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OFFICE OF NUCLEAR REACTOR REGULATION

NRC Inspection Report: 50-498/93-202 and 50-499/93-202

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Licensee: Houston Lighting and Power Company

Facility Name: South Texas Project, Units 1 and 2

Inspection at: South Texas Project

Inspection Conducted: December 6-10, 1993 and January 12-21, 1994

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EXECUTIVE SUMMARY

The NRC Operational Readiness Assessment Team (ORAT) inspection, led by the Special Inspection Branch of the Office of Nuclear Reactor Regulation (NRR), was conducted from December 6-10, 1993, and January 12-21, 1994. The inspection team consisted of staff members from NRR, Region II, and Region III, as well as two consultants. The objective of the inspection was to provide the NRC an independent, broad-scope assessment of the programs, personnel, and management controls in place to support restart of South Texas Project (STP), Unit 1. The ORAT evaluated the areas of plant operations, surveillance, maintenance, modifications, and corrective action programs. The team also reviewed the STP Operational Readiness Plan and the STP Business Plan.

The team's findings were generally supportive of a restart of STP Unit 1. However, the team identified three items as requiring further actions prior to restart. These three issues and Houston Lighting & Power Company's (HL&P) planned actions to address them were detailed in a letter issued by the NRC on January 27, 1994. The three issues pertained to

(1) weaknesses in HL&P programs for ensuring configuration management which resulted in numerous unexpected equipment actuations and equipment clearance order inadequacies

(2) failure to properly control the manual operation of motor-operated valves which are not self-locking and can unexpectedly change position if operated manually and not electrically re-engaged

(3) failure to demonstrate operability of the pressurizer power-operated relief valves from the main control panel

Other significant deficiencies identified by the team but not considered requiring action prior to restart involved

(1) weaknesses in corrective action program implementation, including weak or non-existent root cause analyses, and the failure to address all problems or contributory causes for some apparently significant safety issues

(2) the excessive use and lack of control of technical specification interpretations

(3) inadequate controls for the installation and removal of jumpers and the tracking of operability status during the "normalization" of solid state protection equipment

The team also made several observations deemed significant enough to call to management attention including:

- numerous equipment failures that seemed to be challenging operations and inhibiting progress toward plant startup

- weaknesses in some surveillance testing procedures

- inconsistencies in the performance of some 10 CFR 50.59 screening checklists

Many of the deficiencies and observations identified by the team could be attributed to incomplete or ineffective program implementation or to various procedural weaknesses. In the exit meeting conducted on January 21, 1994, the team encouraged HL&P management to work on improving performance in these areas.

Aside from the specific deficiencies and observations, the team found that HL&P had effectively implemented a comprehensive Operational Readiness Plan for return to power and had developed an ambitious Business Plan which outlined long-range strategies and activities. Work backlogs, both paper-and hardware-oriented, had been significantly reduced during the current extended outage. Control room operators performed in a professional manner; and with the establishment of a six-crew rotation, less administrative burden was put on the operating crew. Operations overtime was not excessive.

The surveillance program at HL&P was adequate to ensure technical specification surveillances were accomplished as required. HL&P's maintenance program was adequate; the recent addition of a second supervisor per crew and the establishment of a work package control center were positive additions to the program. Implementation of the post-maintenance test program, which was found to be inadequate during the first phase of the inspection, had been much improved by the conclusion of the inspection.

The STP corrective action program was marginally adequate with several future enhancements planned. However, root cause analyses and corrective action evaluations need to be improved. Engineering support to the plant was good, as was the observed physical plant condition. Staff morale and attitude were positive.

1.0 BACKGROUND

The South Texas Project (STP) consists of two, four-loop pressurized-water reactor units. The licensee, Houston Lighting & Power Company (HL&P), voluntarily shut down both units in February 1993 after experiencing numerous problems with the performance of the auxiliary feedwater system.

On February 3, 1993, following a reactor trip, the Unit 2 turbine-driven auxiliary feedwater pump started and immediately tripped on overspeed. On February 4, 1993, Unit 1 was required to shut down as a result of repeated failures of the turbine-driven auxiliary feedwater pump to start on demand and operate without tripping on overspeed. As a result of these turbine-driven auxiliary feedwater pump problems, NRC issued a confirmatory action letter (CAL) to HL&P on February 5, 1993, and dispatched an augmented inspection team (AIT) to investigate the details surrounding the turbine-driven auxiliary feedwater pump problems.

Additionally, the NRC Office for Analysis and Evaluation of Operational Data (AEOD) conducted a diagnostic evaluation of the STP between March 29 and April 30, 1993. The AEOD findings were forwarded to the licensee on June 10, 1993. A number of issues that NRC considered of broad enough scope and sufficient safety significance to require resolution before either unit could be restarted were identified in that report.

In its initial response to the diagnostic evaluation team (DET) report, the licensee submitted a letter on August 5, 1993, and forwarded its Operational Readiness Plan (ORP) on August 28, 1993. In addition to responding to the DET short-term problems that the licensee considered necessary to resolve before restart, the ORP addressed the actions planned in response to the CAL, special routine regional inspections, and other concerns and problems. The ORP addressed initiatives that the licensee considered necessary to be completed before the resumption of power operation on either unit.

2.0 INSPECTION OBJECTIVES AND SCOPE

The NRC conducted this inspection in accordance with NRC Inspection Procedure (IP) 93802, "Operational Safety Team Inspection (OSTI)," and IP 93806, "Operational Readiness Assessment Team (ORAT) Inspection." The objective of this inspection was to provide the NRC an independent, broad scope assessment of the programs, personnel, and management controls in place to support restart of STP Unit 1. The ORAT evaluated the areas of plant operations, maintenance, surveillance, corrective action, and modifications, and focused on examples from both safety-related and balance-of-plant systems. The team also evaluated the adequacy and implementation of the licensee's Operational Readiness and Business Plans.

The team has characterized its findings as deficiencies and observations. Deficiencies are the apparent failure of the licensee (1) to comply with a requirement or (2) to satisfy a written commitment to conform to the provisions of applicable codes, standards, guides, or other accepted industry practices that have not been made legally binding requirements. Observations are findings that have no apparent regulatory basis but that are deemed appropriate to call to management attention. Each deficiency designated in the body of the report is listed in Appendix A. Significant observations are listed in Appendix B.

3.0 EVALUATION OF THE BUSINESS PLAN AND OPERATIONAL READINESS PLAN

3.1 Business Plan

The licensee's Business Plan described the activities and strategies that were planned for the period between restart and 1998 for long-term improvement in station performance. Many of the long term actions addressed issues identified in the NRC confirmatory action letter and the NRC diagnostic evaluation report.

The Business Plan noted six areas that required improvement. These areas are (1) leadership and management, (2) communication and teamwork, (3) resources, (4) human performance, (5) self-assessment and corrective action, and (6) material condition and plant reliability. Each improvement area was assigned to a team of individuals responsible for developing action plans for improving their associated area. The team evaluated seven action plans related to resources and human performance and found them to adequately address the required areas of improvement. Actions were verified as being completed using objective evidence.

3.2 Operational Readiness Plan

The Operational Readiness Plan described the actions to be taken by the licensee prior to returning the plant to power operation. The planned actions included improvements to STP hardware, programs, and personnel performance.

The team determined that the Operational Readiness Plan had been effectively implemented. The team evaluated 20 percent of the action items in the Operational Readiness Plan and determined that items were completed either on-time or ahead of schedule. Those items that were identified as requiring completion before restart were either on schedule or ahead of schedule. The plan appeared to be well developed, properly researched, and had been evaluated by several internal and external organizations. There were a number of tracking mechanisms available to ensure that each outstanding item had been assigned a proper status and had been corrected on a timely basis. Items that had been completed were verified complete by the licensee. The personnel responsible for completing Operational Readiness Plan items were knowledgeable and well qualified with regard to their assigned action items and were aware of the status of action items in their organization. The Operational Readiness Plan had strong support from all levels of management, up to and including the Group Vice President, Nuclear.

3.2.1 System Certification Process

As part of the Operational Readiness Plan, the licensee implemented a system certification process. The process was designed to ensure that outstanding issues on selected systems were properly identified, evaluated, and handled prior to restart. A total of 61 systems (full and partial scope) underwent the system certification process. In addition, one generic system book was prepared to review generic issues not related to any specific system.

The system certification program was a three-phase process. In the first phase, the licensee utilized system risk, system availability, and system historical performance as factors for selecting which systems would be certified and for identifying the scope of the review. The remaining two phases were governed by two procedures; OTGP03-ZA-005, "System Readiness," Revision 0, and OTGP03-ZA-0006, "System Acceptance," Revision 0; both procedures were detailed and clearly delineated responsibilities and goals. For each selected system, the system engineer (SE) reviewed an initial population of open items and determined if the items were restraint issues or if they could be deferred. Restraint items were required to be performed before startup of the unit.

All the deferral and restraint items were assembled in a system readiness review package (SRRP) for each system; the package included documented engineering justifications for all deferred items. New work items were evaluated on a bi-weekly basis. The SE then presented the SRRPs to the Readiness Review Committee, which contained representatives from operations, plant engineering, and maintenance, and to the plant manager, for concurrence with the deferrals and restraints.

A comprehensive system walkdown was then performed to identify uncaptured in-plant deficiencies. The system packages were then presented to the shift supervisor to accept the operational readiness of the systems along with the pending open items. The final step was to have the plant manager accept the final SRRPs. Several different management approvals were required to delete restraint items from the outage.

