ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

NRC Inspection Report: 50-498/96-02
50-499/96-02

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: February 11 through March 23, ~~1995~~ 1996

Inspectors: D. P. Loveless, Senior Resident Inspector
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Approved: John L Pellet 4-26-96
J. L. Pellet, Acting Chief, Project Branch A — Date

Inspection Summary

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

Results:

Plant Operations

- An excess reactor coolant system dilution event on February 28, 1996, revealed that licensee procedures failed to ensure that a locked throttle valve was properly aligned. This event-revealed and licensee-corrected violation is being treated as a noncited violation, consistent with Section VII.B.1 of the NRC Enforcement Policy. The Unit 2 Plant Manager committed to a complete review of the controls governing the configuration of all manual throttle valves in the plant (Section 2.1.2).

- The shift supervisor properly limited access to the control room during the performance of rod control cluster assembly rod drop tests on March 2, 1996. The shift supervisor also maintained good command and control throughout the evolution (Section 3.3.1).

- A good prejob brief was conducted in preparation for Unit 1 reactor restart on March 2, 1996 (Section 3.3.1).

- A Unit 2 down power was well executed on February 23, 1996. The operators demonstrated knowledge of system interactions and expected parameter changes (Section 3.3.1).

- Licensed operators failed to document out of calibration control room instrumentation until questioned by the inspectors on February 16, 1996 (Section 3.3.1).

- Plant personnel failed to properly secure a flood, fire, and ventilation boundary door to the Auxiliary Feedwater Pump 1B compartment in the isolation valve cubicle on February 29, 1996. This failure constituted a violation of minor significance and is being treated as a noncited violation, consistent with Section IV of the NRC Enforcement Policy (Section 3.3.2).

- The inspectors identified a ladder secured to the handwheel of a containment isolation valve on March 19, 1996. This condition constituted a violation of minor significance and is being treated as a noncited violation, consistent with Section IV of the NRC Enforcement Policy (Section 3.3.2).

- No valve alignment discrepancies were noted during walkdowns of all three trains of high head safety injection, low head safety injection, and containment spray systems in both units (Section 3.3.3).

<u>Maintenance</u>

- Good coordination of efforts among various organizations was demonstrated during replacement of kidney valve gaskets on Standby Diesel Generator 12 (Section 4.3.1).

- Replacement of Unit 1 main turbine valve springs was well planned (Section 4.3.2).

- Good planning was demonstrated by the inclusion of contingency actions in an inverter replacement work package (Section 4.3.3).

- Technicians utilized good verification techniques during the replacement of an inverter and solenoid (Section 4.3.3).

- Personnel safety was stressed during a Unit 2 hydrogen leak search and repair (Section 4.3.4).

- An unresolved item was opened to further evaluate the practice of increasing reactor power above 50 percent with a quadrant power tilt ratio in excess of the Technical Specification limits without first reducing the power range nuclear instrument setpoints. Because of the complexity, this item was unresolved (Section 5.3.2).

- An auxiliary feedwater pump inservice test was properly conducted, and the testing procedure was clear and met the surveillance requirements defined in Technical Specifications. However, two apparent design deficiencies required additional operator actions and attention during the test (Section 5.3.5).

- The shift technical advisors, control room operators, and instrumentation and controls technicians performed surveillance activities in a professional manner (Section 5.4).

- Complex surveillance tests had been well planned and were executed with good engineering support and continuous management oversight (Section 5.4).

Engineering

- Engineering personnel utilized a logical approach to justify the use of manual actions in place of a failed automatic function of a fuel handling building ventilation system damper (Section 2.2.2).

- The system engineer provided good support and good implementation of the design change process during the replacement of the Standby Diesel Generator 12 kidney valve gaskets (Section 4.3.1).

- The kidney valve design change package was properly developed and included an unreviewed safety question determination as required by 10 CFR 50.59 (Section 4.3.1).

Plant Support

- Security officers demonstrated good awareness and attention to detail during accompaniment of contractors as they unloaded equipment for the protected area perimeter upgrade (Section 6.3.2).

- The emergency response centers were maintained in an excellent state of readiness (Section 6.3.4).

- The material condition of the fire protection, effluent monitoring, and meteorology monitoring systems was good (Sections 6.3.3, 6.3.4, and 6.3.5).

Summary of Inspection Findings:

- Unresolved Item 498;499/96002-01 was opened (Section 5.3.2).
- Inspection Followup Item 498;499/95027-03 was closed (Section 8.1).
- Licensee Event Report 50-499/95-005 was closed (Section 7.1).
- A noncited violation consistent with Section VII.B.1 of the NRC Enforcement Policy was identified (Section 2.1.2).
- Two noncited violations consistent with Section IV of the NRC Enforcement Policy were identified (Section 3.3.2).

Attachment:

- Persons Contacted and Exit Meeting

DETAILS

1 SUMMARY OF PLANT STATUS

1.1 Unit 1 Plant Status

Unit 1 began this inspection period at 100 percent reactor power. On March 1, the reactor was shut down to facilitate testing of the rod control cluster assemblies. Following testing and evaluation of the results, Unit 1 was returned to full power on March 3. On March 7 and 9, reactor power was reduced to 80 percent following a trip of Steam Generator Feedwater Pump 12 to facilitate pump repairs. Unit 1 was returned to full power on March 10 and remained at full power for the duration of the inspection period.

1.2 Unit 2 Plant Status

Unit 2 began this inspection period at 100 percent reactor power. On February 23, reactor power was reduced to 8 percent and the turbine taken out of service to repair a hydrogen leak in the main generator. On February 27, Unit 2 was returned to full power. On March 11, reactor power was reduced to 48 percent to facilitate the repairs of main turbine electrohydraulic system components. On March 12, Unit 2 was returned to full power and remained at full power for the duration of the inspection period.

2 ONSITE FOLLOWUP OF EVENTS (93702)

2.1 Excess Reactor Coolant System Dilution Via Misaligned Valve (Unit 2)

2.1.1 Event Description

On February 28, following a power increase to 100 percent, lithium was added to the reactor coolant system for pH control in accordance with Plant Operating Procedure OPOP02-CV-0001, Revision 4, "Makeup to the Reactor Coolant System," and Plant Chemistry Procedure OPCP03-ZC-0005, Revision 2, "Chemical Addition to the Reactor Coolant System." Shortly afterward, the reactor operator noted that the reactor coolant system average temperature had increased 0.3°F. The operator had not expected to see an increase in temperature because the amount of reactor coolant system dilution should have been limited to approximately 6 gallons of water. The operator calculated that the change in temperature had been caused by a dilution of greater than 60 gallons of water. The reactor operator reduced main turbine-generator load and performed a blended boration to maintain power within the acceptable band.

