ENCLOSURE 2

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

NRC Inspection Report: 50-498/95-27
50-499/95-27

Operating License: NPF-76
NPF-80

Licensee: Houston Lighting & Power Company
P.O. Box 1700
Houston, Texas 77251

Facility Name: South Texas Project Electric Generating Station, Units 1 and 2

Inspection At: Matagorda County, Texas

Inspection Conducted: October 8 through November 18, 1995

Inspectors: D. P. Loveless, Senior Resident Inspector
J. M. Keeton, Resident Inspector
W. C. Sifre, Resident Inspector

Approved: Ronald A Azua for J.L.P. 12/18/95
J. L. Pellet, Acting Chief, Project Branch A Date

Inspection Summary

Areas Inspected: Routine, unannounced inspection of plant status, onsite followup of events, operational safety verification, surveillance observations, plant support activities review, evaluation of onsite engineering, followup on open operations items, and inoffice review of open items.

Results:

Plant Operations

- One violation was identified for the failure to properly rig the Unit 2 fuel handling machine equipment prior to fuel movement. Controls over the actions of the refueling contractor were not adequate. The operators identified the problem immediately and extensive corrective action was taken by licensee management. The fuel handling machine violation could have been reasonably expected to have been prevented by effective implementation of the contractor control corrective actions described in response to Violation 499/93036-02 (Section 2.1).

- During a fill and vent evolution in the reactor coolant system (RCS), operator error caused a valid actuation of the cold overpressure mitigation system. This event resulted from poor control room supervision (Section 2.3).

- A turbine trip and reactor trip resulted from blown fuses on the main generator exciter diode assembly. The operators' response to the event was excellent. All plant systems responded as designed (Section 2.4).

- In general, the licensed operators continued to function at a high level of professionalism. Response to the Unit 2 turbine trip/reactor trip was excellent (Section 3.1).

- Unit 2 control room operators had met all necessary requirements prior to conducting mode changes. Reactor operators conducted operations during the main generator breaker closure in a professional manner (Section 3.1).

- With exceptions noted in Sections 2.3 and 4.2 of this inspection report, communications techniques and formality in the control room was observed to be good (Section 3.1).

Maintenance

- Two automatic starts of the essential cooling water system and component cooling water system pumps occurred. Both events were caused by failed instrumentation and were considered to be of low safety significance (Section 2.2).

- Several system flow path alignments were verified without discrepancy. Material condition of plant equipment was observed to be very good (Section 3.2).

- Surveillance testing observed continued to support plant operations and Technical Specification compliance. Supervisory oversight was observed, good communications techniques were practiced, and test performers were knowledgeable of testing requirements and associated equipment (Section 4.4).

- Precautions and prerequisites of surveillance procedures were being met. Simultaneous tests were well coordinated. On one occasion, a licensed operator manipulated a safety-related pump control handswitch prior to being directed to during the test, when a different pump was to have been used (Section 4.2).

- The Unit 1 shift supervisor exhibited good conservatism in suspending the Essential Cooling Water Train C test upon identifying control room flow indication problems (Section 4.3).

Engineering

- System engineering personnel's response to the Unit 2 reactor vessel O-ring leakage was very good. Conclusions reached were reasonable based on known leakage and a review of industry experience (Section 6.1).

- An inspection followup item was opened to track the evaluation of the impact of threaded pipe stem protectors on the operability of the emergency core cooling system valves (Section 6.2).

- Credit taken for Technical Specification 4.0.5 check valve testing was properly documented and met the requirements of ASME Section XI (Section 6.3).

Plant Support

- Direct radiation measurements in the plant corroborated the health physics technicians' surveys (Section 5.1).

- In general, daily security force operations were handled professionally (Section 5.2).

- One unresolved item related to the control of protected area lighting, corrective actions, and the logging requirements of low light conditions within the protected area was identified (Section 5.2).

- Plant chemistry indications reviewed verified steam generator integrity. Records were maintained in accordance with procedures and management expectations (Section 5.3).

Summary of Inspection Findings:

- Violation 499/95027-01 was opened (Section 2.1).
- Unresolved Item 498;499/95027-02 was opened (Section 5.2).
- Inspection Followup Item 498;499/95027-03 was opened (Section 6.2).
- Violation 498/94009-02 was closed (Section 7.2).
- Unresolved Item 498/94202-01 was closed (Section 8.1).
- Unresolved Item 498;499/94202-02 was closed (Section 8.2).
- Unresolved Item 498;499/94202-03 was closed (Section 8.3).
- Unresolved Item 498;499/94202-04 was closed (Section 8.4).
- Inspection Followup Item 498;499/93048-24 was closed (Section 7.3).
- Inspection Followup Item 498;499/94017-02 was closed (Section 8.5).
- Licensee Event Report 499/94-002 was closed (Section 7.1).
- Licensee Event Report 499/94-007 was closed (Section 7.4).

Attachment:

- Persons Contacted and Exit Meeting

DETAILS

1 PLANT STATUS

1.1 Unit 1 Plant Status

At the beginning of this inspection period, Unit 1 was operating at 100 percent power.

On November 13, Unit 1 reactor power was reduced to 85 percent following a trip of Steam Generator Feedwater Pump 13. On November 14, Pump 13 was restored and reactor power returned to 100 percent.

At the end of this inspection period, Unit 1 was operating at 100 percent reactor power.

1.2 Unit 2 Plant Status

At the beginning of this inspection period, Unit 2 was shut down in Mode 5, with preparations underway to begin refueling operations for Refueling and Equipment Outage 2RE04.

On October 12, Mode 6 was entered and core alterations were commenced. On October 25, core alterations were completed and Unit 2 entered Mode 5. On October 29, the RCS fill and vent was completed and Mode 4 was entered. On October 30, Unit 2 entered Mode 3 and an RCS heatup was conducted to normal operating temperature and pressure.

On October 31, Unit 2 entered Mode 2 and the reactor was made critical at 11:42 p.m. On November 1, after completion of low power physics testing, reactor power was increased to Mode 1 for main turbine roll, balancing, and testing. On November 2 at 10:52 a.m., the Unit 2 main generator breaker was closed and power ascension was commenced. After core physics testing at increasing power level plateaus, reactor power was increased to 100 percent on November 6.

On November 15, at 7:02 a.m., the Unit 2 reactor tripped on a turbine trip signal caused by a main generator lockout. The RCS was stabilized in Mode 3 at normal operating temperature and pressure.

On November 16, Unit 2 entered Mode 2 and was made critical at 10:10 p.m. Mode 1 was entered at 3:05 a.m. on November 17. The reactor was maintained at low power while maintenance on the main generator exciter was completed. The main generator output breaker was closed at 9 p.m., and power ascension was commenced.

At the end of this inspection period, Unit 2 was operating at 92 percent reactor power, with ascension to 100 percent power in progress.

2 ONSITE FOLLOWUP OF EVENTS (93702)

2.1 Inappropriate Control of Fuel Handling Equipment (Unit 2)

On October 18, 1995, contract refueling operators commenced core reload. The first fuel assembly was lifted to the withdrawal limit in the spent fuel pool. After a few inches of travel, the operator noted that the fuel assembly was leaning slightly off vertical. He stopped the fuel handling machine and noted that the bottom nozzle of the assembly was resting on the top of an adjacent fuel rack cell.

