APPENDIX B

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

NRC Inspection Report: 50-498/92-26
50-499/92-26

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: August 2 through September 12, 1992

Inspectors: J. I. Tapia, Senior Resident Inspector
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Approved: A. T. Howell, Chief, Project Section D — Date: 10-14-92

Inspection Summary

Areas Inspected: Routine, unannounced inspection of plant status, onsite followup of events, operational safety verification, maintenance and surveillance observations, preparation for refueling (Unit 1), followup of a previously identified violation, followup of three inspection followup items, management meeting, and Temporary Instruction 2515/109.

Results:

- Three inadvertent engineered safety features (ESF) actuations occurred during this inspection period (Sections 3.1, 3.2, and 3.4). Two of these resulted in violations because of untimely reporting to NRC and an inadequate surveillance procedure. The licensee initiated the Unplanned ESF Actuations Task Force to prevent future unplanned ESF actuations (Section 3.12).

- Performance in the areas of plant operations and operational support was generally good (Sections 3.3, 3.6, and 3.7); however, operator

inattention contributed, in part, to a condition that resulted in the terminal voltage of a safety-related battery being less than the Technical Specification (TS) minimum required voltage (Section 3.13). A second contributor to this event was an inadequate procedure. An inadequate Class 1E direct current distribution system operating procedure was identified as a violation (Section 3.13).

- The level of housekeeping in selected areas of the facility outside the radiological controlled areas was poor (Section 3.14).

- In the area of maintenance, a number of weaknesses were identified. A violation was identified for an inadequate postmaintenance test of an essential chiller circuit breaker (Section 3.10.1). This violation occurred because the corrective actions associated with a similar violation were not properly implemented. The repair of a steam generator power operated relief valve actuator was untimely (Section 3.8). A violation occurred because an instrumentation and controls technician failed to sign four work instruction steps indicating the performance of work even though a second technician had signed the corresponding signature blocks for verification of the work performed (Section 4.3). A minor weakness in a work package associated with an essential cooling water system preventive maintenance activity was identified (Section 4.1.1).

- Several equipment problems, some of which are recurring, were indicative of the need for increased management attention to improve the material condition of the facility (Sections 2, 3.7, 3.10, 3.11, and 8.2).

- In the areas of surveillance and testing, several problems were identified. The inspectors identified examples of temporary procedure changes that were not being incorporated into procedure revisions in a timely manner (Section 5.1). Unnecessary starts of a standby diesel generator occurred because of a procedure problem and human error (Section 5.2). A new negative trend is developing in the area of surveillance and test procedure adequacy. Three examples of inadequate or weak surveillance procedures were identified during this inspection period, and two of these resulted in violations (Sections 3.4, 3.5, and 3.9).

- The Unit 1 fourth refueling outage appeared to be well planned, but the schedule appeared to be aggressive because of the extensive motor-operated valve (MOV) testing that will be conducted. Several positive initiatives pertaining to the outage were identified (Section 6).

- The licensee identified a willful violation involving falsification of NRC required security records. This violation is not being cited because the criteria in Section VII.B.2 of the Enforcement Policy were satisfied (Section 8.1).

- A management meeting between NRC and the licensee was conducted at South Texas Project in order to review the schedule and scope of the planned Unit 1 fourth refueling outage (Section 9).

- The licensee had developed a comprehensive action plan to correct problems in the MOV program (Section 10).

Summary of Inspection Findings:

- Violation 498;499/9226-01 was opened (Section 3.2).

- Violation 498;499/9226-02 was opened (Sections 3.4, 3.9, and 3.13).

- Violation 499/9226-03 was opened (Section 3.10.1).

- Violation 498/9226-04 was opened (Section 4.3).

- Violation 498/9208-02 was closed (Section 7.1).

- A noncited violation was identified (Section 8.1).

- Inspection Followup Item 498;499/9132-04 was closed (Section 8.1).

- Inspection Followup Item 498;499/9214-03 was reviewed but not closed (Section 8.2).

- Inspection Followup Item 498;499/9224-03 was reviewed but not closed (Section 8.3).

Attachments and/or Enclosures:

- Attachment 1 - Persons Contacted and Exit Meeting

DETAILS

1 PLANT STATUS

At the beginning of the inspection period, Unit 1 was in Mode 1 at 100 percent power. On August 13, 1992, at 8:10 a.m., the unit entered coastdown operations. The Cycle 4 fuel load was designed to operate at about 80 percent electrical power until October 3, 1992. Since the unit actually operated at about 92 percent power, the nuclear energy used was greater than expected. On August 13, 1992, unit power reduction was commenced at about 0.7 percent per day. On September 3, 1992, Unit 1 power was reduced from 86 to 75 percent because of a Technical Specification (TS) required shutdown. This event will be documented in detail in NRC Inspection Report 50-498/92-17; 50-499/92-17. The power reduction was terminated when the TS action statement was exited. Power was increased the same day and reactor power was stabilized at 85 percent the next day. The unit ended the inspection period at 80 percent power and decreasing. The Unit 1 refueling outage was scheduled to begin on September 19, 1992.

At the beginning of the inspection period, Unit 2 was operating at 100 percent power. On August 16, 1992, power was reduced to 80 percent to allow for work on a steam generator feedwater pump. The power level was returned to full power the same day. The unit operated at 100 percent power through the end of the inspection period.

2 ONSITE RESPONSE TO EVENTS (93702)

2.1 Excessive Reactor Coolant System (RCS) Leakage (Unit 1)

On September 7, 1992, at 5:18 a.m., Unit 1 declared a Notification of Unusual Event (NOUE) as a result of unidentified RCS leakage in excess of the TS limit of 1 gallon per minute. On the evening of September 5, 1992, control room operators performed a routine RCS inventory and noted an increasing trend but still within TS limits. On the morning of September 6, 1992, a containment entry was made and steam was found coming from the regenerative heat exchanger room. It was suspected that the leak was coming from the alternate charging isolation valve (CV-MOV-006) which had previously leaked and had received applications of Furmanite leak stopping compound on two previous occasions.

Valve CV-MOV-006 was originally identified as leaking on September 6, 1991. The leak was minimal and the licensee continued to operate with the leak until April 1992 when an outage was initiated to place a clamp on the valve to allow application of the Furmanite compound to this valve and another leaking valve in the residual heat removal (RHR) system. The clearance between the valve body and the adjacent concrete wall was limited and this resulted in difficulty in installing the clamp which is used to encapsulate the valve. The limited clearance caused the contractor to place the injection ports in a vertical orientation adjacent to the wall. This is not the preferred methodology. The preferred methodology is to place the injection ports

horizontally on the clamp. As a result, the Furmanite compound sealing capability was less than fully effective. The repair of Valve CV-MOV-006 remained effective until June 1992 when the leak again developed. At that time, more Furmanite compound was applied. This repair remained effective until the degradation that was noted on September 5, 1992.

At 2:12 a.m. on September 7, 1992, RCS letdown and charging were isolated in an attempt to stop the leakage and quantify it. These efforts were not successful and at 4:59 a.m., an RCS inventory calculation resulted in an unidentified leakage rate of 1.185 gallons per minute (gpm). This value exceeded the TS limit of 1.0 gpm and, as a result, at 5:18 a.m., a NOUE was declared. Furmanite representatives were already on site and, at approximately 5:30 a.m., Furmanite compound was again applied to Valve CV-MOV-006. This application of Furmanite compound was the third application during this event. One application occurred on September 6, and two applications were made on September 7, 1992. After the last application, leak rate determinations indicated a reduction in the leakage rate. At 5:52 a.m., normal charging and letdown were returned to service and monitoring of the RCS leakage rate indicated a continuing decrease in leakage. The NOUE was terminated at 7:15 a.m., on September 7, 1992, when the leakage rate was brought below the TS limit.

The licensee plans to implement a permanent repair of Valve CV-MOV-006 during the upcoming refueling outage scheduled to begin on September 19, 1992. Until that time, the licensee implemented once-a-shift containment entries to visually inspect Valve CV-MOV-006, conducted RCS inventory calculations every 8 hours as opposed to the TS required 72 hours, monitored volume control tank levels more frequently, and maintained a higher awareness of containment atmosphere radiation levels.

2.2 Conclusions

The licensee's reliance on Furmanite leak stopping compound to eliminate valve leakage subsequently led to reestablishment of the leak on two occasions because of the difficulty of the installation process.

3 OPERATIONAL SAFETY VERIFICATION (71707)

The purpose of this inspection was to ensure that the facility was being operated safely and in conformance with license and regulatory requirements. The following paragraphs provide details of specific inspector observations during this inspection period.

3.1 Inadvertent ESF Actuation (Unit 1)

During the performance of a routine surveillance test, an inadvertent containment ventilation isolation (CVI) occurred. The CVI signal was generated by a radiation monitor that was not affected by the test procedure. Other inadvertent CVI actuations have occurred during the performance of unrelated surveillance tests. The cause of this event was not clearly

identified by the licensee and the results of the ongoing investigation will be documented in Licensee Event Report (LER) 498/92-008.

The licensee continued to experience problems with recurring unexpected actuations of radiation monitors. For example, on May 8, 1992, a CVI occurred in Unit 2 when Monitor RT-8012 actuated during the performance of the spent fuel pool Exhaust Monitor RT-8035 surveillance test. The cause of the actuation was not clearly identified. As part of the corrective action commitments, a review of the ESF actuations caused by radiation monitors was performed.

Because of the several ESF actuations that have occurred in the past few months, an Unplanned ESF Actuations Task Force has been created to evaluate plant activities in an effort to reduce the number of unplanned ESF actuations. Refer to Section 3.12 of this report for further details of the new task force.

