APPENDIX B

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

NRC Inspection Report: 50-498/92-05 50-499/92-05

Operating License: NPF-76 NPF-80

Dockets: 50-498
50-499

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

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

Inspection At: Matagorda County, Texas

Inspection Conducted: February 2 through March 14, 1992

Inspectors: J. I. Tapia, Senior Resident Inspector
R. J. Evans, Resident Inspector
A. M. Dummer, Reactor Engineer

Approved: A. T. Howell 4-7-92
A. T. Howell, Chief, Project Section D Date
Division of Reactor Projects

Inspection Summary

Inspection Conducted February 2 through March 14, 1992 (Report 50-498/92-05; 50-499/92-05)

Areas Inspected: Routine, unannounced inspection of plant status, onsite followup of written reports of nonroutine events, followup of an open item, onsite followup of events, operational safety verification, and monthly maintenance observations.

Results:

The quality of reviewed reports submitted in accordance with 10 CFR Part 50.73 was good (Section 3).

The material condition of the turbine generator building contributed to a manual reactor trip (Section 4.1). Rain intrusion resulted from deteriorated sealant material and caused problems with the steam generator feed pump speed control circuitry. This led to a manual reactor trip when steam generator levels became uncontrollable. This trip may have been avoided had timely implementation of previously proposed modifications occurred. Personnel error caused a second reactor trip (Section 4.2). An Instrumentation & Controls technician failed to follow procedures during the restoration of a flow transmitter to service and caused a loss of reactor coolant system (RCS) flow signal. This failure to follow procedures resulted in the third trip due to personnel error in the past 6 months. Both of these trips are indicative of a lack of effectiveness in the licensee's trip reduction program that was initiated in September 1989. Additional problems with the main feedwater system occurred during this inspection period, when operators tripped Steam Generator Feedwater Pump 23 because of an electrohydraulic control oil leak (Section 5.7). As a result of these recent main feedwater system problems, the licensee formed a main feedwater system task force.

Portions of the essential cooling water (ECW) system and the AC electrical distribution system were walked down to assure proper operational lineup. The results indicated correct alignment (Sections 5.1 and 5.4).

As a result of longstanding problems with leaks in the ECW system, the licensee requested two temporary waivers of compliance in order to perform leak repairs. Repairs of three leaks were implemented, bringing the total number of leaks repaired to seven. The licensee presented an aggressive plan to provide long-term solutions to the issue. These proposed and ongoing actions indicate a strong engineering approach which results from the assignment of a senior manager to focus on this issue (Section 5.6).

Maintenance activities observed were performed well. However, the licensee identified poor work practices that had the potential for causing a reactor trip. These practices involved not assuring that the control room was aware of ongoing troubleshooting on the main turbine-generator and causing false fire alarms as a result of inadvertently bumping into equipment (Section 5.2). Troubleshooting of a recurring problem with the emergency diesel generators was performed. As with the ECW problem, a manager was assigned to focus attention on resolving several longstanding issues with the emergency diesel generators (Section 6.3).

A list of acronyms and initialisms is provided as an attachment to this report.

DETAILS

1. PERSONS CONTACTED

*P. Appleby, Nuclear Training Manager
*R. Balcom, Manager, Nuclear Security
*H. Bergendahl, Manager, Technical Services
*T. Blevins, Supervisor, Procedure Control
*C. Bowman, Corrective Action Group Administrator
*M. Chakravorty, Executive Director, Nuclear Safety Review Board
*R. Chewning, Vice President, Nuclear Support
*M. Covell, Manager, Emergency Response
*R. Dally, Engineering Specialist, Licensing
*D. Denver, Manager, Nuclear Engineering
*J. Gruber, Division Manager, Material Technical Services
*A. Harrison, Supervising Engineer, Licensing
*R. Hernandez, Manager, Design Engineer
*A. Khosla, Staff Engineer, Independent Safety Engineering Group
*W. Kinsey, Vice President, Nuclear Generation
*D. Leazar, Plant Engineering Manager
*J. Lovell, Director, Nuclear Generation Projects
*D. Manis, Junior Management Analyst
*D. McCallum, Manager, Unit 1 Operations
*A. McIntyre, Director Plant Projects
*J. Pinzon, Senior Licensing Engineer
*S. Rosen, Vice President, Nuclear Engineering
*J. Soward, Manager, Nuclear Quality Control and Material Testing
*M. Wisenburg, Plant Manager

In addition to the above, the inspectors also held discussions with various other licensee and contractor personnel during this inspection.

*Denotes those individuals attending the exit interview conducted on March 17, 1992.

2. PLANT STATUS

Unit 1 began the inspection period in Mode 1 (Power Operation) at 100 percent power. On March 14, 1992, after being on line for 105 days, Unit 1 tripped from full power. The unit tripped as a result of a Loop 2 low flow signal. The trip signal was accidentally generated by a maintenance technician while incorrectly attempting to restore an out of service flow transmitter. The unit was stabilized in Mode 3 (Hot Standby) and remained in Mode 3 through the end of the inspection period.

Unit 2 began the inspection period in Mode 1 at 100 percent power and remained at full power until the reactor was manually tripped on February 24, 1992. The unit was manually tripped because of steam generator feedwater pump (SGFP) speed control problems which resulted from rainwater intrusion. The unit was stabilized in Mode 3. The unit was returned to Mode 1 operation on

February 25, 1992. On February 26, 1992, the main generator output breaker was closed, and the unit was returned to full power operation. On March 9, 1992, Unit 2 power was reduced to about 50 percent power to allow for work on SGFP 23 support systems. Power ascension to full power began 3 days later, and the unit ended the inspection period at full power operation.