During the investigation, licensee personnel discovered that the safety sling designed to be installed in parallel with the load cell had been rigged in series. This caused the fuel to be approximately 1-1/2 feet lower than normal at the withdrawal limit. This prevented the assembly from clearing the top of the spent fuel pool rack. It was determined that the assembly was in a safe and stable condition. Therefore, it was not moved until an evaluation could be performed.

The shift supervisor directed that the core load supervisor go to the fuel handling building and stay in the area until the assembly could be safely moved. Control room operators verified that all spent fuel pool fill sources were available for service if needed. In addition, the transfer canal gate was closed to isolate the spent fuel pool from the reactor cavity and Condition Report 95-12164 was initiated.

Licensee management convened two teams. One team was to evaluate and recommend a course of action to safely place the fuel assembly back in a storage rack in the spent fuel pool. In addition, an event review team was assembled to determine the cause of the event and recommend corrective actions necessary to prevent a recurrence. The Vice President, Nuclear Generation placed a management hold on fuel movement until all reviews were completed and any required corrective actions were in place.

The first team determined that the electrical interlock on the fuel handling machine could be bypassed. This allowed operators to manually lift the bundle an additional few inches. Therefore, the bundle was moved to a nearby fuel storage cell and safely lowered into place. The team also utilized an underwater camera to inspect the original fuel location and the adjacent fuel storage cells. No indication of damage or binding was noted.

The event review team determined that the causes of the event were poor supervisory oversight, inattention to detail, and poor technician knowledge of the South Texas Project fuel handling equipment. Prior to commencing fuel load, the following actions were completed:

- Supervisory oversight in the field was specifically defined and implemented;

- The refueling team was briefed on the event, and the roles and responsibilities of each position involved in the refueling were delineated; and

- The reconfiguration of the fuel handling machine hoist was verified and the fuel handling and refueling machines were exercised utilizing the dummy fuel assembly to ensure proper operation and alignment.

The inspectors reviewed Plant Operating Procedure OPOP08-FH-0002, Revision 1, "Fuel Handling Machine." Precaution 4.9 required the following:

> "An approved safety sling SHALL be attached to the hoist hook and tool to ensure fuel assembly is not dropped if load monitoring device fails."

Therefore, fuel handling machine rigging was not in compliance with procedure Precaution 4.9, in violation of Technical Specification 6.8.1.a (499/9527-01).

During the review of this violation, the inspector noted two contributing factors to the event. First, there was no direct contractor supervision in the fuel handling building. Commencement of fuel movement was considered a critical activity. The contract refueling coordinator, the designated licensee contract technical coordinator, was performing only in the support role of a facilitator.

In the licensee's response to Violation 499/93036-02, dated January 3, 1994, the licensee documented a continuing problem with substandard work performance by contractors. In that response, the licensee stated that the procurement procedure delineated responsibilities for the contract technical coordinator. The response further stated that, although the current program was adequate, management needed to clearly communicate their expectations to the contract technical coordinators with regard to their duties and responsibilities. A policy statement was developed and issued to implement this corrective action. The response specifically stated that the licensee contract technical coordinator was responsible to ensure that the contractor had appropriate field supervisory practices. As stated above, contractor supervision was not in the fuel handling building during the critical initiation of fuel movement.

Violation 499/93036-02 was reviewed and closed in NRC Inspection Report 50-498/95-23; 50-499/95-23. In that report, the inspectors determined that the licensee's program for contractor oversight was comprehensive.

The inspector reviewed Plant General Procedure OPGP03-ZP-0013, Revision 0, "Purchase Order/Contract Management, Monitoring, Reporting and Rating." Definition 2.2 describes the responsibilities of the contract technical coordinator and states that these responsibilities included monitoring performance.

The inspectors reviewed the "Contractor Control and Performance Monitoring Policy Statement," issued January 3, 1994. The document stated that the contract technical coordinator was solely responsible for the performance of the contracted scope of work. Further, this responsibility could not be delegated to the contractor. The statement also required that a "Management Performance Monitoring Plan" be prepared.

The inspector reviewed the "2RE04 Refueling Team Program," developed by the licensee. This document included the management performance monitoring plan. The monitoring plan provided specific monitoring requirements for the oversight of the contractor's refueling activities. These requirements included the following:

- Detailed briefings will be conducted prior to work start for each task, utilizing the prejob checklist. Prejob briefings will be monitored by the contract technical coordinator or designated South Texas Project personnel.

- Field coordination and continuous monitoring will be performed by cognizant Houston Lighting & Power Company representatives to ensure that work control and other program elements are adhered to and craftsmanship meets South Texas Project standards. Typically, these activities will be assigned to a crew and the scheduled monitoring activities will be documented and retained by the contract technical coordinator or designee.

The inspector noted that the prejob briefing performed for the refueling was performed over the sound-powered telephone system as opposed to in a central location. The briefing did not include specific requirements for verification of the readiness of the fuel handling machine. Additionally, supervisors conducting the brief were not aware that the refueling technician was not familiar with the South Texas Project fuel handling machine. This briefing clearly did not meet management's expectations.

According to the event review team's report, the project shift coordinator, the contract technical coordinator's designee, was in the fuel handling building at the time of the event. However, he was not directly involved with the refueling activities and, therefore, stated that he was only responsible to provide support to the contractor. The inspector determined that this failed to meet the licensee requirement for continuous monitoring and did not ensure that management's standards were met.

Although the specific circumstances were different, the inspectors determined that the failure to appropriately monitor and control contractor activities in the field was a common cause in both the fuel handling incident and in Violation 499/93036-02. Furthermore, the inspector concluded that the fuel handling machine violation could reasonably have been expected to have been prevented by continued implementation of the contractor control corrective actions implemented following Violation 499/93036-02. Therefore, this event-identified violation is not subject to the discretion permitted in NRC Enforcement Policy Section VII.B.1.

Prior to the resumption of fuel movement, the inspector observed the underwater camera inspection of the affected fuel assembly and concurred that the assembly had not been damaged during the event. In addition, the inspector reviewed the corrective actions proposed by senior management during a major plant outage.

2.2 Essential Cooling Water and Component Cooling Water Pump Starts (Unit 1)

On October 18, 1995, at 9:55 p.m., Unit 1 Essential Cooling Water Pump 1A and Component Cooling Water Pump 1A received an automatic start signal while the control room operators were securing Essential Cooling Water Pump 1B for scheduled maintenance. This event was determined by licensee reviewers not to constitute an engineered safety features actuation since this was a control signal and not an engineered safety features actuation. Upon investigation, instrumentation and controls technicians identified that the Component Cooling Water Train 1C flow indicating pressure switch in the automatic start logic for Pump 1A was out of calibration. The start circuitry required a low flow signal from two trains to start the third train that was in a standby condition. The logic to start Pump 1A was satisfied by the low flow signal from the secured Train B and the out of calibration Train C flow indication. A condition report was developed. The technicians subsequently recalibrated the flow instrument, and the systems were returned to their normal standby alignment.

On October 25, at 9:27 p.m., Unit 1 Essential Cooling Water Pump 1B and Component Cooling Water Pump 1B automatically started while Essential Cooling Water Pump 1C was being secured. Instrumentation and controls technicians investigated and determined that this event was caused by a failed pressure switch in the Train A essential cooling water flow instrumentation. This condition, combined with the secured Train C essential cooling water system, caused the Train B pump starts. A condition report was developed to repair the failed pressure switch and the Train B systems were restored to their normal standby alignment.