3.2 Inadvertent ESF Actuation of an Auxiliary Feedwater (AFW) Pump (Unit 1)

On August 1, 1992, a manual ESF actuation of AFW Pump 13 was initiated during testing of the solid state protection system (SSPS) Actuation Train C slave relays. The ESF actuation was caused by an operator when he misread a procedural step while performing Procedure 1PSP03-SP-0009C, Revision 1, "SSPS Actuation Train C Slave Relay Test." The purpose of this test is to verify actuation of slave relay output continuity and operability. A portion of this test required the operator to depress and hold Switch S-238 in "Push to Test." The next step required the operator to "verify that AFW pump 13 did not start." The operator misread the procedure to mean "verify that AFW pump 13 will not start." The operator then attempted to start AFW Pump 13 to verify that it would not start; however, the pump started and momentarily discharged into Steam Generator C. The operator immediately realized the error and stopped the pump. The momentary injection into Steam Generator C did not cause a noticeable increase in steam generator water level.

The licensee determined that the causes of this event were inattention to detail, in that the operator misread the test procedure, and weak procedure wording. The procedure contained steps which were almost identical but required a completely different operator response.

The Shift Supervisor and the Duty Operations Manager discussed this event and determined that it was not reportable because the AFW pump was started during a surveillance test. Operators did not believe that a manual start of a pump was an "actuation" as specified in 10 CFR 50.72(b)(2)(ii). The event was also reviewed by the Nuclear Licensing Department 2 days later; however, the reportability of the event was not recognized. The Deputy Plant Manager and the NRC Resident Inspector discussed the need for reportability 3 days after the event when the station problem report was distributed at the Plant Manager's morning meeting. As a result of this discussion, it was determined that the event was reportable because the manual AFW pump start was not part of the pre-planned test sequence. A report was made to the NRC at 1:06 p.m.

on August 4, 1992. When the report was made, the 4-hour reporting limit had been exceeded by approximately 3 days. The inspectors previously identified other examples of the licensee failing to report ESF actuations to NRC within the required 4-hour period. Failure to make the required 4-hour report to NRC is a violation of 10 CFR 50.72(b)(2)(ii) (498;499/9226-01).

3.3 Excessive Reactor Coolant System (RCS) Leakage (Unit 1)

On August 5, 1992, at 9:15 a.m., the Primary Reactor Operator in Unit 1 noted that pressurizer pressure and level were decreasing and that the reactor coolant drain tank (RCDT) level was rising. The operator reduced letdown to the chemical volume control system by switching from the 150 gpm to the 100 gpm letdown orifice. At 9:18 a.m., a high level alarm on the RCDT was received and off-normal Procedure OPOP04-RC-0003, Revision 2, "Excessive RCS Leakage," was entered. In accordance with this procedure, at 9:30 a.m., letdown to the chemical volume control system was isolated. This action resulted in the identification that letdown Isolation Valve LCV-0465 was experiencing valve stem packing leakage that is, by design, collected and directed to the RCDT. At 9:35 a.m., the leakage into the RCDT had stopped. At 9:39 a.m., excess letdown was placed in service. At 10:02 a.m., letdown Isolation Valve LCV-0465 was unisolated and the RCDT level increased 5 percent in 30 seconds. This confirmed the source of the leak. The valve was again isolated and the leak stopped. At 11:08 a.m., LCV-0465 was electrically backseated to isolate the valve stem packing leak. Prior to this action, with letdown and charging isolated, a gross RCS leakage rate calculation indicated 4.274 gpm. After the backseating of the valve, with letdown and charging returned to service, an RCS inventory revealed a leakage rate of 0.705 gpm. The RCS inventory was considered satisfactory at 12:11 p.m. and the event was terminated. The licensee has scheduled repair of LCV-0465 in the upcoming outage.

The diligence of the primary reactor operator in monitoring the control board indications was exemplary. The operator noted the problem prior to the receipt of any alarm and expediciously took the appropriate actions.

3.4 Inadvertent ESF Actuation of a Component Cooling Water (CCW) Pump (Unit 1)

An inadvertent ESF actuation of the Train A CCW pump in Unit 1 occurred during the performance of a routine surveillance test. The test involved the operability verification of the reactor containment fan coolers (RCFC). This event was similar to an event that occurred 2 months earlier in Unit 1. Both events were attributed to inadequate procedures.

On August 8, 1992, a routine test of the Unit 1 RCFCs was being performed in accordance with Procedure 1PSP03-HC-0001. In accordance with procedural requirements, CCW flow was established to the Train B RCFC to verify that an acceptable flow rate through the RCFCs could be established. This increased flow rate of about 4200 gpm from the CCW Pump 1B lowered system header pressure. As a result, the Train A CCW Pump 1A automatically started on low

header pressure. The unplanned actuation of an ESF component was reported to the NRC Operations Center pursuant to 10 CFR 50.72.

The cause of the unexpected CCW Pump 1A start was the result of a lack of adequate procedural guidance. The procedure only required the establishment of flow and did not identify possible actuations or prevention of those actuations. Short term corrective actions taken included revising the applicable RCFC surveillance procedures to place the Standby CCW pump control switches to OFF to prevent accidental starts and adding cautions concerning RCFC load requirements. The system operating procedure was revised to also preclude automatic starting of ESF equipment by placing limitations on pump mode selector switch positions.

A similar event occurred on June 8, 1992, when Unit 1 CCW pump 1C restarted unexpectedly on low header pressure during the performance of a CCW valve operability surveillance. The discharge header pressure decreased because of a high flow condition when one of two running pumps was manually stopped during the performance of the surveillance coincident with the 16-inch RHR Heat Exchanger 1A Outlet Valve FV-4531 inadvertently being left open. Inadequate procedural guidance was determined to be the cause of the event. This event was addressed in NRC Inspection Report 50-498/92-15; 50-499/92-15 and a Notice of Violation was issued on August 5, 1992. NRC concluded that the licensee's failure to provide a fully adequate procedure for the conduct of a routine surveillance testing activity was of concern because the procedure inadequacy was not previously identified either during the routine procedure use or the biennual review process.

In response to the June 8, 1992, event, the licensee committed, in LER 498/92-005, to perform an evaluation to determine which plant procedures needed to be reviewed for incomplete or insufficient procedural steps that require the operation of plant equipment. The licensee intended to ensure that safety-related equipment manipulations were governed by written guidance. The licensee also committed to review procedures for nonsafety-related equipment manipulations which could impact safety-related equipment. The licensee committed to complete the evaluation and establish an action plan by August 28, 1992.

A review of the applicable station problem report (SPR 92-243) was performed during this inspection. The plant procedures evaluation was completed by August 28, 1992; however, some corrective actions were still pending. For example, the applicable surveillance procedures may not receive the required review until their biennial review is due. In the interim, the Operations Policies and Practices Manual was updated to provide instructions to operators to review plant procedures that require manipulation of safety-related equipment prior to performance. This review was determined to be necessary to identify any task that has to be performed but is not specifically addressed in a procedure. A review of Procedure 1PSP03-HC-0001 was conducted prior to its implementation on August 8, 1992, but the operators determined that the procedure was acceptable for use as written because it had been successfully implemented in the past.

TS 6.8.1.a requires that applicable procedures recommended in Appendix A of Regulatory Guide 1.33, Revision 2, February 1978, shall be established, implemented, and maintained. Section 8.b of Appendix A requires specific procedures for surveillance testing. Surveillance Procedure 1(2)PSP03-HC-0001, Revision 2(0), "Reactor Containment Fan Cooler," was established to verify RCFC operability.

On August 8, 1992, Procedures 1(2)PSP03-HC-0001 were found to not be adequately maintained in that the steps which established CCW flow to the RCFC unit did not state the exact expected or required conditions needed to establish flow to the RCFC unit. The step also did not specify to use the system operating procedure to establish the required flow rate. The inadequate surveillance procedural guidance ultimately resulted in an unexpected ESF actuation. The failure to implement and maintain adequate RCFC operability procedures is a violation of TS 6.8.1.a (498;499/9226-02). The failure to maintain the procedure was of concern because the effective date of the procedure was October 6, 1987, and, therefore, two biennial reviews were performed and both failed to identify the procedure deficiency. The licensee issued LER 498/92-010 in response to the August 8, 1992, event. The LER acknowledged that the events of June 8 and August 8, 1992, were both ESF actuations that were attributable to inadequate procedures.

3.5 Improper Inservice Testing of Component Cooling Water Supply to Main Header Check Valve (Units 1 and 2)

During a licensee review of a procedure field change (FC) to Procedure 1PSP03-CC-0003, Revision 3, "Component Cooling Water Pump 1C Inservice Test," it was discovered that the CCW supply to main header check valve had been improperly tested contrary to TS 4.0.5 requirements. The FC required opening the normally closed RHR heat exchanger 1C outlet valve during test performance. Opening the RHR heat exchanger outlet valve provided additional flow from CCW Pump 1C discharge back to the pump suction in order to obtain the required reference value flowrate of 9000 gpm for measuring the pump differential pressure. This also created bypass flow upstream of the supply to main header check valve and downstream of the flow indicator used to measure flowrate through the check valve. The inservice test plan required that the check valve be exercised to its full open position at least once every 3 months. The procedure required a minimum flowrate of 4461 gpm to exercise the check valve to its full open position. Previous performance of the procedure had not obtained an accurate measurement of the flowrate through the check valve and it was uncertain whether the minimum flowrate was satisfied. This condition was common for all CCW pump inservice test procedures.

Because adequate performance of this inservice test could not be verified, all three trains of the CCW system in both units were declared inoperable. The licensee entered TS 4.0.3 at 12:45 p.m. on August 15, 1992. The testing of the check valves was performed within the 24-hour time allowance of TS 4.0.3. This event was reported to the NRC as a TS violation on August 16, 1992.

Since the flowrate downstream of the RHR heat exchanger outlet valves was unknown, the licensee initially believed that the supply to main header check valves had been inadequately tested. Subsequent data obtained from the plant computer demonstrated that each CCW supply to main header check valve received sufficient system flow to exercise the check valve when implementing Procedure OPOP02-CC-0001, Revision 0, "Component Cooling Water." This procedure requires plant operators to verify that flow on all running CCW trains is between 7500 and 15,000 gpm. Additionally, calculation of the flow rate from existing data provided by inservice tests indicated that the minimum flowrate through the CCW supply to main header check valves was satisfied.