The team independently sampled a number of open items against systems and identified two potential items that had not been listed. The licensee determined that one item had been previously closed; the other item was subsequently deferred. The team considered this a minor issue.

The SEs, as well as the respective supervisors were knowledgeable about the various issues and the certification process. The team observed the presentation of the SRRP for the residual heat removal system (RHR) to the plant manager. The plant manager was familiar with the issues that had been identified, including some housekeeping issues that he had recently found in his own walkdown of the system. The plant manager had refused to approve the package until the SE verified the area was clean. His failure to approve this system for readiness was indicative of the thoroughness of the process. In conclusion, the team found that the system certification program was successful at demonstrating that selected systems were ready for operation.

3.2.2 Deferred and Emergent Work

The licensee's evaluation and control of deferred and emergent work was governed by Procedure OPGP03-ZA-0090, "Work Process Program", Revision 7 and

Procedure OPGO3-ZA-0102, "Refueling Outage Scheduling and Scope Control," Revision 2. A licensed senior reactor operator (SRO) of the operations work control group (OWCG) determined the prioritization of all service requests.

For the 61 systems in the system certification process, a deferral form had to be completed and routed to the SEs for all emergent work that the SRO determined could be deferred. For those systems not in the certification process, the decision by the SRO to defer an item did not require a deferral form. In addition, all newly generated service requests were sent to the appropriate systems engineers bi-weekly, with those pertaining to the 61 systems requiring a formal evaluation. This additional mechanism to the normal work process was used to ensure the SEs were aware of any new issues related to their systems.

Once an item was dispositoned, as either included in the outage or deferred, any changes to this status were controlled by an outage activity change request form (OACRF). The OACRF required approval signatures from several different managers. The team verified that significant emergent items for all systems had been scheduled into the outage and that, once scheduled, they were not deleted without a valid justification.

3.2.3 Review of Engineering Backlog

As part of the Operational Readiness plan, the licensee established specific performance goals for closing outstanding engineering oriented items such as temporary modifications, non-conforming plant change forms, and vendor documents. The team reviewed the performance goals and found that if met, they would reduce the engineering backlog to a reasonable level. Engineering trend curves which depicted performance indicators separated by department and group discipline, were provided to management on a weekly basis. The licensee has recently improved its tracking of engineering-oriented open items. Tracking databases, which previously had limited access capability, have been transferred to a database that all engineering personnel can now access. In addition, the licensee was in the process of establishing a new engineering work management system which would provide information on work performance, scheduled work, and unplanned manpower allocation in order to obtain a better understanding and additional control over engineering resources. The team noted that the improvements in this area should help the licensee do a better job of managing the backlog of engineering issues.

3.2.4 Review of Maintenance Backlog

Prior to the inspection, the licensee had committed to reducing to less than 1,000 the number of service requests on Unit 1 and areas common to both units. Although this goal had recently been achieved, the licensee needs to ensure that the backlog remains manageable, in anticipation of the expected influx of service requests that will likely be generated during heatup of the plant.

3.2.5 Plant Assessments

As part of the Operational Readiness Plan, the licensee has conducted several assessments of programs and hardware in order to ensure the readiness of Unit 1 for restart. The assessments consisted of independent assessments led by their nuclear assurance group, self-assessments conducted by line management, and an industry group assessment conducted by a team of senior industry consultants.

The independent assessments conducted by the nuclear assurance group, the planning and assessment group, and the independent safety engineering group (ISEG) were performance based and effective at identifying numerous deficiencies. The weekly activities observed during the assessments were individually documented and discussed with the line management of the audited area. The results were presented in a weekly report card. The report card identified a color rating for each specific area reviewed and included a descriptive report to keep senior personnel apprised of overall plant performance and trends, and to flag deficient areas for additional resources. During the first phase of the inspection, the team identified that the report card indicated poor ratings for the areas of post maintenance testing and configuration management and that management had not taken appropriate actions to ensure the issues identified by the independent assessment had been resolved. After bringing this to the licensee's attention, the team noted that management's awareness of assessment issues was markedly improved. The team noticed that, as the plant got closer to the planned restart date, the report card ratings were appropriately improving. This was indicative of improvements being made in the implementation of the many newly instituted programs on site.

The line management assessments were done to specifically ensure that restraints had been completed before making any mode changes. Therefore, the focus of the assessments was not broad enough to capture additional opportunities to improve performance; and the thoroughness of the assessments varied greatly among departments. The licensee was fully aware of the limitations of the initial line management assessments and had made plans to improve the assessments as more were conducted. The team noted that the later assessments seemed to be of a generally higher quality.

A group of industry consultants also evaluated the licensee's performance. The audit team conducted two assessments, one in November and the other in December. The assessments were broad scope and found several areas in which performance improvements were warranted, such as in the areas of corrective action and in eliminating the backlog of industry information evaluations. The assessment team noted that licensee performance had generally improved between the November and December assessments. Action plans were developed to address all findings, and individuals were assigned followup and closure responsibilities.

In conclusion, the combination of the three assessments appeared to be a useful means for identifying areas requiring additional management attention prior to restart. The assessments were also useful in showing overall performance trends.

4.0 OPERATIONS

4.1 Review Scope

The team reviewed operations readiness for restart by observing control room activities and operators' responses to plant annunciators and abnormal operating events. The team also reviewed shift logs, work packages, equipment clearance orders (ECOs), and various other control room documents. Through work observations and discussion with operations personnel, the team verified that the operations staff was knowledgeable of plant conditions, responded promptly to alarms, adhered to procedures and administrative controls, was cognizant of ongoing surveillance and maintenance activities, and was aware of equipment status.

The team's review included a 48-hour continuous control room observation and an evaluation of the licensee's ability to shut down the plant from the auxiliary shutdown panel. The team also assessed the general material condition of the plant by performing walkdowns of selected plant areas and systems, accompanied by operations staff.

4.2 Shift Staffing

STP recently established a sixth operating crew. During each rotational cycle, 5 crews are assigned to cover control room operations. The sixth crew is assigned to support the operating crew including providing assistance to the Operations Work Control Group (OWCG). This concept has decreased the administrative workload of the operating crew.

At the beginning of the inspection, STP had a total of 82 active licensed operators for both Unit 1 and Unit 2. This was a sufficient number of licensed operators to operate a six-crew rotation and meet the Technical Specifications minimum shift crew composition. Plans to increase the number of licensed individuals are addressed in the 1994 - 1998 Business Plan. To date, approximately 30 additional reactor plant operators (non-licensed operators) have been hired and have entered the training program. The ultimate goal of many of the newly hired reactor plant operators was to obtain an NRC reactor operator license.

The shift supervisor controlled how overtime was used by operations personnel at STP. By means of an automated timekeeping system, the shift administrative aide kept track of overtime use. Shift management could review printouts of hours worked daily. If any person worked more than 60 hours in a 7 day period, the timekeeping system alerted the administrative aide, who then brought the matter to the attention of the shift supervisor. This appeared to be effective in controlling excessive overtime usage at STP.

4.3 Observation of Specific Activities

4.3.1 Shift Turnovers

The team attended shift turnovers on a daily basis. The shift turnover process at STP was very thorough and resulted in the oncoming shift being fully aware of plant and equipment status, operating events, and abnormal system alignments. A high level of licensee management involvement was observed at turnover meetings. The team found that the oncoming shift crews were aware of the recent administrative procedure changes that were implemented during the inspection period. The team verified that turnover checklists and panel walkdowns were thoroughly reviewed before the oncoming shift relieved the previous shift.

4.3.2 Configuration Management

The team assessed the licensee's ability to maintain configuration control by reviewing control room procedures and work documents, observing in-process reviews of ECOs and equipment operation, and by performing system walkdowns. The team noted that equipment lineups accurately reflected system status and that personnel establishing ECOs were attentive in their actions. During the team's walkdowns, no mispositioned valves or breakers were found.

During the first phase of the team's inspection, several events regarding inadvertent equipment actuation or failure of equipment to actuate during testing were noted. The events were described to the licensee as a potential weakness in the area of system and equipment configuration control and were documented in a letter sent to the licensee on December 16, 1993. On the basis of the team's observations and comments, the licensee reviewed station problem report (SPR) histories for similar events over the last year. As a result of the review, 33 SPRs were identified which indicated an adverse trend in this area. The team noted that the licensee had initiated corrective action for each individual event, but had not evaluated the events collectively for potential common causes.

During the second phase of the inspection, configuration control problems continued. On January 12, 1994, reactor coolant pumps were started without loop flow indication because plant instrumentation was not being correctly returned to service. On January 15, 1994, upon starting the 1A charging pump, CV-MOV-8348 opened in response to hydraulic pressure beneath the seat, resulting in two charging pumps being lined up and flowing to the reactor coolant system (RCS) which did not meet Technical Specifications (TS) surveillance requirement 4.1.2.3.2. On January 17, 1994, an electrician performing a "clean and inspect" electrical preventive maintenance procedure on cubicle N32 of motor control center MCC2L1 was injured when he received an electric shock because of an inadequate ECO.

During plant walkdowns, the team also identified several minor discrepancies: (1) incorrect labeling on reactor coolant pump (RCP) seal water injection valves; (2) a temporary modification tag that had been hanging since 1988 on electrical switchgear even though the temporary modification had been removed; (3) stress analyses for certain piping runs which did not consider the weight of radiation collars installed during original construction. The licensee promptly corrected these minor items.

The team specifically noted that a number of SPRs were initiated due to the ECO process. On the basis of its observations and reviews, the team concluded that these events were indicative of a programmatic weakness in configuration management controls at STP. Failure to maintain configuration management is designated as Deficiency 93-202-D1 and was identified by the team as an issue requiring action prior to restart.