3. INSPECTOR FOLLOWUP

3.1 Onsite Followup of Written Reports of Nonroutine Events at Power Reactor Facilities (92700)

3.1.1 (Closed) Licensee Event Report (LER) 1-91-015: Unexpected Actuation of Auxiliary Feedwater Pump 13 During Performance of Engineered Safety Features (ESF) Sequencer Surveillance Test

On April 22, 1991, during a surveillance test of the Unit 1 Train C ESF Sequencer, the Train C Auxiliary Feedwater (AFW) pump automatically started. In addition, the Train C Essential Chillers appeared to load before receiving a start signal. This event was reported to the NRC Operations Center as a 4-hour report in accordance with 10 CFR Part 50.72.

Troubleshooting in accordance with Work Request SF-117815 identified the cause of the event as a failure in the sequencer test circuitry. A light emitting diode (LED) in series with an optical isolator had failed open during the surveillance test. The optical isolator provides a current path for the blocking relay associated with the AFW circuit. Failure of the LED caused the blocking relay for AFW Pump 13 to become deenergized. This caused AFW Pump 13 to start.

The licensee also evaluated the essential chiller loading. It was determined that the surveillance procedure was unclear as to the order in which messages on the test equipment should illuminate to indicate chiller start. The essential chiller had in fact received a start signal before loading. As a result, the licensee determined it was necessary to revise the procedure.

The corrective actions taken by the licensee included replacement of the faulty LED and the optical isolator. The blocking circuit was satisfactorily tested. The licensee also revised Surveillance Test Procedures OPSP03-SP-0010A, B, and C, which are associated with the sequencer manual local test. A note was added to the procedures to clarify which of the output status indicator lights are to be received before an essential chiller start. These procedures have been revised and were effective as of February 12, 1992. These corrective actions are sufficient. This LER is closed.

3.1.2 (Closed) LER 2-89-022: Reactor Trip Due to Actuation of the Overtemperature Delta Temperature (OTDT) Turbine Runback Circuit

On September 19, 1989, Unit 2 was in Mode 1 at 100 percent power. Cross calibration of the incore and excore nuclear instrumentation was being performed. The control room operators were using manual control rod motion with boration and dilution to control neutron flux distribution and temperature. During the test, RCS average temperature (Tavg) increased above the reference temperature value by approximately one degree. The increase in Tavg caused a decrease in the OTDT setpoint and initiated a turbine runback. The turbine runback resulted in a further increase in Tavg and decrease in the OTDT reactor trip setpoint. This caused a reactor trip and subsequent turbine trip. A feedwater isolation occurred on low Tavg and an AFW actuation occurred as a result of a low steam generator water level signal.

The OTDT reactor trip provides core protection against Departure from Nucleate Boiling. The setpoint is automatically reduced upon an increase in coolant temperature. The turbine runback is a nonsafety-related feature designed to be used in conjunction with automatic rod position control. However, as designed, the runback setpoint does not allow sufficient operating margin to prevent unwanted runbacks due to small temperature increases. With control rods in manual, the turbine runback will result in a reactor trip.

The licensee performed several corrective actions as a result of the reactor trip. The OTDT turbine runback feature was permanently disabled on both units. The licensee performed an analysis of generic implications and found no other automatic functions with the same potential to cause a reactor trip because of incorrect time delay settings. The licensee also revised the cross calibration procedure, adding a caution to terminate the test if Tavg reaches 594°F. The inspector reviewed these corrective actions and found them to be sufficient. This LER is closed.

Conclusion

The overall quality of the two LERs was good. The licensee adequately determined the root causes and proposed and implemented satisfactory corrective actions. The LERs reviewed satisfied the reporting requirements of 10 CFR Part 50.73.

3.2 Inspector Followup (92701)

3.2.1 (Closed) Open Item 498;499/8941-01: Operability of Loose Parts Monitoring System

The Loose Parts Monitoring System (LPMS) continuously monitors selected locations on the reactor vessel and steam generators for excessive motion of core internals and noise resulting from loose metallic parts in the RCS. During a previous inspection, documented in NRC Inspection Report 50-498/89-41; 50-499/89-41, the NRC determined the system was not being operated as described in the Updated Final Safety Analysis Report (UFSAR). Modification packages were subsequently developed to replace existing electronics within the LPMS cabinets which are located in each control room. The modifications were required because the original manufacturer no longer supplied or supported the equipment in the field. Existing spare parts in the warehouse were also inadequate to support the system.

A new vendor was awarded the contract to install a new state-of-the-art system, Model LPM-4. The electronics replaced or modified included circuit boards, alarm circuits, logic circuits, the audio amplifier, recorder, core internals amplifier, and system internal clock. The modifications were installed during recent unit refueling outages (Unit 1 third refueling outage and Unit 2 first refueling outage). The cabinet electronics were replaced and startup tested by the vendor. Pre-amplifiers, located in field junction boxes inside containment, had to be replaced to allow for system interface with the new LPMS electronics.