The licensee retracted the report of the TS violation on September 10, 1992, based on this information. Corrective actions included testing the supply to main header check valves in all three trains for both Units 1 and 2, initiating FCs for all CCW pump inservice test procedures providing an option to open the RHR heat exchanger outlet valve when the pump reference value flowrate cannot be obtained and verifying that this valve is closed prior to measuring the CCW supply to main header check valve flowrate.

However, prior to the FCs being incorporated, the procedure did not verify, by flowrate measurement, that the minimum flowrate required to exercise the check valve had been obtained. Although no violation of the inservice test requirements occurred because of coincidental compliance, the inspector considered this lack of procedural guidance to be a weakness.

3.6 Fuel Handling Building (FHB) Exhaust Booster Fan Repair (Unit 2)

During the performance of Procedure 2PSP03-SP-0009C, "SSPS Actuation Train C Slave Relay Test," in Unit 2 on August 15, 1992, the FHB 21C exhaust booster fan tripped on overcurrent as a result of a motor ground. The fan was declared inoperable and TS Limiting Condition for Operation (LCO) 3.7.8 was entered. The action of TS LCO 3.7.8 requires that, with only two FHB booster fans operable, the inoperable fan must be restored within 7 days or the reactor be in Hot Standby within the next 6 hours and in Cold Shutdown within the following 30 hours.

While preparing to conduct repairs, it was determined that, in order to access and remove FHB Exhaust Booster Fan 21C, it would be necessary to isolate the fan from the common ventilation plenum by installing blank flanges on the fan suction and discharge ducts. After installation of the blank flanges, the booster fan could then be removed for repairs and the FHB ventilation system could be returned to operable status. The blank flange installation required that the two operable FHB booster fans and the three independent FHB main exhaust fans be secured while maintenance personnel installed the flanges. During the time that these fan control switches are in the pull-to-lock position, their capability to automatically start and mitigate the effects of an accident would be disabled. This would place the Unit in TS LCO 3.0.3, which would require that, with all three trains of the FHB ventilation system not capable of automatic initiation, the system be restored to operable status within 1 hour or the reactor be in Hot Standby within the following 6 hours.

Discussions between the licensee, Region IV, and members of the Office of Nuclear Reactor Regulation were conducted on August 17, 1992, for the purpose of reviewing a request for a temporary waiver of compliance (TWOC) from the requirements of the TS. The licensee categorized the nature of the request for the TWOC, compensatory measures to be taken during the repair activities, evaluations of safety significance, and the justification for the duration of the request. Concurrent to the discussions with NRC, the licensee's Plant Operations Review Committee reviewed and approved the TWOC request. A TWOC from the requirements of TS 3.0.3 was subsequently granted at 6:20 p.m., on August 17, 1992. This waiver allowed the licensee to place the control switches of the two operable FHB exhaust booster fans and the three independent FHB main exhaust fans in pull-to-lock while maintenance personnel installed blank flanges. The fan repair was accomplished on August 20, 1992.

3.7 Power Reduction (Unit 2)

On August 16, 1992, Unit 2 power was reduced from full power to 80 percent power for about 18 hours to allow for repairs on Steam Generator Feedwater Pump (SGFP) 23. The licensee conservatively reduced power in order to increase the margin to a reactor trip with SGFP 23 removed from service. Three temperature indicating switches were replaced during the pump outage. Switch N2-LP-TIS-7465A, SGFP 23 No. 1 bearing drain temperature, was replaced in accordance with Service Request LP-165608. Switch N2-LP-TIS-7465B, SGFP 23 No. 2 bearing drain temperature, and Switch N2-LP-TIS-7465C, SGFP 23 lube oil coolers discharge temperature, were also replaced in accordance with Service Requests LP-165109 and LP-164759, respectively. The pump was returned to service the same day. The removal of the pump from service and the power reduction to rework secondary side equipment were conservative in nature.

3.8 Repair of Steam Generator Power Operated Relief Valve (PORV) (Unit 2)

During the inspection period, a steam generator PORV, that had been in a degraded condition since December 1991, was repaired by the licensee. Delays had been encountered because of inadequate maintenance scheduling (documented in NRC Inspection Report 50-498/92-21; 50-499/92-21), valve failure (documented in NRC Inspection Report 50-498/92-24; 50-499/92-24), and lack of spare parts. Once spare parts were obtained, corrective maintenance was performed that resulted in the repair of the condition that was causing the hydraulic fluid pump to excessively cycle on and off.

On August 20, 1992, PORV 2B was removed from service for replacement of three actuator internal valves. One of the three valves was suspected to be the cause of the internal hydraulic fluid leakage and all three were scheduled for replacement to ensure the leakage was stopped. The dual lock valve assembly (a double check valve that provides a hydraulic lock during PORV movement to eliminate possible valve motion drift), the pump relief valve, and the accumulator drain valve (a maintenance valve used to equalize the high and low pressure sides) were replaced in accordance with Service Request 163896. Following PORV rework, the dual lock valve assembly was determined to be the source of internal leakage. Postmaintenance testing was performed and the

PORV was returned to service. The hydraulic fluid pump cycle time increased to over 2 hours following replacement of the dual lock valve assembly. This cycle time is now approximately the same as the other PORV hydraulic pumps.

A station problem report was written which investigated the events surrounding the July 17, 1992, PORV 2B failure. Problems encountered included inappropriate postmaintenance testing and work planning, as well as a lack of spare parts. Corrective actions planned included the issuance of a training bulletin. The PORV was repaired and returned to service after the problem existed for approximately 9 months. The inspectors considered this untimely repair to be a weakness in the implementation of maintenance.

3.9 Failure to Perform Surveillance on Bistable Status Monitoring Lights (Units 1 and 2)

On August 24, 1992, at 10 a.m., the licensee discovered that the bistable status monitoring lights for the undervoltage and underfrequency relays were not verified operable on all reactor coolant pump channels during the last unit refueling outages. Reactor trip system instrumentation surveillance requirements, defined in TS 4.3.1.1, Table 4.3-1, specify that trip actuating device operational tests be performed prior to entry into Mode 1 (Power Operation).

Units 1 and 2 entered Mode 1 following their refueling outages without having verified as operable the logic card output to reactor trip system, contrary to TS requirements. NRC was notified of this TS violation on August 25, 1992, at 8:52 a.m. LER 498/92-11 was scheduled to be issued by September 24, 1992.

Acceptance criteria verifying that the bistable status monitoring lights were removed from the applicable surveillance procedures ((1 and 2)PSP06-RC-0005, "Undervoltage Reactor Coolant Pump Trip Actuating Device Operational Test," and (1 and 2)PSP06-RC-0006, "Underfrequency Reactor Coolant Pump Trip Actuating Device Operational Test") in April of 1990 by an FC request to allow operators to mark these steps "not-applicable" since the plant computer was out of service. The FC was erroneously incorporated into the procedures during a subsequent revision of the procedures. As a result, both units entered Mode 1 without verifying as operable the bistable status monitoring lights for undervoltage and underfrequency relays. This is the second example of a failure to implement and maintain a procedure in violation of TS 6.8.1.a (498;499/9226-02).

Corrective actions taken included verifying that the bistable status monitoring lights were operable, updating the surveillance procedures to include bistable status monitoring light operability in the acceptance criteria, scheduling the performance of undervoltage and underfrequency trip acuating device operational tests after entry into Mode 5 (cold shutdown) and prior to entry into Mode 1 during refueling outages, and investigating procedural programs that allow acceptance criteria to be removed from a procedure by the field change process.

3.10 Essential Chiller Operability Problems (Units 1 and 2)

The licensee continued to experience problems with the essential chillers. The problems included failures to start and unexpected trips following a start. Chiller reliability and availability are being adversely affected by these problems, as indicated by the lower than expected availability rate for the essential chillers for the month of August 1992. (Refer to Section 8.3 of this report).

3.10.1 Essential Chiller 21C Inadequate Postmaintenance Test

On August 11, 1992, at 6 a.m., the Train C essential cooling water (ECW) system was declared inoperable for scheduled maintenance. The Train C essential chilled water system was declared inoperable at the same time. At 9:12 a.m. the same day, Essential Chiller 21C was electrically tagged out of service to allow for a breaker inspection and lubrication. The chiller breaker at Load Center E2C2, Cubicle 4A, was racked out and the inspection was performed in accordance with Service Request 115415. The breaker was a Westinghouse 480 Volt Model DS-206 breaker. Recurring problems with this model of circuit breakers have been noted at South Texas Project and at other nuclear plants. During this work, the trip shaft was partially removed to inspect for grease at the pivot points. Work was completed and the breaker was racked in and fuses restored at 11:08 a.m. the same day. On August 12, 1992, at 3:03 p.m., the Train C ECW and essential chilled water systems were declared operable following completion of all scheduled maintenance activities.

The inspectors noted that the postmaintenance test specified in the service request (either perform a surveillance test or equipment operability test) was not performed prior to Essential Chiller 21C being declared operable. Later the same day, control room operators attempted to start Essential Chiller 21C, but the chiller failed to start because of breaker problems. The failure to perform the specified postmaintenance test for the chiller was a violation of TS 6.8.1.a (499/9226-03).

The failure to perform an adequate postmaintenance test was previously identified in NRC Inspection Report 50-498/91-25; 50-499/91-25. On September 13, 1991, Emergency Diesel Generator (EDG) 23 failed to align to its associated emergency bus because the output breaker was not fully racked into position. The day before, EDG 23 had been returned to service following completion of corrective maintenance. The postmaintenance test specified in the work request (WR) failed to verify EDG operability prior to returning the EDG to service. A Notice of Violation (499/9125-02) was issued for the failure to perform an adequate postmaintenance test. In response to the violation, the licensee committed to develop a written policy that required a closure under load of all safety-related 480V, 4.16KV, and 13.8KV breakers that are racked out for any reason. This policy, Number 0-0054, "Electrical Breaker Continuity Checks," was added to the Operations Policy and Practices Manual. The corrective actions to prevent recurrence of the violation were

incorporated but were not adhered to by the plant operators in this case. In response to the event, the licensee issued a station problem report.

