS REVIEWED

AD-QA-100	Revision 7, Station Organization and Responsibilities
AD-QA-101	Revision 18, Procedure Program
AD-QA-120	Revision 6, NCR Control and Processing
AD-QA-197	Revision 4, Use and Control of Installation, Operation, and Maintenance Manuals (IOMs)
AD-QA-200	Revision 11, Material Control Activities
AD-QA-210	Revision 9, Procurement Control Activities
AD-QA-306	Revision 7, System/Equipment Release
AD-QA-324	Revision 3, 5/29/90, Plant Labeling Program
AD-QA-400	Revision 4, Conduct of Technical Support
AD-QA-410	Revision 12, Plant Modification Program
AD-QA-422	Revision 10, Surveillance Testing Program
AD-QA-424	Revision 8, Significant Operating Occurrence Reports
AD-QA-482	Revision 0, Post Maintenance Test Program
AD-QA-500	Revision 11, Conduct of Maintenance
AD-QA-501	Revision 1, Maintenance Procedure Program
AD-QA-502	Revision 16, Work Authorization System
AD-QA-541	Revision 4, Maintenance Equipment Performance and Trending Analysis
AD-QA-542	Revision 4, Crane, Hoist, and Rigging Program
AD-QA-600	Revision 4, Conduct of Instrument and Controls/Computer Section
AD-QA-605	Revision 7, Maintenance and Calibration of Installed Plant Instrumentation
AD-QA-615	Revision 5, Control and Calibration of Plant M&TE
AD-QA-903	Revision 3, Scaffold Erection Review Inspection
AD-QA-922	Revision 4, Weld Filler Metal Control
AI 90-003	Revision 0, Management Inspection of Facilities
C-1023	Revision 3, Furnishing and Erecting of Structural Steel
C-1056	Revision 1, Change 3, TS for Erection of Scaffolding in Safety Related Areas
EDU-ADB-001	Dedication Criteria for Pomona Banana Jack Adapters
EDU-ADB-001	Dedication Criteria for Pomona Terminal Strip Banana Jack Adapters
EPM-QA-424	Revision 2, Engineering Discrepancy Management
EQDF-39-I	Model 1153B Rosemount Manual
IC-070-001	Revision 3, 7/3/89, Calibration of SGTS Alison Fire Detection and Deluge Control System
IC-159-001	Revision 0, Replacement and/or Rework of the Suppression Pool Water Temperature Resistance Temperature Detectors (TE-15751 through TE-15770)
IC-178-005	Revision 0, 10/11/90, IRM and APRM Division B (RPS B1/B2) Half-Scram and SRM/IRM Rod Block Disabling
IOM 532	Model 1153B Rosemount Manual
ME-ORF-010	Revision 0, Reactor Vessel Head Removal