Following system modification, problems with the LPMS were encountered. Action items were developed to install revised software to enhance system performance, replace four LPMS modules that were previously damaged, and install several minor hardware fixes. These items were being tracked through the licensee's commitment tracking system. Plant procedures were revised to incorporate the changes associated with the installation of the new LPMS electronics. The procedures revised included the plant engineering and monthly maintenance procedures. Spare parts were also procured. The systems were in service during this inspection period. This open item is closed.

3.2.2 (Closed) Open Item 498/9108-03; 499/9108-03: Containment Volume Calculation Errors

While gathering data for analysis of the containment response to severe core damage, it was determined that the UFSAR value for containment free volume in Table 6.2.1.1-3 was in error. Errors and omissions were subsequently identified in the reference calculation for containment free volume (Bechtel Calculation 2N079MC 5281, "Free and Sprayed Volumes Inside Containment," Revision 1, November 28, 1983).

Preliminary calculations indicated that sufficient margin existed in the design of the containment and equipment to offset the adverse effects of the errors. This was documented in a Justification for Continued Operation which was reviewed by NRC Region IV and Office of Nuclear Reactor Regulation personnel. Nevertheless, the licensee performed additional analyses utilizing more recent and accurate computer codes which gave a better indication of true mass-energy releases during accidents. The results of these long-term analyses were reviewed during this inspection. Reanalysis of worst case postulated accident energy releases, using the reduced free volume as an input, resulted in increases in the values of calculated peak containment internal pressure from 37.5 psig to 40.5 psig and increase in peak containment internal atmospheric temperature from 323°F to 328°F. These results are bounded by existing design margins. This item is closed.

4. ONSITE FOLLOWUP OF EVENTS AT OPERATING POWER REACTORS (93702)

4.1 Manual Reactor Trip (Unit 2)

On February 24, 1992, at 3:15 p.m., with the reactor at 100 percent power, feedwater flow oscillations were observed on SGFP 23. The speed controller was placed in manual and a feedwater booster pump was started in anticipation of feedwater flow problems. At 4:06 p.m., SGFP 23 was placed in automatic to observe how it would respond. The controller was put back into manual at 4:09 p.m. after problems were still experienced.

Prior to placing SGFP 23 in automatic, inspections by reactor plant operators identified approximately 1 inch of rainwater on the floor of the electrohydraulic control (EHC) cabinet room in the turbine generator building (TGB). At 5:02 p.m., with the controller in manual, SGFP 23 speed increased to 5500 rpm then returned to 5000 rpm.

At 5:03 p.m., the control lights for SGFP 22 blinked and the linear variable differential transformer for the high pressure governor valve failed low as evidenced by the valve position indicator. Subsequently, SGFP 22 tripped on overspeed and the Startup SGFP started automatically. At 5:55 p.m., after the reactor plant operators noted no unusual problems with SGFP 22, the turbine was relatched, and tripped to note its operations. At 5:57 p.m., it was relatched and brought up to 3100 rpm. At 6:02 p.m., the low pressure governor valve position indication linear variable differential transformer indicated that the valve was closed. However, the turbine would respond to increase and decrease signals which manually had been inserted into the controller. It was therefore concluded that there was a problem with the governor valve position indication.

At 6:10 p.m., SGFP 21 was observed to have decreasing speed, and feedwater/steam flow was mismatched on all steam generators. SGFP 21 was placed in manual and given a 100 percent demand signal, but the speed continued to decrease. Turbine load reduction began and control rods were placed in automatic. At 6:11 p.m., control room operators manually tripped the reactor because of decreasing steam generator water level. Steam generator levels were at 47 percent and decreasing at the time of the trip. After the reactor was manually tripped, the expected actuation of auxiliary feedwater (AFW) pumps and the main feedwater isolation occurred. All safety systems functioned as expected.

The cause of this event was attributed to the intrusion of rain water leaking through expansion joints in the TGB roof and into the SGFP EHC control cabinet. The introduction of the water in the control circuitry caused control problems with all three SGFPs. The expansion joints were originally sealed with a precompressed, expandable joint seal and then top coated with a sealing compound. The expandable joint seal did not adhere to the sides of the concrete, comprising the roof of the TGB, and eventually fell out. The exact cause for this is unknown, but the exposure to atmospheric conditions, as well as possible exposure to EHC fluid, may be contributing factors. This problem is being investigated in Station Problem Report (SPR) 920087. As a temporary measure, Service Request (SR) FW-103425 was implemented to apply a Belozona Flexible Membrane to the leaking expansion joints on the roof of the TGB. Similar repairs to the roof in Unit 1 were also implemented. The roof of the EHC control cabinet room and the cable entering the room were water sealed.

For the permanent repair, Plant Modifications 89007 (issued for Unit 1) and 89008 (scheduled issued date of April 17, 1992, for Unit 2) will provide watertight seals at the crane rail trenches, an isolation gap between the turbine pedestal and the roof deck, an isolation gap between the SGFP pedestal and the roof deck, and all the checkered plate hatches on the roof deck. Modification 89007 has been partially implemented with the installation of the watertight seal around the turbine pedestal.

Another cause of this event was the failure to implement timely corrective actions after the identification of previous leaks. These leaks have been identified in three previous SPRs. SPR 880498 was generated after water was found leaking into Motor Control Center 2G6. Modifications 89007 and 89008 were initiated to repair the leaks. SPR 890778 noted general leakage in the TCB, specifically around the condenser air removal system pumps and the instrument air emergency cooling water pump. SPR 900033 was generated after water was found in the main generator voltage regulator cubicle and generator potential transformer cabinets. Corrective actions for these SPRs identified Modifications 89007 and 89008 as the resolution to the problem. These modifications were twice put on hold because of their relatively low priority. The inspectors considered this to be a weakness. Further inspection followup will be performed following the issuance of the LER for this event.