The inspector ascertained from interviews that, although the two events were similar, they were caused by separate, isolated circumstances. The inspector also determined through interview and review of system piping and instrument diagrams that the control room operators had no indication of a failed or out of tolerance pressure switch without performing a calibration on each individual switch. The October 18 event was caused by a pressure switch being out of calibration tolerance and not the result of a failed pressure switch. Therefore, maintenance personnel stated that there was no evidence to indicate that the other trains' pressure switches should be checked for proper calibration. The inspector determined that no evidence existed to indicate whether the pressure switch in Train A had failed prior to the October 18 event. Both events were directly caused by failed instrumentation and were determined to represent low safety significance.

2.3 Power-Operated Relief Valve Actuation During Fill and Vent Evolution (Unit 2)

On October 27, 1995, a fill and vent evolution of the RCS was in progress. Operators were performing the evolution in accordance with Plant Operating Procedure 0POP02-RC-0003, Revision 7, "Filling and Venting the Reactor Coolant System." The pressurizer was completely filled when Power Operated Relief Valve 2-PCV-0656A opened as the result of a rapid pressure increase caused by a mismatch between charging flow and letdown flow. With the pressurizer filled, RCS pressure was to be controlled by matching letdown and charging flows.

The cold overpressure mitigation system was designed to protect the RCS pressure boundary from pressure transients when one or more of the cold legs were less than or equal to 350°F. During this event, the cold overpressure mitigation system was armed for both Power-Operated Relief Valves 2-PCV-0656A and 2-PCV-0656B as required by Technical Specification 3.4.9.3. The valve lift setpoint for the existing RCS temperature was 475 psig.

During this evolution, the unit supervisor was directing the fill and vent activities. The primary reactor operator was supervising a trainee who was performing reactor coolant pump starts in an effort to sweep voids from the RCS loops. A second reactor operator was attempting to maintain RCS pressure by adjusting charging and letdown flows. A senior reactor operator was functioning in an oversight role.

Three 1-minute runs of reactor coolant pumps had been performed. The next step of Procedure 0POP02-RC-0003 directed the operator to start the fourth RCS loop's reactor coolant pump and one additional pump. According to the investigation report, the unit supervisor told the primary reactor operator that "we are ready to start the Delta RCP per 0POP02-RC-0003" and then began to review the procedure for upcoming operations. This diverted his attention from the ongoing evolution.

The primary reactor operator and trainee verified that proper pump start conditions existed and started Reactor Coolant Pump 2D. When the pump started, RCS pressure began to decrease as air was swept out of the loop. The second reactor operator at the panel observed this pressure decrease. He then increased charging flow and decreased letdown flow to maintain RCS pressure in the normal operating band. He increased charging to approximately 200 gpm and isolated letdown by fully closing Letdown Isolation Valve 2-PCV-0135. The RCS pressure began to slowly recover. After approximately 60 seconds, the second reactor operator assumed that the pressure was stable. Based on interviews, the inspector concluded that the second reactor operator was focused on system pressure and was not fully cognizant of the mismatch between charging and letdown flow. The senior reactor operator then instructed the primary reactor operator to start Reactor Coolant Pump 2B rather than going through the unit supervisor, who was directing panel operator activities.

The primary reactor operator and trainee started the second reactor coolant pump. This again caused a slight pressure decrease. As the remaining air was swept out of the RCS loops, pressure began to rapidly increase because charging flow was 200 gallons per minute and letdown flow was zero.

The second reactor operator began to reduce charging flow, and the senior reactor operator opened Letdown Isolation Valve 2-PCV-0135 in an attempt to reduce the pressure. When RCS pressure had increased to approximately 475 psig, Power-Operated Relief Valve 2-PCV-0656A opened momentarily to relieve RCS pressure upon receipt of a cold overpressure mitigation system signal. The unit supervisor observed several alarms associated with the cold overpressure mitigation system and the relief valve opening. Realizing that there was a problem, he began to monitor the evolution. He continued to monitor the plant until it was stabilized. Following stabilization, the remainder of the fill and vent procedure was performed with no further problems.

2.3.1 Event Review

Licensed operators initiated Condition Report 95-12570 to document and track the review of this event. Licensee management designated the condition report as a significant condition adverse to quality and assembled an event review team to determine the event significance, root cause, and corrective actions required. The team determined that the cold overpressure mitigation system responded as designed, resulting in no adverse effects to the reactor. Additionally, the event did not present a hazard to plant personnel or the general public. The cause of the event was attributed to a lack of proper supervision during the evolution, a communication breakdown among team members, and a lack of briefing on expectations prior to the evolution.

2.3.2 Corrective Actions

Licensee management stressed the importance of this event with the individuals involved. Additional training was scheduled to be conducted for all operators on evolutions involving solid plant operations. Also, the fill and vent procedure was to be revised to provide appropriate caution statements prior to starting a second reactor coolant pump.

2.3 Turbine Trip/Reactor Trip (Unit 2)

On November 15, 1995, at 7:02 a.m., the Unit 2 reactor tripped from 96 percent reactor power. The automatic reactor trip was caused by a turbine trip while above 50 percent power. The turbine trip was caused by a trip of the generator lockout relay, which was tripped by the loss of excitation relays. The loss of excitation was the result of several blown diode assembly fuses in the main generator exciter rectifier circuit.

Prior to the event at 12:21 a.m., a senior reactor operator noted a step increase in main generator exciter field voltage from 105 to 121 volts dc and in current from 65 to 73 amps. At 2:36 a.m., the exciter diode fuses were inspected and 15 out of 72 fuses were found blown. Eleven of the blown fuses were on the white phase, three were on the red phase, and the blue phase had one blown fuse. The shift supervisor consulted with the systems engineering supervisor and the system engineer and was advised to continue operation at 100 percent power if the voltage and current remained stable. The shift supervisor also consulted the main turbine-generator vendor manual, which required a shutdown of the turbine-generator if two or more exciter diode fuses per phase were blown. The shift supervisor determined that this criterion had not been satisfied because the blue phase had only one blown fuse.

At 6:45 a.m., during shift turnover, the exciter voltage increased to greater than 150 volts and the oncoming shift supervisor directed that the power be reduced to 90 percent. At 7:02 a.m., while reactor power was being reduced, the unit tripped.

The inspector observed the control room operators during and immediately following the reactor trip. Operator response to the reactor trip was excellent. The shift supervisor and unit supervisor exhibited good command and control throughout the evolution. The plant responded as expected without any mechanical failures beyond the initiating event.

Following the trip, Condition Report 95-13453 was developed and an event review team was assembled to investigate the event and its cause. The inspector reviewed the condition report and the event review team report. The event review team determined that the turbine trip was caused by the sudden degradation of the rectifier fuses and/or diodes in the main generator exciter. The team recommended the following corrective actions:

- Determination of the extent of the damage to the Unit 2 exciter and repair initiation.
- Evaluation of Unit 1 data to determine if similar degradation had occurred in the Unit 1 exciter.
- Evaluation of preventive maintenance related to the exciter with respect to recommendations in the vendor technical manual and relevant vendor technical information.
- Enhancement of Preventive Maintenance Procedure EM-2GE-89000038 for the turbine-generator exciter with a note or caution that provided relevant information related to the number of fuses allowed to be blown and clear actions to be taken if that number should be exceeded.

- Enhancement of control room logs to include relevant high and low limits for exciter voltage and current and the designation of clear actions to be taken should those limits be exceeded.

