APPENDIX A

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

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Licensee: TU Electric
Skyway Tower
400 North Olive Street, L.B. 81
Dallas, Texas 75201

Facility Name: Comanche Peak Steam Electric Station (CPSES), Units 1 and 2

Inspection At: CPSES, Granbury, Texas

Inspection Conducted: October 15 through November 16, 1990

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Inspection Summary

Summary of the Special Announced Maintenance Team Inspection Conducted October 15 through November 16, 1990 (Report 50-445/90-27, 50-446/90-27)

Areas Inspected: A Nuclear Regulatory Commission (NRC) team inspected the maintenance programs and the performance of maintenance activities (safety-related and balance-of-plant), including overall plant performance related to maintenance, management support, and the implementation of the maintenance program for Unit 1. Because of the construction status of Unit 2, only a limited sampling of maintenance activities on Unit 2 were observed. The inspection team used the NRC maintenance inspection guidance of Temporary Instruction 2515/97, Revision 1, dated September 22, 1989.

Results: The inspection team concluded that the licensee's maintenance process consisted of generally well-developed programs with an appropriate level of management involvement so that the process functioned adequately to maintain plant components available to perform their intended functions. The inspectors identified some weaknesses related to work control activities in the area of temporary modifications, and the control of nonsafety-related ("non-Q") wor' activities on safety-related ("Q") components. Within the scope of this inspection, no violations or deviations were identified.

EXECUTIVE SUMMARY

A team of Nuclear Regulatory Commission (NRC) staff members conducted a performance-based inspection of the maintenance process at the Comanche Peak Steam Electric Station (CPSES) from October 15 through November 16, 1990. The purpose of this inspection was to determine whether components, systems, and structures at CPSES were adequately maintained to perform their intended functions when required.

The inspection was conducted under the guidance provided in Temporary Instruction (TI) 2515/97, "Maintenance Inspection," Revision 1, dated September 22, 1989. The team color-coded a "maintenance inspection presentation tree" (Attachment B of this report) that identified the major inspection elements associated with effective maintenance. The tree was used as a visual aid during the exit meeting to depict the results of the inspection.

The inspectors evaluated three major areas: (1) overall plant performance as affected by maintenance, (2) management support of maintenance, and (3) maintenance implementation.

The inspectors concluded that the licensee's maintenance process was functioning adequately to maintain components, systems, and structures such that they could continue to perform their intended function. This conclusion was based upon a limited sampling of observed maintenance activities and the evaluation of the maintenance process. The team had concerns related to the control of work activities, particularly those regarding temporary modifications, and nonsafety-related ("non-Q") work activities on safety-related ("Q") components.

The more significant strengths and weaknesses of the licensee's maintenance program are listed below.

STRENGTHS

Key operations and maintenance managers were extensively involved in the maintenance process. Management strongly supported new programs which were future-sighted and aligned toward improving the control, coordination, and implementation of the maintenance process.

The preventive maintenance (PM) program appeared comprehensive. Programs which contributed to the PM program such as predictive maintenance and maintenance history were well defined.

The material condition of the plant was good. Housekeeping was well maintained. The labeling upgrade program made component identification easy and emergency response guideline (ERG) action areas readily apparent.

Technical support to maintenance activities appeared effective and timely.

Quality assurance audits of the maintenance process appeared strong, comprehensive, and technically oriented.

The maintenance procedures' quality and format appeared strong.

Control of materials appeared effective. This area included the staging of tools, separation of "Q" "non-Q" materials, and the separation/dedication of storage areas for noncompatible materials.

Maintenance training appeared strong with excellent facilities including "as low as reasonably achievable" (ALARA) mockups.

WEAKNESSES

Classification of certain work activities as "non-Q" on "Q" components, in some instances, appeared questionable. Some activities should have been subject to the quality and administrative controls associated with the "Q" classification.

Control of work activities for equipment which had been subjected to temporary modifications appeared weak. Maintenance planners did not have temporary modification information available in the work control center, and operations staffing in the control room did not have temporary modification information marked on vital station drawings.

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INSPECTION DETAILS

1. OVERALL PLANT PERFORMANCE RELATED TO MAINTENANCE

The inspection team reviewed the Comanche Peak Steam Electric Station (CPSES) operating history data and performed plant walkdowns to obtain direct, observable indicators of the effective implementation of maintenance. These areas were evaluated for overall plant performance related to plant operability, equipment availability, and general reliability.

1.1 Conclusions

The licensee had implemented an effective maintenance program. The facility was licensed in February 1990 and had been in power operation since May 1990. Consequently, the operating history data developed to date was minimal and displayed no strong negative or positive indicators. The licensee used the Institute of Nuclear Power Operations (INPO) guidelines to produce monthly "performance indicator" information. This information was extended to include engineering and quality related activities. The team noted that licensee management was monitoring the data and adjusting CPSES programs and practices based on their evaluation.

The housekeeping and material condition of the auxiliary and safeguards buildings were excellent and the licensee's efforts in these areas were considered a strength. The licensee had established programs for structured management and system engineer plant inspection tours, and these programs were found to be effective, as discussed below. The team observed that plant systems and equipment were in generally good condition with relatively few leaks or other problems. Building spaces were clean, well lighted, and generally free of extraneous and uncontrolled material. The conditions of the turbine building and associated systems were less satisfactory. Numerous leaks were found, and areas requiring paint and housekeeping attention were prevalent. The licensee had been effective in scheduling the leaks for repair during planned outages and had begun planning housekeeping improvements.

1.2 Findings

(1) Minor deficiencies were identified by the inspection team during plant tours and work observations. These were either corrected immediately by the licensee or were documented on work orders for followup action. Examples of these minor deficiencies included:

- The component cooling water (CCW) tank room had water on the floor. Piping insulation in the room had been knocked off and was lying on the floor.

- Several instrument tubing supports on the "B" emergency diesel generator (EDG) air-start system were loose.

- The No. 5 safety chiller condenser water box head bolts had inadequate thread engagement on eight of the bolts (about 10 percent of the total).

- Miscellaneous material was found stored in the bottom of the No. 2 catalytic hydrogen recombiner control cabinet: a 3/4-inch air hose with end fittings, a controlled copy of the recombiner operating procedure, a plastic vertical file holder (for the operating procedure) was detached and lying in bottom of cabinet, a light bulb change log, two boxes of miniature light bulbs, and a roll of recorder paper. The licensee had no procedure which specifically addressed storage in electrical cabinets.

- Abandoned and out-of-date controlled copies of control panel drawings (Nos. B587-1200 through 1205) for the No. 4 control room air conditioning compressor (CRAC) control panels were found in the cabinet's door storage slot. The drawings apparently had been left behind during preoperational checkouts in 1989. The licensee found and removed similar drawings in the other CRAC cabinets.

- The louvered panel cover for the B EDG "Min-Max Limiter" module inside the EDG local control panel was found removed and lying in the base of the panel. The technicians accompanying the inspector stated that the cover had been in that condition for some extended time and that the module had been retired in place. The other cabinet for the A EDG was also inspected and the cover found to be satisfactorily installed.

- Eight nitrogen bottles and the tools used to charge the main steam isolation valve (MSIV) hydraulics were stored on the gratings adjacent to the MSIVs in the Loop 2 and Loop 4 bays. These items were controlled in accordance with Procedure STA-661, "Non-Plant Equipment Storage and Usage Inside Seismic Category I Structures," Revision 1, but the storage of high pressure gas bottles near large high energy piping and valves was considered an undesirable practice by the team. The licensee informed the team that this was a temporary condition and the bottles would be removed following repairs to the MSIVs.

- During plant walkdowns, the team observed that Condensate Pump 1-02 had a large shaft leak. A review of submitted work requests verified that the leak had not been identified.

(2) Procedure STA-510, "Plant Management Monitoring Program," Revision 1, and Technical Support Procedure (TSP)-206, "System and Area Walkdowns," Revision 1, provided for management and system engineer walkdowns. The manager walkdown results were documented, but the TSP-206 system engineer walkdowns were not. Two of three system engineers interviewed did not maintain any direct record of either tour accomplishment or deficiencies and corrective actions. Neither procedure required that the documentation of corrective actions such as work orders, and/or operations notification

and evaluation (ONE) forms be maintained for deficiencies identified during walkdowns. Very few of the STA-510 walkdown records referenced specific corrective actions. Discussions with managers participating in the program indicated that the orally assigned corrective actions and follow-up was based on their personal initiative. Similarly, the TSP-206 program provided guidance for documenting corrective actions which was not used by two of the three engineers interviewed. The interviews revealed that the personnel were performing the tours and identifying deficiencies indicating that the programs were fundamentally effective. However, the lack of documentation did not permit management to measure and assure the overall effectiveness. Several managers indicated that the program goal was to maximize in-plant aspects with minimal paperwork.

2. MANAGEMENT SUPPORT OF MAINTENANCE

2.1 Management Commitment and Involvement

The inspection team reviewed management's support of maintenance activities and evaluated the degree of management involvement in the maintenance program. Specifically, the team evaluated the application of industry initiatives and assessed management's involvement. Selected interviews were held with corporate executives and plant managers to determine their assigned responsibilities in the maintenance program and to ascertain the depth of understanding of these individuals for their respective responsibilities. Additionally, the team reviewed applicable procedures and supporting documentation associated with the implementation of the maintenance program.

2.1.1 Conclusions

A strong management involvement and commitment to the maintenance program was evident. The team concluded that the licensee's implementation of maintenance initiatives and program enhancements, including the allocation of sufficient resources to assure effective program improvements, had been aggressive. Management representatives exhibited extensive knowledge, interest, and participation in maintenance issues.