4.2 Reactor Trip (Unit 1)

On March 14, 1992, at 11 a.m., Unit 1 experienced a reactor trip from 100 percent power because of a RCS low flow trip on Loop B. All safety systems functioned as designed. However, the main steam isolation valves were closed to limit RCS cooldown. As a result of previous trips, the licensee has been evaluating the reason for having to close the main steam isolation valves.

The cause of the trip was personnel error. The trip resulted when an instrumentation and controls (I&C) technician incorrectly restored an RCS flow transmitter to service following the completion of a calibration. This calibration is not normally performed at power. The need to perform calibrations of the flow transmitters occurred as a result of an ongoing engineering assessment of setpoints. A review of consecutive calibration results for feed flow and RCS flow transmitters was performed in order to identify negative trends. From that review, four Barton Model 752 differential pressure transmitters were identified which indicated a potential problem with changing spans on consecutive calibrations. This led to the need to perform additional calibrations.

Procedure 1PSP05-RC-0428, Revision 2, "RCS Flow Loop 2 Set 2 Calibration (F-0428)," was being utilized to accomplish calibration of differential pressure Flow Transmitter FT-0428. Step 7.8.3 requires that the transmitter be returned to service by closing both drain valves, opening the equalizer valve, slowly opening the low side isolation valve, closing the equalizer valve, and then slowly opening the high side isolation valve.

The technicians returning RCS flow Transmitter FT-0428 to service failed to utilize the procedure and opened the high side manifold isolation valve first instead of the low side manifold isolation valve. The high side manifold isolation valve is on the instrument line that is common to all three RCS flow transmitters on RCS Loop B. When the I&C Technicians opened the high side manifold isolation valve first, the delta pressure across RCS Flow Transmitters FT-0427 and FT-0429 decreased below the RCS low flow setpoint, resulting in a low RCS loop flow trip condition.

Subsequent to the trip, it was determined that one transmitter, RCS Flow Transmitter FT-0428, was found out-of-tolerance high by 2.75 percent of span. This caused the RCS low flow reactor trip to exceed the Technical Specification (TS) allowable values of TS 2.2.1. As a result of this, the licensee implemented the required action statement of TS 3.3.1 and tripped the affected channel within 6 hours. This transmitter was subsequently recalibrated.

The root cause of this event was failure perform the RCS flow transmitter restoration in accordance with the procedure. As part of the corrective actions, plant management is considering a requirement to have an I&C Crew Leader present at the job site during all critical instrument calibrations. In addition, a discussion of this event and how proper work practices (i.e., procedural adherence, self-checking, etc.) can prevent future events is scheduled to be held with all maintenance craft. Failure to return RCS Flow Transmitter FT-0428 to service in accordance with an approved procedure is a violation of TS 6.8.1.a (498/9205-01).

Conclusion

The two reactor trips are indicative of continuing problems with balance of plant equipment problems, and attention to detail during the performance of safety-related activities. Both of these trips are indicative of a lack of effectiveness of the licensee's trip reduction program that was initiated in September 1989. In addition, the Unit 2 manual reactor trip is indicative of weaknesses in the corrective action program. The failure to follow an RCS flow transmitter calibration procedure is a violation of TS 6.8.1.a.

5. 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 inspectors visited the control rooms on a routine basis and verified that control room staffing, operator decorum, shift turnover, adherence to TS, and overall personnel performance within the control room was in accordance with NRC requirements. Tours in various locations of the plant were also performed to observe work activities and to ensure that the facility was being operated in conformance with license and regulatory requirements. The following paragraphs provide details of specific inspector observations during this inspection period.

5.1 ECW System Flow Path Verification (Unit 1)

The ECW system supplies cooling water to those loads which are necessary for the safe shutdown of the reactor and to mitigate the consequences of postulated accidents. The ECW system also supplies cooling water to various systems during normal operation and shutdown. The ECW system is classified as safety-related and is an ESF support system. A walkdown of the Unit 1 Train A ECW system was performed to verify that the system flowpath was correctly aligned to support plant operation.

The inspection was performed using the applicable checklists of Plant Operating Procedure 1POP02-EW-0001, Revision 11, "Essential Cooling Water Operation." All components were found correctly aligned. The inspector noted an improvement in the documents used. The checklists used had been revised and improved from a human factors standpoint. The checklists were easier to read, because of bolder print, and the components were arranged in an order corresponding to plant locations.

5.2 Inadvertent Turbine High Vibration and Fire Alarms (Unit 2)

On February 6, 1992, at approximately 2:12 p.m., with Unit 2 at 100 percent power, the control room received a main turbine bearing vibration high alarm and a subsequent fire alarm on Turbine Bearings 8 and 9. However, the turbine bearing vibration recording chart showed no indication of high vibration. In addition, bearing lube oil and drain temperatures were normal. A reactor plant operator was dispatched to the main turbine and reported no fire, smoke, or high temperatures. All alarms were cleared and the operators did not manually trip the unit.