- Enhancement of operator, maintenance technician, and engineering personnel training on the main generator system, including lessons learned from this incident.

The inspectors concluded that the corrective actions were appropriate to the circumstances and sufficient to permit restart of the unit. As part of the NRC review, the inspectors determined that a preventive maintenance task had been performed on the exciter prior to the end of Refueling and Equipment Outage 2RE04. Based on a review of the data taken during the performance of that task, the inspectors questioned the disposition of several indications and whether the proper disposition of those indications could have prevented the exciter failure. This review was documented in NRC Inspection Report 50-498/95-24; 50-499/95-24.

2.4 Conclusions

One violation was identified for the failure to properly rig the fuel handling machine equipment prior to fuel movement. Controls over the refueling contractor were considered less than adequate. The inspector concluded that the fuel handling machine violation could reasonably have been expected to have been prevented by continued implementation of the contractor control corrective actions implemented following Violation 499/93036-02. The operators identified the problem immediately and extensive corrective action was taken by licensee management.

Two automatic starts of the essential cooling water vstem and component cooling water system pumps occurred. Both events were caused by failed instrumentation and were considered of low safety significance.

During a fill and vent evolution in the RCS, operator error resulted in inadvertent actuation of the cold overpressure mitigation system.

A Unit 2 turbine trip and reactor trip resulted from blown diode assembly fuses on the main generator exciter. The operators' response to the event was excellent. All plant systems responded as designed.

3 OPERATIONAL SAFETY VERIFICATION (71707)

The objectives of this inspection were to ensure that the facility was operated safely and in conformance with license and regulatory requirements and to ensure that the licensee's management controls were effectively discharging the licensee's responsibilities for safe operation. The following paragraphs provide details of selected, specific inspector observations during this inspection period.

3.1 Control Room Observations

During this inspection period, the inspectors performed daily tours of the main control rooms for both units and conducted routine observations of the licensed operators during a variety of day shift, night shift, and weekend periods. Communications techniques used with reactor plant operators were very good. In general, professionalism demonstrated by the control room staff was good, with two exceptions noted. On one occasion, an operator error caused an inadvertent valid actuation of the cold overpressure mitigation system as described in Section 2.3 and, on another occasion, an operator manipulated a safety-related pump control handswitch prior to being directed to during a test, as described in Section 4.2. Shift turnover information was complete and appropriate. Control room logs were periodically reviewed for completeness and accuracy, with no discrepancies identified.

On October 30, 1995, the inspector witnessed the Unit 2 mode change from Mode 4 to Mode 3. The inspector performed a control board alignment verification of the electrical distribution system breaker indications, the emergency core cooling systems valve alignment indications, and the RCS operational status. All indications were proper for the mode change. Also, the inspector reviewed the unit supervisor's applicable startup check list in Plant Operating Procedure 0POP03-ZG-0001, Revision 9, "Plant Heatup," and found that all applicable prerequisite steps had been completed.

On November 2, the inspector observed licensed operators' activities in the Unit 2 control room during preparations for closure of the main generator breaker. All activities were closely supervised by the unit supervisor. The breaker was closed at 10:52 a.m., officially ending Refueling and Equipment Outage 2RE04. Licensed operators performed in a professional manner and communications techniques demonstrated during the evolution were noteworthy.

On November 15, the inspector observed the Unit 2 control room operators' response to a turbine trip/reactor trip. The control room response was excellent. Operators remained focused on their respective duties throughout the evolution.

3.2 Plant Tours

Throughout this inspection period, the inspectors routinely toured the mechanical auxiliary buildings, electrical auxiliary buildings, and turbine generator buildings of both units. Safety-related equipment was verified to be in very good material condition and appeared to be in proper standby alignment. The inspectors routinely reviewed log books kept at local reactor plant operator stations. In addition, a more detailed review was performed of the plant chemistry and radioactive waste system logs. The inspector determined that these logs were being maintained in accordance with log keeping procedures and supervisory expectations.

On October 31, 1995, the inspector toured the mechanical auxiliary building and the fuel handling building in Unit 2. The flow path valve alignment for the Unit 2 high head safety injection, low head safety injection, and containment spray pumps in all three trains were visually verified to be correct. No discrepancies were identified. Material condition of the system was observed to be very good.

On November 7, the inspector verified the flowpath for Unit 1 Essential Chilled Water System Trains B and C while Train A was out of service for maintenance. The inspector toured the essential chillers and chilled water pumps in the mechanical auxiliary building and observed a small oil leak on a fitting connected to the oil charging valve on Essential Chiller 11C. The inspector reported this condition to the shift supervisor and a condition report was developed. The inspector verified system control board, electrical, and valve alignments.

On November 8, the inspector toured the Unit 1 turbine-generator building. Overall housekeeping was very good. The inspector identified small leaks on the suction drain valves on Steam Generator Feedwater Pumps 11 and 12 on the 35-foot elevation of the turbine-generator building. The inspector reported this condition to the shift supervisor and a condition report was developed.

3.3 Conclusions

In general, licensed operators continued to function at a high level of professionalism. However, two events occurred because of poor supervision and poor communications techniques in the control room. Response to the Unit 2 turbine trip/reactor trip was excellent.

The inspector noted that Unit 2 operators had met all necessary requirements prior to conducting mode changes. The inspector observed the operators conducting operations during main generator breaker closure in a professional manner. Communications techniques were observed to be noteworthy.

With two exceptions noted in Sections 2.3 and 4.2 of this inspection report, communications techniques and formality in the control room was observed to be good. Several system flow path alignments were verified without discrepancy. Material condition of plant equipment was observed to be very good. The identification by the inspectors of plant deficiencies that had not been identified by licensee personnel was rare, and those items were relatively minor in significance.

4 SURVEILLANCE OBSERVATIONS (61726)

The inspectors observed the surveillance testing of safety-related systems and components addressed below to verify that the activities were performed in accordance with the licensee's approved programs and Technical Specifications.

4.1 Full Flow Injection of Cold Leg Accumulators (Unit 2)

On October 18, the inspector observed the performance of Plant Surveillance Procedure OPSP03-SI-0029, Revision 2, "SI Accumulator Tank Upstream Check

Valve Open Test." This test involved the full flow testing of the accumulator check valves during a dump of the accumulators to the reactor cavity with the core offloaded. The inspector verified that the prerequisites for the procedure had been completed and that the performance had been properly authorized.

The operators performing the test were knowledgeable of the system, the test method, and the flow paths involved. Communications had been established with personnel in the plant. The evolution was controlled and properly executed. During the first injection of the Train A accumulator, the flow indication failed to provide an accurate indication. This was verified by the operators by observing the rate of decrease in the accumulator level. The flow indication problems were corrected and adequate data were obtained.

The inspector verified that the data obtained met the acceptance criteria of the procedure and that the requirements of Technical Specification 4.0.5 had been met for each subsystem check valve. The inspector concluded that this had been an appropriately controlled evolution.

4.2 Testing of Emergency Core Cooling System Check Valves (Unit 2)

On October 18, the inspector observed a portion of the testing being performed in accordance with Plant Surveillance Procedure OPSP03-SI-0030, Revision 1, "Safety Injection System Non Intrusive Valve Operability Test." This test provided for the full stroke exercise of emergency core cooling system check valves in accordance with the requirements of ASME Boiler and Pressure Vessel Code, Section XI, Subsection IWV, as required by Technical Specification 4.0.5.