2.1.2 Findings

The licensee's responses to industry initiatives were centered around the recently completed maintenance self-assessment program. The maintenance self-assessments utilized the same elements of maintenance specified in INPO Good Practices 85-038 and in 90-008, "Maintenance Programs in the Nuclear Power Industry." Additionally, the NRC's Maintenance Inspection Guideline and Industry Experience report was used to develop 19 areas for review which were designed to include all aspects of maintenance performance at CPSES. As a result, 159 action plan items were identified. At the time of the inspection, the status of the licensee's action plan items was: 3 items did not meet the established guidelines, 96 items required improvement, and 35 items were designated as efficiency enhancements. The three items identified as not meeting the established guidelines were:

(1) Action Plan 1.4.1: Establish a working group to determine focused sub-tier user level indicator trends in support of Procedure No. STA-501, "Plant Performance Overview Program."

(2) Action Plan 10.3.2: Verify that Procedure MAO 4.02, "Handling and Storage " items were properly packaged prior to placing them in storage.

(3) Action Plan 11.4.1: Revise requirements to specify that preliminary engineering reviews for critical safety-related components should be performed as soon as practical.

The inspection team reviewed the action plan items and determined that appropriate prioritization had been established and that the targeted completion dates generally reflected a meaningful management commitment. It was also determined that the self assessment program provided an excellent method for monitoring and enhancing performance in maintenance activities.

The inspection team also reviewed the licensee's responses to the reports of the INPO near-term operating license (NTOL) assistance visit conducted at CPSES from August 21 through September 1, 1989, the INPO corporate assistance visit conducted September 11-15, 1989, and the INPO followup plant assistance visit conducted April 23-27, 1990. The responses to the INPO recommendations included various aspects of the licensee's preparations for fuel load, fuel load activities, and power-ascension testing evolutions.

Indications of management involvement included:

(1) Senior management oversight in plant activities and programs by the formation of various teams and committees such as:

- The Senior Oversight Committee
- The Operational Quality Assessment Team
- The Human Resource Management System Task Force

(2) Management emphasis on the root-cause analysis program, which resulted in a significant enhancement to the program and implementation of a training program on root-cause analysis. Whereas, the team noted significant improvement in this area since the pre-licensing period, minor weaknesses were noted which are discussed in Section 3.1.2.

(3) Weekly managerial meetings, chaired by the plant manager, which discussed the "Maintenance Backlog" report and the "Weekly Management Summary."

(4) Self-assessments in various areas (e.g., maintenance, engineering, quality assurance).

Outage management programmatic controls were being developed and a dedicated outage planning and scheduling group had been established. The group was tasked with establishing procedures and schedules for both long and short range, planned and forced outages. The group was also tasked to implement an outage coordination plan. At the time of the inspection, Procedure STA-632, "Forced Outages," had been issued to provide guidelines for forced outages. However, another procedure (STA-627) was being developed to provide guidelines for the control of planned outages including compliance with the outage schedule, and line-management responsibilities. Therefore, a meaningful evaluation of the outage planning and scheduling group could not be performed.

INPO significant operating event reports (SOERs) were reviewed by the licensee's plant evaluation section under Procedure STA-507, "Review and Assessment of Industry Operating Experience Reports," Revision 1. The purpose of this program was to ensure that lessons learned from industry operating experience were reviewed and translated into the appropriate corrective actions and/or training programs to improve plant safety and reliability. Applicable reports were distributed to the appropriate personnel. Returned responses were reviewed to verify that the issues were adequately addressed.

The plant evaluation section also assessed NRC information notices, Westinghouse technical evaluations, and INPO significant event evaluation - information network (SEE-IN) documents. The site licensing group evaluated generic letters in accordance with Procedure TNL-4.01, "Incoming Correspondence," Revision 1; Part 21 notifications in accordance with Procedures NEO 2.01, "Identification and Evaluation of Defects Under 10 CFR Part 21," Revision 0, and Nuclear Engineering and Operations (NEO) 9.01, "Evaluation of Adverse Conditions Under 10 CFR Part 21 and 10 CFR 50.55(e)," Revision 4; and NRC Bulletins in accordance with T.U. Nuclear Licensing Draft Procedure TNL 4.11, "Evaluation of NRC Bulletins." Based on a review of these procedures and a sampling of items contained in Procedure STA-509, "Commitment Tracking," Revision 3, the team determined that the program for tracking, implementation, review of regulatory issues, and industry initiatives appeared adequate.

Management support of the maintenance program was also evident from the incorporation of INPO human performance evaluation system (HPES) considerations. The impact of human errors on design procedures, equipment failures and inadvertent reactor trips were effectively incorporated into Procedures STA-513, "Human Performance Evaluation System," Revision 0, and STA-515, "Root Cause Analysis." Collectively these procedures provided for the evaluation of inappropriate human actions which could affect plant safety as well as a consistent method for the application of root-cause analysis techniques. This is further discussed under Section 3.1.

Provisions for maintenance peer evaluations were incorporated under Procedure STA-423, "Evaluation Team," Revision 2. This program appeared to provide a mechanism for the expedient, systematic and objective evaluation of events and off-normal conditions as well as the basis for plant incident evaluations.

Overall plant performance goals and performance indicators were controlled by Procedure STA-511, "Plant Performance Overview Program," Revision 0. Additionally, unique performance indicators for the maintenance department were established under Maintenance Guideline No. 4, "Maintenance Indicators." The CPSES maintenance department indicators report, which was generated monthly, provided detailed information regarding maintenance services and activities. Although this program was relatively new, it adequately addressed plant reliability and productivity goals.

Management commitment and involvement in the application of industry initiatives was also evidenced by the licensee's participation in INPO workshops since 1983 and in the full utilization of the INPO Nuclear Plant Reliability Data System (NPRDS) program. The NPRDS program, which had been utilized since fuel load, focused on the application of a component failure analysis program using industry data obtained from similar plants. It was observed that separate and distinct computer data bases and manually controlled equipment files were being maintained by various onsite groups for the purposes of maintaining maintenance history. It was also noted that none of the systems tracked commercially dedicated components. Action Plan Item 15.1.1 addressed the lack of a coordinated and centralized maintenance history program, and the licensee's proposed resolution is discussed in Section 3.1 of this report.

The licensee's commitment to the application of industry initiatives was reflected in their participation in the Westinghouse Owners Group, Steam Generator Users Group, Diesel Owners Group, and the Checkmate Users Group (corrosion monitoring). The licensee's involvement in some of these groups was relatively recent.

Numerous programs supportive of maintenance efforts had been developed, including the licensee's provisions for in-process observations by nuclear operations management and supervisory personnel in accordance with Procedure STA-510, "Plant Management Monitoring Program," Revision 1. This program required designated plant management personnel to perform evaluations involving direct observation of plant conditions related to work practices, housekeeping standards, industrial safety, radiological protection, personnel performance, and equipment material conditions. Additionally, a recently formed balance-of-plant (BOP) task team provided numerous recommendations regarding enhancements to the BOP with corrective actions scheduled for the near future.

Plant aging considerations were apparent in that programmatic allowances had been established in Procedures STA-736, "Equipment Performance Monitoring Program," Revision 0 and STA-706, "Transient and Fatigue Cycle Monitoring," Revision 0. The team also determined that equipment performance monitoring data was provided to the utility management for aging awareness. These programs appeared to be adequate; however, they were limited in scope. The team observed that the licensee's program did not address plant aging evaluations in areas with high radiation or temperature conditions. Licensee representatives said that they were considering the addition of these environments in their aging studies.

As discussed above, the licensee's maintenance self-assessment appeared to reflect a strong management commitment to the maintenance program. Performance indicators were being generated and trended in accordance with Nuclear Engineering and Operations Procedure NEO 1.01, "Organization of the Nuclear

Engineering and Operations Group," Revision 2, and Procedure STA-511, "Plant Performance Overview Program." The licensee also implemented a QA trending program which utilized data derived from QA surveillances, plant identified deficiency and problem reports, and a system to monitor the extent of repetitive maintenance. Collectively, these programs allowed for an adequate assessment of the maintenance process by management. These programs are discussed further in Section 3.2.

Periodic maintenance program reviews and updates were conducted under Procedure STA-649, "Maintenance Self-Assessment," which included the status of previous action items. This process appeared to satisfy the intent of the self-assessment process. During the maintenance self-assessment, the licensee identified that the existing feedback mechanisms did not allow for the responsive resolution of identified concerns/inadequacies within the maintenance department. The inspection team had also identified the weakness in the resolution of identified concerns. The fact that the licensee's self-assessment had already identified this weakness was considered a strength by the team. Despite the interactive management philosophy at CPSES, personnel within the maintenance organization expressed frustration in that the feedback to work enhancement and improvement issues was not always timely.

2.2 Management Organization and Administration

2.2.1 Conclusions

The licensee's maintenance program appeared adequately controlled with regard to structure, responsibilities and allocation of resources. The licensee was extending the use of measurable maintenance goals and objectives down to the maintenance discipline level. Incorporation of maintenance requirements into the program appeared adequate. The staff effectively used the various performance indicators to monitor the maintenance program.

2.2.2 Findings

Program Coverage for Maintenance

The policies and goals for the maintenance department were delineated in NEO Policy Statement 40, which described activities associated with the "Conduct of Maintenance." Furthermore, the maintenance organization and its interface with corporate and station programs were described in Procedures MDA-101, "Maintenance Department Organization and Responsibilities," ICA-100, "I&C Maintenance Program," and STA-109, "Conduct of Maintenance."

In general, these programmatic controls appeared to adequately describe the organizational structure, personnel responsibilities, and the maintenance program. However, the 1990 goals and objectives which were established for the maintenance organization lacked specificity in that measurable items were not clearly identified. Accordingly, the licensee was in the process of modifying the department goals for 1991 such that specific and measurable indicators would be provided down to the supervisory level.

Allocation of Resources

Management had generally allocated sufficient resources to ensure the effective and efficient implementation of the maintenance program. However, some exceptions were identified through interviews, in that several maintenance managers indicated that they were somewhat understaffed. This condition resulted in a higher-than-desired backlog of work requests. In these cases, additional hiring was imminent.

Overtime had been extensively used by the maintenance planners and had occasionally exceeded licensee procedural limits which were based on NRC guidance. These incidents had been approved by management, but the overtime had generally been approved after the fact. Maintenance planners are not included in the NRC guidelines on overtime, and therefore, the inspection team had no major concern with the overtime assigned to the planners. The team was concerned, however, that the practice of approving of overtime after the fact presented a situation which could lead to occasional abuse of the overtime policy.