In response to the team's concerns in this area the licensee developed and committed to implement a configuration management action plan. The team reviewed the plan which included, in part, establishing a team to review each of the 33 events to validate causal factors and to verify that corrective actions had been implemented. The plan also called for an independent industry review of the actions taken. The team considered that the actions outlined in the plan were adequate.

The team also commented on the licensee's method to track TS-required equipment. The team noted that the licensee's operability tracking log (OTL) was cumbersome and did not clearly distinguish between TS-required OTL entries and other OTL entries which were used to track equipment status. This was designated as Observation 93-202-01.

4.3.3 Procedural Adherence and Usage

The licensee's practices for implementing and adhering to procedures were assessed by reviewing and observing performance of operating and surveillance activities. The team reviewed Administrative Procedure OPGP03-ZA-0010, Revision 15, "Plant Procedural Adherence and Implementation and Independent Verification." The team noted that the licensee did not have clear procedural instructions for delineating who could authorize the changing of approved procedures by marking certain procedural steps N/A. Procedure OPGP03-ZA-0010 states that "Procedure steps with signoff blanks or step checkoffs which are not performed SHALL be marked N/A (or equivalent) and justification SHALL be provided if the basis for the use of the 'N/A' is not apparent or otherwise documented in the procedure."

The team observed the use of N/A during the performance of several procedures including Maintenance Surveillance Procedure 1PSP03-SP-0013, in which a note in the remarks section of the data sheets stated that the steps were not required per the shift supervisor due to the present Mode 5 plant conditions. A second example involved the N/A of prerequisites 3.11 and 3.14 in Procedure OPOP02-RC-0003, Revision 0, "Filling and Venting the Reactor Coolant System." Procedure OPGP03-ZA-0010, step 4.2.4.2 allows the shift/unit supervisor to deviate from prerequisite steps as long as the deviation does not interfere with the safety of personnel or equipment and is documented in the control room logbook. A logbook entry was not made until after questioning by the team. The team observed further use of N/A during Procedure OPOP02-RC-0004, Revision 2, "Operation of Reactor Coolant Pumps"; and OPOP03-ZG-0001, Revision 1, "Plant Heatup." In addition instances were identified where steps had been marked N/A in some postmaintenance testing procedures without proper justification.

Although the team noted that some individual procedures addressed the use of N/A, it was not clear to the team that the intentions of the procedure steps were being met. The team noted that administrative controls for using N/A did not guarantee a proper review and allowed circumventing the procedure change process. Before the end of the inspection, the licensee revised Procedure OPGP03-ZA-0010 to more clearly delineate who could authorize the use of N/A. Failure to establish and implement administrative controls for the use of N/A is designated as Deficiency 93-202-D2.

The team also reviewed Procedure 1PSP03-CV-0003, Revision 3, "Centrifugal Charging Pump 1A Reference Values Measurement." The team noted that the procedure failed to address requirements of the TS which prohibit aligning more than one charging pump to the RCS in Modes 5 and 6. Because of this omission, it was left to the reactor operators to maintain the required TS configuration without clear procedural direction. The team noted that this procedure could not be performed on January 18, 1994, because of a lack of reference flow indication caused by the characteristics of the valve used for throttling flow. Operators also indicated that this was a known problem, but that changes to the method of testing had not been instituted. The licensee initiated an SPR to address this procedure.

The team noted numerous delays of activities because procedures could not be performed as written by operations. The team reviewed procedure changes which had been implemented in 1994. Sixty procedure changes had been issued over a 20-day period. Only about one-third of the procedure changes resulted from plant modifications; the remaining two-thirds resulted from necessary changes to support correct plant operations or to clarify instructions.

These observations indicated poor procedure quality. The use of N/A in procedure steps has apparently increased because of frustration with the quality of procedures. However, the team noted that plant personnel appeared aware of the need to follow procedures strictly, and correct them as necessary. For example, plant heatup was repeatedly delayed awaiting the requisite procedure changes to be processed. The team met with licensee management and discussed the plant's procedure change process. Licensee management stated that a year ago, the operations backlog of procedure changes numbered approximately 1400. This backlog has been reduced to approximately 180. Additionally, the plant staff has a renewed sensitivity to procedure compliance. The team notes procedure quality as a weakness, but recognizes how much progress the licensee has made. This was designated as Observation 93-202-02.

4.3.4 Continuous 48-Hour Control Room Observation

The team observed control room activities during a sustained 48-hour period beginning on the evening of January 13, 1994. The team noted that control room access was limited, noise levels were reasonable, and that the newly established OWCG was effective in limiting the administrative burden on the control room staff. A professional attitude was maintained by operators while carrying out their assigned duties. Operator awareness to plant status, and attention and response to plant annunciators, was considered good. Operator logtaking was detailed and documented plant activities adequately. The professionalism and high morale of the operations staff were identified as strengths by the team.

During the team's observations, two deficiencies and three observations were identified as described below:

(1) Normalization of Plant Instruments

In Modes 5 and 6, test equipment and jumpers were installed on solid-state protection equipment to simulate 100 percent conditions on plant instrumentation. This process was called "normalization". The team identified several weaknesses associated with the normalization procedure (OPMP08-SP-0001, Revision 2, "RPS/ESF System Normalization") and process. The first example involved an I&C technician who failed to correctly remove normalization from loop flow instruments which resulted in an operator starting two reactor coolant pumps without loop flow indication. A second example involved Surveillance Procedure OPSP06-RC-0003, Revision 0, "UV RCP Relay Channel Calibration." The procedure was suspended because both the procedure and personnel failed to recognize that the removal of normalization was required before procedure performance. A third example involved Procedure OPGP03-ZA-0002, "Plant Heatup," Step 5.8.4, which required moving the pressurizer level controller to automatic, was marked N/A due to normalization of the T_{ave} instrument.

From these observations, the team concluded that training of personnel and procedural controls for installation and removal of normalization for testing were weak. The team also concluded that status of plant instrumentation during Modes 5 and 6 was not adequately controlled and was considered another example of configuration management problems. Inadequate controls for normalization of plant instrumentation is designated as Deficiency 93-202-D3. To address the deficiency, the licensee implemented a procedure revision which provided more strict controls for removal of normalization for testing. In addition, the licensee indicated that the OTL would be updated to accurately reflect normalized instrumentation.

(2) Power Operated Relief Valve (PORV) Testing

The team observed the performance of Procedure 1PSP03-RC-0010, Revision 4, "Pressurizer Power Operated Relief Valve Operability Test." The procedure tested the pressurizer PORVs by stroking the valves from the auxiliary shutdown panel. The test fulfilled the requirements of TS surveillance 4.3.3.5.2, "Remote Shutdown System." However, the team noted that the procedure also credited the test as satisfying the requirements of TS 4.4.4.1, Relief Valves, which requires that each PORV be demonstrated operable at least once per 18 months by performing a channel calibration and valve stroke test. Since the PORV was not stroked from the main control board the team questioned the validity of this test for meeting TS 4.4.4.1.

After the team questioned the validity of the test for meeting all TS requirements, the licensee initiated an SPR, revised the procedure, and stroked the valves from the control room. The licensee committed to investigate reportability and evaluate whether surveillance weaknesses similar to the PORV testing exist for other valves. No other discrepancies of this type were identified by the licensee's review while the team was on site. The licensee committed to resolve any discrepancies, if found, before entering

Mode 4. The team's concern regarding testing of the PORVs was designated as Observation 93-202-03.

(3) Second Charging Pump Aligned to the RCS

On January 15, 1994, the team observed the starting of centrifugal charging pump (CCP) 1A on recirculation flow for testing. Upon pump start, the following discrepancies were noted: (1) the auxiliary lube oil pump did not shut off as expected, (2) the seal injection filter high-differential pressure alarm annunciated, and (3) seal injection to each reactor coolant pump increased to more than 20 gallons per minute (gauges pegged high).

After unsuccessful attempts to throttle flow from the CCP, the pump was secured. Subsequent investigation identified that the CCP discharge bypass valve (CV-MOV-8348) was open even though it had been tagged "closed". This did not meet the requirements of TS 3.1.2.3, "Reactivity Control Systems, Charging Pumps - Shutdown", which allows a second charging pump to be started for testing only when the discharge of the second pump is isolated from the RCS. The team noted that two CCPs were aligned and flowing to the RCS for approximately 17 minutes.

The licensee documented the event on an SPR and assigned an event review team to investigate how and why the valve was found open. The licensee's preliminary root-cause evaluation determined that the motor-operated valve (MOV) opened as a result of a pressure transient initiated when the charging pump was started. The MOV had been closed manually by a reactor plant operator performing a valve lineup. The valve had been declutched and the handwheel was engaged which effectively eliminated the self locking feature that results from the actuator and motor gear ratios. As a result of this manual positioning, there was enough valve disc area available, without the normal resistance provided from the gear ratios, to enable the valve to inadvertently open upon start of the charging pump.

The licensee performed an MOV database search to find other valves that may be susceptible to this type of event. Initially, approximately 23 valves per unit were identified; however, before the team left the site, the licensee's evaluation had narrowed the scope to approximately 11 valves per unit. The corrective actions proposed by the licensee included adding a note to the ECO database that cautions operations to electrically close this type of MOV and not to de-clutch the valve for manual operation. Additionally, local valve labels and procedure cautions were initiated. The licensee committed to implement corrective actions before entering Mode 2.

The licensee informed the team that this type of event had occurred previously on Unit 2. This event and the apparently inadequate root cause evaluation of a previous event, is designated as Deficiency 93-202-D4.