At the time that the alarms were received, control room personnel were unaware of the activities of the performance technicians and maintenance personnel in the vicinity of the main turbine. Personnel working near the main turbine inadvertently caused the alarms that could have resulted in a manual reactor trip, had the operators believed that the alarms indicated a turbine fire.

Using Procedure 1PEP07-CD-0002, Rev. 0, "Main Condenser Air Inleakage Test," performance technicians had been pouring water on turbine foundation bolts to check for air inleakage. However, the technicians had not notified the control room of their planned work in the main turbine area that day. During the testing, a performance technician inadvertently impacted the heat detection sensor with his hard hat. The heat detection sensor consists of two metal elements under spring tension. A heat source causes the metal elements to expand and touch, completing an electrical circuit which activates a control room alarm. The impact of the hard hat was sufficient to cause the metal elements to vibrate and touch, resulting in the alarm being received in the control room.

Maintenance personnel were also in the area preparing for completion of TM-146087. This work activity was initiated to tighten loose horizontal joint bolting discovered by the performance technician during air inleakage testing. These maintenance technicians had not notified the control room of their presence.

At the completion of this investigation, the licensee had not found a definitive cause for the high bearing vibration alarms received in the Control

Room. However, inadvertent personnel contact with the loose flex conduit surrounding the vibration monitoring wiring may have caused the bearing high vibration alarm.

This event resulted from poor work practices. Communications between the control room and the technicians were inadequate. The control room was not aware of the work in progress around the turbine. The previous operations shift crew gave permission for work to start, but apparently did not inform the oncoming shift that the work in the turbine area had been approved. Also, the technicians presumed someone else (such as the foreman or system engineer) had already notified the control room of their presence and activities. Workers bumping into the sensors in the area of their work resulted in nonvalid alarms. Control room personnel then had to immediately verify the validity of the alarms. These poor work practices could have resulted in a turbine trip and reactor trip, which would have unnecessarily challenged the plant.

In response to this event, the licensee planned to install placards on all low pressure turbine access doors to help ensure proper control room notification prior to personnel entry. In addition, the licensee will conduct formal training for mechanical maintenance personnel and performance technicians to emphasize the necessity for communication with control room personnel. The heat detection sensor that was impacted, as well as all other sensors in the vicinity of the Unit 2 turbine, have been replaced with sensors that are more resistant to activation as a result of vibration. SR TM-161699, for repair of the turbine bearing vibration probe and thermal detector wiring, was issued and was planned for completion by the next refueling outage for Unit 2.

5.3 Low Steam Generator Power Operated Relief Valve Nitrogen Pressure (Unit 2)

The steam generator power-operated relief valves (PORVs), one for each main steam line, are required for removal of heat from the nuclear steam supply system during periods when the condenser is not available as a heat sink or when the main steam isolation valves are closed. The PORVs are equipped with electrohydraulic actuators. Nitrogen charged accumulators are used to assist in maintaining an adequate PORV hydraulic fluid reservoir pressure. When charged to the proper pressure, the accumulator provides enough stored energy to stroke the PORV without the use of the hydraulic pump.

On February 25, 1992, Unit 2 changed modes from Mode 3 to Mode 2 and from Mode 2 to Mode 1. During a routine review of the emergency response facility data acquisition and display system (ERFDADS) alarm page, the operators noted that Steam Generator 2A PORV (PV 7411) was in an alarmed condition. Low nitrogen pressure was displayed on the alarm page for PV 7411. The PORV was declared inoperable. A historical dump was performed and it was discovered that the alarm came in approximately 7 hours earlier.

Two mode changes (from Mode 3 to 1) were made during the time that the PV 7411 operator nitrogen pressure was low. TS 3.7.1.6 requires that all four PORVs be operable for plant operation in Modes 1 through 4. TS 3.0.4 prohibits mode changes while in a Limiting Condition for Operation (LCO) for selected TS. Changing modes while in TS LCO 3.7.1.6 is prohibited by TS 3.0.4. Short-term corrective actions included reporting the event to the NRC Operations Center and issuing an SR to repressurize the nitrogen accumulator. The cause for the low pressure could not be clearly identified and no abnormal conditions (other than low pressure) were noted.

Subsequent to the event, the licensee performed a design review of the PORV hydraulic and pneumatic subsystems. The licensee determined that the PORV would have operated, with reduced nitrogen pressure, because the hydraulic pump was operable. The pump has a shutoff head pressure of 3000 pounds per square inch gage (psig) and normally maintains system pressure between 1500 and 1900 psig. The PORV will function without the accumulator pressure as long as the pump develops adequate pressure. Therefore, during the period the nitrogen pressure was low, the pump was operable. During loss of emergency power, such as during a station blackout, the PORVs can be manually cycled using the hand pumps. The licensee also performed calculations, using a linear drop assumption, that demonstrated that the nitrogen pressure for PV 7411 was above the alarm setpoints during the mode changes and was, therefore, operable. The event was determined not to be reportable and the NRC Operations Center was informed of the decision. The inspector concurred with the licensee's determination. Although this particular condition did not result in a TS violation, the inspector noted that, in one case in the past, a TS violation had occurred because ERFDADS alarm condition had not been detected in a timely manner.