An immediate investigation was conducted to determine the cause of the unexpected dilution. A review of the system design documentation revealed that the makeup water valve to the chemical-addition tank, Throttle Valve 2-CV-0197, should have been adjusted to limit flow to approximately 2 gallons per minute (gpm). A temporary flowmeter was installed on the line, and actual flow through the addition line was measured at 30 gpm. The inspectors noted that the operators had limited flow through the chemical-addition tank to 3 minutes in accordance with Procedure 0POP02-CV-0001. The inspector also noted that a 3-minute addition with the valve in the as-found position compared closely with the calculated dilution of approximately 60 gallons.

The Unit 1 operators were immediately notified of the problems found in Unit 2. They investigated and found that the Unit 1 valve, Throttle Valve 1-CV-0197, was also positioned to allow about 30 gpm flow rate. The responsible engineer was contacted, and he concurred that the valves should be repositioned to restrict the flow to less than 3 gpm. The operators in both units readjusted the valves to a position that would permit a flow rate of less than 3 gpm and locked them in place. The licensee could not determine the cause of the misalignment in either unit.

2.1.2 Observations and Findings

The inspector reviewed the history of the valves and determined that the valves had previously been part of the licensee's locked valve program. The valves had been removed from the locked valve list because they had been identified as nonsafety related. However, the locks had been retained, apparently to maintain the throttled position. The procedures for performing valve alignment verification were determined by the inspector to be inadequate. Plant Operating Procedure 0POP01-ZA-0001, Revision 9, "Plant Operations Department Administrative Guidelines," Section 5.4.1.2, required that a valve alignment be performed periodically. Section 5.4.3 stated that locked components shall have been verified according to independent verification guidelines. Section 5.5.2.1.d stated that throttled valves shall not be moved to verify position unless specifically authorized by the unit/shift supervisor. The operators appeared to routinely verify that throttle valves were locked, but actual position was only verified at direction of the supervisor. However, upon observation that these valves were locked, the operators would initial the block indicating that the valves had been aligned.

A review of Condition Report 96-2460 indicated that appropriate actions had been completed or were in progress. The licensee staff had identified and reviewed the status of all throttle valves in the plant. The majority of those valves had installed process flow instrumentation that provided on-line indication that the throttle valves had been adjusted to the correct position. The Unit 2 Plant Manager committed to complete a review of the controls governing the configuration of all manual throttle valves in the plant.

The procedures that governed the valve alignment process did not provide adequate guidance to ensure that the chemical-addition tank throttle valves were properly aligned. This event-revealed and licensee-corrected violation is being treated as a noncited violation, consistent with Section VII.B.1 of the NRC Enforcement Policy.

2.2 Inoperable Fuel Handling Building Ventilation System Damper (Unit 2)

2.2.1 Event Description

On March 16, 1996, at 9:10 p.m., licensed operators identified that a high/low flow annunciator on the plant computer was in alarm. The alarm indicated that the associated damper in the fuel handling building ventilation system was not functioning properly. The system was declared inoperable in accordance with Technical Specification 3.7.8 that required, in part, that the fuel handling building exhaust air system, including the associated dampers, be operable. The Technical Specification action statement permitted continued operation for 7 days to restore operability; otherwise, it required operators to shut down the reactor within the following 6 hours.

Instrumentation and controls technicians determined that the flow transmitter that provided control feedback to the damper had failed. Furthermore, licensed operators determined through the plant computer history file that the annunciator had first alarmed on March 14 at 8:25 a.m. Therefore, the shift supervisor conservatively designated that the allowed outage time of 7 days had started on March 14 and made a log entry stating this designation in the operability assessment system. Because the instrumentation and controls technicians had not anticipated problems with the transmitter replacement, the corrective actions had been scheduled to be implemented on March 18, following the weekend.

The technicians subsequently replaced the flow transmitter. During the postmaintenance test, the replacement transmitter failed in the same manner as the original transmitter. Further investigation determined that the transmitter failures had been caused by a higher than normal voltage supplied by the dc power supply.

2.2.2 Observations and Findings

On March 21, the inspectors questioned the continued operation of the facility given that the actual allowed outage time had been exceeded. Licensing organization personnel stated that the starting date for the allowed outage time had been changed to the time of discovery in accordance with guidance provided in Generic Letter 91-18.

The inspector reviewed the generic letter. Section 6.6 discussed allowed outage times for equipment upon discovery that a surveillance test had not been performed. The discussion of this topic included a statement that the allowed outage time begins upon discovery that a system was inoperable. However, the failure to meet the Technical Specifications for the inoperable system was still considered reportable in accordance with 10 CFR 50.73.

The licensee's compliance with the Technical Specifications and the implementation of the allowed outage time will be further reviewed upon issuance of the licensee event report.

The system was declared operable at 5:22 p.m. on March 22. The basis for operability was that the dampers could continue to perform their safety-related function with a failed flow transmitter, provided that operators took manual control to reposition the dampers within 15 minutes.

The inspectors reviewed the training material developed for the operators taking manual action if the transmitter failed during an actual event. The material was adequate to satisfy the requirement.

The inspectors reviewed the licensee's justification for using manual action to replace an inoperable automatic function. The justification was in order, with the safety analysis properly addressed, and adequate operator training had been performed. The inspector reviewed the annunciator response procedure, Plant Operating Procedure 0POP09-AN-22M2, Revision 4, "FHB EMER EXH Flow HI/LO," and found that it to be acceptable.

2.3 Conclusions

The procedures that governed the valve alignment process did not provide adequate guidance to ensure that the chemical-addition throttle valves in both units were properly aligned. This event-revealed and licensee-corrected violation is being treated as a noncited violation, consistent with Section VII.B.1 of the NRC Enforcement Policy. The Unit 2 Plant Manager committed to complete a review of the controls governing the configuration of all manual throttle valves in the plant.

The licensee's response to an inoperable fuel handling building ventilation system damper was evaluated. The failure to meet the Technical Specifications for the inoperable system was reportable in accordance with 10 CFR 50.73. The licensee utilized an appropriately justified use of manual actions to replace an inoperable automatic function of the damper. The safety analysis addressed the questions raised by Generic Letter 91-18, and adequate operator training had been performed. The event will be reviewed further with the issuance of the licensee event report.

3 OPERATIONAL SAFETY VERIFICATION (71707)

3.1 General Comments

Using Inspection Procedure 71707, the inspectors conducted frequent reviews of ongoing plant operations. 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.

In general, based on the specific events and noteworthy observations in the sections below, operators were professional and safety-conscious, plant equipment material condition was excellent, and safety-related systems were properly aligned. The control room supervisors maintained strong command and control over routine operations. Operators demonstrated strength in the use and understanding of plant operating procedures. Supervisors and operators were generally responsive to reported conditions in the plant and followed the corrective action process; however, one exception was noted. Additionally, two examples of inadequate securing of equipment were observed.