MI-AD-002	Revision 4, Tool Control Program
MI-AD-006	Revision 1, Use and Control of Vendor/Contractor Personnel
MI-AD-020	Revision 1, Employee Feedback
MI-PS-001	Revision 13, Work Plan Standard
MI-PS-008	Revision 1, Post Maintenance Testing Guide
MT-EO-021	Revision 1, Votes-MOV Diagnostic Test
MT-GE-009	Revision 4, Insulation Resistance Checks
MT-GM-001	Revision 6, Coupling Alignment (Horizontal Equipment)
MT-GM-003	Revision 9, Valve Disassembly, Reassembly and Rework
MT-GM-005	Revision 7, Safety/Relief Valve Setting
MT-GM-010	Revision 5, Pump Packing
MT-GM-014	Revision 5, Rigging and Lifting Equipment Inspection
MT-061-001	Revision 6, Reactor Water Cleanup and Pump Disassembly, Inspection, and Reassembly
MT-199-001	Revision 6, Reactor Building Crane Operating Procedure
NDI-1.3.3	Revision 3, Nuclear Services Charter
NDI-QA-2.4.7	Revision 3, Procurement of Quality Material and Services
NDI-QA-3.3.1	Revision 6, NRC Correspondence
NDI-QA-6.2.2	Revision 12, Industry Events Review Program
NDI-QA-15.1.1	Revision 5, Communication Interfaces with NPE
NPRDS entry	RFW pump discharge air-operated check valve failure, January 31, 1989
NPRDS entry	HCU nitrogen accumulator for control rod 46-51, March 1, 1989
NPRDS entry	CRD pump vibration, March 2, 1989
NPRDS entry	RFW pump discharge air-operated check valve failure, June 1, 1989
NPRDS entry	HPCI pipe routing temperature switch TSH-IN603C chattering, June 25,1989
NPRDS entry	Unit 1 RFW pump discharge valve thermal binding, September 10, 1989
NPRDS entry	RFW pump discharge air-operated check valve failure, December 26, 1989
NQAP 11.1	Revision 7, Quality Control Inspection Program
NQAP 11.2	Revision 7, Receiving Inspection
NQAP 11.4	Revision 4, Training, Qualification and Certification of Inspection, Examination and Testing Personnel
NSI-4.1.1	Revision 0, Preventive Maintenance Improvement Program
PM B04691	Six Year Inspection HPCI Terry Turbine
SE-024-E04	Revision 0, 18 Month Diesel Generator E Auto Start on ECCS Actuation Test Signal
SE-024-E05	Revision 1, 18 Month Diesel Generator E 24 Hour Run and 4000KW Load Rejection
SI-178-402	Revision 6, 18 Month Time Response Test of APRM Channels A, B, C, D, E, F
SI-280-201	Revision 5, Monthly Channel Functional Test of Reactor Vessel Pressure Channels PS-B21-2N021A, C, E, G and PIS-B212N021B, and D (Core Spray System and LPCI Permissive)

SI-283-207	Revision 5, 12/7/88, Monthly Functional Test of Main Steam Line Flow Channels A, B, C, & D
SM-102-A03	Revision 7, 18 Month Channel "A" 1D610 - 125 VDC Battery Electrical Parameter Test and Inspections, Battery Service Discharge and Battery Charger Capability Test
SOOR 1-90-131	River Intake Transformer Deluge System
SO-149-002	Revision 10, Quarterly RHR System Flow Verification
SO-152-002	Revision 11, Quarterly HPCI Flow Verification
WA S03509	Reactor Building Closed Cooling Water Heat Exchanger SW Isolation Valves 110060, 110061, and 110062

Anchor Darling Instruction and Operating Manual
Audit 89-057 Personnel Training and Qualification
Audit 89-090 Test Control Program
Audit 90-005 TS Compliance
Audit 90-006 Plant Maintenance Program (electrical maintenance)
Form 480-Non-VT-2 System Leakage Test
INPO Good Practice MA-319 Methodology for Preventive Maintenance Program Enhancement
Policy Letter OPS-6 Revision 6, Qualification, Training, and Certification of Personnel
Policy Letter 89-004 5/30/89, Procedural Adherence
RWP 90-583 for HPCI/RCIC turbine work
Final Safety Analysis Report, Revision 39
PP&L IPE Revision 1, Individual Plant Evaluation
PP&L Maintenance Function Five Year Plan, PLI 64965, August 14, 1990
PP&L Safety Rule Book
SSES Managing For Excellence Action Plan
Tactics for Excellence Through Accountable Management Manual
Unit 1 ISI Composite Pressure Test Diagram - Functional Test HPCI System

APPENDIX 5

ABBREVIATIONS

AI	administrative instruction
AISC	American Institute of Steel Construction
ALARA	as low as reasonably achievable
ANS	American Nuclear Society
ANSI	American National Standards Institute
AOT	allowed outage time
APRM	average power range monitor
ASME	American Society of Mechanical Engineers
ATWS	anticipated transient without scram
BOP	balance of plant
BWR	boiling-water reactor
CF	capacity factor
CFR	Code of Federal Regulations
CRD	control rod drive
CSTR	combo shop tool room
CTS	construction tool supply system
DCC	document control center
ECCS	emergency core cooling system
EDG	emergency diesel generator
EPRI	Electric Power Research Institute
EPTAR	equipment performance and trending analysis report
EQ	environmental qualification
EQDF	Equipment Qualification Data Form
ERF	equipment release form
E&S	Engineering and Support (Construction)
ESF	engineered safety feature
ESS	engineered safety system
ESW	emergency service water
EWR	engineering work request
FSAR	final safety analysis report
GE	General Electric
HCU	hydraulic control unit
HP	health physics
HPCI	high-pressure coolant injection
I&C/C	instrumentation and controls/computer
INPO	Institute of Nuclear Power Operations
IOM	installation, operation, and maintenance manual
IPE	individual plant evaluation
IRM	intermediate range monitor