Parts and materials availability were adequate to support maintenance activities as evidenced by the small percentage of jobs that were delayed as a result of parts unavailability. However, this success was largely due to the frequent use of parts from Unit 2. The licensee was implementing a spare parts program which was intended to reduce, and eventually eliminate, the dependence on Unit 2 for spare parts. All performance indicators and interviews showed that engineering and technical support of maintenance activities were excellent. Use of contractors for maintenance work was minimal, other than full-time contractors working within the maintenance groups and functioning effectively as TU employees.

Definition of Maintenance Requirements

The licensee had incorporated a comprehensive list of related activities into the maintenance process in a manner that showed foresight and attention to detail. In particular, the identification of preventive maintenance (PM) activities was considered excellent. The PM program was being consolidated in a PM improvement program that would incorporate the concept of reliability-centered maintenance. The PM program appeared sensitive to maintenance history data and several cases were observed where new PMs were added or frequencies increased to respond to high-failure rates. Predictive maintenance, which included vibration, oil, thermographic, and motor analyses, was also observed to be a strength for its use as a diagnostic tool to avoid unplanned corrective maintenance.

The licensee's program to update maintenance requirements to reflect vendor's manuals revisions appeared adequate. However, manual updates were being processed slowly and balance of plant manuals were not yet controlled.

The licensee's response to NRC and industry initiatives regarding maintenance of check valves was specifically examined during this inspection. In particular, testing of air-operated valve (AOV) accumulator check valves and floor drain check valves was considered. The licensee's program to test accumulator check valves appeared adequate in all applications related to safety. However, no maintenance or testing of floor drain check (or nonreturn) valves was being performed. The safety concern of back-flow through the floor drain system and potential damage to redundant safety equipment was expressed in NRC Information Notice (IN) 83-44. The licensee acknowledged this deficiency, but stated that the recently issued Supplement 1 to IN 83-44 was under review and may result in the testing and/or maintenance of components in some floor drain systems.

Performance Measurement

The licensee had established a comprehensive program to measure the performance of activities in the maintenance discipline. A strength in this effort was the quality assurance audit program, as discussed in Section 2.3 of this report.

Performance indicators were established and used by maintenance supervisors to monitor trends in the various aspects of the maintenance program. Though these indicators provided useful information, the team noted that measurement of "Q" and "non-Q" work backlogs were combined together. As such, it was difficult to determine the safety significance of the backlogged items.

A limited programmatic scope reduced the overall effectiveness of the root cause analysis and repetitive maintenance programs. An analysis of the root cause of maintenance-related failures was conducted only when such failures led to the issuance of a plant incident report (PIR). This condition is further discussed in Section 3.2.

The licensee had fully implemented a surveillance program for supervisors in the I&C, electrical, and mechanical maintenance disciplines to observe work activities in progress. Based on a review of the observation reports, the implementation of the program had been satisfactory, although many of the reviews seemed to lack depth.

Document Control System for Maintenance

The document control system for maintenance was established and provided generally accurate information. The data base controlling the work control system, the management maintenance computer program (MMCP), was demonstrated to maintain good control over document traceability. However, from a user perspective, the system was cumbersome and much of the information needed to perform searches was scattered among many other data bases. As a result, searching, sorting, and data integration was not timely and, in certain instances, not effective. The licensee had taken action to improve the document control system and to place all relevant data within the same main frame computer. This would allow document searches and related jobs to be completed at one terminal. The first phase of this conversion project, the plant reliability information system for management (PR-ISM), was expected to be operational in the summer of 1991. A full conversion of all data bases into an integrated total plant system (TPS) was scheduled to be completed in 1992.

The licensee's strong commitment to implement a state of the art document system was perceived as a strength.

Maintenance Decision Process

Management visibility and involvement in maintenance decisions was provided in various ways, including the normal communication paths, routine and special meetings, the budget process, and routine performance reports. The team observed or reviewed these activities and concluded that they were functioning adequately and that plant and corporate management were apprised of maintenance objectives, performance, and impact on other plant areas.

2.3 Technical Support

The team evaluated the licensee programs and activities related to the support of the maintenance program by various technical support organizations.

2.3.1 Conclusions

Effective communication channels had been established between technical support and the maintenance groups at the site. Technical evaluations related to maintenance work were adequate in scope, technically correct, and well documented. The licensee's quality assurance audits of maintenance activities were technically oriented and were identified as a strength. The quality control program was functioning satisfactorily but had been experiencing some difficulty in transitioning from a construction to an operations perspective. Radiological controls had been effectively integrated into the maintenance process. The licensee had also established a strong program to ensure the safety of maintenance workers and other plant personnel. A noted strength was the licensee's efforts to minimize the amount of flammable material stored in the power block. The licensee had established an effective program to integrate regulatory documents into the maintenance process.

2.3.2 Findings

The support engineering groups, including design engineering, were located at the site and provided close involvement and communications with the maintenance disciplines.

The licensee had established a program which provided the means to process a request for information or provide clarification regarding technical issues. Procedure STA-504, "Technical Evaluation," delineated the requirements for the request and response documentation.

The equipment qualification maintenance manual (EQMM) provided the documented basis for the qualification of equipment by plant engineering, including specific maintenance requirements (e.g., shelf life, lubricants, etc.). Maintenance activities on EQ components were developed considering the EQMM requirements. Document reviews and personnel interviews revealed that the licensee was currently reviewing and enhancing the equipment qualification (EQ) packages. The licensee had also begun a preventive maintenance improvement program (PMIP) to provide additional assurance that EQ matters would be fully addressed. Reviews of the EQ packages were scheduled for completion in the near future and the PMIP was to be implemented in the next 2 years.

Two instances involving the identification of questionable conditions regarding equipment qualifications were reviewed and are described below:

- During the performance of Procedure EET-TP-90-004, "Power Ascension HVAC Temperature Survey," the licensee identified that Rooms 109 and 110 exceeded the specified 104°F acceptance criteria. The team reviewed the technical evaluation (TE-SE-90-1533) performed by the licensee to assess the impact of the elevated room temperatures on the equipment. The technical evaluation documented that the maximum temperatures were within the individual equipment qualification requirements.

  A technical evaluation (TE-TP-90-1608) was performed to address the elevated room temperatures on the equipment qualification. The licensee determined that the qualified life was not exceeded on any of the exposed equipment. The evaluations appeared to be acceptable.

- During hot functional testing, the licensee identified that one of the eight flow paths (TE-5452) associated with the power range neutron detectors was indicating 145°F with the reactor coolant system at 557°F. The alarm setpoint was noted to be 135°F. The local maximum temperature at the power range neutron detectors was rated at 97°F as a result of the use of installed startup test instrumentation. The licensee subsequently processed a design modification (DM 90-172) to change the temperature alarm setpoint from 135 to 150°F. The maximum temperature of 150°F was addressed by a technical evaluation (TE-TP-90-2248). As a result, the qualified life of electrical Amphenol connectors on all the neutron detectors was revised. This change appeared to be a conservative approach since the local temperatures could not be determined during normal operations. The licensee's technical evaluation appeared to be adequate.

Engineering Support

The licensee had established a priority-based program for updating drawings affected by design changes. Design Engineering Procedure ECE 5.05, "Design Drawings," Revision 2, required that drawings "vital" to the support of plant operations be updated within 48 hours of design change installation. Other, less important drawings were not required to be promptly updated. Review of work packages and discussions with the electrical maintenance staff indicated that the emergency lighting and the fire protection detection and actuation system electrical drawings were not considered "vital" and had not been updated promptly. As a result, the maintenance staff had to individually research several open design change authorization (DCA) packages and hand-correct the fire protection drawings prior to their use for testing or maintenance activities. This had the potential for inadvertently disabling or actuating the systems and represented a significant concern to the licensee's staff.

The acting electrical maintenance manager advised the team that this concern had been previously identified. Prior to plant licensing, updating the fire protection drawings had been given a higher priority by design engineering but this priority had somehow eroded and work had been suspended. In late September 1990, maintenance management recognized this problem and reidentified the need to design engineering. The licensee began tracking the status of this problem in the weekly management summary report on October 1, 1990. At the time of the inspection, the licensee had budgeted resources and restarted the fire protection drawing update.

The use of probabilistic risk assessment (PRA) techniques was not specifically addressed by any of the current maintenance programs, thus limiting the present development of a reliability centered maintenance (RCM) program at CPSES. The technical support organization was charged with developing guidelines for a RCM program. An individual plant examination, as required by Generic Letter 88-20, was committed to be completed by September 1, 1992.

Quality Assurance and Quality Control

Audits and surveillances performed in 1989 and 1990 of maintenance activities were reviewed and found to be detailed and comprehensive with meaningful deficiencies and observations identified. The quality assurance organization designated lead auditors for the various plant functional areas, including maintenance. The technical depth and emphasis on performance functions reflected the caliber and technical capabilities of the audit personnel. Responses to audit findings appeared appropriate. Close interaction between the maintenance organization and the QA auditing group in resolving deficiencies was evident. QA management reported that audit findings were generally well received by the audited groups. Audit finding responses were generally adequate and had been provided on a timely basis. The trending of quality-related plant deficiencies appeared to be effectively implemented, and had been used as input to determine the requirements for the surveillance program. The process allowed functional groups to request audits or surveillances for assistance in resolving weaknesses or defining problem areas. A monthly report of quality deficiencies was provided to plant management for their review and action. This area appeared to be a strength.

The quality control portion of the QA organization was adequately defined, and was functioning to review quality-related work orders for adequate work definition and for the identification of required hold points. Licensee management had identified problems related to clarifying QC hold point requirements and QC/Maintenance/I&C interfaces. Licensee management was working to resolve these problems through weekly meetings. In addition, a task team had been formed to develop an operationally oriented appendix to the electrical, mechanical and I&C plant specifications to assist in the definition of the QC/maintenance interface.