(4) Proper Control During TS 3.4.9.3 Operations

The team evaluated overpressure controls during solid plant operations. The team reviewed TS 3.4.9.3, "Reactor Coolant System - Overpressure Protection System," and noted that the licensee was utilizing a footnote that allowed, with both PORV's inoperable, the use of a 7-day period to allow functional testing of the PORVs. The team observed that the licensee was maintaining cold overpressure mitigation, as allowed by the footnote, by maintaining two operating residual heat removal (RHR) loops (with their associated RHR relief valves).

The TS footnote also stated that during this 7-day period, operation of systems or components which could result in an RCS mass or temperature increase would be administratively controlled. The team questioned whether adequate administrative controls were maintained over the pressurizer heaters as they were not tagged in the "off" position. Additionally, the team questioned performing the previously mentioned CCP start during a period when both PORV's had not been declared operable. The team's concern with the licensee's controls for cold overpressure protection was designated as Observation 93-202-04.

(5) Plant Material Condition

The team noted that plant cleanliness and material condition was generally good. However, the team observed a number of equipment failures during plant operations and testing. Examples of the failures included: (1) the No. 12 emergency diesel generator output breaker tripped while the diesel was fully loaded; (2) reactor water makeup pump seal and coupling failures; (3) failure of an auxiliary lube oil pump to stop as designed upon start of the 1A CCP and; (4) failure of the digital rod position indication to properly respond during post-maintenance testing. With few exceptions, operator response to these events was adequate. The team's observation that equipment failures were causing unnecessary challenges to the operating staff was discussed with licensee management. This was designated Observation 93-202-05.

4.3.5 Alternate Shutdown Drill

The team evaluated the licensee's control room evacuation capabilities to ensure that operations activities associated with the alternate shutdown panel could be adequately performed. The evaluation consisted of: (1) performing a review of an off-normal procedure, OPOP04-ZO-0001, Revision 3, "Control Room Evacuation" to ensure adequate controls and displays were provided for required operator tasks; and (2) observation of a simulated control room evacuation drill.

The team noted that operators were knowledgeable of, and could adequately locate, the controls and displays required to carry out their assigned tasks. During the drill, difficulties were experienced in communicating with operators in the turbine generator building (TGB) using the primary communication method. The primary reactor operator at the auxiliary shutdown panel and the TGB reactor plant operator quickly shifted to the backup communication method with no apparent difficulty or impact on the drill.

The team provided the licensee with additional comments associated with the drill for their consideration. These observations included: (1) the inability to use the plant pager from the auxiliary shutdown panel; (2) high ambient noise level in the alternate shutdown panel room; and (3) labeling discrepancies in the emergency diesel generator rooms. The team also noted that only two of the immediate actions of Procedure OPOP04-ZO-0001 were verified as completed upon formally establishing control at the auxiliary shutdown panel. All immediate actions were completed within 15 minutes. The team noted that prompt verification of immediate actions was important and verification should be completed as soon as possible. The licensee stated that it would take these observations into consideration. This was designated Observation 93-202-06.

4.3.6 Operator Training/Simulator Exercises

The team observed three crews engaged in simulator requalification training during simulation of a reactor startup and a plant startup from Mode 4 to turbine roll. Crew composition was the same as normal operating crew size and the same as for examination purposes.

Crew interactions, operations, and activities during the simulator exercises were identical to those interactions, operations, and activities observed in the control room during the 48-hour control room observation. Crews demonstrated strong face-to-face, radio, and telephone communication skills in both the simulator and main control room. The crews were professional in all their actions and exhibited good procedural adherence practices.

The crews and simulator instructors involved tried to make the scenarios seem as lifelike and real-time as possible. The training scenarios observed were utilized as training exercises as much as possible. The scenarios selected for startup training were adequate for ensuring licensed operators had the requisite skills and knowledge necessary for conducting a plant startup following an extended shutdown.

4.4 Human Factors Engineering

4.4.1 Main Control Room Layout

The team evaluated the licensee's main control room layout and environmental conditions to ensure that operations activities could be performed adequately. The review consisted of (1) performing a walkdown of selected emergency operating procedures (OPOP05-series procedures) and off-normal procedures (OPOP04-series procedures) to ensure adequate controls and displays were provided for required operator tasks; (2) evaluating main control room ambient lighting, instrument glare, labeling, and temperature; and (3) observing operations personnel performing activities in the main control room.

The team found that the general material condition of main control room panel controls and displays, including equipment labeling, instrument glare, and ambient lighting levels, were adequate. In addition, the team found by means of the walkdown of selected OPOP05 and OPOP04 procedures that the controls and displays required for implementation of the emergency operating and off-normal procedures were clearly demarcated and provided sufficient parametric information to enable operators to carry out the required tasks.

4.4.2 Alternate Shutdown Panel

The team evaluated the licensee's alternate shutdown panel to ensure that operations activities associated with the local control station could be performed adequately. The review consisted of (1) performing a walkdown of off-normal Procedure, OPOP04-ZO-0001, Revision 3, "Control Room Evacuation," to ensure adequate controls and displays were provided for required operator tasks; and (2) observation of a simulated control room evacuation drill.

The team found that the general material condition of the alternate control room panel controls and displays, including equipment labeling and ambient lighting levels, were adequate. The team noted that the high ambient noise level in the alternate shutdown panel room often made communications difficult. Without a visual indication of an incoming call, it was difficult to recognize incoming calls.

4.4.3 Control Room Habitability

The team evaluated the licensee's main control room for habitability to ensure that operations activities could be performed adequately. The team found that the ambient environmental conditions (e.g., lighting, temperature, noise) in the main control room were adequate to ensure operators could carry out their specified duties.

4.5 TS Interpretations

The team reviewed the licensee's TS interpretation book ("Addendum to the Technical Specifications") and sampled several interpretations. The review caused the team to become concerned about the high number and technical content of the TS interpretations. Although the TS interpretations were sequentially numbered to 136, it appeared there were approximately 70 active interpretations.

Several interpretations were reviewed for technical accuracy. Although the interpretations did not raise specific safety concerns and, in most cases, the intent of the TS seemed to be met, it appeared to the team that the book had often been used to clarify the TS, when a TS change was more appropriate. For example, (1) TS interpretation No. 132, regarding TS 2.2.1, allowed a tolerance for the time constants used in the reactor trip system instrumentation setpoint for OTdT and OPdT, (2) TS Interpretation No. 74, regarding TS 3.0.2, allowed temporary changes to component operability status to facilitate post maintenance testing, and (3) TS Interpretation No. 54, regarding TS 3.1.2.1, allowed for the operability of the boration flow path with valve emergency power not available. In addition, the interpretations did not appear to be kept up-to-date. For example, the TS interpretation definition for "OPERABLE-OPERABILITY" did not reference Generic Letter 91-18, which contains important information on this subject.

The team met with the licensing manager who referenced an internal business plan commitment to evaluate the TS interpretations. The licensee had performed an initial review and determined (preliminarily) that it would keep approximately 11 interpretations, revise the TS basis on 7 interpretations, submit TS changes for 11 to 17 changes, and delete approximately 25 interpretations (to be picked up by training and/or procedure clarifications). The interpretations that the team questioned were included in the licensee's category to be formally submitted to the NRC for consideration. The licensee committed to reduce the number of TS interpretations by a significant fraction, concentrating first on those interpretations with the least margin to literal compliance with the TS specific wording.

The team believes that the extensive use of TS interpretations may foster a mind-set that the TS can be altered to any given situation. One example of where this can lead to non-conservative positions was identified by the team during the 48-hour continuous control room observation. The team reviewed the standing shift orders and noted that one shift order allowed calling the emergency diesel generator operable while in "Pull-to-Stop," when installing or removing instrument recorders for troubleshooting. The team discussed this interpretation with the shift supervisor, who referenced that this interpretation followed the logic of another TS interpretation that allowed a containment isolation valve to be out of position with a reactor plant operator standing by the valve. The team noted to the licensee that the emergency diesel generator auto-start feature is not operable with the machine in "Pull-to-Stop." The licensee reviewed this situation and issued a field change to OPGP03-ZA-0002-4, "Emergency Diesel Generator," which stated that placing the diesel generator in "Pull-to-Stop" renders the diesel inoperable in Modes 1-4.

The questionable TS interpretations including the example given above of the emergency diesel generators being considered operable in "Pull-to-Stop," is designated as Deficiency 93-202-D5.

5.0 SURVEILLANCE

5.1 Review Scope

The team performed the following activities to verify that the licensee was adequately performing the required TS surveillances:

- Reviewed the licensee's TS surveillance test program.
- Observed the licensee perform several surveillance tests.
- Reviewed documentation for a sample of surveillance tests that the licensee had performed before this inspection.
- Interviewed licensee personnel involved in performing TS surveillance-related activities.

5.2 Surveillance Program Review

The licensee had developed and implemented Station Procedure OPGP-ZE-0004, "Plant Surveillance Program," Revision 11. This procedure described the licensee's administrative structure and personnel responsibilities for implementation and control of the surveillance test program. Station

Procedure OPGP03-ZA-0055, "Plant Surveillance Scheduling," Revision 6 described the licensee's administrative structure and division of responsibilities for the scheduling of the performance of TS surveillance tests. The licensee used a computer-generated schedule to ensure that TS surveillance tests were performed as required. On the basis of the computer-generated schedule, a surveillance coordinator in each maintenance area (electrical, mechanical, and instrumentation and control) developed a surveillance test work package for each scheduled surveillance test. The controls in place appeared to be adequate for ensuring TS surveillances were scheduled and performed as required.