ISI	inservice inspection
ISLT	inservice leak test
LCO	limiting condition for operation
LER	licensee event report
LLRT	local leak rate test
LPCI	low-pressure coolant injection
MG	motor generator
MIP	maintenance improvement program
MOV	motor operated valve
MSIV	main steam isolation valve
MT	magnetic particle test
MTI	maintenance team inspection
M&TE	measuring and test equipment
NCR	nonconformance report
NDE	nondestructive examination
NDT	nondestructive testing
NPE	Nuclear Plant Engineering
NPRDS	Nuclear Plant Records Data System
NQA	Nuclear Quality Assurance
NQAP	NQA procedure
NRC	Nuclear Regulatory Commission
NSAG	Nuclear Safety Assessment Group
NSSS	nuclear steam supply system
NUMARC	Nuclear Utility Management and Resources Council
OJT	on-the-job training
PC	protective clothing
PCAF	procedure change approval form
PFR	Project Funding Request
PIF	performance improvement form
PM	preventive maintenance
PMIP	preventive maintenance improvement program
PMIS	plant maintenance information system
PMR	Plant Modification Request
PMT	postmaintenance/modification testing
PP&L	Pennsylvania Power and Light
PRA	probabilistic risk assessment
QA	quality assurance
QC	quality control
RCA	radiological control area
RCIC	reactor core isolation cooling
RFW	reactor feedwater
RHR	residual heat removal
RPS	reactor pressure system

RPV	reactor pressure vessel
RTD	resistance temperature detector
RWCU	reactor water cleanup
RWP	radiation work permit
SALP	systematic assessment of licensee performance
SBLC	standby liquid control
SEIS	Susquehanna Equipment Information System
SGTS	standby gas treatment system
SOOR	significant operating occurrence report
SRC	Safety Review Committee
SRM	source range monitor
SSES	Susquehanna Steam Electric Station
SW	service water
TBTR	turbine building tool room
TEAM	Tactics for Excellence Through Accountable Management Manual
TS	technical specifications
VAR	volt amperes reactive
VOTES	valve operation test and evaluation system
WA	work authorization

APPENDIX 6

SPECIFICS FROM WALKDOWN INSPECTIONS

10 CFR 50.59 Safety Evaluations (Section 1.2)

This section contains details from observations which indicate potential unreviewed safety questions that had not been identified by the licensee. These are in addition to and in support of the finding listed in Section 1.2 of the report, Plant Walkdown Inspection.

The inspection team identified four modifications that were installed on safety-related systems without documented 10 CFR 50.59 safety evaluations. The modifications either lacked proper documentation or were documented on work authorizations (WAs) without written safety evaluations.

On October 14, 1990, the inspector noted temporary lighting strings at the Unit 1 and 2 control rod drive hydraulic control units on the 719-foot levels. The lighting strings, although protected with fire wrap, were in close proximity to redundant division wire ways and presented a potential for secondary bridging with safety-related divisional channels. The licensee's response to this concern was that the condition was previously identified in Nonconformance Report (NCR) 526, issued on March 26, 1984. The NCR documented that non-Class 1E temporary lighting cables were violating the separation criteria on Class 1E reactor protection system raceways. In response to the NCR, the licensee fire-wrapped the temporary lighting cables until Plant Modification Request (PMR) 89-9134 (Unit 1) and PMR 89-9135 (Unit 2) were approved and the modifications installed. The fire wrap installation and the documentation of the original temporary cable installations were done under WA 90082 (Unit 1) and WA 90083 (Unit 2). The inspector reviewed the NCR and discussed the issue with plant staff to determine if a 10 CFR 50.59 safety evaluation had been conducted and documented for the temporary installations. The NCR did not document or reference a safety review for the installation and plant staff could not retrieve a safety evaluation for the installation. The inspector had the following concerns relative to the performance of a safety review and dispositioning of the NCR: the condition has existed since before March 26, 1984, indicating the modification had become permanent by lack of corrective action; the processing of the NCR apparently did not result in a written safety evaluation for the modification; the implementation of WAs to install the fire wrap on the light strings and to document the modification provided additional opportunity to identify, perform, and document the required safety evaluation, however, the review was not adequate to identify the deficiency; and two operability/reportability reviews did not result in documenting safety evaluations.