3.2 Inspection Scope

The inspectors conducted daily inspections of the control room, making routine observations concerning equipment conditions and operator behavior. Plant tours were conducted to independently assess the condition and standby readiness of plant safety equipment. In addition, the high head and low head safety injection and containment spray systems were selected for the evaluation of the operability of engineered safety features.

3.3 Observations and Findings

The inspectors made the following noteworthy observations during this inspection period:

3.3.1 Control Room Observations

On February 16, the inspectors observed that the power range nuclear instrumentation meters on Reactor Control Panel CP005 in the Unit 1 control room were indicating greater than 100 percent reactor power while the local indication on the power range nuclear instrument cabinets indicated 100 percent reactor power. The inspector questioned a licensed operator about these indications. The licensed operator stated that the meters in Panel CP005 were only used for a quick visual reference and that the power range indication in the qualified display processing system in conjunction with local indication were used for operator indication. The licensed operator stated that the control panel indication was adequate for its intended use but probably out of calibration and should coincide with both the local instruments and the quality display processing system. The inspector noted that this condition had existed for an unknown period and that a condition report had not been written until the inspector had raised the issue. Condition Report 96-1825 was developed to address the condition.

On March 2, the inspector observed the Unit 1 control room operators during the performance of rod control cluster assembly rod drop testing. The shift supervisor effectively limited control room access to personnel directly involved with required operations in accordance with plant administrative procedures. The shift supervisor also maintained good command and control of unit operations throughout the evolution. The inspector observed a very good prejob briefing and review of procedures for the withdrawal of the shutdown rod banks in preparation for reactor restart.

On March 12, the inspector observed a power decrease in Unit 2. The unit supervisor held a briefing with the operators and outlined the plan of action. Each operator was assigned specific duties during the power decrease. The licensed operators displayed deliberate actions as the power decrease was commenced. The operators demonstrated good knowledge of system interactions and expected parameter changes. The down power was well executed in accordance with the appropriate plant operating procedure. Operators were very professional and knowledgeable.

On March 19, the inspector observed operations and instrumentation and controls maintenance personnel performing troubleshooting activities following a loss of control board indication for the Train B essential cooling water traveling screen. The troubleshooting activities were being performed in accordance with a plan of action developed by the shift supervisor and the system engineer in accordance with plant administrative procedures. The inspector reviewed the plan and determined that it was well organized and included contingency actions for each probable root cause as determined by the troubleshooting activity. The inspector observed good control of the activity by the shift supervisor to ensure that the activities did not affect safe operation of the unit.

On February 26, the inspector observed the Unit 2 operators latch the main turbine generator, increase its speed to synchronize output with the grid frequency, and close the main-generator breaker following the repair of a hydrogen leak on the main generator. During the evolution, the control room operators noted that Governor Valve 3 had not indicated closed following a main turbine trip test. The reactor plant operator at the turbine determined that a bolt had pulled out of the indication linkage, thus preventing the closed indication from functioning. The shift supervisor delayed turbine start up until the linkage was repaired and the governor valves were retested and functioned properly. The operators showed very good attention to detail in identifying this condition. The shift supervisor demonstrated good command and control of the evolution.

3.3.2 Plant Tours

On February 29, during a tour of the Unit 1 isolation valve cubicle, the inspectors found the door to the Auxiliary Feedwater Pump 1B compartment unsecured. This door was identified as a flood, fire, and ventilation boundary and was required to be closed and secured to facilitate pump operability. The inspectors observed that no one else was in the lower portion of the isolation valve cubicle at that time. The inspectors toured the Pump 1B compartment then closed and secured the door. The inspectors informed the shift supervisor of the unsecured door. The shift supervisor developed Condition Report 96-2491 to investigate the reason for the unsecured door.

The shift supervisor subsequently informed the inspectors that a group of reactor plant operators had been performing training walkdowns in the lower portion of the isolation valve compartment. Security records indicated that the group had left the area 50 minutes prior to the inspectors' arrival. The shift supervisor stated that, based on this information, the pump had been technically inoperable for 50 minutes. The shift supervisor stated that signs technically inoperable for 50 minutes. The shift supervisor stated that signs would be prepared to clearly state that doors must be closed and secured.

The inspectors reviewed the design basis for the door. 10 CFR Part 50, Appendix A, Criteria 2 through 4 require that licensee design against safety function losses caused by flooding, fire, and dynamic effects of piping ruptures, respectively. The licensee's procedures for breaching fire barriers; heating, ventilation, and air conditioning boundaries; and flood boundaries all define this door as a required boundary. The main design concern was that a high energy line break in a specific section of a limited number of lines in the overhead could cause flooding of the pump room. Given the very narrow scope of concerns, the fact that the event was an isolated case, and that the door could not have been unsecured for longer than 50 minutes, the inspectors determined that failure to properly control the design basis for the Auxiliary Feedwater Pump 1B comparment door had minor safety significance. However, 10 CFR Part 50, Appendix B, Criterion III, requires, in part, that design bases are correctly translated into procedures. Although the licensee's procedures clearly document that the auxiliary feedwater pump room doors are required boundaries, they do not require that the doors be secured closed. This failure to properly secure the door constitutes a violation of 10 CFR Part 50, Appendix B, Criterion III, and is of minor significance and being treated as a noncited violation, consistent with Section IV of the NRC Enforcement Policy.

On March 8, the inspector verified that alignments had been made in accordance with Plant Operating Procedure 0POP01-ZO-0004, Revision 4, "Extreme Cold Weather Guidelines." The inspector observed that ventilation system control panel switches had been placed in the proper alignment. The reactor plant operators were observed logging the additional parameters required by the procedure. The inspector reviewed the logs and found the entries to be in order. This infrequently used procedure had been appropriately implemented, and all operators demonstrated a good knowledge of the requirements.

On March 19, the inspectors toured the annulus between the Unit 2 fuel handling building and reactor containment. The inspectors noted old portable sump pumps, hoses, ladders, and a number of tools. Sealing material from the seal between the buildings had failed and fallen to the floor. The inspectors noted that this condition was an exception to the normally excellent housekeeping in the plant.

In addition, the inspectors observed that an extension ladder had been tied to the handwheel of the low pressure sludge lancing system Containment Isolation Drain Valve 2-SL-0013. Although the valve was locked in position, the locking device was situated such that excessive sideways force from the ladder could have opened the valve off its seat.

The inspectors noted that the drain line was physically capped. Also, the position of the ladder, the hand wheel, and the locking device would have prevented the valve from opening more that a slight amount. In addition, the ladder was in an unfrequented location. Therefore, the likelihood that an individual would climb the ladder and impact the valve position was low. Based on the condition of the valve, the inspectors determined that the safety significance of this condition was minor.