5.3 Surveillance Procedure Review

The team selected and reviewed the documentation for 10 TS surveillance tests that had been performed by the licensee before the team's visit. The team compared the selected surveillance test procedures to the STP TS surveillance test requirements to verify that the testing and surveillances being performed by the licensee would provide assurance that the tested items would perform their design functions when required. The team also verified that the documentation for the selected surveillance tests was administratively adequate and that recorded data met TS acceptance criteria. During this review, the team identified a problem related to the licensee's test performers not performing some steps in surveillance test procedures and marking them "Not Applicable". This problem is discussed in Section 4.3.3 of this report.

5.4 Observation of Surveillance Test Performance

The team observed the performance of selected portions of the TS surveillance tests listed below. Additional surveillance tests, which the team observed being performed, are discussed in Section 5.5 of this report.

- 1PSP06-DJ-0001, "125 Volt Class 1E Battery 7 Day Surveillance Test," Revision 11, performed on December 8, 1993
- 1PSP03-CH-0005, "Essential Chilled Water Pump 11B Reference Values Measurement," Revision 7, performed on December 8, 1993
- 0PSP05-NI-0032, "Source Range Neutron Flux Channel II Calibration (N-0032)," Revision 2, performed on December 9, 1993
- 1PSP05-SY-0001, "Time History Seismic Channel Calibration," Revision 2, performed on December 9, 1993.

The portions of the surveillance tests observed by the team were satisfactorily performed by licensee personnel in a professional manner and in accordance with approved procedures. The test personnel appeared to have a comprehensive knowledge of the surveillance procedure, equipment being tested, test equipment used, and equipment responses. Communications between the people performing surveillance tests at the different test locations were excellent. Each person participating in the surveillance test had a copy of the surveillance test procedure and followed along as the test leader read the step-by-step instructions. Each action performed was repeated between the test performers before performing the action and again after the action was completed.

During performance of Test 1PSP05-SY-0001 on December 8, 1993, the licensee's instrumentation and control (I&C) technician determined that he was using Revision 2 to the surveillance test procedure when he should have been using Revision 3. Revision 3 had become effective on November 11, 1993. The licensee evaluated the two revisions and determined that the revision was mainly a procedure format change and an enhancement of previous revisions and that the intent of the procedure had not changed. The licensee wrote a station problem report (SPR) to document this occurrence (SPR No. 933423).

The licensee provides classroom training to maintenance personnel on the following procedural controls which the licensee has implemented to ensure that personnel use the current revision of appropriate documents:

PGP03-ZA-0010, "Plant Procedure Adherence and Implementation and Independent Verification," Revision 15

- Step 4.2.11. states that working copies of procedures SHALL be verified to be the current revision with all effective amendments prior to use, and

- Step 4.2.11.2 states that for procedures included in a maintenance work package, verification SHALL be performed as specified in OPGP03-ZA-0090, "Work Process Program."

PGP03-ZA-0090, "Work Process Program," Revision 7

- Step 3.7.2.4 states that the work supervisor shall review work packages before the work is performed to ensure the package is "ready to work," which includes verifying that all references are current, and

- Step 3.7.4.3 states that upon completion of the work, the work supervisor shall ensure that the revision level of the documents used has been verified.

At the team's request, the licensee searched the SPR data base and identified seven other SPRs that had been written during 1993 because the wrong revision of a document had been used. The SPRs were written in the following time frame: one was identified in January (that occurred in November 1992), two in February, one in March, one in April, one in May, one in August, and the one discussed above in December.

The licensee stated that, on the basis of existing procedure instructions and personnel training, adequate controls existed to reasonably ensure maintenance personnel used the current revision of all appropriate documents while performing maintenance activities. The licensee considers the occurrences reported in these SPRs to be isolated instances of human error that did not exhibit a common thread for corrective action. The trend for repetitive occurrences of this type event was decreasing, as six of the SPRs were written in the first five months of 1993 and two were written in the last seven months of the year.

The licensee's procedural controls and training appeared to be adequate to ensure STP personnel use the current revision of appropriate documents. However, the number of occurrences, even though trending down, indicates that continued licensee attention (occurrence trending) in this area is warranted. This was designated as Observation 93-202-07.

5.5 Surveillance Test Procedure Upgrade Program

The licensee has initiated a Surveillance Test Procedure Upgrade Program to upgrade all of the licensee's TS surveillance test procedures (approximately 1120 procedures). The licensee initially selected 51 surveillance test procedures for upgrade which it considered to be problem procedures. On December 16, 1993, the licensee completed upgrading and implementing the 51 surveillance procedures initially selected. The team observed the performance of three of these upgraded procedures in the field. The three surveillances observed were

- OPSP06-PK-0005, "4.16KV Class 1E Degraded Voltage Relay Channel Calibration/TADOT-Channel 1," Revision 0, performed on January 13, 1994

- OPSP06-PK-0001, "4.16KV Class 1E Undervoltage Relay Channel Calibration/TADOT-Channel 1," Revision 0, performed on January 13, 1994

- OPSP06-RC-0003, "Undervoltage RCP Relay Channel Calibration," Revision 0, performed on January 15, 1994

Licensee personnel performing these surveillances indicated that they liked the new format and thought it was more user-friendly, especially in the areas of place-keeping and data-recording.

While observing the performance of the surveillance tests in the field, the team noted the following problems:

- Step 5.3.8 of Surveillance Procedure OPSP06-PK-0001 states, "Remove all test equipment." The team had a concern that a general statement like this, in lieu of instructions to remove the specific test equipment that had been installed, could result in test equipment (i.e., jumpers) either being prematurely removed or, in a worse case, being left installed and potentially making equipment inoperable.

- Electricians had to stop the performance of Surveillance Procedure OPSP06-RC-0003 on January 15, 1994, because the following problems arose:

(1) In Step 5.2.1, the identification of relays in the surveillance procedure did not match the STP identification label installed on the equipment. The procedure stated to clean and inspect relay 27D (the relay is a type 27D relay). The STP label on the equipment identified the relay as "UNDERVOLTAGE DEVICE 27A."

(2) Step 5.2.2 states: "Push and hold Relay 27D 'TRIP TEST' button and verify target indicator shows red flag." This step could not be performed because the relay was already in a tripped condition because the reactor coolant pump (RCP) had been shut down. Step 4.1 states: "This procedure may be performed in any mode of operation." However RCPs are not normally running in Mode 6.

The licensee took the following actions to correct these problems:

(1) The licensee revised Procedure OPSP06-PK-0001 to identify the specific test equipment to be removed. In addition, the licensee is revising other similar electrical surveillance test procedures (approximately 14 procedures) that have been upgraded and were written in the same format as OPSP06-PK-0001.

(2) The licensee is revising the surveillance procedures writer's guide, Procedure OPGP03-ZE-0005, "Plant Surveillance Procedure Preparation," Revision 11, to prohibit the use of generic statements such as "Remove all test equipment" and to require that all test equipment being removed is specifically identified. The licensee is also revising Procedure OPMP01-ZA-0004, "Maintenance Procedure Writers Guide," Revision 8 to reflect this same change.

(3) The licensee revised Procedures OPSP06-RC-0003, 0004, 0005, and 0006 so that the relay identification in the procedures matches the appropriate labels on the equipment in the plant.

(4) The licensee issued a memorandum to the maintenance surveillance coordinators requiring them to review each surveillance procedure before it is actually worked for problems like or similar to those discussed above.

The team concluded that the licensee had developed and implemented adequate programs and procedures to ensure TS surveillances were accomplished as required; however, in some instances, certain remaining procedural inadequacies could lead to work performance problems. These procedural problems should be corrected by the licensee's procedure upgrade program. This was designated as Observation 93-202-08.

6.0 MAINTENANCE

6.1 Review Scope

The team observed mechanical, electrical, and instrumentation and control (I&C) work activities in progress. The team focused on the licensee's ability to adequately control the maintenance program and its governing procedures.

The team evaluated the work control program, the work process program, organization, material control, technical support, facilities, work in progress, vendor control, preventive maintenance, and the postmaintenance testing program.

6.2 Work Control Program

During the inspection the licensee implemented a Work Package Control Center (WPCC). The WPCC was implemented on January 10, 1994, by office memorandum Maint-94-4-0004, dated January 6, 1994. The WPCC was responsible for controlling the location of work packages by providing a centralized, controlled access location from which all work packages would be stored, released, and returned. Although the licensee had already implemented this program, the Work Process Control procedure (OPGPP03-ZA-0090) that governs this activity had not been updated to reflect the new WPCC. The licensee was in the process of updating the procedure to address the team's observation.

The team monitored the performance of the Operations Work Control Group (OWCG) which was manned by the recently established operations sixth crew and individuals from the maintenance and planning organizations. The OWCG was responsible for evaluating service requests, developing associated equipment clearance orders, and coordinating postmaintenance and operability testing. The team noted that the OWCG was functioning well and had reduced the administrative burden of the operating crew.

The team also reviewed the material control program and the maintenance and test equipment (M&TE) control program and the governing procedures. Material and M&TE were staged at least one week in advance of an upcoming job. Review of the procedures and interviews with the crafts personnel indicated the licensee had adequate control of its material and M&TE programs.

6.3 Technical Support

The licensee implemented a Technical Support Engineer (TSE) Program in July 1992, within the Plant Engineering Department. The purpose of the TSE is to provide on-the-spot technical advice to the Maintenance Department, with the capability of calling in systems or design engineers when needed. This process sets up an effective link between the Engineering Department and the Maintenance Department.