The annunciator alarm on the main control board, that normally actuated when ERFDADS setpoints reached an alarmed state, had been previously disabled. The alarm was disabled because of the high number of nuisance actuations. To compensate for the disabled alarm, plant operators were required to review ERFDADS alarms every shift (8 hours). Since there were no controls to require an ERFDADS alarm review to be performed prior to mode changes, this alarm was not detected until the next required 8 hour shift review. Corrective actions planned included adding annunciators for ERFDADS points important to safety to the main control board, changing procedures to require an ERFDADS alarm review prior to mode changes, and adding this event into the operator training program.

5.4 Alternating Current (AC) Electrical Distribution System Walkdown (Unit 2)

The ac power distribution system provides sufficient switching flexibility and equipment redundancy to ensure reliable power supply to the Class 1E plant loads during startup, normal operation, shutdown, and following a design basis accident. A walkdown of portions of the Unit 2 ac electrical distribution system was performed to verify that the breakers were in the correct position to provide power to the Class 1E plant loads.

The inspection was performed using checklists from Procedure 2POP02-AE-0001, Revision 3, "AC Electrical Distribution Breaker Lineup." All breakers were found in the correct position as required by the checklists. There were some differences noted between the nomenclature of the checklist and equipment labels in the non-1E portions of the system. These differences were not safety significant, and the licensee was informed.

5.5 Valves Wide Open Test (Unit 1)

The licensee performed a test to determine the effect of lowering RCS Tavg on electrical power output. The test resulted from a desire to reduce the RCS hot leg temperature in order to decrease the potential for steam generator tube degradation. The results of the test are to be utilized in determining the economic feasibility of operating with a reduced hot leg temperature.

The test was performed in accordance with Procedure 1TEP02-ZG-0001, Revision 1, "Valves Wide Open Test." The procedure requires that operators borate to reduce the RCS Tavg and determine the hot leg temperature that corresponds to the full open position of the turbine generator valves. When the hot leg temperature decreases, the steam generator pressure also decreases. In order to maintain rated power at the reduced steam generator pressure, the turbine governor valves must be opened wider. The test was initiated on February 21, 1992, with the plant stable at 97.3 percent power, Tavg at 591.8°F (Tavg at 100 percent power is 593°F), and Governor Valve No. 4 approximately 10 percent open. Temperature was decreased in 2°F increments. Each temperature decrease and subsequent data collection required about 1 1/2 hours. At the minimum temperature plateau of 582.9°F (established by test criteria), Governor Valve No. 4 opened to approximately 42 percent, and generator output decreased from 1275 to 1269 megawatts-electrical (MWE). After the test was completed, reactor power was again taken to 100 percent.

A preliminary review of the test data indicated that the MWe reduction was less than predicted for the given temperature reduction. However, the test was performed at the reduced power of 97.3 percent in order to increase the OTDT trip setpoint operating margin. In order to provide a more accurate test, the licensee plans to perform the test at a power level between 99 and 100 percent on April 3, 1992, in Unit 2.

5.6 Repair of ECW Leaks

The licensee has a history of problems with weld leaks and dealloyed flanges in the ECW system. During this inspection period, one leak was repaired in the Unit 1 Train B and two flanges were repaired in the Unit 2 Train B.

On August 6, 1991, a leak was identified in the Unit 1 Train B ECW piping near the component cooling water heat exchanger. The leak was observed to be coming from a crack in the circumferential weld (field weld FW0043) which connects the 30-inch ECW line to the component cooling water heat exchanger outlet nozzle. Weld history records indicated that the original weld had been reworked during construction because of weld defects. Repair of the weld was performed in September, 1991 (documented in NRC Inspection Report 50-499/91-27; 50-499/91-27).

In December 1991, the weld was again identified to be leaking. The flaw was a crack approximately 6 inches in length on the surface and almost 9 inches in length in the pipe inner diameter. The leak rate was in the form of a spray and was about 2 gallons per minute. SR EW-154081 was issued to rework the weld. The work scope consisted of removing the section of piping containing the faulty weld and installation of a new piping "pup" piece. The work was started on March 2, 1992, and was completed on March 6, 1992. Since the work required a time interval of greater than 72 hours (TS 3.7.4 allowed outage time), the licensee requested a temporary waiver of compliance on February 27, 1992. The waiver asked for a temporary relief from the 72-hour allowed outage time. A temporary waiver of compliance was issued by the NRC to provide a one-time waiver for operation in Modes 1-4 up to 240 hours with one train of ECW out-of-service. The repairs were completed and Train B ECW was returned to service after being out-of-service for 104 hours.

The cause of the December 1991 weld crack was determined to have resulted from an inadequate welding process that was implemented during the September 1991 repairs. The welding process was modified to incorporate the use of temporary ceramic backing rings, which were expected to result in a more satisfactory weld. To date, seven weld cracks have been identified and repaired.

During a routine walkdown by quality control personnel in January 1992, material defects were identified on two cast flanges. A crack was found in the 6-inch ECW inlet line to Essential Chiller 21B and dealloying was found in the outlet line. The inlet line crack was located in the flange weld, while the dealloyed section was located in the cast weld-neck flange. The through-wall crack was on the 6-inch Line EW-2208-WT3 at Field Weld FS 3452. The crack consisted of three small indications on the pipe surface and was no longer than 1 1/2 inches in length on the weld outer diameter. The dealloyed area was on 6-inch Line EW-2209-WT3 near Field Weld FS 3451. The flaw was a small dealloyed area with an indication of residue on the flange base metal. Both defects resulted in minor seepage with no measurable volume present.