The 1990 maintenance self-assessment identified a number of actions needed to improve the maintenance process. The team observed that additional audits or surveillances were warranted to determine the effectiveness of the implemented actions, but had not been planned by the QA organization. Following discussions with the team, QA management indicated that selected action plan items would be considered for future audit review beyond the scope of currently schedule audit and surveillance activities.

Radiation Protection

The radiation protection (RP) group created interfaces with the maintenance organizations by placing people in both the maintenance planning and work control organizations. This enabled early evaluation of potential radiological hazards associated with work items and provided the manpower required to support the work. Interviews indicated that requests for radiation work permits (RWPs) were processed in a timely manner and RP requirements resulted in minimal delays. The RP group appeared to have a good rapport with the maintenance groups.

Major work packages for outages were submitted sufficiently in advance to allow the staff members responsible for the as low as reasonably achievable (ALARA) reviews to have adequate time for the review and assessment. The collective radiation exposure had been very low (less than one man-rem) as a result, in part, of the newness of the plant.

Training for radiation workers and respirator users appeared adequate to inform the workers of the hazards involved with nuclear work and the associated precautions needed to work safely.

To provide support for maintenance, RP had provided adequate procedures and facilities for whole body counting, dosimetry processing, respirator fit testing, bottle filling (for self-contained breathing apparatus) and decontamination activities. Respirator issuance and decontamination facilities appeared inadequate to meet heavy demand, but the licensee had already made plans for changing and relocating these facilities.

Occupational and Industrial Safety

The licensee had adequate programs for personnel safety in the areas of hazardous material identification and control, control of flammable materials, confined space entry requirements, electrical safety, and the use of personnel protective equipment (e.g., safety glasses, hard hats, hearing protection). Work activities observed during the inspection period were conducted with appropriate attention to personnel safety practices, including use of safety belts and tie-offs for work in elevated areas. The team was informed that the Near Miss Report and Unsafe Condition Report programs required by STA-211, "Administrative Control of Industrial Safety," Revision 1, had been effective in identifying and resolving safety incidents and potential safety problems. A spill response team was established for significant spills of chemicals, oils, gasoline, volatiles, or other materials which may be hazardous to personnel or to the environment.

During plant tours, the team observed that the storage of flammable materials was minimized in the power block. Flammable cleaning fluids, aerosols, and other materials utilized in maintenance activities were delivered to the jobsite in the appropriate quantities required. The craft utilized suitable containers and removed the materials at the completion of work activities. This practice was considered a strength by the team.

Regulatory and technical documents were effectively integrated into the maintenance process and received periodic review and updating. The licensee had a variety of programmatic controls and procedures which ensured the effectiveness of the program. The team confirmed this effectiveness through a review of selected requirements from Technical Specifications, Final Safety Analysis Report (FSAR), Generic Letters, and NRC Bulletins.

3. MAINTENANCE IMPLEMENTATION

The objective of this part of the inspection was to determine the extent of control of (1) maintenance work, (2) plant maintenance organization programs, (3) maintenance facilities, equipment, and material, and (4) personnel. In these areas, the inspectors assessed the implementation of the work control process by reviewing maintenance records and observing maintenance in progress, including the work planning process, preparation of work orders, post-maintenance testing, and scheduling and backlog controls. The inspectors also reviewed completed work packages and maintenance activities in the mechanical, electrical, and instrumentation and control disciplines as well as those for contracted maintenance. The inspection team also evaluated the deficiency and control program, maintenance trending, support interfaces, training, and staffing control. The inspection team's interviews and observations of the craft and supervisory personnel were used to ascertain the knowledge level and understanding of plant policies and programs.

3.1 Work Control

3.1.1 Conclusions

The licensee's work controls and work practices had been adequately implemented. The quality of the equipment-related maintenance work procedures was considered a strength. The planning and maintenance staffs were encountering some minor problems with job preparation and coordination that appeared to be a result of the transition from the construction phase to operating activities. None of the preparation or coordination problems identified had the potential to result in safety problems. The programs for work order control, job planning, work prioritization and scheduling, control of backlog, and post-maintenance testing were in place and functional. Deficiency identification and root-cause analysis programs were functional but improvements appropriate to these areas were identified.

In general, the licensee's program for the review of completed work documents was adequate. Several completed work packages that had already been placed in the vault contained minor documentation errors that indicated the review of work packages by supervision may need improvement.

3.1.2 Findings

The maintenance activities observed by the team were adequately performed. Proper authorizations were obtained prior to each job observed by the team. Work instructions were generally complete and appeared to be followed by the craftsman/technician. Supervisory personnel were actively involved with each job and were available to provide problem resolution.

Equipment Control

During discussions with control room operators performing safety tagging practices, the inspectors determined that valves and other components inside clearance boundaries (but not themselves tagged) were frequently manipulated to support maintenance or testing. Procedure STA-605, "Clearance and Safety Tagging" neither authorized nor prohibited such manipulations and it did not provide mechanisms to assure that the items were returned to the proper position or condition. The licensee's program for positive control of system and component operating configuration required that such manipulations be strictly controlled and documented. As a result, the licensee issued Procedure Change Notice No. 1 to STA-605 on October 24, 1990. This change required that any component so manipulated be listed on the clearance documentation and have a "caution" tag attached. This change resulted in the item being included in the post-work return to service review activities.

The inspection team also reviewed clearance and tagging center operations performed by off-shift operations personnel in the site work control center (SWCC). Operators were rotated from control room duty and contributed good knowledge of plant conditions and equipment status to the work control process. Reactor operators prepared tagouts, while senior reactor operators reviewed tagouts. Final review was provided by the shift supervisor prior to assigning auxiliary operators to hang the tags. The clearance and tagging process appeared adequate. The inspector was walked through a typical tagout preparation, including the preparation of impact sheet and the use of computerized aids to assist in preparing the tags, and reviewing the drawing status. Complete files of vital station drawings and other relevant drawings were located in the tagging center. Additional drawings were available through the Computer Aided Design (CAD) system, which contained over 40,000 station drawings.

The team interviewed the operators concerning the information available to them for temporary modifications (TMs) which could impact the preparation of a clearance for systems or equipment. The team found that vital station drawings did not contain notations to indicate that they were affected by TMs, nor were drawings changed by red-lining or by revision to indicate the changes made by a TM. Drawings impacted by a TM were recorded on a computerized database, but this database was not routinely used by the tagging center personnel. The control room maintained a TM log and retained the original copy of all active temporary modifications, but such information was not available in the SWCC. The operators interviewed indicated that TM information was not routinely reviewed during preparation of clearances, but that impacts were expected to be addressed by maintenance planners in preparing the work orders (WOs) for clearances or by control room personnel in reviewing clearances and hanging tags. It was also determined that maintenance planners did not have current TM information available to them.

The failure to update vital station drawings with TM impacts appeared to be a significant weakness in the clearance and tagging process and in control room operations. Information was indirectly available and required operator knowledge of TMs and detailed research of information through several levels of information. This condition had the potential for introducing deficiencies in identification of valves, instruments or electrical connections that should be reflected in clearances, or could create problems during plant events while operators try to resolve configuration differences between plant drawings and as-found conditions.

The weaknesses associated with the control of temporary modifictions were discussed with the licensee during the inspection. The licensee agreed to take immediate corrective actions to make temporary modification information more readily available to the operations crew, Work Control Center (WCC) personnel and maintenance planners. Prior to the conclusion of the inspection, it was observed that marked-up copies of vital station drawings were included in the temporary modification files in the control room. Additionally, a temporary modification log was being maintained in the WCC along with current temporary modification information. The licensee further stated the intent to require periodic review of the temporary modification information to ensure accuracy and consistency between the information in the control room, WCC and maintenance planners.

Work Order Control

The CPSES program and processes for identifying work needs; review, approval, and use of the work request and work order documents; and the adequacy of controls for emergency maintenance were reviewed and found generally acceptable. The team identified problems with the licensee's safety classification of some work activities.

The CPSES procedures for nonsafety-related ("non-Q") work activities did not require the use of formal work procedures nor the application of quality assurance and quality control measures. Procedure STA-610, Attachment 8.D, "Determination of Work Order Type," permitted work on safety-related ("Q") components to be categorized as "non-Q." Examples in the procedure were relatively simple, nonintrusive activities such as oil sampling, cleaning, removal/reinstallation of lagging, etc.

The team identified a number of cases in which work activities on safety related systems and components were nonconservatively categorized as "non-Q" and completed without the provisions applicable to safety related work.

Examples of this practice included instrument calibrations and troubleshooting on instruments that were non-1E but were either code pressure boundaries or were categorized as "Category 2" instruments by Regulatory Guide (RG) 1.97, "Instrumentation for Light Water Cooled Nuclear Power Plants to Assess Plant and Environmental Conditions During and Following and Accident." Category 2 applied to instruments for monitoring and control of engineered safety feature systems such as RHR flows and temperatures, ECCS flows and tank levels, ultimate heat sink flows and temperatures. Regulatory Guide (RG) 1.97, Table 1, Category 2, Item 5, "Quality Assurance" permits relaxation of quality requirements consistent with the instrumentations' importance to safety. The licensee, however, appeared to have applied a broad relaxation of quality requirements to all Category 2 instruments. The team noted the following calibration and repair activities were categorized as nonsafety-related:

Work Order	Component	Description
P90-2207	1-PI-6711B	Safety Chilled Water Outlet Pressure
C90-2533	1-FS-2191, 2192	Feed Water Flow
C90-1538	1-F-2184	Feed Water Flow to #4 Steam Generator
C90-2626	1-TE-0604	RHR Heat Exchanger 1-01 Outlet Temperature
C90-3367	1-FT-6709	Safety Chiller #1-06 Chilled Water Return Flow

Mechanical maintenance activities were similarly observed to extend beyond the principles of Procedure STA-606 including the following examples:

Work Order	Component	Description
C90-66[illegible]	Air Lock	Install Hand Pumps/Hoses
C90-7118	1B EDG	Lube & Inspect per EDG Owners Group Recommendations
C90-3255	1-HV-2134	Jacking Feed Water Isolation Valve Open with PortaPower
S901697	EDG Start Air	Check Valve Testing
P-906818	DDAPRM-01	Change and Sample Reactor Makeup Pump Lube Oil

The team considered these examples to be inappropriate categorizations of "non-Q" activities which should have been subject to quality and administrative controls similar to those associated with the "Q" safety-related equipment. The licensee reviewed the specific examples above and advised the team that CPSES would: (1) clarify the procedure guidance for performing "non-Q" work on safety related components to assure that the "non-Q" work was performed only on "non-Q" attributes, (2) enhance the use of quality control involvement in the post work review process for "non-Q" work, (3) consider increasing the use of peer verification in the "non-Q" work process, and (4) provide training to the affected personnel as necessary to support items (1) through (3).