3.10.2 Essential Chiller 21C Trips

On August 12, 1992, at 5 p.m., Essential Chiller 21C tripped on low oil pressure following a routine start. Two subsequent starts were attempted and the chiller failed to start each time. Troubleshooting was performed in accordance with Service Request (SR) CH-165751. The troubleshooting activities focused on the Westinghouse Type DS-206 power supply breaker. The breaker was discovered to have been discharged and recharged with no change in position lights and, therefore, in the trip free condition (condition where breaker opens immediately after closing). During troubleshooting the breaker functioned properly the first time but did not work properly the second time. At 1:53 a.m., on August 13, 1992, Chiller 21C was started and was left running.

At 11:54 a.m. the same day, while still out of service for troubleshooting, the chiller tripped on compressor high discharge temperature. The licensee later discovered that the chiller tripped because the operating procedure was incorrectly performed. The compressor prerotational vanes were prematurely closed during the process of manually stopping the chiller for further troubleshooting. Since the vanes were prematurely shut, the compressor discharge temperature increased to the trip setpoint and the chiller unexpectedly tripped offline to avoid overheating.

Further troubleshooting of the breaker revealed misadjustment of the trip latch overlap and too much grease in the vicinity of the latch surface. These two conditions may have caused the intermittent breaker trips. The overlap was subsequently readjusted and the excess grease was removed. At 4:40 p.m. on August 13, 1992, the Train C essential chilled water system was declared operable following successful postmaintenance testing. The station problem report discussed in Section 3.10.1 will also address these maintenance issues.

3.10.3 Essential Chiller 21A Trips

On August 16, 1992, Essential Chiller 21A tripped twice on compressor high discharge temperature. SR 165740 was issued to troubleshoot the cause of the trip. The current and temperature control module (controls position of prerotation vanes) was found to be defective and was replaced. The postmaintenance test was completed satisfactorily. On August 25, 1992, Chiller 21A was again removed from service because the prerotation vanes were not moving in automatic or manual control. SR 166279 was issued to troubleshoot this chiller problem. The current and temperature control module, previously replaced under SR 165740, was found to be defective and was again replaced. The first module installed was apparently a defective module that was previously rebuilt while the second module installed was a new module.

3.10.4 Essential Chiller 11B Trip

On August 27, 1992, Essential Chiller 11B tripped off while plant personnel were replacing a burned out bulb for the run indication light. During the changeout process, the lamp socket was twisted, and the control power supply breaker tripped open when a short was detected. The chiller tripped on a loss of control power. The power supply breaker was reclosed and the chiller was restarted. The chiller was out of service for approximately 4 minutes. SR CH-178844 was written to troubleshoot the cause of the breaker trip. The lamp socket was subsequently discovered to be loose and was tightened. The bulb was also replaced and a functional test was performed. The system run light and the chiller operated as designed.

3.10.5 Essential Chiller 21A Fails to Start Upon Demand

On August 30, 1992, Essential Chiller 21A failed to start during the performance of the Surveillance Procedure OPSP03-SP-0010A, Revision 1, "Train A Diesel Sequencer Manual Local Test." Locally at the chiller, the run status light was on and the auxiliary oil pump was running, which indicated the chiller had received a start signal; however, the power supply breaker was found open. SR CH-166297 was issued to investigate the cause of the chiller's failure to automatically start on demand. The breaker was inspected and manually cycled several times (this breaker is also a Westinghouse Type DS-206 breaker) with satisfactory results. Locally at the chiller, no apparent problems were identified. The chiller was manually started locally with satisfactory results. The surveillance procedure was reperformed with no problems encountered. The cause of the chiller failure was not identified and the chiller was subsequently returned to service. SR PL-165033 was written to perform additional breaker tests at the next available opportunity.

3.11 Turbine Generator Problems (Units 1 and 2)

Two problem areas associated with the turbine generators were reviewed by the inspectors. These problems included generator hydrogen cooling system and turbine glad seal system leaks.

3.11.1 Turbine Generator Hydrogen Cooling System Leaks

Hydrogen is used to cool all the generator internals, except for the stator coils which are water cooled. In the past, the licensee has experienced problems with leaks of hydrogen from the generator hydrogen cooling system. These leaks had the potential for creating personnel and equipment safety hazards. The leaks were identified to be from the generator seals. These leaks were in the order of 1700 - 2000 cubic feet per day. Subsequent corrective actions included rebuilding the seals, replacing the gland seal brackets, and replacing the hydrogen dryers. The single tower dryers were replaced with dual tower dryers because the single tower dryers did not have sufficient capacity.

Currently, hydrogen leak rates are approximately 500 cubic feet per day in Unit 1 and slightly higher in Unit 2. The source of the leaks is no longer mainly from the generator but from the new dryers. Releases from the dryers are diverted to the vent stack, which is the preferred path. The dryer in Unit 1 is functioning properly, but the Unit 2 dryer has internal valve leaks which contribute to its higher release rate. The licensee actively trends hydrogen loss in order to detect any increase in leakage and to identify new sources of leaks.

3.11.2 Gland Seal System Leakage

The purpose of the gland seal system is to prevent the leakage of air into the turbines and to keep steam from leaking to the outside of the turbine. Degradation of the high pressure turbine gland seal has allowed water to enter the bearing/lube oil system. Water intrusion into the turbine lube oil can reduce the ability of the oil to provide bearing lubrication. Currently, the licensee has a permanently installed bearing/lube oil conditioner, which extracts particles and water from the oil, and a portable Gulfgate manufactured system which also removes water from the oil. To further prevent water contamination, the licensee has increased condenser vacuum around the gland seal in order to redirect excess steam leakage back to the condenser.

The licensee plans to repair the high pressure turbine gland seals during the upcoming unit refueling outages. To perform the repairs, the high pressure turbine rotor has to be removed. Steam cuts are expected to be found on the shaft of the inner seal. An inconel shaft overlay and a stainless steel inner gland are planned to be used to repair the gland seal. These repairs are expected to reduce the amount of water introduced into the lube oil.

3.12 ESF Task Force (Units 1 and 2)

During the inspection period, an Unplanned ESF Actuations Task Force was developed. The goal of the task force is to prevent unplanned ESF actuations at STP. The task force consists of a chairman and four additional members. The Plant Operations Manager was designated as the chairman. The four members consist of representatives from the Plant Engineering Department, Plant Operations Department, Design Engineering Department, and Independent Safety Engineering Group.

The initial meeting of the task force was held on August 12, 1992. In an attempt to eliminate unexpected ESF actuations, the task force decided to focus on personnel practices and procedures. Two subsequent meetings were held during the inspection period. Items discussed included:
(1) recommendations for equipment improvements in the radiation monitoring systems, (2) review of an Independent Safety Engineering Group report on causal factors on previous actuations, (3) review of surveillance procedures that can cause ESF actuations, and (4) review of outstanding modifications of the radiation and toxic gas monitoring systems.

3.13 Discovery of Low Battery Voltage Level (Unit 1)

The licensee discovered that the terminal voltage for a Unit 1 safety-related battery was below TS limits in Unit 1. An inadequate procedure and two other problems caused this event. The weaknesses involved procedural errors, misleading control board indications, and operator inattention. A station problem report was written to investigate the event and to determine corrective actions to prevent recurrence.

The Class 1E 125V dc system in each unit at STP is designed to provide a reliable source of control power to equipment of various systems during normal operation and postulated design bases events. The system is designed to operate for a period of 2 hours following a loss of all offsite power. The system consists of four independent subsystems powered from three ESF trains. Each subsystem consists of one station battery, two battery chargers, and one distribution switchboard. The battery chargers rectify (convert alternating current to direct current) 480 volts-alternating current (VAC) three-phase power to 125V (volt) dc (direct current) power. Upon loss of alternating current power to the chargers, the batteries automatically assume the load without switching. During normal plant operations, the batteries "float" on the dc bus at 130V dc and are maintained fully charged by the battery chargers. Alarms are provided in the main control room for charger overvoltage (140V dc) and undervoltage (117V dc). Additionally, each of the distribution switchboard bus voltage levels are indicated on an analog meter in the main control room.

Operability requirements for the dc systems in Modes 1-4 are defined in TS 3.8.2.1. Battery bank and charger operability are required to be demonstrated, in part, by verifying that the total battery terminal voltage is greater than or equal to 129 volts on a float charge, as required by TS 4.8.2.1.a(2).

On September 11, 1992, at 2:30 p.m., the Unit 1 Battery Charger E1B11-1 was placed in service and Battery Charger E1B11-2 was removed from service for the TS required 8-hour load test. At 4:20 p.m. the same day, the licensee discovered that the Battery E1B11 terminal float voltage was 128V dc, a value less than the 129V dc minimum required by TS 4.8.2.1.a(2). At 4:31 p.m., action was taken to restore the battery terminal float voltage to greater than the TS lower limit and the voltage was restored to within the limits several minutes later. The battery float voltage was less than the TS limit for 2 hours and 4 minutes. TS 3.8.2.1.a states, in part, if one of the required battery banks and/or chargers for Channel II (Train D) or Channel III (Train B) is inoperable, then restore the inoperable battery bank or charger to operable within 2 hours (otherwise, a plant shutdown is required). Since the Battery Charger E1B11-1 was determined to be inoperable for over 2 hours, the licensee initially determined that a violation of TS had occurred. This condition was reported to the NRC Operations Center.

Subsequent to the event, the licensee determined that the inoperable charger was not a violation of TS. Although the allowed outage time had been exceeded

by 4 minutes, the condition was corrected before the plant was required to be shut down. Therefore, since there was no TS violation, the condition was not required to be reported to NRC. The licensee retracted the report on September 21, 1992.

The cause of the event was attributed to three factors, including procedure error, misleading control panel indications, and operator inattention. Procedure 1POP02-EE-0001, Revision 5, "ESF Class 1E DC Distribution System," established the guidelines for operating the 125V dc distribution system. Step 7.1.8 provided instructions to verify that Battery Charger E1B11-1 amperage and voltage are within established limits. Step 7.1.8.2 provided instructions to ensure that charger voltage is between 125 and 135 volts dc. The charger voltage was 128V dc; therefore, the procedure step was satisfied. The licensee subsequently changed the procedure to ensure the charger voltage was greater than or equal to 129V dc and less than or equal to 135V dc to satisfy the TS required limits. Failure to maintain an adequate Class 1E DC distribution system operating procedure is the third example of Violation 498;499/9226-02.