The inspector reviewed Procedure OPSP03-SI-0030 and verified that it had been approved for performance. The inspector independently verified that the precautions and prerequisites of the procedure were being met and that the individuals involved understood their roles as described under the responsibilities section of the procedure.

The test was commenced at 4:46 a.m. The inspector noted that several other tests of the emergency core cooling systems and the refueling pool were being performed simultaneously. The tests were well coordinated, and the inspector concluded that the multiple tests did not impact the quality of the test activities.

The inspector observed the testing for Train A valves. The system engineers performed Plant Engineering Procedure OPEP07-ZE-0008, Revision 2, "Non Intrusive Check Valve Testing," in conjunction with the test procedure to ensure that the check valves opened fully during the test. This test utilized an audio signal of the valve to ensure that the disk traveled fully to its back seat as indicated by the sound of contact. All Train A valves were verified to be fully opened, with exception of Safety Injection Header Suction Check Valve 2-SI-0002A. This valve was subsequently determined to have been successfully exercised as documented in a surveillance requirement credit package discussed in Section 6.3 of this inspection report.

During the test, the inspector observed the reactor operator take the control handswitch for the Train A high head safety injection pump from the pull-to-lock position to the automatic position. The test coordinator informed the operator that they were supposed to be starting the low head safety injection pump. The reactor operator immediately returned the high head pump handswitch to the pull-to-lock position.

The inspector questioned the shift supervisor about the incident and why that action had not been immediately noted and raised by the operator's peers. The shift supervisor informed the inspector that the procedure allowed the operator to start either of the pumps and that only a communication error had occurred. The operator had specifically intended to start the high head pump and the procedure allowed this action.

The inspector discussed this occurrence with the Plant Manager and the Plant Operations Manager. Following interviews of the individuals involved, they informed the inspector that the preevolution briefing had not specified the pump intended to be used first during the evolution. Corrective action had been taken in this area. However, this was not determined to be a wrong component event, and the action taken was within the limits of the test procedure. The inspector reviewed the facts and concurred with this interpretation.

4.3 Essential Cooling Water System Train C Test (Unit 1)

On October 24 and 25, 1995, the inspectors observed operations personnel performing portions of Plant Surveillance Procedure OPSP03-EW-0019, Revision 10, "Essential Cooling Water System Train C Testing." This procedure provided instruction for the operability verification of Train C essential cooling water system pumps and valves in accordance with Technical Specifications.

The inspector reviewed the in-hand procedure and determined that it was properly reviewed and approved. The inspector ascertained that the instructions were clear and adequately verified system operability.

In the course of performing Section 5.4, "Testing Essential Cooling Water Pump 1C," of the procedure, the operators were instructed to record essential cooling water system flow values from the qualified display processing system Flow Transmitters 1-FT-6874 and 1-FT-6906 associated with Essential Chiller 11C. The operators identified that these qualified display processing system parameters were reading off-scale high. The operators determined that the local indications were reading 725 and 1330 gpm, respectively, and that the display system indications had upper detection limits of 700 and 1300, respectively. With these parameters unavailable in the control room, the shift supervisor conservatively suspended the test in accordance with Plant General Procedure OPGP03-ZE-0004, Revision 15, "Plant Surveillance Program," and contacted instrumentation and controls technicians to evaluate the flow instruments.

The inspector observed the resumption of the surveillance test by the oncoming shift operators following the troubleshooting activity. The instrumentation and controls technicians had corrected the flows by adjusting flow levels in accordance with Plant Operating Procedure OPOP02-EW-0001, Revision 7, "Essential Cooling Water Operations." The inspector reviewed the method used to balance the system flows and determined that it was appropriate. The inspector observed good communications techniques during the turnover between shifts and good use of self-verification techniques throughout the activity.

4.4 Conclusions

Surveillance testing observed continued to support plant operations and Technical Specification compliance. Supervisory oversight was observed; good communications techniques were practiced; and test performers were knowledgeable of testing requirements and associated equipment.

Precautions and prerequisites of surveillance procedures were being met. Simultaneous tests were well coordinated. On one occasion, a licensed operator manipulated a safety-related pump control handswitch prior to being directed to do so during the test. Licensee management determined that the preevolution briefing had not been adequate to prevent inappropriate manipulation of the pump handswitch.

The Unit 1 shift supervisor exhibited good conservatism in suspending the Essential Cooling Water Train C test upon identifying control room flow indication problems.

5 PLANT SUPPORT ACTIVITIES REVIEW (71750)

The objectives of this inspection were to ensure that selected activities of the licensee's support programs were implemented in conformance with the facility policies and procedures and in compliance with regulatory requirements.

5.1 Health Physics Activities

During routine tours of the plant, the inspectors observed that posting and labeling of areas and radioactive materials were in compliance with the regulations and the licensee's procedures. Direct radiation measurements were utilized for independent confirmation of health physics technicians' surveys. A sample of doors required to be locked for the purpose of radiation protection were verified to be secured. Plant workers were observed to be in compliance with the appropriate radiation work permits and were knowledgeable of plant radiological conditions.

5.2 Physical Security Observations

The security force officers searched packages and personnel professionally. Vital area doors were verified locked and in working condition. Protected area barriers were properly maintained and in good condition. The inspectors verified that isolation zones around protected area barriers were maintained free of equipment and debris. During backshift tours, the inspectors determined that, in general, the protected area was properly illuminated. One exception was identified and noted below.

On October 13, a security officer informed the inspector that a site-wide badge check was in progress. Through interview, the inspector ascertained that a security officer in one of the perimeter towers was found to be less than fully alert and compensatory measures were in progress. The inspector verified that the event was properly entered in the regulatory log and that appropriate actions had been taken.

On October 16, the inspector was informed by the security force supervisor that the security officer operating the x-ray machine in the East Gatehouse identified a handgun in the briefcase of a member of the licensee's staff entering the protected area. The supervisor stated that the briefcase did not enter the protected area and compensatory actions were taken. The inspector verified that the event was properly entered in the regulatory log.

On October 22, during an evening tour of the north perimeter of the protected area, the inspector identified several temporary trailers that did not have proper illumination beneath them. The security supervisor was notified of the lighting deficiency and responded with an officer to correct it. A string of lights had previously been placed under the trailers. However, they had not been plugged in that evening.

During followup discussions with security managers, the inspector asked for a copy of the condition report generated by the security force supervisor and was told that none had been written. The inspector also asked if the level of lighting beneath the trailers had been verified and he was informed that it had not because the security officers were unable to find their light meter. The inspector asked if the event had been logged and was informed that licensee management had determined that the lighting deficiency did not require logging in the regulatory log.

After further discussions, Condition Report 95-1659 was written on October 27 to evaluate the event. The inspector continued to pursue the logging requirements for this type of problem. The inspector contacted the Region IV security inspectors, and it was determined that the issue would be reviewed during the next security inspection. This item will be tracked as Unresolved Item 498;499/95027-02.

5.3 Plant Chemistry and Monitoring Equipment Reviews

The inspectors frequently observed that plant water chemistry and radioactivity indications were within the Technical Specification limits. Chemistry reports were reviewed, radiation monitoring traces observed, and main control room logs audited. Annunciator status and the secondary plant Nitrogen-16 monitoring equipment indicated continued steam generator tube integrity. Additionally, the inspectors audited the status of meteorological indication.