SR EW-147774 was issued to repair the dealloyed flange. The work consisted of replacing the flange with a new flange. SR EW-147775 was issued to repair the cracked weld. A request for a temporary waiver of compliance was generated to allow for relief from TS 3.7.14. The request was prepared to allow the 72-hour allowed outage limit for Essential Chiller 21B to be extended for 24 hours. The work on the two flanges began on March 10, 1992, but was completed within 72 hours; therefore, the request for the temporary waiver of compliance was not required.

The licensee has developed an action plan to monitor for ECW leaks and repair the leaks as found. Routine walkdowns of the ECW system are being performed. Repairs will be planned and implemented as the leaks are located. Long-term plans for inspection, detection of underground piping leakage, and rehabilitation are being developed. On March 13, 1992, the licensee conducted a meeting in the NRC offices in Arlington, Texas, where they presented the results of their efforts to resolve these problems with the ECW system. The results of that meeting will be documented by separate correspondence.

5.7 Loss of SGFP (Unit 2)

On March 9, 1992, a reactor plant operator, performing a turbine building watch, reported an EHC fluid leak on SGFP 23. Control room personnel immediately started the startup feed pump and a third feedwater booster pump and then tripped SGFP 23. The reactor was taken to 49 percent power as a result of the leak and because the SGFP master controller was responding erratically. This reduced power level was maintained to minimize the possibility of a reactor trip. Troubleshooting disclosed a cracked EHC tubing line to the low pressure stop valve. The crack was about 1/4 inch of the diameter around a 5/8-inch tubing line. Subsequent review identified the cause of the crack as inadequate purge during initial welding. The EHC line was repaired in accordance with approved instructions. The cracked section was sent to an offsite laboratory for further analysis. A defective summing amplifier was identified as the cause of the problem with the master controller. The amplifier was replaced.

Prior to the implementation of repairs to the EHC line, a maintenance planner was working in the SGFP housing when the fire protection deluge system actuated. The planner reported no fire, smoke, or excessive heat in the housing. The licensee initiated a SPR (920088) to investigate the cause of the actuation. The licensee's investigation was not complete at the end of this inspection.

Conclusion

During the inspection period, the Unit 1 Train A ECW system and portions of the Unit 2 AC electrical distribution systems were found in the correct positions to support plant operations. Improvement was noted in the quality of the ECW procedure. A turbine trip/reactor trip near miss occurred because of poor work practices, consisting of poor communications between plant workers and the control room and workers bumping into plant sensors.

The licensee made two Unit 2 mode changes with a steam generator PORV potentially inoperable. The licensee subsequently determined that the PORV was not inoperable and a TS violation had not occurred. However, the original concern with inoperability occurred as a result of the licensee making a mode change without being aware of a recently energized ERFDADS alarm that indicated low accumulator nitrogen pressure. This is similar to a previous event. The licensee took corrective actions to require an ERFDADS alarm review prior to a mode change.

A special test to determine the effect of RCS temperature on electrical power was performed. The test was determined to be well planned and controlled by the licensee.

In response to continuing problems with ECW leaks, three additional leaks were repaired. The licensee has taken an aggressive approach to resolve the ECW weld cracks and dealloying problems. Actions, such as repairs, have been taken and strategic plans are being developed to resolve this longstanding issue.

A loss of an SGFP was caused by an EHC leak. During recent months, several problems have affected the reliability of the main feedwater system, including a manual reactor trip (Section 4.1). As a result of these problems, the licensee has formed a main feedwater system task force.

6. 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. The inspector verified that the activities were conducted in accordance with approved work instructions and procedures, that the test equipment was within the current calibration cycles, and that housekeeping was being conducted in an acceptable manner. All observations made were referred to the licensee for appropriate action.

6.1 Plant Computer Battery Preventive Maintenance (Unit 1)

On February 6, 1992, the 250V DC plant computer battery system for Unit 1 was inspected in accordance with preventive maintenance (PM) Work Orders EM-1-CU-86004642 (monthly PM) and EM-1-CU-86004655 (Quarterly PM). The work consisted of measuring the battery voltage, individual cell voltages, specific gravity, and electrolyte levels, as well as an inspection for corrosion. Three out of 120 individual cells fell below the acceptance criteria for specific gravity; therefore, an equalizing charge was required. Additionally, numerous cells had low electrolyte levels. The electrolyte levels were restored to the required amounts. Following a several day equalizing charge, the battery was returned to service.

6.2 Troubleshooting of Containment Hydrogen Analyzer (Unit 1)

On February 6, 1992, Containment Hydrogen Analyzer A1-CM-AIT-4102 failed during the performance of a routine surveillance test. The hydrogen concentration output reading was below the minimum allowed value. SR CM-135835 was issued to troubleshoot and recalibrate the analyzer as necessary. Calibration of the analyzer was conducted in accordance with Procedure 1PSP05-CM-4102, Revision 2, "Containment Hydrogen Analyzer Calibration."

During the calibration, the span adjustment potentiometer was found damaged. The pin securing the potentiometer housing to the panel was broken. A replacement was not immediately available. A request for action was written to allow for temporary repair of the old potentiometer until a new one was procured. The potentiometer was reworked and the calibration was completed without any additional problems being observed. The hydrogen analyzer was returned to service. An additional work request was issued to replace the potentiometer when parts become available and SR CM-135835 was closed out. There were no concerns identified with this work activity.