The 125V dc bus voltage is indicated on the main control board, as well as locally. The analog gauge in the control room is color coded in green, yellow, and red bands. In accordance with NUREG 700, "Guidelines for Control Rooms Design Reviews," red is defined as unsafe or dangerous, immediate operator action is required, or an indication that a critical parameter is out of tolerance. Amber (yellow) indicates a potentially unsafe hazard, caution or attention is required, or an indication that a marginal value or parameter exists. Green indicates a safe condition, no operator action is required, or indication that a parameter is within tolerance. The main control board analog gauge has a green band that extends from 116 to 134V dc. The green band should not exist below 129V dc because the parameter would be out of the TS required limit.

During the time frame the charger output voltage level was low, the only abnormal indication present in the control room was the analog gauge, which indicated 128V dc. The low voltage alarm was not energized because the 117V setpoint had not been reached. Additionally, the licensed plant operators are required to routinely review the main control board during their shift. The Operation Policies and Practices Manual, Policy 0-0015, states, in part, that operating personnel should pay particular attention to indications and alarms through frequent monitoring, and prompt action should be taken to determine the cause of and correct abnormalities. However, the licensed operators failed to recognize the low voltage level during their board observations. The event was still under licensee investigation at the end of the inspection period.

3.14 Housekeeping

On September 11, 1992, [illegible]s of Region IV management accompanied the resident inspectors on [illegible]r of various portions of the plant. The focus of the tour centered on the material condition of the Unit 2 Turbine-Generator

Building (TGB). NRC determined that the condition of equipment and the state of cleanliness of the building required attention. Specific items which were noted included excessive leaks on the condensor air removal pumps, dirt on the Instrument Air and Service Air compressors, accumulations of insect carcasses in the nonessential swithcgear room, clogged and ineffective filters for the building air intakes, and standing water around the main generator stator winding heat exchanger.

On September 15, 1992, Region IV managers again accompanied the resident inspectors on a tour of additional areas of the facility. This tour focused on the ECW intake structure, the Unit 1 isolation valve cubicle, and the Unit 1 TGB. Conditions in the ECW intake structure were found to be less than optimal. Large accumulations of dead insects, dirt, and spider webs were located throughout the building. The filters on the electric motors of the ECW pumps were partially obstructed. There were dead insects on the cover of the filter. There were two recorders for measuring the differential pressure across the intake screens that appeared to be abandonded in place. One of the recorders had a WR tag attached to it that was over 2 years old. The other recorder did not have a tag on it and contained no recorder paper. There was excessive leakage from one ECW pump seal that was spilling onto the floor. In the TGB, an oil leak was identified that was dripping onto the floor just outside the feedwater pump speed control housing that was not being collected. The AFW pumps in the isolation valve cubicle were covered with dead insects and dirt. Several WR tags were over 1 year old. A leak on steam generator blow-down system Valve 1-SB-FV-4155 was identified which had no tag or identifying information attached to it.

The level of housekeeping in the areas inspected was poor and indicated a lack of management emphasis on housekeeping. The inspector discussed this observation with the Plant Manager subsequent to the tours. The Plant Manager concurred with the observation that there was [illegible] enough attention being given to wiping down equipment or assuring that general cleanliness was being maintained in those areas inspected. He indicated that additional attention would be given to this area.

3.15 Completed Work Package Review

NRC was informed of a concern that work had been performed on the main steam isolation valve bypass valves prior to recieving work start authority in order to maximize production during the previous Unit 2 refueling outage. The inspector reviewed work packages available which pertained to work performed on the main steam isolation valve bypass valves during the period in question. Work packages MS-128714 and MS-132350 were identified as being applicable.

Discussions were held with the Shift Supervisor who was involved in the authority to grant work start during the day in question. The Shift Supervisor indicated that he had originally voided his signature, dated September 19, 1991, indicating authorization for work start when the concerned individual questioned the certification of the contractor (Newport News Industry (NNI)) employees to perform the work in question. The Shift

Supervisor added that the work was accomplished only after the issue was resolved. On September 3, 1991, the Maintenance Manager had issued a memorandum certifying as technically qualified to conduct secondary valve maintenance, a number of NNI personnel, based on their NNI training, experience, and qualifications. The inspector was unable to substantiate the individual's concerns based on the documented information that was available and on the results of information gathered from personnel interviews. The inspectors could not identify any information that would suggest inappropriate action by the licensee or its contractor with respect to the qualification of contract NNI workers, nor with the manner in which work start was eventually authorized.

3.16 Conclusions

During this inspection period, there were three inadvertent ESF actuations. In one instance, the cause of the ESF actuation could not be identified. The other two actuations were caused by personnel error and an inadequate surveillance procedure. A violation was cited for not reporting one of these actuations to NRC within the required time. A second violation was cited because of an inadequate surveillance procedure. As a result of these and other ESF actuations, the licensee initiated an Unplanned ESF Actuations Task Force in order to identify actions to prevent unplanned ESF actuations.

During this inspection period, the licensee identified additional examples of inadequate surveillance procedures. A violation of TS 4.3.1.1 surveillance requirements was identified by the licensee as the result of a procedural review. The inappropriate incorporation of a temporary field change into a permanent revision of four procedures resulted in inadequate testing of the undervoltage and underfrequency relays for the reactor coolant pumps. A procedural weakness was identified which led to improper testing of CCW system check valves.

Operations and operational support activities were generally good. A reactor operator was diligent in monitoring the control board indications and quickly identified excessive reactor coolant system leakage. The licensee took conservative action to reduce Unit 2 power in order to repair a steam generator feedwater pump. The quality of the licensee's request for a TWOC in order to repair a failed FHB exhaust booster fan was good. However, operator inattention, combined with misleading control board indications and procedural inadequacies, resulted in the terminal voltage of a safety-related battery being less than the TS limit.

Several weaknesses were identified in the areas of material condition, housekeeping, and maintenance. The level of housekeeping in several areas outside of the radiological controlled areas was poor. Several problems with the essential chillers recurred during this inspection period. A violation was cited for an inadequate postmaintenance of an essential chiller circuit breaker. This violation occurred because of a failure to implement corrective actions for a similar violation. The repair of steam generator PORV actuator was untimely.

4 MONTHLY MAINTENANCE OBSERVATIONS (62703)

Selected maintenance activities were observed to ascertain whether the maintenance of safety-related systems and components was conducted in accordance with approved procedures, TS, and appropriate codes and standards. All observations made were referred to the licensee for appropriate action.

4.1 ECW Maintenance

On August 11, 1992, the inspector observed several maintenance activities being performed on Train C of the Unit 2 ECW system.

4.1.1 Cathodic Protection Cover Replacement (Unit 2)

The inspector observed portions of activities that removed and replaced covers on Cathodes ACAW-1A5 and 1A6. These activities were conducted under WR NM-151229 and Work Authorization Number (WAN) 91029861. The covers were floor plates for cathodic protection of the ECW pumps. The inspector verified that the system had been properly removed from service and tagged and that the work was authorized by the craft foreman and Unit 2 Shift Supervisor. The maintenance personnel were familiar with the scope of the job and qualified to conduct the work.

While reviewing the work procedure, the inspector noted that Step 2.00 instructed the workers to call the Unit 1 Shift Supervisor and report the completion of the previous steps of the work package. When the worker was questioned by the inspector on the reason for calling the Unit 1 Shift Supervisor when the work was being conducted on Unit 2, the worker speculated that the step was a misprint and should be changed. The worker also stated that he suspected the error was made by the planner because the packages are mass produced for all three trains of both units. The worker resolved the questionable step by stopping work and taking the package to his foreman for resolution. The step was changed to indicate the Unit 2 Shift Supervisor was the individual to whom work completion should be reported. The maintenance activity then continued without further problems.

The inspector noted that the work package had been reviewed by the Planning Department, the craft foreman, and the Unit 2 Shift Supervisor without the error in Step 2.00 being detected. This was considered a weakness.

4.1.2 ECW Self-Cleaning Strainer Lubrication and Inspection (Unit 2)

The inspector observed routine maintenance being performed on the ECW self-cleaning strainer. The work was planned under Preventive Maintenance (PM) Activity MM-2-EW-87016663 and authorized under WAN 91033232, Revision 5.0. The activities consisted of inspecting the self-cleaning strainer assembly for indication of wear or leakage and checking the level of lubricating oil in the strainer gearbox. The procedure was reviewed by the required supervision and

the craft foreman and the Unit 2 Shift Supervisor authorized the work. The inspector verified that all equipment had been properly tagged and removed from service.

4.1.3 ECW Traveling Water Screen 2C, Inspection and Lubrication (Unit 2)

The inspector observed portions of ECW Traveling Water Screen 2C, Inspection and Lubrication. This activity was conducted under PM MM-2-EW-87016656 and WAN 92004109, Revision 7.0, in conjunction with PM MM-2-EW-89003171 and WAN 92017041, Revision 4.0. All prework activities were noted to have been satisfactorily performed. In addition to the inspector, a licensee quality assurance inspector reviewed these activities.

A portion of the work included draining the oil from the traveling screen gearbox, flushing, and replacing the oil. The inspector verified that the replacement oil was the grade and specified oil required by the procedure. The procedure specified numerous lubrication points on the traveling screen that required a specific high pressure, lithium based grease. The inspector verified that the grease used in the PM activity was the proper weight and grade specified in the procedure. These activities were conducted in a satisfactory manner, with no problems noted.

4.2 Replacement of Instrument Loop Card (Unit 2)

On August 31, 1992, instrumentation and controls technicians attempted to test main steam line Pressure Channel P-526 in accordance with Procedure OPSP02-MS-0526, Revision 1, "Steam Pressure Loop 2 Set 3 Analog Channel Operation Test (ACOT)." During the surveillance, the cover fell off of the coarse gain potentiometer on Card PY-526B, Steam Pressure Set 3 Loop 2 Lead/Lag Amplifier. The surveillance was terminated and the loop was declared inoperable.