The inspectors determined that this condition was in violation of Plant General Procedure OPGP03-ZA-0098, Revision 2, "Station Housekeeping." This procedure stated that tall items should be secured when stored near safety-related equipment. Procedure OPGP03-ZA-0098 also provided the following guidance for securing equipment:

> Tie the equipment to a substantial structural member such as a main beam or main column. The item should not be secured to miscellaneous commodities or their supports such as piping, conduit, electrical cable trays, equipment, etc.

This failure to follow procedures constituted a violation of minor significance and is being treated as a noncited violation, consistent with Section IV of the NRC Enforcement Policy. This minor violation was documented because of the inappropriate use of a containment isolation valve as a tie-off.

The inspector reported the condition of this area to the unit supervisor. The ladder was immediately untied and removed. Condition Report 96-3186 was written to address the issue, and mechanical maintenance personnel were contacted to remove the material. The inspectors noted that this was the first time a ladder had been identified tied to the handwheel of a valve. The immediate corrective actions taken were determined to be adequate.

3.3.3 Engineered Safety Feature System Walkdowns

The inspectors used Inspection Procedure 71707 to walk down accessible portions of the following engineered safety feature systems:

- All three trains of the high head safety injection system (Units 1 and 2)
- All three trains of the low head safety injection system (Units 1 and 2)
- All three trains of the containment spray system (Units 1 and 2)

Equipment operability, material condition, and housekeeping were acceptable in all cases. The inspectors verified that all manual containment isolation valves appeared to be closed and were secured in position. No valve alignment discrepancies were noted. The inspectors identified no substantive concerns as a result of these walkdowns.

3.4 Conclusions

Licensed operators were professional and demonstrated good attention to detail. The shift supervisors demonstrated good command and control of plant activities. Control room access was appropriately restricted. The operators demonstrated a good understanding of an infrequently used procedure. The control room operators and shift supervisors were responsive to reported conditions. Three exceptions were noted to the otherwise good performance in operating the plant.

The power range nuclear instrumentation meters on Reactor Control Panel CP005 in the Unit 1 control room had been indicating greater than 100 percent reactor power for an extended period without a condition report being written until the inspector raised the issue. Also, plant personnel failed to secure the Auxiliary Feedwater Pump 1B compartment door. This failure constituted a violation of minor significance and is being treated as a noncited violation, consistent with Section IV of the NRC Enforcement Policy. Finally, the inspectors identified a ladder secured to the handwheel of a containment isolation valve. This failure constituted a violation of minor significance and is being treated as a noncited violation, consistent with Section IV of the NRC Enforcement Policy.

4 MAINTENANCE OBSERVATIONS (62703)

4.1 General Comments

Using Inspection Procedure 62703, the inspectors observed station maintenance activities and reviewed associated documentation to ascertain that the activities were conducted in accordance with the licensee's approved maintenance programs, the Technical Specifications, and NRC regulations. The observed maintenance activities were performed in accordance with approved work instructions. Maintenance personnel were knowledgeable and assured identified adverse conditions were brought to the attention of supervisors and system engineers. The inspectors frequently observed supervisors monitoring work activities. Specific observations were detailed in the sections below.

4.2 Inspection Scope

The inspectors observed all or portions of the following work activities:

Unit 1:

- 306613: Replace Leaking Standby Diesel Generator 12 Test Port Isolation (Kidney) Valve Gaskets
- 328673: Main Turbine Reheat Intercept and Stop Valve Spring Replacements

Unit 2:

- 340686: Electrohydraulic Control System Autostop Inverter and Solenoid Replacement

- 333131: Repair of Main Generator Drain Line Hydrogen Leak

4.3 Observations and Findings

Activities witnessed included work in progress, postmaintena test runs, and field walkdown of the completed activities. Additionally, th work packages were reviewed and individuals involved with the work were interviewed. All observations made were referred to the licensee for appropriate action. The specific maintenance activities observed were discussed as follows:

4.3.1 Replacement of Diesel Kidney Valve Gaskets (Unit 1)

On March 5, the inspector observed mechanical maintenance personnel replacing the gaskets on several kidney valves on Standby Diesel Generator 12 in accordance with Work Order 306613. This work was performed to repair leaking kidney valves as identified in Condition Report 95-13533. Each kidney valve was mounted to an adapter that was attached to the exhaust side of each cylinder head. This configuration permitted access to and instrumentation of the exhaust side of the head for engine analysis.

The inspector observed the removal of the kidney valves and adapters on Cylinders 6L and 9L to replace the copper gasket that forms a seal at the interface between the cylinder head and the adapter. The inspector noted that the mechanic who was working the Cylinder 6L valve was having difficulty removing the adapter mounting bolts. The mechanic stated that the bolts were tightly bound because the bolt holes in the adapter were slightly misaligned with the threaded bolt holes in the engine. The mechanic contacted his supervisor who contacted the system engineer. The supervisor and the engineer concluded that the misalignment could have contributed to the previously observed leakage and elected to replace the adapter. After inspecting the bolt and bolt hole threads, the mechanic verified proper alignment and installed the replacement gasket and adapter.

The inspector also observed that the mechanic who was working on Cylinder 9L was unable to remove the preexisting gasket and contacted his supervisor. Again the system engineer was contacted. The best solution was determined to be the installation of a new gasket on top of the old one. During an interview, the system engineer stated that the diesel generator manufacturer had been consulted and concurred with their decision. The vendor further stated that the installation of a second gasket would not adversely affect the operability or performance of the diesel generator.

Design Change Package 95-13533-1 was developed to facilitate the installation of the second gasket. The inspector reviewed Design Change Package 95-13533-1 and determined that it included an unreviewed safety question determination as required by 10 CFR 50.59 and a design change notice to amend system diagrams to allow the installation of two gaskets as necessary. No discrepancies were identified.

The inspector observed portions of the postmaintenance test of Standby Diesel Generator 12 and did not identify any kidney valve leakage. The mechanics exhibited good system knowledge by identifying potential problems. The mechanics also utilized proper work program procedure by informing their supervisor of these problems. The inspector determined that there had been good coordination of efforts among the various organizations involved in this activity. The system engineer provided good support and good implementation of the design change process.

4.3.2 Main Turbine Valve Spring Replacements (Unit 1)

On March 2, the inspector observed portions of the replacement of actuator springs on the intercept valve for Low Pressure Turbine 3 and on the stop valves for Low Pressure Turbines 1 and 3 by mechanical maintenance personnel in accordance with Work Orders 328672, 328673, and 328674. All three valves were being repaired concurrently by three separate crews. The necessary equipment and parts were prestaged at each valve location. The inspector determined that the activities were well planned.

The inspector reviewed the work packages for these activities and found no discrepancies with the packages or implementation. The inspector also observed the maintenance supervisor and the Unit 1 maintenance manager providing oversight for these activities.