Equipment Records and History

The licensee had established computerized data bases as part of the maintenance management computer program (MMCP) and the maintenance information tracking (MIT) program that contained maintenance history information for permanent plant equipment and components. The responsibilities and requirements for establishing and maintaining these data bases were defined in plant procedures. The procedures specified requirements for updating the master equipment list (MEL) and documenting nuclear plant reliability data system (NPRDS) information. The team evaluated the effectiveness of the data base management system as part of their observations of ongoing work, by reviewing work documentation, and by reviewing MMCP features and data. The equipment history data base information included the affected component, system, the failed part, the apparent cause, and any corrective actions performed. The historical records were easily accessed. However, use of the system was cumbersome for data sorting as discussed under trending analysis in Section 3.2. Maintenance planners, system engineers, and the technical support staff were, however, able to use the data base with reasonable effectiveness. The licensee was in the process of developing a new, integrated computer system, plant reliability - integrated system for management (PR-ISM) which would replace the existing fragmented data bases with a much more powerful and user friendly system. The licensee's initiatives in this area were considered to be a strength.

Weaknesses were identified in the operations notification and evaluation (ONE) form evaluation process. equipment failure analyses, and the root cause analysis (RCA) processes. Procedures STA 515, "Root Cause Analysis," Revision 1, and STA-414, "Processing of ONE Forms," Revision 2, required RCAs to be done only for more significant ONE forms categorized as plant incident reports (PIRs). The inspection team reviewed these procedures and 30 of the ONE forms to evaluate the effectiveness of the processes. The inspection team considered 18 of the ONE forms reviewed to contain one or more problems.

No specific requirements or guidance were provided to assure that simpler events not meeting the PIR criteria received a root cause and generic implications determination even though a "formal" RCA was not necessary. In some cases (most notably, I&C), management required that a fundamental root cause determination be included in the non-PIR ONE Form resolutions, but the results were occasionally too simplistic and indicated a lack of worker understanding of the concepts. For example, a typical statement regarding generic implications was that the issue under review was not generic because it had not been repetitive or recurrent. The team's concerns regarding the ONE forms were specifically discussed with the technical support manager.

The formal RCAs also had some shortcomings. Factors identified as root causes frequently did not reflect other considerations which could have been the true root cause. For example, when personnel error was identified as a root cause, poor training and procedures were identified as contributory. However, in none of the reviewed cases was the cause of the poor training or procedures addressed, (e.g., why did the procedure review and approval process permit a poor procedure to be issued?). Similarly, consideration of generic implications was weak. In some cases the reports indicated a misunderstanding of generic concepts. Discussions with the licensee indicated that this may be a mix of poor documentation in the reports and poor understanding of the generic concept. A number of cases were identified wherein RCA "recommendations" did not appear to have been carried out (i.e., no indication of action assignment, implementation, or verification were included in the packages).

On October 25, 1990, the licensee provided a written position regarding this concern, in which they stated that the procedures and practices would be reviewed to ensure that the RCA and the ONE Form documentation accurately reflected the techniques and actions applied to the problem. Further, the licensee committed to evaluate the need for expanding or modifying simplified RCA techniques for simpler events. This concern will remain an inspector followup item pending future NRC review (445/9027-01; 446/9027-01).

Work Prioritization, Job Planning, and Scheduling

Procedure STA-606, "Work Requests and Work Orders," Revision 14, Sections 4.18 and 6.1, established a system for prioritizing work orders for "emergency" (Code 11), "priority" (Code 12), "expedite" (Code 21), and "routine" (Code 22). The classification codes were loosely defined and no specific instructions existed for the prioritization process which tended to be informal and subject to judgement. Some detailed guidance for assigning priorities was included in training materials, but it focused largely on the work scheduling process. Based on this information, it did not appear that priorities were assigned on the basis of safety significance except when such distinctions were imposed by a technical specification requirement, involved a personnel hazard, or involved an imminent degradation of plant equipment. The inspectors reviewed a sample of work order prioritizations. Although weaknesses were identified, it was noted that most prioritizations were satisfactory and tended to be conservative. This was evidenced by an apparent excessive usage of the "expedite" priority where "routine" would have probably been more appropriate. Though this practice may be generally perceived as cautious and conservative, excessive use of the "expedite" code could dilute the attention given to the truly more important jobs.

Job planning at CPSES involved preparation of work packages for each work order which included steps required to establish and remove clearances, complete the repairs, perform post work testing, review the post work documentation, and update the equipment history. Each discipline department performed its own planning function. The electrical and mechanical maintenance planners guidelines were reviewed. The guidelines appeared to provide uniformity and comprehensive coverage in work package preparation. The licensee stated that the mechanical maintenance planning capability could use improvement. This was evidenced by high overtime occurring in the planning group, and by 80 low priority work requests (Priority 22 and 32) yet unplanned. Specification of special and standard tools were included on most work orders. The inspectors also noted that improvements could be made in this area in order to avoid work delays as further discussed below.

Job scheduling was performed at two levels. Scheduling of daily work was based on a system/train work window of one week duration and relied on the grouping of jobs in the MMCP data base. More complex tasks had manually prepared planning charts developed to show interdepartmental, plant conditions, and logistic support needs. Only outage or very complex activities were scheduled on a computerized critical path system. Department level scheduling activities provided the fundamental job coordination to assure that parts, materials, and outside support were provided.

The licensee's 1990 "Maintenance Self-Assessment," Chapter VI, identified a number of planning process improvements including the need for additional quality control support, improvements in deficiency tagging, post-work review, and control of interdiscipline work. The inspectors believed that completion of the maintenance self-assessment action plan items would improve these activities.

The inspection team identified a number of examples of work planning and coordination problems:

° Work Order (WO) 90-6898 involved verifying the stroke length of the steam generator atmospheric relief valves and was scheduled to work initially on October 22, 1990. The job required scaffolding which was reported as having been installed, but was not. No reason was provided for the oversight.

° WO C90-6702 involved the rework of electrical train separation violations in HVAC Panel X-CV-03. Work instructions required rebending and retying wire bundles to achieve a 1-inch separation. The craft determined the instructions could not be performed and the desired results achieved without determinating, installing shorter wires, and reterminating the wiring. This situation would have been avoidable if an effective pre-work walkdown of the job had been performed.

° WO C90-6704 involved correcting separation violations in control board CP1-ECPRCB-11 by retying wire bundles. The craft determined that additional mounting points for cable ties were unnecessary, again a condition that resulted from differences between the work instructions and actual working conditions.

None of the planning problems observed had direct safety implications.

<u>Backlog Controls</u>

Information from MMCP was used to provide trending of maintenance backlog data and indicators. Trend data was regularly provided to licensee management. Deferred maintenance activities were being worked based on the WO priority assigned. As previously discussed, the prioritization process was inconsistent and resulted in some items not appropriately prioritized for their significance.

One backlog measurement method used was the ratio of preventive maintenance man-hours to total maintenance man-hours. As of September 30, 1990, this ratio was 55.5 percent and was greater than the minimum target value of 50 percent. The larger ratio indicated that CPSES was successfully monitoring for failure precursors and correcting conditions before failures occurred. The licensee also monitored the ratio of corrective maintenance backlog greater than 3 months old to the total corrective maintenance backlog. As of October 15, 1990, this ratio was 22.9 percent, and indicated a timely work-off of backlog work orders.

CPSES management was sensitive to balance-of-plant (BOP) maintenance concerns and had formed a BOP task team to evaluate BOP events and maintenance backlogs. The BOP task team's findings and recommendations had been provided to management and were under evaluation for implementation. One of the recommendations regarding the modification of main feed water regulating valves was scheduled for the November 2, 1990, outage.

Maintenance Procedures

Procedure STA-202, "Administrative Control of Nuclear Operations Procedures," Revision 20, provided instruction and controls for the preparation, review, approval, and revision of maintenance procedures. The maintenance and I&C department staffs had personnel specifically assigned responsibility for the development and upkeep of the procedures. The quality, availability, and use of work instruction procedures was considered a strength. The inspectors performed detailed reviews of several procedures and found them to be acceptable. The procedures for the overhaul and repair of medium voltage circuit breakers and the testing and calibration of protective relaying were examples of particularly good procedures. The CPSES 1990 "Maintenance Self-Assessment," Chapter V, identified some problems involving procedure currency and administrative controls which, when implemented, would further improve the procedures program.

The team's review of Maintenance Department Administrative Procedure MDA-202, "Maintenance Department Procedure User's Guide," Revision 1, Procedure Change Notice (PCN) 3, indicated that Step 6.1.1 stated, "In cases of emergency, an individual may deviate from an approved procedure to prevent injury to personnel, the general public or damage to the facility." The procedure did not clarify that, if the activities controlled by the procedure were related to requirements of the license or Technical Specifications, then review and approval by a senior reactor operator was required. The licensee revised the procedure prior to the close of the inspection to limit procedure deviations to those activities under the direct control of maintenance and outside the purview of 10 CFR 50.54.

The team also noted that some of the procedures were lengthy to perform. For example, WO P90-3482 required the performance of Procedure INC-4906A, "Channel Calibration Residual Heat Exchanger No. 1 Bypass Flow Control Channel 0618." Although there were minimal delays in the actual performance of the procedure, the affected RHR loop was inoperable for approximately 15 hours while completing the work. The team was concerned about the extensive amount of time that an ECCS loop was required to be out of service. The I&C maintenance manager was aware of difficulties of this nature with the procedures and informed the team that studies were underway to improve them. No timeframe, however, was provided to the team for upgrading the procedures.