Under the guidance of SR BS-165716, the card was replaced and applicable sections of the calibration procedure were performed to verify the card operability. Since this SR involved work on a component that potentially could result in a reactor trip, extra precautions were taken, including the use of a work supervisor. The inspectors witnessed the card calibration and identified no problems with the work being performed. The steam pressure channel was returned to service the same day.

4.3 Maintenance on RCS Loop 2 Flow Transmitter (Unit 1)

During the excessive RCS leakage event on September 7, 1992, RCS Loop 2 Flow Transmitter RC-FT-427 failed low. In accordance with TS 3.3.3.1, the failed channel was placed in the tripped condition. This had the effect of reducing the margin to a possible reactor trip since the failure of one more transmitters in the loop would satisfy the logic required for a reactor trip.

Because of the reduced margin to trip, the licensee generated a Priority 2 SR to initiate troubleshooting and repair of the failed transmitter. SR RC-173817 provided the specific work instructions to accomplish this work.

The inspector noted, while in the control room, that four procedural steps in the work instructions had been signed as having been verified, but the corresponding lines indicating the performance of work had not been signed. The inspector noted this condition to the Deputy Plant Manager who was also present in the control room. The Shift Supervisor was informed and he ordered immediate corrective action to verify the performance of the steps in question under the observation by the Deputy Plant Manager. The work was subsequently completed and the flow transmitter was returned to service after a faulty card was replaced.

Procedure OPGP-ZA-0010, "Plant Procedure Adherence and Implementation and Independent Verification," Step 4.2.19 requires that procedure steps with signoff blanks be signed or initialed, as appropriate, as soon as practical after the action has been performed. The technicians performing work on the flow transmitter failed to follow this requirement when the performer of the steps in question failed to sign his name after he completed the actions. This failure to follow an approved procedure is a violation of TS 6.8.1.a (498/9226-04).

4.4 Replacement of Process Instrumentation System Power Supply (Unit 2)

On September 3, 1992, the inspector witnessed the replacement of the primary power supply in Relay Rack ZRR-040 of the Westinghouse 7300 process instrumentation system. This 26.0V, 65 ampere power supply had no indication of dc amperage or voltage. Its replacement was considered a high risk job because it had the potential to affect availability of main feedwater to the steam generators. If the backup power supply were to have been lost during the replacement, the feedwater deaerator level and pressure control also would have been lost. In addition, the recirculation valves for Condensate Pump 23 and SGFP 23 would have opened and reduced feedwater flow. These events could result in a reactor trip.

The preparations for this job included performing an analysis of the risk associated with the replacement and holding a prejob briefing where contingencies were discussed. The inspector reviewed the results of the analysis and attended the briefing. The actual replacement was also witnessed and found to have been conducted in a systematic and careful manner. Licensee management was involved in monitoring all steps of the process.

4.5 Conclusions

Observed maintenance was generally performed well. Preparations and planning for high risk jobs were good. A minor weakness was identified in the review of a work package that had a reference to the wrong unit. Maintenance personnel were familiar with the equipment and equipment was properly tagged and removed from service. One violation for failure to follow a procedure was identified when a technician failed to document his signature for work accomplishment. This violation was indicative of continuing problems in the area of documenting work performance and verification.

5 BIMONTHLY SURVEILLANCE OBSERVATIONS (61726)

Selected activities were observed to ascertain whether the surveillance of plant systems and components were being conducted in accordance with TS and other requirements. The inspection included a review of the procedures being used, assurance that the test equipment was correct for the task being performed, and verifying that data measured was within acceptance criteria limits. All comments and observations were reported to the licensee for resolution.

5.1 Steam Generator Blowdown System Valve Operability Test (Unit 1)

On August 13, 1992, the inspector observed Unit 1 control room operators conduct Procedure 1PSP03-SB-0001, Revision 5, "Steam Generator Blowdown System Valve Operability Test," which was being conducted under WAN 92011261. The purpose of the surveillance was to remotely shut the steam generator blowdown and sample valves to ensure the stroke time was within American Society of Mechanical Engineers Section XI requirements.

During the review of the procedure, the inspector noted that a total of four FCs had been applied to the procedure, with two dating to 1990, and a third implemented on December 19, 1989. Procedure OPGP03-ZA-0002, "Plant Procedures," states that quality-related plant procedures shall be reviewed at least every 24 months in order to ensure that the procedures are maintained current. Additionally, Procedure OPGP03-ZA-0002 states that, although procedure revision to incorporate FCs is not required as a result of biennial reviews, consideration should be given to revising procedures which contain three or more FCs or which contain FCs more than 2 years old. The surveillance procedure 1PSP03-SB-0001 satisfied both of these criteria. During this inspection period, a second example was identified. Procedure OPSP05-RC-0440, Revision 0, "Delta T and T Average Loop 4 Set 4 Calibration," was over 2 years old and had 11 FCs attached. Some of the FCs were also over 2 years old. The inspectors considered the lack of timely incorporation of FCs into permanent procedure revisions to be a weakness.

After a short crew briefing, the shift supervisor approved the surveillance for work start. The operators exhibited good control and the surveillance proceeded without any problems noted.

5.2 EDG Operability Test (Unit 2)

During the inspection period, an EDG was tested using two revised surveillance procedures. EDG 21 was started and operated as designed; however, the EDG was unnecessarily started twice, once because of procedure problems and once because of human error during test performance. The inspectors noted that unnecessary EDG starts could result in additional wear and stress of the EDG components.

TS 4.8.1.1.2 requires that each EDG be demonstrated operable by:
(1) verifying that the fuel level in the associated fuel tank is acceptable,

(2) ensuring the engine will start from ambient conditions and accelerate to 600 revolutions per minute, with adequate voltage and frequency, within 10 seconds, (3) verifying the generator is synchronized and loaded to greater than 5500 kilowatts (kw) within 10 minutes and operates at 5500 kw or more for at least 60 minutes, and (4) verifying the EDG is aligned to provide power to the associated emergency bus. A footnote to this TS requirement states that diesel starts from ambient conditions shall be performed only once per 184 days in these surveillance tests, and all other engine starts for the purpose of these surveillance tests shall be preceded by an engine prelube period and/or other warmup procedures such as gradual loading (greater than 150 seconds) recommended by the manufacturer so that the mechanical stress and wear on the engine is minimized.

The licensee previously performed the rapid load method of testing each month during EDG surveillance testing. A 5500 kw load was applied to the EDG within 10 minutes each time the monthly test was performed. Concerned with the possibility of premature wear of the EDGs, the licensee changed their EDG operability test philosophy. The licensee decided to revise their surveillance procedures to gradually load each EDG to 5500 kw over a 2-hour period prior to the 60-minute run. The rapid load test would be performed every 6 months rather than monthly. The licensee determined that the proposed changes complied with the TS requirements, including the TS 4.8.1.1.2 footnote, since the revised procedures were based on the manufacturer's recommendations and were determined to be needed to reduce EDG stress and wear.

The EDG operability test surveillance procedures were subsequently revised to combine the two unit procedures into one and to provide instructions on how to test the EDGs with a rapid or gradual load application. The gradual load instructions were applicable to all monthly operability surveillance test engine starts, with the exception of the 184-day rapid load test specifically required by TS. A second surveillance procedure, the slave relay test procedure, was used to test the ability of the EDG to start upon receipt of a safety injection (SI) signal. This procedure was revised to also combine the two unit procedures into one procedure, and to provide clear instructions on when to transition from the slave relay test procedure into the operability test procedure.

On August 26, 1992, the Unit 2 plant operators prepared to start and test EDG 21 in accordance with monthly Test Procedure OPSP03-DG-0001, Revision 0, "Standby Diesel 11(21) Operability Test," and quarterly Test Procedure OPSP03-SP-0011A, Revision 0, "Train A Diesel Generator Slave Relay Test." The licensee was prepared to start the EDG using the slave relay test procedure and transition to the operability test procedure to perform the 60-minute required run. Just prior to test performance, a decision was made to postpone the test of EDG 21 using Procedure OPSP03-SP-0011A because procedure problems were identified. The locations specified in the new procedure for taking electrical measurements were in error. The shift supervisor decided to run EDG 21 using Procedure OPSP03-DG-0001 only and requested that engineering review and revise the slave relay test procedure. EDG 21 was started in

accordance with the operability test procedure using the gradual load portion of the procedure. The inspectors witnessed the test start and verified that no abnormal conditions, such as local leaks, were present. The test was performed without incident.

On September 4, 1992, EDG 21 was restarted to perform revised Procedure OPSP03-SP-0011A. The procedure attempted to verify the ability of the EDG to start and run unloaded following the receipt of a SI signal. Step 7.6.3 provided instructions to place the SI test switch (switch injects a simulated SI signal into the EDG control circuitry) in the "push to test" position and wait for a countdown from the control room. Additionally, a caution just prior to Step 7.6.3 provided instructions to not depress the switch until Step 7.6.4. This delay was required to allow the control room operator to be prepared to time the EDG start with a stopwatch to ensure the TS start time requirements were met. The licensed operator performing the surveillance test prematurely pressed the SI test switch during test performance, which started EDG 21 before the control room operator was prepared to take the TS required timed data. The procedure was completed without any further problems being encountered. Following test completion, the control room operators declared the surveillance test run as a "No Test," and the procedure was reperformed without incident.

The decision to delay the test the first time and the decision to reperform the test were both conservative in nature. Collectively, however, a high number of unnecessary EDG starts could have a long-term negative effect on the EDGs, including premature engine wear and stress.

5.3 Conclusions

The failure to incorporate procedure FCs into a procedure revision in a timely manner was identified as a weakness. The licensee's decision to perform a gradual start of EDGs during the monthly operability tests was conservative because this change in the method of testing should result in reduced engine wear. An EDG was unecessarily started twice, once because of procedure problems and once because of human error. A high number of unnecessary EDG starts could have a long-term negative effect on the EDGs, including premature engine wear and stress.

6 PREPARATION FOR REFUELING (60705)

Prior to Unit 1 shutdown, an assessment of the licensee's implementation of controls for refueling operations was performed. The assessment included an observation of fuel receipt and inspection, a discussion of significant outage activities planned, outage staffing and supervision, and control of plant risks during shutdown conditions.