There were indications that the licensee was trying to improve the craft's ability to handle possible problem areas that could arise during routine maintenance activities because of inattention to detail. An example of the licensee's efforts in this area was noted in the I&C shop where a simulator training program for increasing the crafts awareness of "attention-to-detail" problems had been developed. The team witnessed a demonstration of the trainer, and it appeared to provide a good simulation of self-verification under the real time constraints of performance. The simulator was set up so that two technicians were tested at the same time. One technician was responsible for manipulating the simulator panel while the other technician read the procedure from another location. This also allowed the licensee to strengthen the verbal communication skills of the crafts. The electrical and mechanical maintenance groups were working on using the same training program or on developing their own to improve the craft's ability to handle similar problems.

6.4 Observation of Work in Progress

The team observed maintenance work being performed by the mechanical, electrical, and I&C crafts to determine if the activities were adequately planned, controlled, and performed in accordance with applicable approved procedures and vendor recommendations, and by qualified personnel. The team interviewed several crafts personnel and first-line supervisors to determine their understanding of the processes and practices used by the Maintenance Department.

The team observed the following field work activities:

- SR 164380 - Essential chill water pump, inboard bearing replacement and stator winding repair
- SR 157054 - Solid state protection system safeguard test cabinet B, relay replacement
- SR 168082 - Main steamline 2 isolation bypass, replace operator springs
- SR 308947 - Steam generator feedpump non-return valve inspection
- SR 211893 - Feedwater MOV lube, inspect, and refurbished
- SR 211896 - Feedwater MOV refurbished
- PM 8700451 - Replacement of temperature control element in a valve cubicle room
- PM 87013923 - ECW traveling water screen lubrication

On the basis of the limited review conducted by the team, ongoing maintenance activities appeared to be appropriately reviewed and were found to be properly planned, controlled, and performed in a manner that exhibited adequate technical knowledge of plant systems, good procedural adherence, and an adequate knowledge of station processes and procedures. First-line supervisors appeared to be aware of ongoing work and were involved in close supervision.

The licensee had recently implemented a two-supervisor-per-crew system in all of the maintenance shops. This system was set up to have one supervisor act as the administrative supervisor and the other to be the production supervisor. The production supervisor was responsible for ongoing work, while the administrative supervisor was responsible for scheduling the upcoming week's maintenance activities. The two supervisors switched responsibilities weekly. This appeared to be a sound approach to controlling and scheduling maintenance activities.

6.5 Postmaintenance Testing Program

Station Procedure OPGP03-ZM-0025 "Post-Maintenance Testing Program," Revision 4, described the methods for identifying PMT requirements, for performing the pertinent testing, and for acceptance of the completed testing. The maintenance planner was responsible for specifying PMT requirements with guidance from the PMT reference manual and, if necessary, the responsible engineer(s). A work start authority designated by the Operations Work Control Group (OWCG) was responsible for reviewing the PMT instructions, authorizing test start, and accepting documented test results. The test performer was not permitted to deviate from the prescribed PMT instructions without documented concurrence from the work start authority. Operability testing was identified by the plant operations group and was performed after successful completion of the PMT.

In September 1993, the PMT program underwent significant changes, including the separation and distinction between the postmaintenance and operability testing functions and the creation of matrices to be used to specify the PMT requirements and document their completion. The "Post-Maintenance Testing Reference Manual," Revision 8, was revised to include the component matrices which cross-reference specific work activities to applicable PMT steps to clearly identify testing requirements. The licensee provided formal training for the maintenance planners to introduce the new PMT program, but did not give the maintenance crafts any training. The licensee performed a self-assessment of the new PMT program in November 1993 and found that weaknesses in the implementation of the new program were due primarily to inadequate training.

At the end of the first phase of the inspection, the team concluded that, although the licensee had made significant progress in developing an adequate PMT program, implementation of this program appeared to be weak and inconsistent. Additionally, the licensee's self-assessment of the new PMT process had identified implementation weaknesses, yet no corrective action was initiated to correct those deficiencies. The team noted that some planners used the matrices verbatim without removing steps that were not applicable and others ignored the matrices completely. The maintenance crafts were not trained on the new philosophy or new matrices and appeared uncomfortable with, and confused about, the use of the PMT matrices. The team identified work packages with inadequate detail to define test acceptance criteria and initial test conditions. The team also identified several packages in which PMT steps were marked N/A with no indication of who determined they were not applicable or when this determination was made.

Between phases of the inspection, in December and early January, the licensee's work control manager held informal meetings with the maintenance planners to ensure consistent implementation of the new PMT program. They also formed a PMT group, with a maintenance planner from each discipline (mechanical, electrical, and instrumentation and control), which was responsible for reviewing all work packages to ensure consistent application of PMT requirements before issuance, coordinating with crafts and operations to resolve problems with packages which had been issued, and training maintenance crafts on new PMT philosophy and use of PMT matrices. The licensee also reviewed all previously issued work packages in which the PMT had not yet been completed to assess the adequacy of PMT requirements. During the second phase of the inspection, the team witnessed additional PMT activities in progress and reviewed additional packages.

The team concluded that the implementation problems identified in the first phase of the inspection appeared to have been corrected. The maintenance planners and crafts seemed confident with the new PMT program and were working to the new procedures and guidance. Planners, crafts, operations, and engineering personnel appeared to work together and coordinate effectively. The team determined that the PMT requirements appeared to be adequate and applied consistently with the few exceptions noted above, but the matrices will need some minor revisions as deficiencies are identified by the planners and crafts upon implementation.

6.6 Use and Control of Vendor Technical Information (VTI)

The team reviewed implementation of Station Procedure OPGP04-ZA-0108, "Control of Vendor Documents," Revision 0, and Engineering Instruction (EI) 1.39, "HL&P Revision of Vendor Manuals and Drawings," Revision 3, to determine the current effectiveness of the VTI program. The team verified that a sample of vendor technical manual revisions and vendor bulletins had been properly incorporated into the parent documents and distributed to potential users and to user libraries. No discrepancies were identified in the physical control or use of the sampled documents. Use of VTI was also observed in the field maintenance activities witnessed and reviewed by the team.

7.0 CORRECTIVE ACTION PROGRAM AND OPERATING EXPERIENCE REVIEWS

7.1 Corrective Action Program and Procedures

The team evaluated implementation of the licensee's programs for correction of equipment deficiencies and conditions adverse to quality; causal determinations and analyses; effectiveness of corrective and preventive actions; trending and evaluation of program performance; and plans for performance improvement.

The South Texas Project corrective action program (CAP) was controlled by Station Procedure OPGP03-ZX-0002, "Corrective Action Program," Revision 1, issued in May 1993. Station problem reports (SPRs) processed in accordance with procedure ZX-0002 were the principal vehicle for identifying, documenting, reporting, tracking, trending, and resolving conditions adverse to quality.

Revision 2, which became effective during this inspection on December 10, 1993, created a senior management-staffed Problem Review Group (PRG) to evaluate the significance of and prioritize emerging SPRs. Revision 2 also improved the processing flow for SPRs.

The team reviewed 35 SPRs to determine whether the issues identified had been adequately evaluated, their causes analyzed, and appropriate corrective and preventive actions prescribed and implemented. The team identified several problems with both Revisions 1 and 2 of the station procedure and its implementation. The procedure grouped the SPRs into six categories based on the significance of the deficiency or initiating event with those in categories 4,5,and 6 not requiring a root-cause determination. The team noted that many safety significant deficiencies had been classified in these categories not requiring a root-cause determination. For example:

- A main steam safety valve as-found setpoint test failed apparently due to a deformed valve spring. The cause of deformation was not determined and the defective spring was discarded without determining cause or whether generic implications might exist. (SPR 930644)

- Overthrust conditions, burned out thermal overloads, and wiring identification problems on an RHR pump mini-flow recirculation valve RH-MOV-0067B motor operator were inadequately addressed by the SPR until the team raised questions. (SPR 930801)

- Standby diesel generator starting air distributor failure from foreign material intrusion did not receive causal analysis, and several apparent or contributory causes were not addressed in the corrective or preventive actions. (SPR 931835)

- SPRs identified 16 cases of improper maintenance installation activities during March 1993; these were identified as an adverse trend. The causal analysis ignored the evident trend and concluded that no further corrective or preventive action was needed due to the individual SPR corrective actions already taken. (SPR 931376)

Also, SPR dispositions did not always address all problems or contributory causes identified as part of the event or event investigation. For example:

- The use of incorrect turbine-driven auxiliary feed pump overspeed trip unit tappets, breakdowns in vendor technical information program controls, and breakdowns in document change notice controls were identified but no root or apparent causes were identified and no corrective or preventive actions were specified. (SPR932706)

- Loss of jumper control for 480 V ac 1E load centers was identified as being generic to all like switchgear, but no apparent action was taken to address the potentially affected equipment. (SPR 923647)

- Burned out overloads occurred in conjunction with overthrusting RH-MOV-0067B but were not addressed. This issue was subsequently dispositioned when identified by the ORAT. Handwritten, unofficial wiring labeling identified along with MOV-0067B problems, was characterized as having generic implications but there was no followup. (SPR 930801)

- An EDG air-start distributor failure investigation identified but did not address breakdowns in foreign material exclusion practices or inspection processes. Similarly, the work package referred the workers to the technical manual and gave essentially no step-by-step work instructions. (SPR 931835)

- Installation of incorrect shaft key material in an ECW MOV included craft performance as a causal factor but no corrective or preventive actions addressed the performance issues; credit was taken for prior training to address the SPR concerns. (SPR 931593)

- Incorrect shims were specified for ECW check valves due to mismanagement of a series of four design change notices (DCNs). A fifth DCN was issued to correct the problem, but the performance deficiencies in DCN control were not addressed. (SPR 932704)

The team also identified that adverse-trend SPRs often did not address inadequate corrective actions or deal with performance problems. Lack of better focused cause codes contributed to poor treatment of adverse-trend SPRs. For example:

- An effective adverse-trend review was not done for 177 calibration problems and failures of Rosemount transmitters. The adverse-trend SPR was closed on the basis that statistical justification that the failure rate was not aberrant and that no other performance-based problems were identified. (SPR 931742)

- See the previously discussed problem regarding SPR 931376 involving 16 cases of maintenance installation errors in one month.