4.3.3 Electrical Inverter and Solenoid Valve Replacement (Unit 2)

On March 11, the inspector observed instrumentation and controls technicians replacing the Channel 2 electrohydraulic control auto stop inverter and solenoid in accordance with Work Order 340686. Condition Report 96-2923 had been written to address voltage and current fluctuations on the output of the inverter.

The inspector observed the technicians verifying the identification of the Channel 2 inverter and filter in Terminal Box M1. Box M1 contained both Channels 1 and 2 components, making these self-verification techniques critical. Throughout the replacement of the inverter, the technicians identified, verified, and labeled the leads as they were disconnected and reterminated in accordance with the work instruction. While preparing to remove the filter circuit box, the technicians identified that the replacement filter circuit box leads were not configured the same as the original circuit box. The technicians stopped work and informed their supervisor. After discussing the discrepancy with the shift supervisor, the craft supervisor instructed the technicians to test the circuit with the original filter in place. A condition report was developed to investigate the cause of this discrepancy.

Although the postmaintenance test indicated that the circuit no longer exhibited voltage and current fluctuations, the test indicated voltage and current readings that were higher than expected. The craft supervisor discussed the test results with the shift supervisor and the system engineer. During this discussion, it was determined that the high voltage and current measurements could have been attributed to a defective solenoid coil. The technicians were instructed to replace the solenoid coil. In reviewing the work package, the inspector ascertained that the package included instructions for the replacement of the solenoid coil as a contingency. The inspector considered including contingency actions in the work package to be very good planning.

The inspector observed the replacement of the solenoid coil. The technicians utilized good verification techniques throughout the inverter and solenoid replacement. The inspector determined that the craft supervisor's actions demonstrated good supervisory oversight. Also good engineering support was provided for this activity.

4.3.4 Repair of Main Generator Hydrogen Leak (Unit 2)

On February 23-25, the inspector observed maintenance activities during portions of preliminary investigations and the repair of a hydrogen leak on the Unit 2 main generator. Because of a rapid increase in hydrogen usage, the maintenance and engineering staff responsible for the generator performed a detailed search for leaks in the generator hydrogen system. On February 23, their search had exhausted possible areas that were readily accessible and had narrowed the search to an area beneath the generator that was covered by a fiberglass plate that had to be removed. The inspector observed the briefing in preparation for removing that plate. Safety precautions for working in an area with an explosive atmosphere were strongly stressed. The investigation was performed in a professional manner. The appropriate emphasis was placed on personnel safety.

Upon removal of the cover, the hydrogen leak was discovered to be coming from a pipe break on a moisture drain line from the bottom of the generator. A plan of action and work instructions were prepared and issued. On February 25, the inspector observed the completed repair. Maintenance technicians were maintaining proper cleanliness controls in the work area. The technicians demonstrated good attention to detail, assuring that all hangers were properly attached to the repaired pipe. The activity was very well controlled.

4.4 <u>Conclusions</u>

The inspectors verified that the activities were conducted in accordance with approved work instructions and procedures, the test equipment was within the current calibration cycle, and housekeeping was being maintained in an acceptable manner. In general, maintenance technicians demonstrated good work practices with appropriate attention to personal safety. When adverse conditions were identified, supervisor and system engineering involvement was promptly sought. Maintenance work packages were thorough and well planned. Good supervisory oversight of the craft in the field was routinely observed. The design change process was properly implemented and produced a properly developed design change package.

5 SURVEILLANCE OBSERVATIONS (61726)

5.1 General Comments

Using Inspection Procedure 61726, the inspectors observed specific surveillance testing activities of safety-related systems and components to verify that the activities were performed in accordance with the licensee's approved programs and Technical Specifications. In general, the observed surveillance activities were professionally performed in accordance with approved procedures. Specific observations are detailed in the sections below. In particular, the shift supervisors demonstrated good control and guidance for the surveillance activities observed.

5.2 Inspection Scope

The inspectors observed all or portions of the following surveillance activities:

Unit 1:

- Plant Surveillance Procedure OPSP10-DM-0003, Revision 2, "Automatic Multiple Rod Drop Time Measurement"

- Plant Surveillance Procedure OPSP10-NI-0002, Revision 3, "Excore QPTR Determination"

Unit 2:

- Plant Surveillance Procedure OPSP03-NI-0001, Revision 8, "Power Range NI Channel Calibration"

- Plant Surveillance Procedure OPSP02-SI-0931, Revision 1, "RWST Level ACOT"

- Plant Surveillance Procedure OPSP03-AF-0002, Revision 3, "Auxiliary Feedwater Pump 12(22) Inservice Test"

5.3 Observations and Findings

The inspectors verified that the activities were conducted in accordance with approved surveillance testing procedures, the test equipment was within the current calibration cycles, and that the acceptance criteria of the procedure was in conformance with the Technical Specification surveillance requirements. The inspectors independently calculated selected test results to verify accuracy and confirmed that the test results were properly reviewed by the unit supervisor. The surveillance schedule had been met for all tests observed and the test results were verified to meet the Technical Specification requirements.

5.3.1 Rod Control Cluster Assembly Drop Time Testing (Unit 1)

On March 2, 1996, the inspectors observed the licensee perform tests to measure the rod drop times for individual shutdown and control rods, as a followup to a control rod insertion anomaly. The anomaly occurred on December 18, 1995, when, following a Unit 1 reactor trip, three rod control cluster assemblies stopped inserting at six steps from the bottom. Following this event, during subsequent tests, one additional rod control cluster assembly stopped inserting at six steps from the bottom.

On March 2, licensee personnel performed timing tests in accordance with Procedure OPSP10-DM-0003. Operators initiated the tests from the control room and recorded the rod drop time traces using the computer-based automatic multiple rod drop system. The tests were performed with the reactor in Mode 3 at full reactor coolant system flow conditions.

Prior to the tests, during manual insertion of the control banks for reactor shutdown, Rod F10 in Control Bank C, one of the rods that had stopped at six steps from the bottom on December 18, stopped inserting at six steps from the bottom. Following an evaluation by operations and engineering personnel in consultation with the vendor, the decision was made to enter Procedure OPSP10-DM-0003 to measure the drop times of all of the shutdown banks simultaneously.

The inspector reviewed the procedure and ascertained that it contained steps to evaluate incomplete rod insertions, to borate the reactor coolant system if required, and to manually insert the affected rods to the bottom. Following the withdrawal of all shutdown banks, the operators opened the reactor trip breakers to initiate the test. When the rod control cluster assemblies in the shutdown banks were dropped, three rods in Shutdown Bank B and one in Shutdown Bank E stopped inserting at 6 steps from the bottom. The three rods in Shutdown Bank B were the same rods that had stopped at six steps from the bottom on December 18. A nuclear engineer performed the procedurally required evaluation and determined that no boration was required. The operators then manually inserted the five rods to the bottom, including Rod F10 in Control Bank C. The final 6 steps of inserting Rod F10 required a demanded insertion of about 30 steps, which was not required for the other rods.