6.3 Diesel Generator 23 Troubleshooting Activities (Unit 2)

On December 6, 1991, Emergency Diesel Generator (EDG) 23 was started in the emergency mode. EDG 23 came up to rated speed, voltage, and frequency within 10 seconds. When the engine was released from the emergency mode, EDG 23 tripped with no test mode trips indicated at the local control panel. The cause of the trip was not known and subsequent starts were satisfactory. The licensee committed to perform troubleshooting of EDG 23 during the next scheduled train outage. For EDG 23, the train outage began on February 24, 1992.

SR DG-148218 was issued to perform the troubleshooting activities. The work start was authorized on February 26, 1992. The work activities included a tightness check of terminations, test of relay contact resistance, recording of relay actuation voltages, inspection of the pneumatic air header controls, and startup test inspection of EDG 23. All electrical components were found to be satisfactory. A small amount of debris was found in the pneumatic air header check valve; however, the debris was not conclusively determined to be the cause of the EDG trip. Short-term corrective actions taken included changing out the air line filters and cleaning out the associated piping. Long-term corrective actions planned included adding PM instructions to clean the check valves and interconnecting piping when the air line filters are replaced.

The licensee has also experienced problems with the EDG output voltage control circuitry. The instantaneous prepositioning circuit board, part of the voltage control circuitry, functions in an emergency to bring the EDG up to the designed voltage of about 4.16 kV without the need for operator action. Once released from the emergency mode, relay contacts on the board change state and the current path bypasses the fixed voltage regulator. The EDGs have a history of problems with the prepositioning boards (further details are provided in NRC Inspection Report 50-498/91-30; 50-499/91-30). The most common problem experienced with the prepositioning boards is relay contact sulfidization. This phenomenon occurs over time (years) and results in an increased resistance in the circuit. The voltage control circuitry is negatively affected by the increased resistance. SR DG-146602 was issued to test the contact resistance of the relay on the EDG 23 prepositioning board. This SR was written in response to Station Problem Report 910463 which was issued because of previous problems with high contact readings on other EDGs.

During the performance of SR DG-146602 on February 27, 1992, higher than expected resistance was found on the prepositioning board for EDG 23. The prepositioning board was replaced and the as left readings were satisfactory. To date, four of six prepositioning boards have been replaced in the EDGs on site. The licensee plans to replace the remaining two when spare parts become available. Additionally, the licensee is performing an evaluation to determine the feasibility of replacing the relays on the prepositioning boards with relays that have gold plated contacts (this evaluation was not complete by the end of the inspection period). This type of relay would be less susceptible to sulfidization and, therefore, would maintain low resistance characteristics over time. On March 13, 1992, the licensee conducted a meeting in the NRC offices in Arlington, Texas, where they presented the results of their efforts to resolve this and other longstanding EDG issues. The results of the meeting were positive and indicated that EDG reliability is expected to increase upon implementation of scheduled modifications.

6.4 Concrete Expansion Anchor Installation

A review was conducted of the licensee's procedure for the performance, inspection, and documentation requirements associated with coring, chipping, or drilling of concrete within permanent plant structures. These requirements are delineated in Standard Modification Procedure SMP-CC-030, Revision 0, "Coring, Cutting or Drilling Concrete." This procedure provides technical direction which is used in conjunction with the development of work packages as required by appropriate work authorizing documents. The scope of the procedure includes coring through concrete to install penetrations using tools capable of cutting reinforcing steel, and drilling in concrete with tools considered incapable of cutting reinforcing steel. The latter tool consists of carbide tipped bits.

The inspector selected Work Package 115171EC-01 for specific review of the adequacy of work process documentation. The work involved drilling a 6-inch diameter core in order to install an electrical conduit in the Unit 2 electrical auxiliary building. Subsequent to the conduit installation, temporary formwork was utilized to grout around the conduit. All required actions were well documented. In addition, the inspector verified that the individuals involved were certified to perform the work listed and that the required rebar cutting request form was correctly generated.

6.5 Conclusion

The cause of the EDG 23 trip that occurred on December 6, 1991, was not conclusively identified during the troubleshooting process. The licensee did perform considerable troubleshooting, but was unsuccessful in determining the cause. Corrective actions to possibly prevent recurrence, including additional PMs to be performed, have been formalized. An EDG improvement plan has been developed in order to resolve issues that affect EDG reliability and availability, including continuation of an EDG task force.

During the inspection of other maintenance activities, maintenance personnel performed well.

7. EXIT INTERVIEW

The inspector met with licensee representatives (denoted in paragraph 1) on March 17, 1992. The inspector summarized the scope and proposed findings of the inspection. The licensee did not identify as proprietary any of the information provided to, or reviewed by, the inspectors.

ATTACHMENT

LIST OF ACRONYMS

AC	alternating current
AFW	auxiliary feedwater
ECW	essential cooling water
EDG	emergency diesel generator
EHC	electrohydraulic control
ERFDADS	emergency response facility data aquisition and display system
ESF	engineered safety features
I&C	instrumentation and controls
LCO	limiting condition for operation
LED	light emitting diode
LER	licensee event report
LPMS	loose parts montitoring system
MWE	megawatt - electrical
OTDT	overtemperature delta temperature
PM	preventive maintenance
PORV	power-operated relief valve
RCS	reactor coolant system
SGFP	steam generator feedwater pump
SPR	station problem report
SR	service request
Tavg	average temperature
TGB	turbine generator building
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report