- A similar problem with a trend of 10 SPRs documenting work package planning errors was evaluated as not significant on the basis of circumstances of the individual deficiencies.

Although middle management was becoming more aware of senior management's expectations and was raising the standards for solving and preventing the problems identified in SPRs, review of reports from the three months immediately preceding this inspection indicated the process was still weak and vulnerable to error. Weaknesses in the implementation of the corrective action program are identified as Deficiency 93-202-D6.

Technical Specification 6.5.1.6 requires the Plant Operations Review Committee (PORC) to review problems and deficiencies which are handled by the SPRs. The process and criteria for selecting and forwarding SPRs for the PORC review were weak and resulted in relatively few direct SPR referrals. The PORC was reasonably active in reviewing SPRs identified through other means and some PORC members were also PRG participants so that generally sufficient review was being provided. The licensee was evaluating the current PORC charter and practices at the time of this inspection.

Although none of the examples identified by the team involved items of immediate safety significance or direct impact on plant restart, they collectively indicated continuing weaknesses in the licensee's program. During this inspection, the STP nuclear assurance group completed surveillances of closed SPRs and operability determinations for potential restart impact. These surveillances identified no restart or immediate safety impact.

In response to the team's concerns, on January 7, 1994, the licensee issued Revision 3 to procedure ZX-0002 which gave the PRG the latitude to categorize the SPRs based on their actual safety significance. The team observed the PRG processes and noted improvement in this activity. However, Revision 3 did not change Section 4.4.5.2, which required only identification of the apparent cause and causal factors and which did not require consideration of preventive actions for category 4, 5, and 6 SPRs.

Also, on January 20, 1994, the General Manager, Nuclear Assurance, provided the team with a commitment for four initiatives to improve CA program performance as follows:

(a) The licensee will continue monitoring the effectiveness of the deletion of categorization examples from Procedure ZX-0002 and PRG oversight of categorization of events to assure that root-cause evaluations are required for events deemed to be significant.

(b) Equipment Failure Analysis/Root Cause Analysis training will be provided by the Site Engineering Department to selected plant personnel to improve the quality, clarity, and depth of equipment failure root-cause analyses. Training will be provided on staggered bases during 1994.

(c) The effectiveness of corrective actions of SPRs closed by the Corrective Action Group (CAG) will be monitored by nuclear assurance to ensure actions focus on the root and contributory causes and are adequate to prevent recurrence.

(d) All adverse-trend SPRs will be provided to PRG for closure review and Procedure ZX-0002 will be revised to include this review during the next routine process change.

7.2 Business Plan Elements and Future Plans

During 1993, the Corrective Action Group had been reorganized and placed in the quality assurance organization, a new manager with prior CAP development experience had been hired, and mid-to-long-range planning responsive to prior NRC issues was incorporated in the South Texas Project 1994-1998 Business Plan. Budgeted and scheduled initiatives included improved CAG staffing, more vigorous problem identification, line management ownership of the corrective action processes, improved training and staff performance for causal analyses, and improved trending and oversight. The team found that the action plans and initiatives were generally responsive to the problems identified during this inspection and, over time, could reasonably be expected to improve licensee performance.

7.3 Operating Experience Review Program

The team reviewed the STP Operating Experience Review (OER) Program established by Interdepartmental Procedure IP-2.2Q, "Operating Experience Review," Revision 9, and its implementation for 2 NRC generic letters, 2 NRC bulletins, and 10 NRC information notices. This review included the timeliness and technical substance of the licensee's OER evaluation and the suitability of actions taken in response to the items. The licensee's evaluations and associated actions were found acceptable. Response actions were typically completed on time, or approved deferrals were processed. The overall number and extent of overdue items was not significant and was being tracked by the Independent Site Engineering Group (ISEG).

The backlog of all OER items was being monitored by ISEG, and performance indicators had been issued to each cognizant department up through the vice-president level. Backlog dropped from 140 open OERs in April 1993 to less than 50 in December 1993. A year-end surge of action plan items and some delays in processing due to the impact of restart work on the plant staff has caused the backlog to increase slightly into 1994.

The licensee and NRC Region IV staff had identified problems with completion of restart-related OER items. ISEG recently completed a review of mode-restraint items ensuring that all items were identified and on track for completion.

7.4 Justifications for Continued Operation (JCOs)

Justifications for continued operation were administered in accordance with Interdepartmental Procedure IP-1.5Q, "Preparation of Justifications for Continued Operation," Revision 2. The team reviewed all 16 currently effective JCOs, and found them in conformance with the procedure and of sufficient technical substance to support their conclusions. JCO 91-0099, "Dealloying of Large Bore Flanges and Fittings" (in essential cooling water (ECW) systems) and JCO 91-0273, "Through Wall Cracks in ECW Pipe Welds," were further reviewed by the team for effective implementation of ongoing inspection and field compensatory and corrective actions. No problems were identified.

8.0 PLANT MODIFICATIONS

To evaluate the effectiveness of the plant modification program, the team reviewed the applicable procedures, examined modification packages, and interviewed the cognizant engineers for each package reviewed. The team focused their review on the thoroughness of the 10 CFR 50.59 reviews and the specification of adequate postmodification testing requirements.

8.1 Plant Modification Program

The governing procedure describing the licensee's process for controlling, processing, and implementing plant modifications was defined in Station Procedure OPGP04-ZE-0310 "Plant Modifications," Revision 0. Detailed procedures describing completion of the documented safety evaluations for changes to the facility, procedures, tests, or experiments as required by 10 CFR 50.59 were provided in Interdepartmental Procedure IP-3.20Q, "10 CFR 50.59 Evaluations," Revision 6. Proposed changes to the facility, procedures, and tests or experiments were initially screened and, if a 50.59 safety evaluation was required, an unreviewed safety question evaluation was completed. The modification packages were then reviewed by the Plant Operations Review Committee and the plant manager for approval. The responsible design engineer prepared the packages and evaluations following an initial scoping meeting, including 10 CFR 50.59 safety evaluations and details of the design change, and obtained appropriate interdisciplinary and management reviews and approvals. The systems engineer's responsibilities included specifying postmodification testing (with input from operations, design engineering, maintenance, and other disciplines) and assuring proper implementation and completion of the modification packages.

8.2 Modification Package Review

The team reviewed the following modification design packages (MDPs) to verify the completeness and engineering adequacy of the 10 CFR 50.59 evaluations and determination of postmodification testing:

- MDP 91-019 installed a new 2-square-inch vent path for the reactor coolant system to provide an alternative means to meet the technical specifications for overpressure protection. The postmodification testing included a valve operability test as well as a system hydrostatic test and system leakage test per ASME Code Section XI.

- MDP 88167 (Unit 1) and 88168 (Unit 2) installed manual operators, replacing the electrohydraulic actuators on the essential cooling water chiller outlet control valves. The team noted that the valves needed to be machined for new keyways to accommodate the manual actuators, but the vendor drawings had not been revised to reflect this alteration. The licensee had begun revising the necessary documents before the team's exit. The postmodification testing plans for the mechanical portion verified valve operability. The team did not review the electrical portion of this modification.

- Plant Change Form (PCF) 212910A modified the valve plug and stroke on the feedwater preheater isolation bypass valves to increase the valve actuator closing thrust against reverse flow pressure. The postmodification testing plans included verification of stroke time and travel, limit switch actuation, valve flow rate, valve closure on feedwater isolation, valve seating at normal operating conditions, and a system leakage test per ASME Code Section XI.

- PCF 176835A installed an overspeed-trip test device and rapid bleeddown device in the auxiliary feed pump terry turbine governor to improve maintenance and surveillance efficiency. The postmodification testing included verification of proper installation of the governor, a turbine overspeed trip test, and a comprehensive inservice pump test.

- Engineering Change Notice Package 88-J-0088 added a relay and used a timer contact on an existing relay to energize relay 28R after 25 seconds from the initiation of a chiller start signal. The postmodification testing verified that the alarm light illuminated in 25 seconds after starting the unit.

- MDP 93-049 installed bypass lines, including a valve and flow instrumentation, around the existing condenser outlet valves of the essential chillers. The valves were subsequently throttled to ensure chiller unit operability during cold weather operation. This modification was installed in two phases. During the first phase, the bypass assembly was physically installed with the valve in the closed position. The licensee determined that since the valve was installed in the closed position, the modification did not constitute a change to the facility as described in the safety analysis report (SAR) and, therefore, an unreviewed safety question evaluation (USQE) was not performed. The team felt that a USQE should have been performed since the modification was a change to the facility regardless of the valve position. In completing the 50.59 evaluation process for the second phase of the modification which would have the valve in its required throttled position, the change to the facility was acknowledged and the appropriate USQE was performed. The appropriate postmodification tests were conducted during the first phase which consisted of a valve operability test, system leakage test per ASME Code Section XI, and calibration of the installed transmitters. The postmodification test for the second phase validated that the essential chilled water system would function as required during cold weather conditions.