Following completion of the shutdown bank tests, each control bank was tested individually. All the control bank rod control cluster assemblies dropped to rod bottom except three rods in Control Bank C that stopped at six steps from the bottom. Of these three rods, only Control Rod F10 had previously failed to drop to rod bottom. The operator manually inserted the three control rods to the bottom.

The inspectors observed the nuclear engineers performing preliminary analyses as the data was being collected. From discussions with the engineers, the inspector determined that the engineers were analyzing the drop time traces to identify rods that exhibited a reduction in previously measured recoil. The engineers stated that reduced recoil may be an indication of degrading rod drop performance. The engineers determined that there had been no significant change in rod drop times as compared with the times measured during rod drop tests conducted during Refueling and Equipment Outage 1RE05. Final licensee analysis of recoil data was not available during the inspection period. The data indicated that the longest rod drop time was 1.62 seconds, and the overall average time was 1.58 second. These results were well within the Technical Specification required maximum time of 2.8 seconds. The engineers also determined that all the rods that had failed to drop to rod bottom were located in high burnup fuel (greater than 43 gigawatt days per metric ton uranium).

The following summarizes the results of the tests:

All the rods dropped satisfactorily to the bottom with the following exceptions:

- Shutdown Bank B - Rods C9, N9, and N7 stopped at six steps from the bottom.
- Shutdown Bank E - Rod D8 stopped at six steps from the bottom.
- Control Bank C - Rods F6, F10, and K10 stopped at six steps from the bottom.

The rod control cluster assembly rod drop test was well planned and executed with good support from engineering personnel and continuous management oversight.

5.3.2 Calculation of Quadrant Power Tilt Ratio (Unit 1)

On March 3, the inspector observed the shift technical advisor (STA) perform a quadrant power tilt ratio (QPTR) calculation during a reactor power increase in Unit 1. Prior to exceeding 50 percent power, a QPTR calculation had indicated a QPTR of greater than 1.02. Operators had, therefore, entered Technical Specification Action Statement 3.2.4.a. that required the operators to reduce thermal power at least 3 percent from rated thermal power for each 1 percent that QPTR exceeds 1.00 within 2 hours and similarly reduce the power range neutron flux-high trip setpoint within the next 4 hours whenever a QPTR value greater than 1.02 was observed. This requirement was applicable in Mode 1 above 50 percent rated thermal power.

The calculations were performed in accordance with Procedure OPSP10-NI-0002. The STA used a plant computer routine to perform the QPTR calculations. The completed surveillance test package was given to the shift supervisor for his review. After this review, the test results were discussed in detail with the shift supervisor. The surveillance test activity was performed in a professional manner.

The test results were reviewed against the acceptance criteria and were found to be acceptable. The QPTR calculation resulted in a high value of 1.0200, which was at the upper Technical Specification limit. However, the shift supervisor chose to remain in the Technical Specification action statement during the power increase and perform another QPTR determination at a higher power level to verify that the power tilt was decreasing as predicted.

At 77 percent reactor power, another QPTR determination was made. The result indicated that the maximum tilt was 1.0122, well within the limits as expected. The shift supervisor officially exited the Technical Specification action statement.

During a review of the test documentation, the inspector observed a note in the QPTR determination procedure that stated:

> If the QPTR > 1.02 and Reactor Power is ≤ 50%, then requirements of Technical Specification 3.2.4 action a. should be completed before power is raised above 50%.

This had not been accomplished because reactor power had been increased above 50 percent without resetting the power range trip setpoints as stated in the action statement. As previously stated, Technical Specification 3.2.4 is applicable in Mode 1 above 50 percent of rated thermal power. Therefore, the inspector questioned whether this action had been required according to Technical Specification 3.0.4, that stated, in part:

> Entry into an OPERATIONAL MODE or specified condition may be made in accordance with ACTION requirements when conformance to them permits continued operation of the facility for an unlimited period of time.

The inspector notified plant management of the perceived discrepancy. Condition Report 96-3038 was developed to determine if the Technical Specification and procedural requirements had been met.

The inspector interviewed the shift supervisor who had been in command and control when reactor power was increased above 50 percent. The supervisor stated that they knew that a power tilt existed prior to going above 50 percent and that the following actions had been taken:

- The reactor operators performed a QPTR at 48 percent reactor power that indicated a tilt ratio of 1.0471.

- The reactor engineer had been contacted and briefed on the situation.

- The STA had plotted reactor power versus QPTR as instructed by the reactor engineer. The plot had predicted that the tilt should decrease below the limit by the time reactor power reached 55 percent.

- A plan of action had been developed to increase power with the instrumentation and controls technicians standing by to reset the power range trip setpoints within the time limits of the action statement in Technical Specification 3.4.2, if required.

- The reactor engineer agreed to the increase above 50 percent reactor power in accordance with the action plan, based on the predictions plotted by the STA.

- The plant manager was contacted and briefed. He concurred with the actions taken by the shift supervisor.

- The shift supervisor stated that reactor power would be limited to 85 percent until an acceptable QPTR had been achieved.

The inspector reviewed the licensee's procedures for a definition of the word "should," as found in the note in the QPTR determination procedure. The definition found in Plant General Procedure OPGP03-ZA-0039, Revision 15, "Plant Procedures Writer's Guide," stated that "should" denotes a recommendation. A caveat to the definition stated that the individual responsible for the procedure was also responsible for enforcement of the usage.

The inspector reviewed Generic Letter 87-09, "Alternatives to the STS Requirements to Resolve Three Specific Problems with Limiting Conditions for Operation and Surveillance Requirements," for guidance in the interpretation of Technical Specification 3.0.4. The guidance appeared to require that the power range trip setpoints be lowered before increasing power above 50 percent.

The inspector reviewed the South Texas Project Electrical Generating Station Updated Final Safety Analysis Report, Section 4.4.2.10, "Flux Tilt Considerations." This document stated, in part, that:

> . . . design value of the enthalpy rise hot channel factor . . . is assumed to be sufficiently conservative that flux tilts up to and including the alarm point . . . will not result in values of (hot channel factor) greater than that assumed in this submittal . . . When the indicated quadrant power tilt ratio exceeds 1.02, corrective action (e.g., power reduction) must be taken. The procedure to be followed is explained in detail in the Technical Specifications. The quadrant power tilt ratio limit assures that the radial power distribution satisfies the design values used in the power capability analysis.