The inspectors noted in Unit 2 a reactor water cleanup control panel, 2C040, that was modified to install a door stop for the panel door. The panel was drilled for the addition of a small drop-down latch to hold the panel door open during maintenance. The latch was held in place with a bolt through the panel front and a nut and washer. Upon review, it was found that the modification was installed in August 1984 by WA V43705 (rather than through an approved PMR) as a safety

measure to keep the door from closing on technicians working on the panel. Although the WA included drawings and may have had limited engineering review, no drawing revisions or engineering reviews were documented. The licensee's response to the concern was that an approved PMR had added a plastic panel to the inside of the door to reduce the potential for the door to close on technicians, so the latch was no longer needed. The licensee initiated WA V04102 to remove the latch and acknowledged that the change should have been made through the modification process rather than by a maintenance action.

On October 9, 1990, the inspector noted that the Unit 2 standby liquid control accumulator 2T207B charging connection cap had a hole drilled through the cap to allow for the connection of a Shrader valve that was too large to fit under the cap. The hole presumably allowed personnel to charge the accumulator without removing the cap. As the accumulator is a safety-related component, the inspector questioned the modification to the system and asked to see the modification and safety evaluation for the change to the system. Subsequent investigation by the licensee found a similar modification made on the Unit 1 accumulator 1T207A charging connection cap. The licensee's written response to the issue indicated that the charging connections which penetrated the cap did not agree with any design documentation, and that approval to support the Shrader valve replacement and cap modification could not be located. NCR 90-0343 (Unit 1) and 90-0344 (Unit 2) were issued on October 17, 1990, to document the condition. The licensee could not locate a 10 CFR 50.59 safety evaluation for the modification.

On October 10, 1990, the inspector noted a structure on top of the Unit 2 main steam flow panel 2C041 on the 719-foot elevation. The structure consisted of unistrut, galvanized metal, and universal angle and was connected to the top of the safety-related instrument panel and containment wall-mounted instrument tubing supports. The structure was identified as "temporary protection" with mylar tape and appeared to protect flexible hoses connecting instrument tubing runs to panel-mounted instruments. Other instrument racks in Units 1 and 2 did not have similar structures or protection. The inspector questioned the additional loading (about 100 lb) on the instrument rack and a small instrument tube support. The licensee was asked to retrieve documentation on the modification, including the date of installation, modification package, design analysis, and 10 CFR 50.59 safety evaluation. During a subsequent investigation, the licensee found that drawings and documentation for the panel did not indicate any design modification, analysis, or written safety evaluation for the temporary structure. The licensee issued NCR 90-0342 on October 18, 1990, to document and evaluate the deficiency.

OTHER ISSUES NOTED BY THE TEAM

Seismic Mounting of Gas Bottles

The team noted multiple deficiencies with seismic mounting of gas bottles within the plant. Deficiencies included missing structural members on a bottle rack, improper thread engagement, and loose seismic restraints.

The Unit 2 hydrogen/oxygen bottle rack 2C226A, at the 719-foot level, had loose bottle restraints. The licensee issued and completed WA V04080 to tighten the restraints. During reinspection of this and other similar racks, inspectors noted that the rack was missing two structural tubular steel members between the layers of bottles. The missing steel members are shown on drawing C01083 (E-105840), Revision 14, "Reactor Building Units 1 & 2 Miscellaneous Steel Sections and Details in Section D." The licensee initiated NCR 90-0300 to document and evaluate the condition. In response to the NCR, the licensee walked down all Unit 1 and 2 racks to identify similar conditions. During the reinspection, inspectors also identified inadequate thread engagement on bottle restraints on containment instrument gas backup nitrogen bottle rack 2T212A-M, and loose restraints on containment instrument gas backup nitrogen rack 2T213A-M. Because of the number and generic nature of the deficiencies with bottle racks, the licensee issued Significant Operating Occurrence Report 1-90-322 to address the generic issue.