Post-Maintenance Testing

Procedure STA-623, "Post Work Test (PWT) Program," established the responsibilities and methods for ensuring that testing was specified and performed following maintenance. The PWT program was invoked by Procedure STA-606, "Work Requests and Work Orders," for the control of all maintenance activities. The manager of the work control center had overall responsibilities for development and implementation of the PWT program while discipline managers and the shift supervisor were assigned support, review, and test execution responsibilities. A "Post Work Test Guide" (PWTG) provided general testing requirements and test procedure references for various equipment. It was noted that the ultimate responsibility for proper PWT assignment was assigned to the responsible work organizations' planners and the shift supervisor. The licensee planned to progressively upgrade the PWTG to become more comprehensive and complete. Post-work test reports (PTRs) documented the test requirements, assignments, and completion. The PWT program and its implementation appeared to be functioning satisfactorily.

3.2 Plant Maintenance Organization

3.2.1 Conclusions

The maintenance and I&C departments programs were well understood and effectively implemented by the maintenance personnel. Technicians and craft personnel displayed appropriate expertise and worked confidently and efficiently. However, in one instance, I&C technicians were observed working on equipment with which they were not familiar.

Managers and supervisors in both departments were supportive of the programs. Management personnel were cognizant of program shortcomings and were actively seeking improvement (e.g., hiring five additional technicians to meet current staffing targets while evaluating the need for further resources). Controlled procedures were updated in open work order packages whenever procedure revisions were made. Some weaknesses were observed in the administration of the work request tags. Several tags were observed to be still hanging on equipment in the field after work had been completed.

Control of contracted maintenance appeared to be adequate, with most work being performed under licensee procedures and program controls. The deficiency identification and resolution systems appeared adequate, but the assessment for generic impact of deficient conditions needed strengthening. A strong commitment to interdepartmental support of the maintenance department was evident. The clearance and tagging process had recently been strengthened, but additional emphasis may be needed to minimize the work control problems recently experienced.

3.2.2 Findings

Control of Contracted Maintenance

The construction/operations maintenance support group (COSG) consisted of onsite contractors who served as an overflow source of labor in the execution of modification and maintenance work tasks assigned by nuclear operations. Additionally, some contractors had been hired to fill positions in the maintenance and I&C departments. Maintenance activities performed by contractor personnel were governed by Procedure STA-606, "Work Requests and Work Orders," which required the same work guidelines for contractors as for plant personnel. Thus, contractor work was initiated, authorized, performed, and reviewed to the same standards as those applied to licensee employees. Quality assurance audits, surveillances, and maintenance supervisor observations also applied to contractor work on an equal basis. The selection of contractor personnel was based on INPO guidelines.

The team determined that onsite contractors were controlled to an extent equivalent to licensee employees. The occasional use of offsite contractors for maintenance work was usually subject to licensee procedures and QA/QC controls. On rare occasions, contractor procedures and QA/QC controls were utilized, but were implemented by licensee work orders and subject to licensee in-process monitoring.

A loss of control of contracted maintenance occurred during two recent events evaluated by the licensee. Laboratory testing of used charcoal samples from control room filtration units was performed by a contractor laboratory under environmental conditions conflicting with those specified in the FSAR. In the second event, COSG personnel mistakenly installed a valve in Unit 2 instead of Unit 1 as a result of a failure to carefully check the clearance number and the tag number on the valve. These events appeared isolated and the corrective actions taken appeared satisfactory.

Deficiency Identification and Control

The principal method for reporting deficiencies and initiating corrective action was the operations notification and evaluation (ONE) form system. The instructions for generating and dispositioning ONE forms were delineated in plant procedures. The procedure included guidelines for the screening the event for reportability and operability, and for the identification and resolution of corrective actions. All site personnel, including contractors, were responsible for identifying deficiencies in quality-related material, equipment, and activities. Personnel received ONE form training during their general employee training. Technical and management personnel reviewed the ONE forms for adequacy of the operability, reportability assessments, and to ensure that appropriate actions were taken. Feedback was provided to the originator after a deficiency was resolved. Other systems used to identify maintenance deficiencies and implement corrective actions included deficiency reports, plant incident reports, and work requests. All of the systems employed appeared to be generally effective in implementing corrective actions. Team observations regarding root cause analysis and consideration of generic implications involving ONE Forms are discussed in Section 3.1.2.

Maintenance Trending

The licensee had well documented programs for maintenance trending. Trending information was available from several data bases. Licensee management recognized weaknesses in having multiple data bases and had taken steps to develop a common data base, the PR-ISM system (discussed in Section 3.1).

The maintenance trending program had the capability of identifying generic issues. However, some corrective actions and failure analyses performed were oriented toward specific solutions and did not consider generic implications. In addition, there was a high threshold applied to the performance of failure analysis. A failure analysis was required when the component was on the critical component list, part of NPRDS, or its failure exceeded the number expected from a statistical analysis. If none of these criteria were met, then failure analyses were not performed.

The threshold for the performance of root cause analysis was also high, and generic considerations were also considered a weakness. Root cause analyses were not required until the deficient condition was identified as a plant incident report (PIR), as discussed in Section 3.1. The licensee had analyzed 23 incidents for root cause determinations. There were 98 root causes identified for 14 of the 23 events. Of these, 17 were considered design errors, 25 were considered personnel errors, 18 were considered procedure errors, and 38 were general concerns. Of the general concerns, 21 of the 38 involved personnel actions. Although the trend data indicated that 46 of the 98 root causes were personnel related, the licensee did not consider that a generic trend related to personnel actions existed.

Monitoring of ONE Forms, root cause analyses, and other maintenance activities for trends and/or adverse conditions was the responsibility of the QA organization. Although the trending function was adequately performed, the team was concerned that the QA organization in lieu of the nuclear operations organization performed the trending analysis. This programmatic aspect eliminated QA from being an oversight organization.

The team observed that the licensee was not trending rework activities, mainly as a result of the recent issue of Procedure STA-517, "Repetitive Maintenance," on September 14, 1990. Prior to the issuance of the procedure, work orders were not annotated with repetitive maintenance. In addition, it was noted that Procedure STA-517 did not require identification of generic repetitive maintenance. The procedure required only identification of specific equipment tag numbers for which similar work had been performed during the preceding 3 months. As such, the systematic identification of repetitive maintenance affecting identical components installed in different loops or trains was eliminated. The team considered the scope of the procedure as well as the short review period to be a weakness in the trending program.

Support Interfaces

Discussions with maintenance management and observation of work activities indicated that support from other departments was sufficiently provided. Shift turnover meetings provided adequate opportunities for interaction and coordination between maintenance, operations, radiation control, system engineers and other onsite groups. Daily plan-of-the-day meetings provided broader-scope interaction between maintenance, operations, and support groups on work prioritization and scheduling requirements.

The more important support interfaces for conduct of maintenance activities were with the operations and technical support organizations. These appeared to be operating adequately, except, in one area related to the clearance and tagging of systems for conduct of maintenance activities. Clearance 1-90-1991 was prepared and tags were placed to allow the rework of reheater drain tank valves. While removing the packing on Valve 1HD-680, a steam leak occurred when the valve was moved off its back-seat by the maintenance personnel. Initial review of the event revealed that Drain Valve 1HD-0878 was not specified to be opened on the clearance to preclude pressurization of the piping section containing 1HD-680. The team noted that previous clearance and tagging problems had also occurred, with several of the problems resulting in plant events and subsequent licensee event reports (LERs) (e.g., LERs 90-020 and 90-021). A clearance and tagging task force comprised of operations and maintenance personnel investigated the incidents. Procedure changes and training programs were developed to minimize the misconceptions and misunderstandings between the two organizations concerning tagging of plant equipment. However, the incident described above indicated that additional attention to the clearance and tagging process and system status control may be warranted.

3.3 Maintenance Facilities, Equipment, and Material Control

3.3.1 Conclusions

Maintenance facilities, equipment and material controls were determined to be generally acceptable. Areas identified as requiring improvement were the hot shop and decontamination facilities and the review of the controls for "out-of-calibration" meter and test equipment.

3.3.2 Findings

Maintenance Facilities and Equipment

The licensee had provided adequate shop areas for the maintenance disciplines. The mechanical and electrical crafts, supervision, and managers were located near the personnel access building. The mechanical and electrical planning groups were located adjacent to the shop areas. The meter and relay shop was located on site near the Unit 1 turbine building. A parts storage area and supply room was provided locally in the shops. The I&C shop was located near the maintenance building; the I&C manager, supervisors, and planners were located in the shop area.

The licensee provided a separate group and shop to perform calibrations of measuring and test equipment (M&TE). The M&TE shop was located on site near Unit 2, providing for close support to the plant and limiting transportation distances for the M&TE.

The site work control center (WCC) and quality control (QC) groups were located on the east side of the site within the protected area. However, WCC and QC were a substantial distance from the maintenance shops. The location of WCC, QC, and the maintenance groups, including the schedulers and planners, required additional movement to facilitate face-to-face coordination and planning. The site document control center and engineering (technical and system engineers) were a short distance from the personnel access building outside the protected area.

The licensee had self-identified a number of significant deficiencies associated with the maintenance facilities and equipment. A number of actions were in process, including the review and upgrade of maintenance shop areas, the hot shop, and the decontamination facilities.

During the inspection, the inspectors observed work activities to remove the cage from a Unit 2 main feedwater control valve (FCV) in preparation for a change-out of the Unit 1 FCV internals for all four valves. The complete work activity appeared to be appropriately performed, made good use of like components for mockup training, and stressed proper preparation for a complex work activity.

Material Controls

The inspector found that the identification and procurement of materials was effectively performed in accordance with approved procedures. The licensee was improving their master parts list by identifying quality and procurement information for identified items. The evaluations were completed for 6,000 of the 10,000 identified components. The users designated the priority according to the safety significance of the component.