  This item and an item related to temporary modification TI-AF-91-030 which added heat tracing to the auxiliary feedwater pump lube oil cooler were discussed with the licensee because neither change was considered as a change to the facility. The licensee agreed to review its procedure regarding what constitutes a change to the SAR and provide appropriate training as necessary to prevent recurrence. This was designated Observation 93-202-09.

- MDP 91-026 replaced the steam generator feedpump turbine speed analog controllers with a new fault-tolerant digital control system because the existing controllers were obsolete and subject to common-mode failures. The postmodification testing plans included wiring and electrical signal verification, an uncoupled turbine operational test, and a comprehensive final turbine operational test at normal operating conditions.

The team concluded that, except for inadequate 10 CFR 50.59 screening and the failure to update the related vendor documents as previously described, the modifications were properly prepared, implemented, and controlled in accordance with approved licensee procedures. Appropriate postmodification testing was specified as necessary to verify the functionality of the design changes. The engineers were knowledgeable about the relevant procedures and the specific details of the packages.

9.0 SYSTEM WALKDOWNS

The team walked down portions of the residual heat removal, essential cooling water, containment spray, main feedwater, and main feed systems in order to independently verify operability. During these system walkdowns, the team verified the following:

- system equipment conditions
- system valves, breakers, and switches properly aligned
- appropriate locking devices on valves required to be locked

The plant was toured to assess the material condition of its equipment and to verify overall plant cleanliness and equipment stowage.

9.1 Residual Heat Removal

The team walked down portions of the residual heat removal system accompanied by the system engineer, his supervisor, and a representative from the Operations Department. The system was verified to be properly aligned as required by procedure. Overall, the condition of the system was acceptable, except for some housekeeping items which had been noted earlier by the plant manager.

9.2 Essential Cooling Water (ECW)

The team inspected the accessible portions of the ECW system in the ECW pump house and mechanical auxiliary building (MAB) including the pump bays, the ECW/CCW heat exchangers, the essential chiller condenser supply and return service, and the ECW MAB sump and penetration area. The area housekeeping and system material condition were generally good with painting and cleaning going on in the pump house. Two minor discrepancies were identified:

(1) Maintenance hold tags were found on ECW flow indicators in the pump house. These tags should have been removed when the indicators were taken from storage and reinstalled in the system. The systems engineer had the tags removed.

(2) The ECW piping and fittings in the essential chiller cooling loop are largely aluminum bronze but use ferritic and austenitic fasteners, fittings, and bypass piping. Several flange stud nuts were installed without the fiber isolation washers intended to inhibit galvanic action between the dissimilar metals. The licensee issued service requests to install the washers.

9.3 Containment Spray

Two members of the team walked down the containment spray system in the containment and fuel handling buildings. The team members obtained the latest valve lineup sheets from the control room for containment spray (CS), and for safety injection (SI) (since many of the CS and SI valves were in close proximity). The system engineer was knowledgeable about the system. No valves were found out of position. Two minor discrepancies involved a CS pump suction test connection valve that was still locked closed, although the piping and instrumentation diagram (P&ID) did not show it to be locked, and a low-head safety injection (LHSI) pump flush isolation valve that was in its normal position of open, but which the team thought should be closed to provide a second valve boundary. The licensee removed the lock, and the licensed operator who accompanied the team on the walkdown stated the position of the flush isolation valve would be evaluated.

9.4 Main Feedwater and Main Steam Systems

The team walked down selected parts of the main feedwater and the main steam systems. The team did not raise any concerns during these walkdowns. The team observed the following items during these walkdowns: equipment hardware, equipment labeling, equipment/component defects as indicated by deficiency tags, and housekeeping. The team was accompanied on the walkdown by a licensed operator and a system engineer. Housekeeping in the areas walked down was good, especially in some of the turbine building areas that had been recently painted.

9.5 Miscellaneous Observations

While observing the performance of a surveillance test in the safety-related "C" train battery room, the team observed that there was a portable eyewash station on the floor. The eyewash station was not restrained to keep it from moving if a seismic event occurred. Entries on an inspection tag on the eyewash station showed that it had been inspected periodically until December 10, 1992 (the last entry on the tag). The eyewash station appeared to have been abandoned in the battery room. One of the licensee's seismic engineers told the team that because the eyewash was on the floor, it would not have presented a problem during a seismic event. One of the licensee's safety representatives told the team that the eyewash station had probably once been on a wooden platform that had been removed because of fire loading concerns. The team was concerned that the licensee's controls for taking equipment and material into areas containing safety-related equipment may be inadequate.

The temporary eyewash station had probably been placed in the room because deficiencies had been noted on the permanently installed eyewash station in the room. A service request tag had been hung on the permanently installed eyewash station because the flow on the left eyewash head was low and a plastic cover was missing on the right eyewash head assembly. The service request tag was dated October 9, 1992.

The team noted the licensee had previously implemented Station Procedure OPGP03-ZA-0098, "Station Housekeeping," Revision 0 to control equipment and material that was taken into the plant.

- Step 4.4.5 states that the supervisor is responsible for ensuring ancillary equipment (tool boxes, dollies, chain falls, compressed gas bottles, etc.) taken into the plant during refueling or maintenance is properly secured to prevent damage to safety-related equipment during a seismic event.

- Addendum 8, "Good Housekeeping Practices," Step 10 states that ancillary equipment (gang boxes, pressurized gas bottles, dollies, block and tackle gear, etc.) should be secured to prevent movement during a seismic event.

The team noted that the licensee failed to follow this procedure and to adequately control equipment placed in an area that contained safety-related equipment; this was designated Deficiency 93-202-D7. The licensee took the following corrective actions to address this deficiency:

- Revised Procedure OPGP03-ZA-0098 (Rev. 1) by adding Addendum 12, "Guidance for Temporary Storage of Equipment in Cat. 1 Bldgs." Addendum 12 clarified the required actions that have to be taken for temporary storage of tools and equipment in the plant.

- On January 13, 1994, issued Office Memorandum, "Seismic II/I Issue" (Maint. 94-9-010), to all maintenance supervisors. The memo provided guidance for temporary storage of equipment in Category I buildings. The memo stated that all maintenance supervisors were to discuss the contents of the memorandum in their next crew briefing.

10.0 EXIT MEETING

At the conclusion of the inspection the team conducted an exit meeting that was open for public attendance. During the exit meeting, the team's findings were presented. The following people were in attendance.

NAME	TITLE	AFFILIATION
W. T. Cottle	Group Vice President	HL&P
J. F. Groth	Vice President, Operations	HL&P
L. W. Myers	Plant Manager, Unit 1	HL&P
G. L. Parkey	Plant Manager, Unit 2	HL&P
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D. R. Taylor	Resident Inspector	USNRC/REGION II D.
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J. Phelps	Shift Supervisor	HL&P
B. Kruppa	Health Physics Technician	HL&P
R. Hood	Health Physics Technician	HL&P
R. Asbury	Engineer	HL&P
M. Chambers	Engineer	HL&P
R. Grantom	Supervisory Engineer	HL&P
D. R. Keating	Director ISEG	HL&P
B. S. Verbeck	Senior Secretary Operations	HL&P
T. D. Wacker	Maintenance	HL&P
L. Settles	Maintenance	HL&P
J. Johnson	Acting Director Quality Assurance	HL&P
M. E. Kanavos	Manager	HL&P
F. E. Teague	Site Manger	EBASCO
J. M. Genber	Work Control Manager	HL&P
D. Stonestreet	Outage Manager	HL&P
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J. Daugherty	Technician	HL&P
M. Luna	Technician	HL&P
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J. Egan	Partner	Shaw Pittman
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D. Fehlido	Reporter	KHUV-TV
M. Schlangenstein	Reporter	Bloomberg
M. Graczyk	Reporter	Associated Press
W. Balleza	Photographer	KPRC-TV

J. Wong	Photographer	KTTOY-TV
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S. D. Phillips	Consultant	HL&P
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R. Helton	Senior Staff Specialist	HL&P
R. C. Craft	Consultant	

Appendix A

List of Deficiencies

Number	Title	Report Location
93-202-D1	Weaknesses in Controls for Maintaining Configuration Management	4.3.2
93-202-D2	Inadequate Controls for Deleting (N/A) Procedural Steps	4.3.3
93-202-D3	Inadequate Controls for the Normalization of Instrumentation	4.3.4
93-202-D4	Improper Operation of Two Contrifugal Charging Pumps (Technical Specification 3.1.2.3)	4.3.4
93-202-D5	Questionable Technical Specification Interpretations	4.5
93-202-D6	Weaknesses in Corrective Action Program Implementation	7.1
93-202-D7	Inadequate Controls for Temporary Equipment Storage	9.5

Appendix B

List of Observations

Number	Title	Report Location
93-202-01	Operability Tracking Log Weaknesses	4.3.2
93-202-02	Procedure Quality Weaknesses	4.3.3
93-202-03	Failure To Stroke PORVs From Main Control Board	4.3.4
93-202-04	Cold Overpressure Protection Controls	4.3.4
93-202-05	Equipment Failures Challenging Operations	4.3.4
93-202-06	Slow Verification of "Immediate Actions" During Alternate Shutdown Drill	4.3.5
93-202-07	Latest Revisions to Procedures Not Always Used	5.4
93-202-08	Weaknesses in Surveillance Testing Procedures	5.5
93-202-09	Inconsistencies in Performance of 10 CFR 50.59 Screening Process	8.2