Scaffolding Deficiencies

During plant walkdowns the team noted several large scaffolds in safety-related areas which did not meet construction requirements in plant construction technical specifications for erection of scaffolding or scaffold review inspection requirements.

A large scaffold was under construction in Unit 2 on the 719-foot elevation over safety-related instrument panel 2C041. This was a safety concern as the unit was near full power. Several aspects of the scaffold construction were not in accordance with construction technical specification C-1056, Revision 1, "Erection of Scaffolding in Safety Related Areas," and AD-QA-903, Revision 3, "Scaffold Erection Review Inspection." The scaffold had been in place for about 4 days with the following deficiencies:

(1) Several aluminum platform planks directly above both safety-related and non-safety-related instrument panels were not locked or wired in place as required by construction technical specification C-1056, "Erection of Scaffolding in Safety Related Areas."

(2) Minor cantilevers on two platform planks were not allowable by procedures without specific NPE approval. Cantilevered planks were not approved or wired in place as required.

(3) One scaffold tube was installed through the middle of the recirculation jet pump instrument panel centered between two instrument tubing runs with about 1.5 inches clearance on either side. Another scaffold tube was installed through one side of a safety-related instrument panel. The procedure did not directly address routing the tube through instrument panels.

(4) The scaffold had no bottom restraint or top restraint tied to building steel or concrete as required by procedures.

(5) Diagonal support bracing was minimal and did not meet the procedural requirements. This was considered to be a safety hazard since personnel had to walk on the lower platform to erect the upper levels.

(6) AD-QA-903, Section 6.1.9 specifically states that no shift supervisor approval is required for scaffold erection in safety related areas if the scaffold procedures are followed. The programmatic allowance was viewed by the team as non-conservative since the activity has the potential to affect safety and should require evaluation.

On the basis of the licensee's response that the scaffold was under construction and had not been inspected, the inspector performed field inspections of two additional completed scaffolds which had inspection certificates attached. The following weaknesses were noted regarding scaffold in the Unit 1 core spray room:

(1) The weight of one corner of scaffold was bearing on a pipe support rather than on the scaffold leg.

(2) The scaffold had no bottom restraint tied to building steel or concrete. The upper scaffold restraint was tied to another scaffold rather than to building concrete or steel. An allowance for restraining scaffold from other scaffolds was not addressed by procedures.

(3) Scaffold planks were not locked or wired in place.

(4) Diagonal bracing was minimal.

The inspector concluded that weaknesses existed in scaffolding construction and inspection. A potential personnel hazard existed because platform planks were not being locked in place and the seismic adequacy of inspected scaffolds was questionable.

Material Storage Deficiencies

During plant walkdowns, the team identified a number of material storage deficiencies in safety-related areas of the plant. Deficiencies involved such items as large tool boxes, 55-gallon drums, wheeled circuit breaker test units, and large portable pumps on wheels. The team considered these items potential missile hazards which should have been removed or restrained. Specific discrepancies identified by the team included a 55-gallon drum and toolbox in Unit 2, 719-foot elevation by the penetration room access door, small and large (2'x 2'x 6') toolboxes between load centers in Unit 2 at the 749-foot elevation 4-kV vital load center room, wheeled circuit breaker test units in load center rooms, a tool box in the Unit 2 core spray room, 2 I-beams standing up in the Unit 2 high-pressure coolant injection (HPCI) room, and a spare circuit breaker adjacent to panel 2C810. In response to inspector concerns, the licensee removed or stored identified items. This has been a long standing problem at the station, the current actions begin taken to resolve the problem is discussed in Section 1.2, Plant Walkdown Inspection.