The licensee performed and documented material receipt inspections in accordance with approved procedures. Materials on hold or rejected were identified and properly segregated from accepted materials. Items with shelf-life limitations had tags affixed upon receipt which gave the expiration date. Expired shelf-life material was controlled at the time of issue. Additionally, the licensee had a tracking system for shelf-life material. The inspector observed that the expired shelf-life printout did not list the expiration dates for all the materials, which prevented identifying expired items. As such, the new material management data base would not identify expired shelf-life material automatically. The inspector noted that shelf-life items with long lead times would not be available for use by the craft when needed as a result of the tracking system weaknesses. The licensee stated that they would correct these weaknesses by January 1991.

The storage facilities for oils, chemicals and hazardous materials, combustibles, and Level A materials were in separate locations. The Level A storage did not meet all requirements since the area was dusty. The licensee made provisions for the degraded storage level by adding a note to the applicable procedure. The licensee specified that action would be taken to guard against dust for items requiring Level A protection. Unqualified materials were stored in a separate holding area with nonconformance tags attached.

The licensee transferred installed equipment from Unit 2 to Unit 1 in accordance with approved procedures using the permanent equipment transfer process (PET). At the time of the inspection, 14 percent of the material transferred had not been replaced but was being procured.

The licensee was completing construction of a new warehouse located within the protected area. The licensee planned to prestage material for design modifications and stock materials with a high turnover rate. The warehouse was scheduled for service in January 1991.

Maintenance Tool and Equipment Control

The maintenance tool and equipment control program appeared to be adequately proceduralized. The quantities of personal issue tools and tool room inventory were sufficient to support job task performance. The existing facilities included a cold tool room located in the maintenance shop and a hot tool room located in the Unit 1 safeguards building. The PR-ISM tool control computer program was recently implemented to enhance the tool issue and return system. More stringent controls were established which required issuance of uniquely identified tools to designated personnel by badge number and also provided required return dates for the issued tools. The existing procedure controls adequately addressed the handling and disposition of defective tools and the establishment of minimum tool inventories in each tool room.

Materials in the tool rooms were staged in accordance with applicable procedures. The team noted that safety and nonsafety-related materials were properly segregated. The tool rooms had separate locations for storage of chemicals, oils, and combustibles. During walkdowns of the maintenance shops, the team identified intermingled "Q" and "non-Q" bar stock. The licensee corrected the situation by stacking the material on separate, labeled shelves.

Control and Calibration o˜ "easuring and Test Equipment

The program for the control and calibration of measuring and test equipment were found to be generally acceptable. Specific areas requiring improvement, which had previously been identified by the licensee included an expedited review of out-of-calibration M&TE when used for critical work and the development of a trending program for M&TE failures.

The M&TE program was governed by Procedure STA-608, "Control of Measuring and Test Equipment," Revision 15. This procedure accurately reflected all of the commitments of Chapter 17.2.12 of the FSAR and contained appropriate controls ˊ ˑ the issuance and usage of M&TE. Specifically, it was determined that

STA-608 contained both accuracy requirements for utilizing M&TE, as well as, standards used to calibrate the M&TE.

Based on a sample of 10 M&TE items from the licensee's master list, it was determined that M&TE and reference standards were of the proper range, type, and accuracy to verify conformance to established requirements. M&TE was properly controlled, adjusted and maintained at prescribed intervals. The MT&E was traceable to specific inspections, tests or calibration activities.

During the inspection, several examples of overdue calibrations for unreturned M&TE equipment were identified. This is a finding similar to that identified in NRC Inspection Report 50-445/90-36; 50-446/90-36. This area continues to be an NRC concern. The team noted that the licensee had developed an action plan to expedite the review of out of calibration M&TE as well as a formal trending program to identify M&TE programmatic issues.

3.4 Personnel Control

3.4.1 Conclusions

The licensee had established adequate staffing of maintenance and I&C departments. Even though present overtime hours were higher than desired, the licensee was monitoring the situation in order to control the overtime. The supervisor to craft person ratio in all groups was considered reasonable and effective.

The licensee had implemented an effective qualification and training program for craft personnel. The licensee was in the process of implementing the formal training program for the technical staff and managers.

3.4.2 Findings

The mechanical, electrical, and I&C groups appeared to be adequately staffed with experienced and qualified personnel. The maintenance department included about 150 craft personnel and the I&C group consisted of about 50 craft personnel. The supervisor to craft person ratio was about 8 to 1 in each group. The I&C department was staffed with approximately 25 percent contractor personnel. The contract personnel worked for the licensee as an integral part of the I&C group. The I&C group had approximately five vacancies at the time of the inspection, and the licensee was actively pursuing filling the positions.

Document reviews and personnel interviews revealed that the staff turnover rate was considered to be acceptable. Vacancies resulted mostly from personnel accepting other positions within the utility. At the time of the inspection, the electrical maintenance manager position was vacant as a result of a company promotion.

The departmental overtime goal was approximately 10 percent. The overtime worked, about 20 percent, exceeded the goal. However, the licensee stated that the overtime would decrease as the plant continued operation. The overtime worked during forced outages was on an as needed basis, not to exceed the established guidelines for nuclear plant workers.

Critical maintenance activities which supported licensee requirements and power production were worked until completion. The licensee had established controls for emergency maintenance in Procedure STA-606, "Work Requests and Work Orders." Document reviews and personnel interviews revealed that no emergency maintenance activities had occurred on Unit 1. Interviews revealed that the licensee utilized a standing work order to allow troubleshooting activities under the direction of the shift supervisor, while necessary personnel call outs were completed. The troubleshooting activities were accomplished in accordance with Procedure ICA-102, "I&C Troubleshooting Activities." In addition to the normal controls addressed by the work order, ICA-102, provided a brief description of the boundaries for troubleshooting activities and established the documentation requirements.

The maintenance groups were scheduled to provide extended 2-shift coverage 5 days a week, supplemented by scheduled and call out overtime as needed. The meter and relay group generally worked a 40-hour 5-day week, supplemented by scheduled and call out overtime. The maintenance crews were scheduled 7 days a week 24 hours per day to support operating activities. I&C group planners worked two 8-hour shifts and were subject to call out overtime.

The licensee had established a positive discipline methodology as described in the utility supervisor handbook. Document reviews revealed the methodology was to be used when disciplinary action was needed.

The licensee's training and qualification program received INPO accreditation on October 25, 1990. Station procedures and department procedures specified the training and qualification requirements for maintenance personnel. Maintenance personnel received recurrent training on general employee and radiation protection training, including the as low as reasonably achievable (ALARA) program. The licensee had procedures in place to provide on-the-job training to trainees by experienced and qualified trainers and evaluators. The licensee had qualified the craft personnel by waivers for both general and specific tasks. The waiver process considered the person's past experience, training received, and the recommendation of his supervisor. The team determined from review of documentation and discussions with the licensee that the background of maintenance personnel was adequate, but the experience and training of many of the records reviewed indicated that their background was not fully documented for the individual. The skills possessed by each craft person was designated on qualification matrices, which were used in assigning personnel for conduct of work. The contractors on site at the time of the inspection had received the same general training as the plant personnel. The licensee intended to process the waivered craft personnel through the basic training courses over the next 5 years.

Management involvement in training was demonstrated by the extensive training facilities which contained full scale working components to include valves, pumps, valve operators, and various types of transmitters. The licensee had a working replica of a control rod drive mechanism and the solid state protection system including pertinent control room control panels. One ALARA mockup included an operating system containing pumps, valves, pressure transmitters, and other hardware. Other ALARA mockups included the lower portion of a steam generator and a working replica of the traversing incore probe and indexing machines.

From review of training department procedures and test documents the inspector determined that the licensee standardized the testing of personnel. The inspector reviewed the training records for selected individuals and found the qualifications to be documented and traceable. The licensee was in the process of implementing a formal training program for the technical staff and their managers.

The licensee's craft training program received INPO accreditation during the period of the inspection, as described above. Most of the I&C technicians, however, received waiver of the qualification requirements based on prior experience. On one occasion, technicians were observed working on equipment with which they were unfamiliar. While performing Work Order P90-3482 on the RHR Heat Exchanger No. 1 Bypass Flow Control Channel 0618, the technicians obtained the as-found data for 1HC-618 at the remote shutdown panel, and noted that the readings were outside the calibration band at two points. The adjustment necessitated the removal and adjustment of the manual control station. Neither technician knew how to remove the instrument and considered removing the seismic mounting brackets within the panel. It was noted that one technician was qualified on the equipment by waiver, while the other technician had received specific training on the process control system several years ago.

Although the licensee had formalized requirements for independent verification, technicians were observed on two occasions improperly signing off steps in the procedure. During the performance of WO P90-3482, "Channel Calibration on RHR Heat Exchanger No. 1 Bypass Flow Control Loop F-0618," the technician who lifted a lead, signed as the independent verifier, while the other technician, verifying the lifting of the lead, signed as the performer. During the performance of WO P90-4882, "Channel Calibration on RHR Heat Exchanger No. 2 CCW Discharge Flow Loop F-4558," two different technicians similarly signed for actions performed by the other on several occasions. The supervisor was informed of these occurrences and conducted a training session with all technicians the following morning.

4. EXIT INTERVIEW

The inspectors met with Mr. W. J. Cahill and other members of the licensee's staff, as denoted in Attachment A, at the end of the inspection on October 26, 1990. The inspectors summarized the scope of the inspection and presented the preliminary inspection findings. The licensee did not identify as proprietary any of the materials provided to or reviewed by the inspectors during this inspection.

On November 16, 1990, Messrs. J. Jaudon, J. Gagliardo, and T. McKernon held an exit meeting with Mr. W. J. Cahill and other members of the licensee's staff and discussed the scope and findings of the inspection. Persons attending the exit meeting are identified in Attachment A.

The color-coded presentation tree (Attachment B) was used as a visual aid during the exit meeting to depict the results of the inspection.