5.4 Conclusions

Direct radiation measurements in the plant corroborated the health physics personnel surveys.

Daily security force operations were handled professionally. One unresolved item was identified, related to the control of protected area lighting, corrective actions, and the logging requirements of low light conditions within the protected area. This issue will be reviewed and resolved as part of the next security inspection.

Plant chemistry indications reviewed verified steam generator integrity. Records were maintained in accordance with procedures and management expectations.

6 EVALUATION OF ONSITE ENGINEERING (37551)

6.1 Engineering Disposition of Reactor Vessel O-ring Leakage (Unit 2)

6.1.1 Event Description

On October 30, 1995, during the Unit 2 heatup near the end of Refueling and Equipment Outage 2RE04, a high temperature alarm was received on the reactor vessel O-ring leak-off line. Operators closed Leak-off Isolation Valve 2-RC-069A downstream of the inner O-ring, and Isolation Valve 2-RC-069B downstream of the outer O-ring was opened, which effectively placed the outer O-ring in service.

A second high temperature alarm was received about 1 hour later. Leakage collected from Telltale Drain Valve 2-RC-099, was recorded as 60 milliliters per minute (ml/min). The leakage appeared to stop and restart periodically over the next 36 hours. Leak rates were measured at 20 ml/min and 30 ml/min coincident with high temperature alarms. No leakage was detected in the absence of elevated temperatures. After about 24 hours at normal operating temperature and pressure, the leakage indications from the outer O-ring stopped. This was attributed to either the leak-off line downstream of the outer O-ring being plugged with boron crystals or the outer O-ring seating, thereby correcting the leak.

Based on the small total volume of fluid leaking from the outer O-ring measured during the 36 hours of leakage, blockage of the leak-off line was deemed unlikely. Close observation of the gap between the reactor vessel flange and the reactor head using a mirror was performed on two occasions. No evidence of steam or moisture from leakage had been observed. Additionally, airborne radioactivity in the reactor containment building had not increased.

6.1.2 Event Evaluation by the Systems Engineering Department

The stainless steel clad O-ring seating surfaces on the reactor vessel and head were designed to be very resistant to erosion or corrosion. Very little damage caused by leakage around the O-ring and subsequent steam cutting of the vessel or head surface had previously been observed in the industry. The stainless steel O-ring had a relatively soft silver coating, which was subject to steam cutting. However, new O-rings had been installed during the refueling outage. Therefore, steam cutting of the O-ring surface would have resulted in a gradual increase in leakage. This was not observed.

According to the engineering review, the probable cause of the leak from the outer O-ring was a very small particle lodged between the O-ring and the seating surface. If the particle dislodged, the leak rate would probably increase. The particle in the outer O-ring was assumed to be very small because of the very small leakage observed when the O-ring was placed in service. Dislodging such a particle would result in a very small leak rate relative to the Technical Specification limit.

Leakage from the outer O-ring traversed the outside of the O-ring groove, then proceeded through a 0.4- X 0.06-inch rectangular slit to the leak-off line. These pathways were very small and, therefore, could potentially become blocked by boron crystals, causing any leakage to reroute through the reactor flange. Had this occurred, leakage detection would have been masked or eliminated.

Engineering calculations determined that the maximum measured leak rate of 60 ml/min could have resulted in a hypothetical maximum of approximately 60 pounds of boron crystal deposits within the O-ring groove and outside of the flange during a normal 18-month operating cycle. Licensee engineers determined this was acceptable. Leakage at this low rate would be evaporated based on the high degree of superheat before, or upon, exiting the gap between the flanges. If flange steam leakage were to occur, cameras mounted adjacent to the reactor head would provide a means of detection.

6.1.3 Consequences of Outer O-ring Failure

If additional leakage developed, it would be routed to the reactor coolant drain tank as designed. The tank level indication was designed to quantify and trend leakage to an accuracy of approximately 2 gallons per hour. This leak rate would be significantly less than the Technical Specification maximum of 10 gallons per minute. Temporary temperature instrumentation was installed on Valves 2-RC-069A and 2-RC-069B. These instruments, along with permanent

Temperature Element 2-TE-0600, would have provided indication and alarm capability if more leakage had occurred. Thus, degradation of the outer O-ring sealing capability would be detectable.

6.1.4 Engineering Department Recommendations

Based on the system engineers' evaluation, the nuclear engineering department's management recommended that Unit 2 resume power operations with the known O-ring configurations. A 10 CFR 50.59 unreviewed safety question evaluation was performed. It documented the bases of this recommendation with regard to safety consequences. In addition, a letter from the nuclear steam supply system vendor further reinforced the acceptability of this recommendation.

6.1.5 NRC Evaluation

The inspector reviewed the engineering evaluation, consequences of further leakage, and recommendations. The evaluation of the consequences of renewed leakage appeared to be acceptable and of minimal safety consequence. The recommendation to continue power operation with the known seal conditions was reasonable. The systems engineering department personnel were observed to be very responsive to the reactor operators' concerns.

6.2 <u>Plant Impact Evaluation for Information Notice 95-31 (Common)</u>

During a plant tour, the inspectors noted that the emergency core cooling system Containment Sump Suction Valves SI-MOV-0016A, -B, and -C in both units were rising stem gate valves with threaded pipe stem protectors. Recent generic information contained in Information Notice 95-31, "Motor-Operated Valve Failure Caused by Stem Protector Pipe Interference," applied to potential damage to valves of this design. The inspector questioned the engineering personnel and began following the activity pertaining to the applicability of this notice to plant motor-operated valves. This issue was left open to facilitate completion of a detailed review during the next inspection period and will be tracked as Inspection Followup Item 498;499/95027-03.

6.3 <u>Surveillance Credit Taken for Exercise of Check Valves (Unit 2)</u>

On October 18, the inspector observed the testing of emergency core cooling system check valves as documented in Section 4.2 of this inspection report. During the performance of Procedure OPSP03-SI-0030, as documented in Section 4.2 of this inspection report, Safety Injection Header Suction Isolation Valve 2-SI-0002A failed to meet the acceptance criteria for a nonintrusive full stroke exercise of the valve. However, during this test, licensed operators logged flow parameters of the system during the full flow system testing. Engineers later determined that the indications logged were sufficient to verify the full stroke exercise of Valve 2-SI-0002A.

The inspector reviewed the surveillance credit package that had been prepared, reviewed, and approved by the plant operations review committee. This document stated that the nonintrusive test results for Valve 2-SI-0002A had been indeterminate. However, flows through the check valve recorded during this testing were documented to be greater than 6550 gpm. The total required accident flow rates had been previously calculated to be greater than or equal to 5920 gpm. This acceptance criteria was documented in Plant Surveillance Procedure OPSP03-SI-0021, Revision 1, "Safety Injection System Valve Operability Test." The engineers also noted that the flows recorded were those through the cold leg injection path versus the hot leg injection path utilized during a performance of Procedure OPSP03-SI-0021.

The inspector reviewed ASME Section XI, Subsection IWV-3522. The code stated that normally closed valves shall be tested, proving that the disk moves promptly away from the seat when the closing pressure is removed and flow is initiated through the valve. Confirmation may be verified "by other visual means." NUREG-1482, "Guidelines for Inservice Testing at Nuclear Power Plants," stated that, if accident flow rate is passed through the check valve being tested, nonintrusive techniques are not necessary to establish the functionality of the valve. This is addressed further in NRC Staff Position 2 on alternative to full-flow testing of check valves. This position states that the most common method to full-stroke exercise a check valve open is to pass the maximum required accident flow through the valve.