Separation Criteria

During plant walkdowns, the team identified a violation of separation criteria for Class 1E redundant channel divisional conduits. Flexible conduits Y2K120 (blue), V2K119 (green), and X2K122 (orange) serving reactor vessel level instruments did not meet the 1-inch separation distance of technical specification E-1012, "Electrical Separation Criteria," or IEEE-384, 1974, "Independence of Class 1E Equipment and Circuits." The licensee acknowledged the item and initiated NCR 90-0338 to document and evaluate the deficiency. The deficiency has minor safety significance because the conduit circuits are low-energy instrument loops. The licensee action was appropriate.

Instrument Panel Deficiencies

During walkdown of instrument panels, the inspectors noted several miscellaneous deficiencies on the panels. On Unit 1 HPCI instrument panel 1C034, unistrut nuts were misaligned on PSH-E41-1N012A test valve bracket. The team noted that three of four unistrut spring nuts were misaligned on a junction box mounted on rack number 1C014 located in the Unit 1 core spray pump room. Additionally, the slotted mounting brackets for the junction box were mounted to the rack without washers to fully span the slotted bracket. The licensee issued WAs V06848 and V06849 to correct these deficiencies. On the same panel, tapered washers were not used on the panel with concrete anchor bolts, therefore uniform torquing and anchorage could not be assured. Specification C-1023, "Technical Specification For Furnishing and Erection of Structural Steel," Section 2.0, commits Susquehanna to the American Institute of Steel Construction (AISC) manual, "Specification for the Design, Fabrication, and Erection of Structural Steel For Buildings." The AISC manual requires tapered washers on tapered beams or channels. Additionally, an oversized lockwasher was used on one bolt. The licensee issued an engineering work request (EWR) to evaluate misaligned unistrut nuts and the effect on seismic qualification. The licensees action was appropriate.

Drywell

The team performed a walkdown inspection of the Unit 1 drywell on October 18, 1990, and noted several strengths and weaknesses. All levels and major azimuths were well identified, and updated radiological survey information was conspicuously posted. Equipment was well protected; e.g., the blowdown pipes to the suppression pool were covered with netting to prevent debris from entering, and main steamline vacuum breaker openings were covered. The drywell preservation program was functioning well; e.g., no evidence of corrosion was noted on the liner or floor. A large selection of tools was available to workers at the drywell entrance. A Health Physics rover with a transceiver headset was on shift and in communication with the access control point to resolve any problems encountered by any workers in the drywell. Most manual and power-operated valves showed evidence of good preventive maintenance.

Weaknesses noted included large amounts of such discarded materials as: tape, gloves, tie wraps, wire ends, WD40 can tops, and plastic sheeting. Numerous groups of nuts, bolts, pins, and washers which were not bagged or tagged as to their source or use were found lying in various places. A pre-startup closeout inspection planned to increase worker attention on the job could improve worker attention to detail.

One worker was observed moving under an open area without a hard hat. Hard hats at the drywell entrance were scarce and although hard hats are required to be worn, many were noted unused on the 704-foot level. (Section 4.6)

Several equipment closure problems were noted. Junction box 1W104A utilized amphenol connectors for connecting cables. Several unused male connectors in the box were either covered with a non-durable plastic cap or not covered at all(704', 355 deg az). RTD NAMCO caps were loose on reactor recirculation pump B motor instrumentation. Similarly, a Crouse Hinds closure cover was loose on RTD/TC 187185 for drywell cooler 1V414B (at the RBCW outlet throttle valve) and the closure cover was loose on the RTD/TC sensor to SRV K, main steamline D relief valve lift/leak detector PSV141F013K. A drywell temperature monitor (RTD/TC) was not mounted or labeled, and was hanging loose by its conduit (suspended about 15' - 767', 313 deg az) with the closure cap loose. A lack of support for conduit caused a potential minimum bend radius problem for the main power cables (E1K984) to the HPCI supply valve motor-operated valve (MOV). The power cables were located in 1-1/2-inch stainless steel flexible conduit and 1-1/2-inch steel braid conduit, but were unsupported for a substantial run after exiting the MOV at an acute angle.

Some evidence of improper tool usage was noted on a machine pipe plug installed at manual valve 2RV-PP-141O7A2, FW to reactor vessel second isolation valve. The plug showed signs that it had been installed with a pipe wrench instead of a box-end wrench, leaving the pipe plug deeply marred.