Section 4.4.2.11.6 stated that:

> The total heat flux hot channel factor, F_Q, is defined by the ratio of the maximum to core average heat flux. As presented in Table 4.3-2 and discussed in Section 4.3.2.2.6, the design value of F_Q for normal operation is 2.50.

In contrast, the Unit 1 Cycle 6 Final Nuclear Design Report indicated a value of 2.70 as the maximum heat flux hot channel factor. The inspector was concerned that the documents reviewed appeared to contain other inconsistencies.

In addition, licensee representatives stated that a QPTR exceeding 1.02 was an expected condition rather than an exception as indicated in the safety analysis. Because of the routine nature of exceeding 1.02 during startup, the practice of resetting the flux trips prior to exceeding 50 percent reactor power had been discontinued. The inspector asked for the safety analysis that supported the discontinuation of this practice.

The following questions were being reviewed at the end of this reporting period:

- Was a USAR change and 50.59 evaluation required for the change in core conditions?
- Were the operators' actions in compliance with Technical Specification 3.0.4?
- Were the procedures involving a QPTR >1.02 adequate?
- Had this anomaly been properly addressed, provided that it was considered an expected condition?
- What is the resolution to the apparent discrepancy between hot channel factor values in the UFSAR and the hot channel factors used in the current core load calculations?

Because of the open questions, this item was considered unresolved (498;499/96002-01).

5.3.3 Power-Range Nuclear-Instrument Channel Calibration (Unit 2)

On March 12, the inspector observed the STA performing a secondary plant calorimetric to facilitate calibration of the Unit 2 power-range nuclear instruments. Reactor power had been stabilized at 98 percent to facilitate the completion of the calibration. The calculations were performed by the STA and compared to data provided by a plant computer routine. The STA properly recorded the required data from control room instruments in a timely fashion. The new setpoints were accurately determined, and the gain of the nuclear instruments was reset. The STA demonstrated a detailed knowledge of the calorimetric and the nuclear instrumentation adjustment process.

The inspector reviewed the final data package as approved by the shift supervisor. The data package was properly completed and the acceptance criteria had been met. The inspector observed the control room chart recorder indications. Prior to the test, the chart recorders indicated approximately 98 percent reactor power. The nuclear instruments were adjusted to approximately 96 percent in accordance with the STA's calorimetric calculations. The inspector also performed an independent channel check on all four power-range channels at the nuclear instrument cabinets, once the reactor was at 100 percent reactor power. The channel check clearly met the Technical Specification required acceptance criteria. Therefore, the power-range channel calibrations were found to be appropriately completed.

5.3.4 Refueling Water Storage Tank Water Level Channel Testing (Unit 2)

On March 12, the inspector observed portions of the performance of the Unit 2 refueling water storage tank level analog channel operational test (ACOT). The inspector observed the control room operator and an instrumentation and controls technician during a discussion of a possible problem. Annunciator 1M02 C1, "RWST LEVEL HI/LO," did not alarm as expected. The shift supervisor was informed. The technician and the shift supervisor proceeded to the instrument racks in the relay room where they reviewed the procedural steps to the point where the problem had been identified. The inspector observed that there was an additional technician and the technicians' supervisor present in the relay room. The procedure had been correctly performed and communications among the individuals were very formal.

The shift supervisor directed that the surveillance test be completed and that a condition report be written to address the problem. Condition Report 340693 was written. The inspector reviewed the surveillance test acceptance criteria and the annunciator alarm function that had failed. It was verified that the failed alarm was not essential to successful completion of the surveillance requirement. The test was completed and all acceptance criteria were met. The inspector also determined that the procedural acceptance criteria implemented the surveillance requirements of Technical Specification 4.3.2.1.7. The problems that occurred during the test were correctly dispositioned in accordance with procedural guidance and management expectations.

5.3.5 Auxiliary Feedwater Pump Inservice Test (Unit 2)

On March 15, the inspector observed portions of the inservice testing of Auxiliary Feedwater Pump 22 and associated system valves. The inspector reviewed Procedure OPSP03-AF-0002 and determined that it had been approved for implementation by the shift supervisor. All the prerequisites for the test had been completed and properly signed as complete. The inspector independently verified that the procedural prerequisites had been met.

During the performance, the inspector identified two apparent operator work arounds. First, Step 5.3.5.1 required the reactor plant operators to obtain and utilize ice to cool the pump cubicle High Temperature Switch B2HC-TSH-9745. This was designed to prevent the cubicle ventilation supply fan from starting on high temperature during the test. The cubicle temperature was monitored while the switch had been deactivated by the ice to ensure that the temperature limits of Technical Specification 3.7.13 were not exceeded. However, the inspector found that this equipment was not well designed for the required testing.

In the second case, the inspector noted that Annunciator 6M03-F-6, "FWIV Low N_2 Press Low," was alarming routinely during the test. Upon closer observation, the inspector noted that the annunciator alarmed each time that an operator in the isolation valve cubicle operated his radio microphone. The inspector found that this condition necessitated additional operator compensatory action.

Communications techniques utilized by all test personnel were clear and continuous. The pretest briefing was thorough and completely addressed the various sections of the test procedure. The inspector noted that the vibration instrumentation used during the test had been calibrated within the current calibration cycle. The inspector independently performed each calculation and comparison required by the test procedures. No calculational errors were noted, and all data met the acceptance criteria. In addition, the inspector reviewed the acceptance criteria and determined that they were in accordance with the surveillance requirements of Technical Specifications 4.7.1.2.1.a.1 and 4.7.1.2.1.a.3.

The inspector determined that the surveillance test had been well performed and that the testing procedure was clear and met the surveillance requirements defined in Technical Specifications. Two apparent design deficiencies required additional operator actions and attention during the test. The inspector discussed these concerns with the shift supervisor and Condition Reports 96-3320 and 96-3611, respectively, were written to address the issues.

5.4 Conclusions

The shift technical advisors, control room operators, and instrumentation and controls technicians performed surveillance activities in a professional manner. Complex tests had been well planned and executed with good engineering support and continuous management oversight. Procedures were correctly followed and management expectations in resolving problems encountered had been met.

Because of the complexity of the issues raised during the document reviews of the QPTR surveillance, this issue was considered unresolved (498;499/96002-01).

6 PLANT SUPPORT ACTIVITIES REVIEW (71750)

6.1 General Comments

Using Inspection Procedure 71750, the inspector observed selected activities in the area of radiological controls, physical security, fire protection, emergency preparedness, and effluent and meteorological monitoring. In general, these plant support programs were being implemented in conformance with facility policies and procedures and in compliance with regulatory requirements.

6.2 Inspection Scope

The inspectors routinely observed daily activities of plant personnel in the subject functional areas.

6.3 Observations and Findings

The inspectors verified that activities observed were well conducted and were in accordance with applicable requirements.