ATTACHMENT A

EXIT MEETING ATTENDEES

1. TU Electric Personnel

W. J. Cahill, Jr., Vice President, Nuclear Engineering and Operations
A. B. Scott, Vice President, Nuclear Operations
J. J. Kelley, Jr., Plant Manager
M. R. Blevins, Nuclear Operations
C. L. Terry, Quality Assurance
B. Wieland, Maintenance Manager
C. B. Hogg, Chief Engineer
H. D. Bruner, Sr. Vice President, Engineering
B. W. Wells, Quality Assurance
D. E. Pendleton, Assistant Project Manager, Unit 2
J. H. Scott, Executive Assistant
W. L. Stendebach, Compliance Engineer
T. A. Hope, Compliance Supervisor
H. A. Marvray, Licensing Engineer
J. L. Barker, Manager Independent Safety Engineer Group
D. McAfee, Manager Quality Assurance
W. G. Guldemond, Manager Site Licensing
S. L. Ellis, Manager Performance and Testing
G. J. Stein, Technical Administrative Assistant - Maintenance
D. Dillinger, Plant Evaluation Engineer
O. Bhatty, Quality Assurance
R. J. Adams, I&C Engineering Supervisor

2. Citizens Association for Safe Energy (CASE)

E. F. Ottney, Project Manager

3. NRC

J. P. Jaudon, Deputy Director, Division of Reactor Safety (DRS)
J. E. Gagliardo, Chief, Operational Programs Section, DRS
T. O. McKernon, Team Leader, Operational Programs Section, DRS
W. D. Johnson, Senior Resident Inspector
R. M. Latta, Senior Resident Inspector, Unit 2
D. M. Graves, Resident Inspector
D. D. Chamberlain, Project Section Chief, Division of Reactor Projects

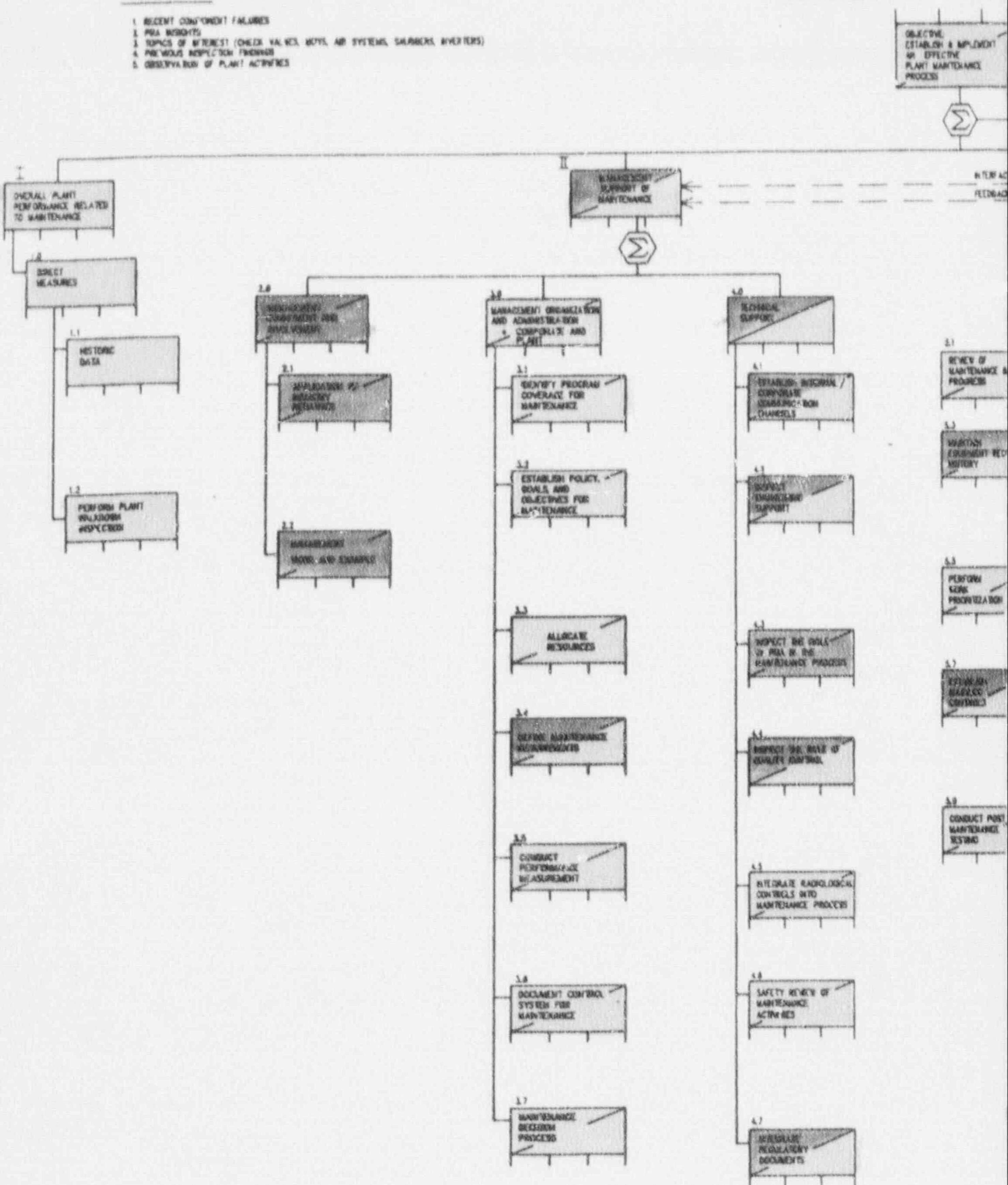
ATTACHME

PRESENTATION

MAINTENANCE INSPEC

TREE INITIATORS

1. RECENT COMPONENT FAILURES
2. PRA INSIGHTS
3. TOPICS OF INTEREST (CHECK VALVES, MOVS, AIR SYSTEMS, SNUBBERS, INVERTERS)
4. PREVIOUS INSPECTION FINDINGS
5. OBSERVATION OF PLANT ACTIVITIES



NOTE: THIS DWG. IS USED IN CONJUNCTION WITH 425001, 425802, 425803, 425804, 425806, 425807 & 425808.

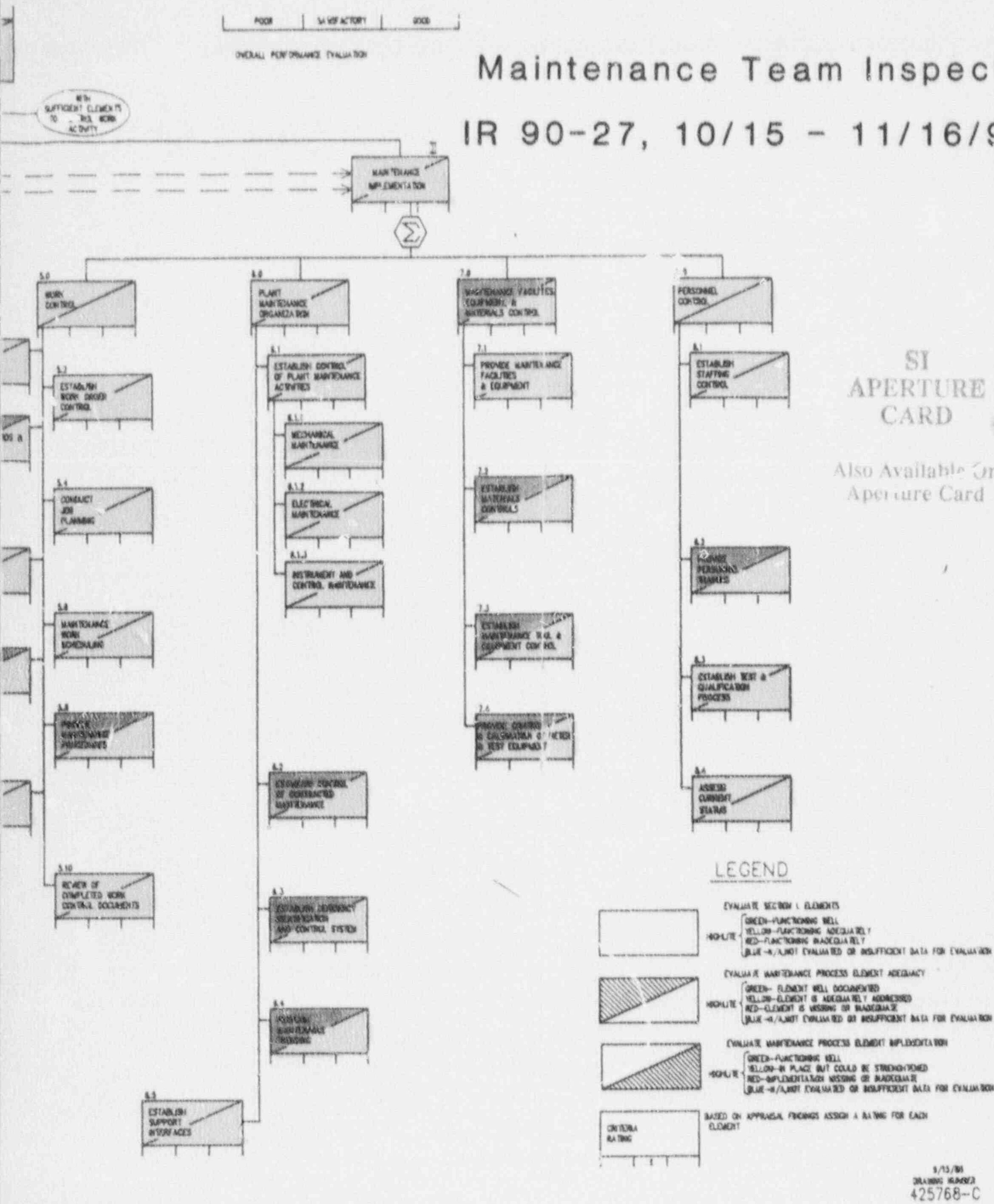
NT B

TREE
TION TREE

Comanche Peak (CPSES)

Maintenance Team Inspection

IR 90-27, 10/15 - 11/16/90



SI APERTURE CARD

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