6.1 New Fuel Receipt, Inspection, and Storage

The licensee has been receiving shipments of new fuel in preparation for the Unit 1 refueling outage, scheduled to begin September 19, 1992. There were a total of 76 fuel bundles that were delivered to South Texas Project.

The inspectors observed the licensee receiving new fuel in accordance with Procedure OPEP02-ZM-0002, Revision 3, "New Fuel Receipt, Inspection, and Storage." The licensee inspected the shipping cask and fuel bundles for damage prior to placing them in the proper storage location. This was done through radiological contamination surveys and visual inspections. All serial numbers were recorded and compared to vendor documents to ensure the proper fuel had been received. The licensee performed well in the receipt, inspection, and storage of new fuel.

6.2 Unit 1 Fourth Refueling Outage Scope

The Unit 1 fourth refueling outage was scheduled to begin on September 19, 1992. A 62-day outage duration was planned, with a completion date of November 20, 1992.

6.2.1 Outage Scope

A full core off-load will be performed utilizing an integrated head lift, which will result in an extended "no mode" work window. A total of 76 new fuel bundles will be installed in the reactor core. An integrated containment leak rate test will not be performed; however, 89 local leak rate tests are scheduled to be completed. EDG 12 (B Train) will undergo a vendor recommended 5-year inspection and EDGs 11 and 13 (A and C Trains) will receive 18-month inspections. The containment spray additive system will be deleted (this system was abandoned in place in Unit 2 during the last refueling outage). The toxic gas monitors will be replaced and the actuation logic will change from 1 out of 2 to 2 out of 3. The high pressure main turbine gland seal system will be modified (requires pulling the rotor) because of gland seal leakage. Repairs scheduled to be made to the ECW system include repair of three 30-inch lines (two cracks, one fabrication flaw), replacement of 12 6-inch flanges, and replacement of one leaking thermowell. Ninty-six MOVs will be tested. The main condenser tubes will be chemically cleaned. A total of 39 mechanical and 2 hydraulic snubbers will be functionally inspected, and 16 hydraulic snubbers will be visually inspected. Fifty-six modifications are scheduled to be installed. Also, 974 surveillances, 1357 service requests, and 1373 preventive maintenance activities are also within the scope of the outage.

6.2.2 Outage Management

Several changes in plant staffing were made to assist in the outage management. A position of outage director was developed to assist the Plant Manager in the accountability and coordination of outage activities. This position will be staffed around-the-clock using department managers on a

rotating shift. Other positions developed include the outage manager, outage shift managers (supervisors), and outage coordinator positions. This multi-disciplined team was developed to manage the outage by controlling the schedule to ensure the correct jobs are worked, shutdown risk is managed, and the schedule sequence is followed. The licensee also plans to strictly control the amount of overtime worked in order to reduce fatigue. Additionally, licensee management has stressed to the plant staff that quality of work performance was more important than meeting the schedule. During normal plant operations, a 5-day rotation is used by plant operators with one shift always in training. Since the operations requalification training was rescheduled, a four-shift rotating staff will be used during the outage. This operations shift rotation schedule was developed to increase the staffing available and to reduce overtime. Maintenance craft personnel were scheduled to work a 5-day, 12-hour schedule, which is intended to assure each person receives 2 days off each week.

A new program, the outage reactor plant operator (RPO) training program, will be used to maximize RPO hands-on training during the outage. This training will provide the RPOs with the opportunity to perform tasks on equipment not normally operated at power.

6.2.3 Shutdown Risk Assessment

A shutdown risk assessment was performed to support the "defense in depth" philosophy of planning and providing for safety system availability during the outage. This assessment was performed in accordance with industry available guidance and is expected to receive a high level of management attention. Some of the safety functions involved with shutdown risk considerations included onsite and offsite power availability, decay heat removal, reactor coolant inventory, spent fuel pool cooling, containment integrity, building ventilation, reactivity management, control of hazards (such as fire or movement of heavy loads) and personnel safety. In response to the assessment, the licensee will have two RHR trains and associated EDGs available in Modes 5 and 6, one train available in "no mode," the equipment hatch to the reactor containment building closed in Mode 5 when the reactor vessel water level is lowered, and two offsite power sources available at all times.

6.3 Conclusions

The Unit 1 fourth refueling outage appears to be well planned by the licensee. The schedule appears aggressive, however, because of the number of MOVs scheduled to be tested. Shutdown risk assessment activities and the planned use of shift outage managers and coordinators were considered positive licensee initiatives.

7 FOLLOWUP ON CORRECTIVE ACTIONS FOR VIOLATIONS AND A DEVIATION (92702)

7.1 (Closed) Violation 498/9208-02: Failure to Tag Breakers Associated with Inactive Components

On April 1, 1992, during a walkdown of Equipment Clearance Order (ECO) 1-92-502, the inspectors identified four electrical circuit breakers that were not tagged in accordance to procedural requirements. The four circuit breakers were associated with the Unit 1 Train A ECW system to essential chilled water system chiller outlet valves that were previously removed by the implementation of a temporary modification. The failure to follow the configuration control procedure resulted in a potential personnel and equipment hazard because no controls were in place to ensure that the four electrical circuits remained de-energized.

The cables associated with the four essential chilled water system chiller outlet valves were determinated, retracted to the nearest cable pull box, and insulated; however, there were no provisions in either the temporary modification or work package implementing the temporary modification regarding control of the component power supplies. Procedure OPGP03-ZO-0003, Revision 11, "Temporary Modifications," did not provide specific guidance regarding determination of power cables.

Corrective actions included adding the four power supplies to the ECO tag out on April 1, 1992, revising the temporary modification procedure to require the system engineer to accept responsibility for ECOs, which are required to remain in place after the installation of a temporary modification to ensure proper controls are maintained, and conducting a review of existing temporary modifications with emphasis placed on similar types of power cable modifications.

The inspectors conducted a review of selected ECO tag-outs to insure corrective actions taken have been effective. Two ECOs were selected and were walked down in the plant to ensure compliance with the ECO program. ECO 1-91-2900 was issued to ensure the four flush lines to a heat exchanger were tagged shut, and ECO 1-92-0900 was issued to isolate a level switch to allow for mechanical repair of a vent. Both ECOs were properly implemented and no discrepancies with procedural requirements were identified.

8 FOLLOWUP (92701)

8.1 (Closed) Inspection Followup Item (498;499/9132-04): Falsification of Plant Records

During an NRC physical security inspection conducted during December 9-13, 1991, (NRC Inspection Report 50-498/91-32; 50-499/91-32), the inspector identified an incident involving possible falsification of an NRC-required security record. This issue was characterized in the report as an inspection followup item pending further investigation of the incident to determine whether the security officer actually falsified the patrol log and to review

other patrol logs that may have been falsified. The licensee's investifation determined that the security officer did falsify the patrol log. In addition, they also identified one other falsified patrol log entry made by another security officer. Both security officers were denied unescorted access and their employment with the security force contractor was terminated.

The inspector's review of the licensee's actions concerning this violation determined that the licensee had satisfied the requirements regarding enforcement discretion discussed in the Enforcement Policy. The violation was licensee-identified and was documented as a loggable event. NRC was notified of each instance of log falsification even though these violations were not required to be reported to NRC. The violation was corrected in a reasonable period of time. Although the violations were willful, they were committed by low level individuals (i.e., security officers) and were isolated actions of the employees, without management involvement. In addition, licensee management has, in the past, demonstrated aggressive actions in identifying and correcting other isolated instances of willful violations. Finally, the licensee took substantial disciplinary actions by terminating the two security officers and also provided additional log taking guidance to station personnel. This violation will not be subject to enforcement action because the licensee's efforts in identifying and correcting the violation meet the criteria specified in Section VII.B.2 of the Enforcement Policy.

8.2 <u>(Open) Inspection Followup Item 498;499/9214-03: EDG Cooldown Cycle Problems</u>

The licensee continued to experience problems with the Unit 2 EDGs during the EDGs' cooldown cycles. Limited actions have been taken by the licensee because of the time interval required to repair the apparent problems. The causes of the cooldown cycle trips are not expected to be fully resolved until the end of the Unit 2 refueling outage, scheduled to begin in Febraury 1993.

During this inspection period, the Unit 2 EDGs tripped during the cooldown cycles several times. On August 5, 1992, EDG 22 tripped during the cooldown cycle early because of a possible pneumatic header check valve leak. On August 12, 1992, EDG 23 tripped 13 seconds into the cooldown cycle because of a previously identified pneumatic header leak. On September 4, 1992, EDG 21 tripped about 2 minutes into the cooldown cycle after receiving a jacket water high temperature alarm. Local and remote jacket water temperature indications were normal, which indicated a pneumatic header leak was present on EDG 21.

The licensee has written SRs and has performed troubleshooting activities whenever possible. The licensee believes the root causes of the problems cannot be corrected within the time frame of routinely scheduled maintenance outages. Corrective actions needed to repair the causes of cooldown cycle trips would take longer than the 72-hour TS allowed outage time. For example, the crankcase cover has to be removed from the engine block to allow for access of selected sections of the pneumatic header. Therefore, complete repair of the air header leaks is not expected to occur until the end of the next Unit 2 refueling outage, scheduled for the spring of 1993. Long-term

corrective actions planned by the licensee include development of a preventive maintenance to leak check the pneumatic header during refueling outages.

The cooldown cycle is a design feature that is used to check the operability of selected EDG components. This equipment operability check cannot be completed because of the premature shut downs being experienced by the EDGs during the cooldown cycles. This inspection followup item will remain open to track licensee efforts to resolve the problems that are resulting in the cooldown cycle trips.

8.3 (Open) Inspection Followup Item 498;499/9224-03: Essential Chiller Reliability and Unavailability

During a previous inspection, a weakness was identified in the essential chiller trending and corrective action program, as indicated by the excessive number of chiller trips and failures to start. During this inspection period, the licensee continued to experience problems with the essential chillers (refer to Section 3.10 of this inspection report).