The inspector also determined that the indication utilized for the data collection was control board process instrumentation. This indication does not have a high level of accuracy. However, NUREG-1482, Section 4.1.2, stated that instruments used to verify flow measurements for check valve full-stroke exercise were not subject to the range and accuracy requirements for instrumentation used for pump inservice testing.

Based on the review of the operators' recorded flow rates, flow paths utilized, quality of instrumentation, and the previously calculated acceptance criteria for full-flow testing of these check valves, the inspector concluded that the full-stroke exercise requirements for Valve 2-SI-0002A met the requirements of ASME Section XI and Technical Specification 4.0.5.

6.4 <u>Conclusions</u>

The system engineering department's response to Unit 2 reactor vessel O-ring leakage was good. Conclusions reached were reasonable based on known leakage and a review of industry experience.

The evaluation to assess the impact of threaded pipe stem protectors on the operability of the emergency core cooling system valves will be tracked as an inspection followup item.

Credit taken for Technical Specification 4.0.5 check valve testing was properly documented and met the requirements of ASME Section XI.

7 FOLLOWUP ON OPEN OPERATIONS ITEMS (92901)

7.1 (Closed) Licensee Event Report 499/94-002: Centrifugal Charging Pump 1A Discharge Bypass Valve Found in the Open Position

This event report documented an event in Unit 1 in which Seal Injection Bypass Valve 1-CV-MOV-8348 was found partially open in violation of an equipment clearance order when Centrifugal Charging Pump 1A was started while Unit 1 was in Mode 5. The licensee investigation determined that the valve had been closed manually and the clutch was engaged. In this condition, the manual gear ratio was low enough that the starting pressure of the charging pump was sufficient to push the disk of the globe valve in the open direction. This event was documented in NRC Inspection Reports 50-498/93-055; 50-499/93-055 and 50-498/93-202; 50-499/93-202.

The licensee's corrective actions included a search of the motor-operated valve data base to identify valves susceptible to this type of event and adding caution statements in equipment clearance orders and labels placed on the affected valves. The inspector verified that the labels on a sample of the valves identified in the licensee's data base search warned that the valves should not be closed manually for equipment clearance order purposes.

7.2 (Closed) Violation 498/94009-02: Failure to Approve Procedure Change

This violation documented an event in which licensee operations personnel labeled steps in Plant Surveillance Procedure OPSP03-SP-0009B, Revision 1, "SSPS Actuation Train B Slave Relay Test," as not applicable and changed the intent of the test without an evaluation. Although plant procedures allowed the shift supervisor to authorize the omission of specific steps, the technical review required was inadequate.

Licensee corrective actions included the following actions.

- Satisfactory performance of the surveillance test with the correct steps.

- A briefing of shift personnel on the event.

The inspector reviewed Plant General Procedure OPGP03-ZA-0010, Revision 20, "Plant Procedural Adherence and Implementation and Independent Verification." This revision allowed the shift supervisor or unit supervisor to omit steps to operating procedures based on plant operating conditions only after ensuring that the alternate performance did not have an adverse impact on safety. Additionally, supervisors may determine that steps do not need to be performed. In this circumstance, the procedure provides clear guidance for how to document a step as not applicable.

7.3 (Closed) Inspection Followup Item 498;499/93048-24: Operator Work Around Caused by Waterhammer In the Auxiliary Feedwater System

The NRC Diagnostic Evaluation Team Report identified multiple examples of ineffective problem identification and resolution. One specific example was that licensed operators had been required to control auxiliary feedwater flow to the steam generators utilizing a stop check valve not designed for throttling. This action was performed to reduce the waterhammer in the system. Management did not properly address this problem until after the thermal cycles on the steam generator nozzles that this control method caused were identified as an issue.

In a letter to the NRC, dated December 24, 1987, the licensee described a series of hydraulic transient events that had occurred in the Unit 1 auxiliary feedwater system. Corrective actions included the installation of control valve stops preventing flow from decreasing below 50 gpm in the system. In February 1988, the installed stops were noted to provide a positive method to eliminate the pressure pulsations that induced the hydraulic transients.

In February 1992, operators documented in Station Problem Report 920044 that the control valves provided a minimum of 75 gpm when indicating closed and that this prohibited maintaining RCS temperatures in Mode 3 at no-load conditions. Therefore, flow was being stopped and started utilizing the containment isolation stop-check valves. This had now been recognized as resulting in unacceptable thermal cycling of the steam generator nozzles, even though the design basis cycle limit was not exceeded.

In June 1992, the modification review board approved modification of the control valves with a new valve trim designed to prevent these problems. This modification was installed in Unit 1 during Refueling and Equipment Outage 1RE05 and in Unit 2 during Refueling and Equipment Outage 2RE04. The inspector reviewed the postmodification testing records for these modifications performed in accordance with Temporary Engineering Procedure OTEP07-AF-0015, Revisions 1 and 2, "Auxiliary Feedwater Flow Control Valves Low Flow-Rate Vibration Test." The inspector concluded that the modification improved the operating characteristics of the valves. In addition, interviews with licensed operators indicated that the work around had been resolved.

The problem with an excessive number of operator work arounds had been identified and addressed prior to the restart of the units as part of Restart Issue 5 in the NRC South Texas Project Restart Action Plan. This issue was closed for Unit 1 as documented in NRC Inspection Report 50-498/93-55; 50-499/93-55 and for Unit 2 as documented in NRC Inspection Report 50-498/94-20; 50-499/94-20. These closures documented that the licensee had met its goals for reducing operator work arounds and that all operator work arounds were being aggressively addressed by licensee management until closure.

The inspectors routinely review the licensee's Daily Communication and Teamwork Meeting package and attended the associated meeting. Every Tuesday, licensee management reviewed the open main control board items and inoperable automatic functions. These items constituted those items that could potentially cause operator work arounds. The number of these items remained low and well below the original restart goals, and the high level of attention by senior management was noted to have continued since the restart.

Based on the correction of the specific operator work around identified in the Diagnostic Evaluation Team report, and the continued management attention in the area of operator work arounds, this item is considered closed.

7.4 <u>(Closed) Licensee Event Report 499/94-007: Turbine Trip/Reactor Trip Upon Main Transformer Lockout</u>

On June 25, 1994, Unit 2 was operating at 47 percent reactor power, while plant personnel completed main turbine lubricating oil system maintenance prior to resumption of full power operation. At 5:15 p.m., a main transformer lockout occurred that caused a direct main generator trip and a reactor trip from undervoltage on the reactor coolant pump buses. As a result of the main transformer, all 13.8 KV normal power was lost to the balance of plant electrical buses. Class 1E electrical power to Bus E2A was resupplied by the automatic start of Standby Diesel Generator 21. Class 1E Buses E2B and E2C remained powered by normal offsite power throughout the event. All safety-related systems responded as designed.

A special inspection of the secondary plant equipment failures and human factors surrounding this event was performed as documented in NRC Inspection Report 50-498/94-24; 50-499/94-24. All aspects of the event were reviewed at that time, including a finding that the licensee's proposed corrective actions would appropriately address the causal factors of the event. One exception noted was the lack of an action plan to address the noted weaknesses in abnormal operating procedure branching instructions.