6.3.1 Radiological Protection and Chemistry Controls

During routine tours of the plant, the inspectors observed that postings 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 personnel 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. The daily radiological protection activities observed were acceptably implemented.

6.3.2 Physical Security Activities

The security force 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 the protected area was properly illuminated.

On one occasion, the inspector observed the central alarm station alarm panel and the actions of the security officers in attendance. The operability of the alarm monitors reflected the perimeter modification in progress. Security officers were properly posted as a compensatory action for those areas that had the alarm monitors deactivated. The central alarm station was properly manned and functioning well.

On another occasion, the inspector observed security officers accompanying contractors as they unloaded components for the perimeter upgrade. The security officers demonstrated good awareness and attention to detail.

6.3.3 Fire Protection

The inspectors toured the fire protection pump house and the Unit 1 fire protection valve gallery. The material condition of the fire protection equipment was good. No discrepancies were identified.

6.3.4 Emergency Response Facilities

On March 22, the inspector toured the emergency offsite facility. All communications equipment was in standby readiness. The emergency response facilities data acquisition and display system was on line and providing current plant status. Status boards were clean and in position, and printed documentation was available and in good condition.

The inspector toured the Unit 1 technical support center. The center was in very good standby condition. The inspector noted that an alarm typewriter was in alarm and that the paper was misaligned in the automatic paper feed mechanism. The inspector informed the shift supervisor who dispatched an administrative assistant to investigate and correct the condition.

The inspector observed the technical support center condition in Unit 2. The center was neat and orderly. Readiness for immediate use was apparent. The inspector also noted that an alarm typewriter was in alarm and notified the shift supervisor who dispatched a nonlicensed operator to investigate. The technical support center was found to be in good condition.

The inspectors concluded that the emergency response facilities were being maintained in excellent condition and in standby readiness and were not utilized for daily plant activities that would negatively impact the availability of the facilities.

6.3.5 Effluent and Meteorological Monitoring

On March 12, the inspector performed a walk down of the Unit 1 gaseous waste processing system. No discrepancies were identified. The inspectors noted that radiation levels in the area were extremely low.

On March 21, the inspector performed a walkdown of the Unit 1 unit vent. The overall material condition was good and no leakage was identified.

6.4 Conclusions

Daily plant health physics activities were acceptable. Daily security force operations were appropriately performed. The fire protection system was in good material condition. Emergency response centers were in an excellent state of readiness. The level of material condition of the effluent monitoring and meteorology monitoring systems was good.

7 FOLLOWUP ON OPEN OPERATIONS ITEMS (92901)

7.1 (Closed) Licensee Event Report 50-499/95-005: "Inadvertent Automatic Start of Safety-Related Pump Caused by Operator Error"

This report documented an inadvertent actuation of Component Cooling Water Pump 2C caused by a low pressure signal from an isolated pressure switch in the Train B essential cooling water header. The licensee investigation determined that the pressure switch had been isolated for calibration and the isolation valve had not been reopened upon completion of maintenance activity.

This event and the licensee corrective actions were reviewed in NRC Inspection Reports 50-498/95-06; 50-499/95-06 and 50-498/95-09; 50-499/95-09 and dispostioned as a noncited violation. The inspectors also reviewed previous component cooling water actuations and identified one other event caused by operator error. The previous event was the result of a switch manipulation error by a control room operator and not by an isolated pressure switch. The inspectors considered the pressure switch event to be an isolated occurrence. Based on these reviews, this item was closed.

8 FOLLOWUP ON OPEN ENGINEERING ITEMS (92903)

8.1 (Closed) Inspection Followup Item 498;499/95027-03: Evaluation of Stem Covers on Rising-Stem Motor-Operated Valves

This issue was left open to evaluate the licensee's review of the rising stem gate valves used at South Texas Project. This review was prompted by Information Notice 95-31, "Motor-Operated Valve Failure Caused by Stem Protector Pipe Interference." The licensee's reviews were extensive and engineering personnel determined that no events similar to those described in the notice had occurred. The following actions had been taken or were in progress:

- The information notice was discussed with the motor-operated valve maintenance personnel to raise their awareness.

- Electrical maintenance management included the information notice in their initial and continuing motor-operated valve training course.

- Mechanical maintenance management included the information notice in their initial and continuing motor-operated valve training course.

- Engineering personnel developed an ongoing plan to inspect motor-operated valves that had been determined to be susceptible to stem protector interference.

The valves that the inspector had been concerned with, Containment Sump Suction Valves SI-MOV-0016A, -B, and -C, were shown by the engineers to be of a design that was not susceptible to stem protector interference. Based on the information provided and the actions taken, this item was closed.

9 REVIEW OF UPDATED FINAL SAFETY ANALYSIS REPORT (UFSAR) COMMITMENTS

A recent discovery of a licensee operating their facility in a manner contrary to the UFSAR description highlighted the need for a special focused review that compares plant practices, procedures, and/or parameters to the UFSAR descriptions. While performing the inspections discussed in this report, the inspectors reviewed the applicable portions of the UFSAR that related to the areas inspected. The inspectors verified that the UFSAR wording was consistent with the observed plant practices, procedures, and/or parameters, with the exception of the unresolved item identified in Section 5.3.2.

ATTACHMENT

1 PERSONS CONTACTED

1.1 Licensee Personnel

H. Butterworth, Manager, Unit 2 Operations
J. Calloway, Owner Liaison
T. Cloninger, Vice President, Nuclear Engineering
B. Dowdy, Operations Manager, Unit 2
R. Gibbs, Unit Supervisor
A. Granger, Administrator
J. Groth, Vice President, Nuclear Generation
T. Jordan, Manager, Systems Engineering Department
F. Mangan, General Manager, Plant Services
L. Martin, General Manager, Nuclear Assurance and Licensing
B. Masse, Plant Manager, Unit 2
M. McBurnett, Manager, Licensing
L. Myers, Plant Manager, Unit 1
D. Schulker, Engineer, Compliance
A. Spencer, Manager, Operations Support
S. Thomas, Manager, Design Engineering Department
F. Timmons, Manager, Nuclear Plant Protection Department
L. Weldon, Manager, Simulator

The personnel listed above attended the exit meeting. In addition, the inspectors contacted other personnel during this inspection period.

2 EXIT MEETING

An exit meeting was conducted on March 25, 1995. During this meeting, the inspectors reviewed the scope and findings of the report. The licensee acknowledged the information presented at the exit meeting. The Unit 2 Plant Manager concurred with the findings concerning a mispositioned chemical-addition valve and agreed to complete a review of the controls governing the configuration of all manual throttle valves in the plant. Licensee personnel did not identify as proprietary any information provided to, or reviewed by, the inspectors, with one exception. Although one document concerning reactor core analysis was identified as containing proprietary information, none of the report's specific information was included in this inspection report.