In response to inspector inquiries on essential chiller availability, the licensee's Plant Engineering Department performed an investigation of the Units 1 and 2 essential chilled water system availability rates. From January 1 through May 30, 1992, the Unit 1 essential chilled water availability rate was 95.5 percent and the Unit 2 rate was 96.8 percent. When ECW is unavailable, the essential chilled water system is also considered unavailable. When these ECW system unavailability hours were subtracted from the total essential chilled water unavailibility hours, the Unit 1 essential chilled water system availability rate was 98.3 percent and the Unit 2 availability rate was 98.8 percent.

The licensee also performed another survey of availability rates for the essential chillers for the month of August 1992. The Unit 1 essential chillers were available only 90.2 percent of the time in August 1992, while the Unit 2 essential chillers were available 84 percent of the time. The lower than expected availability rates for August 1992 appeared to contradict the rates estabished for January 1 through May 30, 1992. Additional information is required in order to determine whether the rates for August 1992 were indicative of a declining trend or a statistical variation. To further analyze the information provided by the licensee, the inspectors plan to determine the availability rates because of forced corrective maintenance outages since January 1, 1992. This inspection followup item remains open pending further NRC review of the essential chilled water system reliability and availability rates.

9 MANAGEMENT MEETING (30702)

On September 11, 1992, the Regional Administrator and members of the Region IV staff met with licensee representatives at South Texas Project. The purpose of the meeting was to discuss the work scope and schedule for the fourth Unit 1 refueling outage, which was scheduled to start on September 19, 1992.

A second purpose of the meeting was to discuss the assessment of shutdown risks associated with the outage. A summary of this meeting will be provided by separate correspondence.

10 GENERIC LETTER 89-10, "SAFETY-RELATED MOTOR-OPERATED VALVE TESTING AND SURVEILLANCE" (2515/109)

During September 3-4, 1992, a followup inspection of the MOV program was conducted. This program was previously inspected during February 24-28, 1992 (NRC Inspection Report 50-498/92-06; 50-499/92-06), and June 16-18, 1992 (NRC Inspection Report 50-498/92-21; 50-499/92-21). During the former inspection, Unresolved Item 498;499/9206-01 was identified questioning the validity of information supplied by Westinghouse (the supplier of 118 MOVs at STP) regarding the stall thrust capacity and overthrust capability of a large number of MOVs. During the period of July 7-9, 1992, the NRC conducted a vendor inspection at Westinghouse (NRC Inspection Report 99900404/92-01) and concluded that the stall thrust and overthrust information supplied by Westinghouse could not be used generically by licensees without site-specific justification. The purpose of the September 1992 inspection was to assess the licensee's action plan to address the findings from the NRC inspection at Westinghouse.

10.1 MOV Stall Thrust

The inspectors reviewed a document entitled "South Texas Project Plan For Resolution of Westinghouse Stall Thrust Concerns," dated September 3, 1992. This document outlined the licensee's plan of action to address the issues of stall thrust at degraded voltage and overthrusted actuators.

Regarding the stall thrust issue, the licensee had decided to conduct a series of motor stall tests in addition to MOV diagnostic tests at degraded voltage during the upcoming Unit 1 refueling outage (1RE04, scheduled September 19 to November 20, 1992). The purpose of these tests was to determine the applicability of stall thrust values supplied in Westinghouse calculations. Additionally, the licensee was in the process of recalculating the available thrust for Westinghouse MOVs (80 of the total of 118 were performed to date) using the standard industry sizing equation. Five MOVs in the SI system were determined by these calculations to be marginally sized, but were considered by the licensee to be operable based on the licensee's assertion that the actual stem friction coefficient was substantially less than that used in the calculations. This assertion was based on approximately eight diagnostic test results that demonstrated very low stem friction values. Additional stem friction coefficient measurements will be obtained during Refueling Outage 1RE04. The licensee stated that each of the five marginal MOVs could perform its safety function but acknowledged that the valves may not be able to be repositioned thereafter because of motor overheating. None of the affected MOVs would require repositioning once their safety position was achieved.

The licensee intended to install strain gages on a number of MOVs to improve the accuracy of the diagnostic testing system. During Refueling Outage 1RE04, a total of 33 strain gages were to be installed.

Should tests or calculations reveal an MOV operability concern, the licensee stated that a station problem report or nonconformance SR would be initiated to both correct the identified problem and assess the resulting implications for the other unit.

The inspectors' review of the action plan did not indicate an immediate operability problem, though several concerns were identified and communicated to the licensee. One of these concerns was that the stall tests were scheduled to be performed under static (no flow) conditions. As a result, the momentum and load sensitive behavior effects associated with dynamic conditions would not be experienced, and the measured stall thrust would tend to be higher than that actually available under design basis conditions. The licensee, who had cited operational limitations as the basis for conducting the stall tests under static conditions, acknowledged that a calculational adjustment to the measured stall thrust values would be necessary.

10.2 Other MOV Issues

The inspectors noted that the licensee had used the motor running efficiency in its sizing equations for MOV open-to-close operation. This was in variance to Limitorque's (the actuator manufacturer) recommendation to use motor pull-out efficiency for this case. The licensee provided several diagnostic traces which appeared to support their position but agreed to contact Limitorque directly for their concurrence.

The inspectors noted that the licensee had not provided margin for torque switch setting and repeatability within the framework of its initial review for MOV operability following completion of the MOV sizing equations. Thus, the number of marginal valves may have been understated in the licensee's program plan. The licensee acknowledged this shortcoming and stated that it would be addressed.

The inspectors also noted that the maximum expected differential pressure listed in Westinghouse calculations for MOVs A1SIMOV0006A, C1SIMOV0006C, and A2SIMOV0006A was numerically less than the highest possible differential pressure that could be experienced under normal plant operation. Based on the inspectors' review and discussions with the licensee, system operation appeared to justify the use of the lower pressure for degraded voltage conditions, though justification had not been provided in the calculation. Operation of the MOVs at the higher differential pressure may be necessary for certain normal operational functions, but it appeared reasonable that this operation need not be considered at degraded voltage. The licensee stated they would review these calculations and make the necessary changes.

The licensee's action plan for overthrusted actuators and use of the Westinghouse and Kalsi up-rating programs was aimed at reducing all actuator

as-left thrusts to less than 110 percent of the nominal actuator rating (the limit typically used by nuclear utilities). For specific cases, the licensee stated that the Westinghouse and Kalsi up-rating programs would be used but that site-specific applicability evaluations would be conducted. The licensee acknowledged that some MOV modifications would likely be necessary to implement this plan.

10.3 Conclusions

As an overall assessment, the inspectors concluded that the licensee had taken an aggressive first step at resolving the concerns identified in Unresolved Item 498;499/9206-01. A large allocation of resources, personnel, and expertise was being mobilized to strengthen and realign the program. Upper management appeared to be in strong support of this initiative. This support was typified by the MOV engineering team being assembled and the contracting of experienced consultants for use during the upcoming Unit 1 refueling outage. The unresolved item will remain open pending NRC review of the implementation of the licensee's MOV action plan.

ATTACHMENT 1

1. PERSONS CONTACTED

1.1 Licensee Personnel

B. Auguillard, Senior Development Analyst
W. Cartee, Consultant, Planning and Assessment
R. Dally-Piggott, Engineering Specialist, Licensing
D. Hall, Group Vice President, Nuclear
R. Hernandez, Manager, Design Engineer
T. Jordan, General Manager, Nuclear Assurance
W. Jump, Manager, Nuclear Licensing
R. Kerr, Senior Engineer, Independent Safety Engineering Group
R. Kersey, Engineer, Design Engineering
W. Kinsey, Vice President, Nuclear Generation
C. Kloman, Test Coordinator, Motor Operated Valve
D. Leazar, Manager, Plant Engineering Department
M. McBurnett, Manager, Integrated Planning and Scheduling
M. McGeheraty, Motor Operated Valve Test Coordinator
M. Pacy, Division Manager, Design Engineering Department
G. Parkey, Plant Manager
U. Patil, Motor Operated Valve Program Manager
S. Phillips, Nuclear Licensing Engineer
R. Rehkugler, Director, Quality Assurance
C. Rowland, Design Engineering Department
G. Schinzel, Engineer Supervisor, Plant Engineering
L. Taylor, Manager, Maintenance Planning

1.2 NRC Personnel

R. Evans, Resident Inspector
T. McKernon, Reactor Inspector
M. Runyan, Reactor Inspector
T. Westerman, Chief, Plant System Section

The personnel noted in Sections 1.1 and 1.2 attended the exit meeting on September 4, 1992.

1.3 Licensee Personnel

R. Balcom, Manager, Nuclear Security Department
H. Bergendahl, Manager, Technical Services
C. Bowman, Corrective Action Group Administrator
M. Chakravorty, Executive Director, Nuclear Safety Review Board
R. Dally-Piggott, Engineering Specialist, Licensing
R. Hamilton, Plant Operations Technical Supersivor
T. Jordan, General Manager, Nuclear Assurance
W. Jump, Manager, Nuclear Licensing
D. Leazar, Manager, Plant Engineering
M. Ludwig, Administrative, Participant Services
M. McBurnett, Manager Integraded Planning and Scheduling
A. McIntyre, Director, Plant Projects

R. Murphy, Manager, Plant Analysis
M. Pacy, Division Manager, Design Engineering Department
G. Parkey, Plant Manager
K. Richards, Acting Maintenance Department Manager
B. Tedder, Supervisor, Plant Quality Assurance
T. Underwood, Deputy, Plant Manager
L. Weldon, Manager, Operations Training

1.4 NRC Personnel

J. Tapia, Senior Resident Inspector
R. Evans, Resident Inspector
C. Guerra, Radiation Specialist

The personnel noted in Sections 1.3 and 1.4 attended the exit meeting on September 14, 1992.

In addition to the personnel listed below, the inspectors contacted other personnel during this inspection period.

2 EXIT MEETING

Exit meetings were conducted on September 4 and 14, 1992. During these meetings, the inspectors reviewed the scope and findings of the report. The licensee did not identify as proprietary, any information provided to, or reviewed by, the inspectors.