As a result of the event, all 13.8 KV normal power was lost to the balance of plant electrical buses and Class 1E Switchgear E2A. The reactor operators took action to restore power utilizing Plant Operating Procedure 0POP03-AE-0001, Revision 2, "Loss of Any 13.8 KV or 4.16 KV Bus."

During the response, the operator misinterpreted the wording of branching instructions in the procedure. The operator proceeded to an alternate addendum when directed to a different step in the same addendum. The operator consulted the unit supervisor when he realized that his interpretation of the branching instructions had returned him to an already completed addendum in the procedure. The unit supervisor read the procedure step and initially made the same misinterpretation as the reactor operator. The shift supervisor, upon entering the control room and inquiring about the status of restoring electrical power, immediately recognized the problem and gave proper direction to restore power. The operators estimated that restoration of balance of plant electrical power was delayed by approximately 10 minutes because of the misinterpretation.

The inspector reviewed Plant Operating Procedure 0POP01-ZA-0007, Revision 9, "Plant Operations Procedure Writer's Guide." This revision added specific examples of how to write branching instructions for consistency. The inspector also reviewed Field Change 94-0960 to Procedure 0POP03-AE-0001. This change modified the branching instructions to be consistent with the writer's guide format.

In addition, the inspector reviewed the corrective actions addressed in the licensee event report that had not been previously reviewed. These included:

- The vendor recommended replacement of the pilot wire relays with a modified design was performed.
- Licensed operator training in this area was evaluated and enhanced. Lessons learned discussions were also conducted with the reactor plant operators.
- A review of all modifications issued since 1993 was conducted by licensee personnel. One was found to have a potential to cause a plant trip. This modification was slated for additional evaluations prior to implementation.
- Plant General Procedure 0PGP04-ZE-0310, Revision 1, "Plant Modifications," was revised to add a requirement for a failure mode and effects analysis on the design check list.

Based on the previous special inspection findings and the review of implementation of corrective actions, this item is closed.

8 IN-OFFICE REVIEW OF OPEN ITEMS (90712)

8.1 (Closed) Unresolved Item 498/94202-01: Failure to Follow the Plant Change Form Processing Procedure

This unresolved item was opened as a deficiency in the Special Inspection Branch engineering inspection as documented in NRC Inspection Report 50-498/94-202; 50-499/94-202. By NRC Region IV letter dated March 30, 1995, this item was cited in a Notice of Violation as Example a. of Violation 498;499/94202-05. The response to this violation was then reviewed and closed as documented in NRC Inspection Report 50-498/95-25; 50-499/95-25. Therefore, this unresolved item is administratively closed.

8.2 <u>(Closed) Unresolved Item 498;499/94202-02: Failure to Document the Quarterly Checks of Temporary Modifications</u>

This unresolved item was opened as a deficiency in the Special Inspection Branch engineering inspection as documented in NRC Inspection Report 50-498/94-202; 50-499/94-202. By NRC Region IV letter dated March 30, 1995, this item was cited in a Notice of Violation as Example b. of Violation 498;499/94202-05. The response to this violation was then reviewed and closed as documented in NRC Inspection Report 50-498/95-25; 50-499/95-25. Therefore, this unresolved item is administratively closed.

8.3 <u>(Closed) Unresolved Item 498;499/94202-03: Failure to Assess Pressurizer Safety Valve Setpoint Out-of-Tolerance Conditions</u>

This unresolved item addressed multiple failures of the pressurizer safety valves to be found within Technical Specification tolerances upon surveillance testing. This issue was addressed by the licensee as documented in Licensee Event Reports 498/92-018 and 499/93-011. This issue and these reports were reviewed and closed as documented in NRC Inspection Report 50-498/95-25; 50-499/95-25. Therefore, this unresolved item is administratively closed.

8.4 <u>(Closed) Unresolved Item 498;499/94202-04: Failure to Initiate Licensee Event Reports for Main Steam Safety Valve Setpoint Out-of-Tolerance Conditions</u>

This unresolved item addressed multiple failures of the main steam safety valves to be found within Technical Specification tolerances upon surveillance testing and the failure of the licensee to report these failures in accordance with 10 CFR 50.73. This issue was addressed by the licensee in a revision to Licensee Event Reports 498/92-018 and 499/93-011, originally written to address similar failures of the pressurizer safety valves. This issue and these reports were reviewed and closed as documented in NRC Inspection Report 50-498/95-25; 50-499/95-25. Therefore this unresolved item is administratively closed.

8.5 <u>(Closed) Inspection Followup Item 498;499/94017-02: Implementation of Fire Watch Program</u>

This inspection followup item was opened to track the NRC review of the South Texas Project fire watch program. A previous inspection had identified that a continuous fire watch was inattentive to his specified duties. The specific finding was documented as a noncited violation. However, the issue brought into question the supervisory oversight of the licensee's fire watch program.

Fire watch personnel training was specifically reviewed as documented in NRC Inspection Report 50-498/95-01; 50-499/95-01. These inspectors concluded that fire watch personnel were very knowledgeable of their on station fire watch duties, responsibilities, and general program requirements. Additionally selected fire watch logs were reviewed, with no discrepancies noted.

In addition, the resident inspectors routinely toured spaces where continuous fire watch personnel were stationed. No recent examples of fire watch personnel being less than fully alert were observed. The inspector reviewed Plant General Procedure OPGP03-ZF-0013, Revision 5, "Fire Watch Program," and ascertained that it provided clear guidance for the fire watch program.

ATTACHMENT

1 PERSONS CONTACTED

1.1 Licensee Personnel

H. Atkins, Supervisor, Mechanical Maintenance
M. Berrens, Manager, Work Control, Unit 1
H. Butterworth, Manager, Operations Support
J. Carlin, Manager, Nuclear Training
D. Daniels, Manager, Operating Experience
J. Groth, Vice President, Nuclear Generation
S. Head, Supervisor, Compliance
T. Jordan, Manager, Systems Engineering
J. Lanier, City of Austin Representative
D. Leazar, Director, Nuclear Fuel and Analysis
F. Mangan, General Manager, Plant Services
L. Martin, General Manager, Nuclear Assurance and Licensing
R. Mayes, Lead Operations Specialist
M. Murray, Senior Consultant, Maintenance
J. Phelps, Shift Supervisor
K. Richards, Manager, Work Control, Unit 2
A. Rodriguez, Supervisor, Security Administration
G. Schinzel, Manager, Mechanical Maintenance
J. Sheppard, Assistant to Group Vice President
M. Smith, Administrator, Audits and Assessments
S. Thomas, Manager, Design Engineering Department
R. Wilkinson, Supervisor, Electrical Maintenance, Unit 1

The personnel listed above attended the exit meeting on November 22, 1995. Those designated with "#" also attended the exit meeting on December 6. In addition, the inspectors contacted other personnel during this inspection period.

2 EXIT MEETING

An exit meeting was conducted on November 22, 1995. During this meeting, the inspectors reviewed the scope and findings of the report. The licensee acknowledged the information presented at the exit meeting. Licensee personnel did not identify as proprietary any information provided to, or reviewed by, the inspectors.

An additional exit meeting was conducted on December 6 to further discuss the fuel handling violation. During this meeting, the inspectors reviewed the findings associated with the event and certain aspects of the NRC enforcement policy. The General Manager, Nuclear Assurance and Licensing stated that he agreed that a violation had occurred. However, he did not agree that the violation was a repeat of previous contractor control problems.