Two manual valves showed evidence of leakage. RRP B suction elbow tap vent first isolation valve 143O15B showed evidence of packing leakage. The downstream pipe nipple and cap from the second isolation valve had much corrosion on the pipe, indicating leakage through the two isolation stops and the pipe vent cap. FW 1B shutoff valve HV141F011A (752', 340 deg az) had the packing gland follower cocked off to the side so that the gland was nearly rubbing the valve stem on one side and a large gap existed on the other side.

HPCI Turbine

During observation of work on the HPCI turbine, the team noted two piping configuration concerns. The HPCI turbine throttle stop/trip valve steam chest high-pressure drain line was supported by two spring can hangers and snubbers. One spring can (support SP HBB-135-H2011) had vertical misalignment of approximately 10 to 15 degrees, so that the lower rod was nearly touching the spring can, although no offset was shown on the hanger drawing (drawing SP

HBB-135-H2011, Rev. 1F3). The licensee initiated NCR 90-0320 to investigate and correct the condition.

A 3/4-inch high pressure steam drain line exited the auxiliary steam supply to the HPCI turbine on the turbine side of the root stop valve. The drain line, including a steam trap, was noted to run horizontally approximately 6 feet, turn at 90 degrees and run for 2 more feet, turn again at 90 degrees in the vertical direction, and run for an additional 10 feet without any pipe support (isometric drawing SP-HBD-3023-1, 3/4" Pipe for Steam Trap Line, Reactor Building El. 645'-0"). Hangers were not specified by the drawing, but were "field run". The team was concerned that the unsupported pipe could become a hazard to safety equipment in case of a seismic or fatigue event. The licensee initiated an EWR to resolve the concern.

250-V Vital Battery Room

During walkdowns of the 250-V vital battery rooms, the inspector identified a tight bend radius on an intercell jumper for the Unit 1 division 2 battery. The intercell jumper had a bend radius of about 1.5 inch for Belden 4/0, 600-V wire. Additionally, the intercell jumper was not supported and over time could sag, further reducing the bend radius. The inspector considered the lack of support for the jumpers an installation design deficiency. The licensee's response indicated that CD Power Systems, Inc., the battery vendor, did not see any problem with the bend radius from a battery qualification standpoint. The inspector reviewed their response and determined that CD Power Systems addressed battery qualification and the load of the cables on the terminal plates, but did not address the potential for the condition to worsen over time. The inspector requested that the licensee obtain the minimum bend radius requirements from Belden, the wire manufacturer, and that the licensee justify a potential nonconforming condition that could get worse over time. During the onsite followup inspection, the licensee told the inspector that the cable in question was a Belden Welding cable and, according to Belden, no minimum radius is specified.

Miscellaneous Deficiencies

Packing leaks on Unit 2 core spray pump valves 252-F020B and 252-F020D were evidenced by discoloration of piping insulation and the presence of water on the floor beneath the valves. Licensee personnel agreed that the packing was leaking and initiated WA V03989 to repack the valves during the next Unit 2 refueling outage.

The cover plate for a cable junction box for conduit 1MS190, located in the Unit 1 suppression pool, was missing. The licensee initiated WA S01540 to investigate the missing cover plate.

A Parker 3/8-inch stainless steel tee fitting located below Unit 1 core spray pump suction pressure gauge PI-E21-1R001C was found leaking. The licensee initiated WA S07707 to correct the condition.

Two wire ring tongue lugs not taped or insulated were found in panel 1C606, located in the Unit 1 lower relay room. The licensee initiated WA S01578 to correct the condition.

The bypass log contained many entries that were maintained in excess of 1 year, bypass number 1-87-003 for example. The licensee responded that this change to the rad waste system was installed in January 1987 to prevent a potential contaminated spill. The team is concerned that long-term bypasses are allowing temporary measures to become design changes or modifications and are not being regarded as such. The licensee responded by stating that the issue of long-term changes will be implemented by PMR 89-3036.

The Unit 2 HPCI turbine platform was dirty and did not reflect the cleanliness standards observed in other areas of the plant. The licensee is cleaning up the area.