APPENDIX

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

NRC Inspection Report: 50-498/92-14 Operating License: NPF-76
50-499/92-14 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 (STP), Units 1 and 2

Inspection At: Matagorda County, Texas

Inspection Conducted: April 26 through June 6, 1992

Inspectors: J. I. Tapia, Senior Resident Inspector
W. J. Kropp, Senior Resident Inspector, Region III
R. J. Evans, Resident Inspector

A. T. Howell 7-8-92

A. T. Howell, Chief, Project Section D Date
Division of Reactor Projects

Inspection Summary

Inspection Conducted April 26 through June 6, 1992 (Report 50-498/92-14; 50-499/92-14)

Areas Inspected: Routine, unannounced inspection of plant status, in-office review of written reports of nonroutine events, onsite followup of written reports of nonroutine events, onsite followup of events at operating power reactors, operational safety verification, monthly maintenance observations, bimonthly surveillance observations, engineered safety features system walkdown (Unit 2), and a management meeting.

Results:

On May 19, 1992, both units entered TS 3.0.3 and a Notification of Unusual Event was declared as a result of an inadequately performed Technical Specification (TS) Surveillance Requirement (Section 2). This event will be documented in detail in NRC Inspection Report 50-498/92-17; 50-499/92-17.

The overall quality of licensee event reports was good (Section 3).

In the area of plant operations, performance was mixed. Operators responded well to a failed steam pressure transmitter (Section 5.3), and promptly initiated a TS 3.0.3 required plant shutdown because two steam generator blowdown sample valves failed to close (Section 4). However, a control room operator was not sufficiently attentive during a boration evolution that he initiated and, as a result, an excess boration event occurred (Section 5.6). This issue will be tracked by an inspection followup item. In addition, the flow rate indication associated with a unit vent radiation monitor was not updating, but this was not detected for 5 days even though the flow value was logged every shift. Similar events have occurred on at least two previous occasions (Section 5.4). Finally, a weakness in the justification for continued operation (JCO) process resulted in a TS required surveillance log sheet not being properly revised (Section 5.7).

Several recurring equipment problems were noted. Continuing problems with equipment reliability were noted throughout the inspection period. Although the licensee had undertaken extensive troubleshooting and other actions, neutron flux source range monitor operability is being continually challenged (Section 6.1). An inspection followup item will track emergency diesel generator (EDG) unavailability which has increased, in part, because of troubleshooting associated with EDG trips that have occurred during the cooldown cycle (Section 6.3). Spurious actuations of radiation monitors were noted, but the causes have not been identified (Section 5.1). One weakness associated with safety-related battery maintenance was identified (Section 6.4). Maintenance craft inattention to detail resulted in an inadvertent transfer of an essential cooling water (ECW) system travelling screen local/remote switch (Section 5.2).

The two observed surveillances were performed well. A positive example of the self-verification process was identified when a technician checked his work and discovered a calculation error (Section 7). However, an unresolved item was identified pertaining to whether a licensed operator complied with the administrative procedure that governs plant surveillances (Section 5.8).

Train A of the Unit 2 essential chilled water system was properly aligned to support plant operation (Section 8).

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

DETAILS

1. PERSONS CONTACTED

Houston Lighting & Power Company

*P. Appleby, Nuclear Training Manager
*C. Ayala, Supervising Engineer, Licensing
*H. Bergendahl, Manager, Technical Services
*W. Cartee, Audits and Assessments
*M. Chakravorty, Executive Director, Nuclear Safety Review Board
*D. Chamberlain, Supervising Engineer, Plant Engineering Department
*R. Chewning, Vice President, Nuclear Support
*F. Comeaux, Consulting Engineer, Independent Safety Engineering Group
*R. Dally, Engineering Specialist, Licensing
*H. Daunhardt, Operations Support Supervisor
*D. Denver, Manager, Nuclear Engineering
*T. Jordan, General Manager, Nuclear Assurance
*W. Jump, Manager, Nuclear Licensing
*D. Leazar, Manager, Plant Engineering
*A. McIntyre, Director, Plant Projects
*G. Parkey, Plant Manager
*D. Sanchez, Director, Maintenance
*W. Wood, Senior Staff Consultant

Central Power & Light

*B. McLaughlin, Owners' Representative

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

*Denotes those individuals attending the exit interview conducted on June 8, 1992.

2. PLANT STATUS (71707)

Unit 1 began the inspection period in Mode 1 (Power Operation) at 100 percent power. The unit remained at full power until May 19, 1992, when power was reduced to comply with TS 3.0.3 requirements following the licensee's determination that a surveillance procedure inadequately tested the manual reactor trip circuitry. TS 3.0.3 was exited when the NRC granted a temporary waiver of compliance from one of the surveillance requirements of TS 4.3.1.1, and power was stabilized at 84 percent. Power ascension began the same day and the unit returned to full power the next morning. Unit 1 remained at full power through the end of the inspection period.

Unit 2 began the inspection period in Mode 1 at 100 percent power. Unit 2 entered TS 3.0.3 on April 28, 1992, because of two stuck open containment isolation valves. Power was reduced to comply with the TS 3.0.3 action statement. Power was stabilized at 93 percent after power was removed from the closed valves and TS 3.0.3 was exited. The unit returned to full power the same day. Unit 2 also entered TS 3.0.3 on May 19, 1992, because of the same surveillance deficiency that was applicable to Unit 1. Power was reduced to 83 percent before the TS 3.0.3 was exited. Power was increased and the unit returned to full power the next day. On May 26, 1992, power was reduced to 90 percent to allow for maintenance on two feedwater heaters. The unit returned to full power the next day and remained at 100 percent through the end of the inspection period.

The May 19, 1992, event was the subject of an NRC special inspection. This event will be documented in NRC Inspection Report 50-498/92-17; 50-499/92-17.

On Thursday, May 28, 1992, the licensee announced two management personnel changes. The Plant Manager was reassigned to the position of Assistant to the Group Vice President. The Planning and Assessment Manager was reassigned to the position of Plant Manager. At the end of the inspection period, the position of Planning and Assessment Manager was still vacant.

3. INSPECTOR FOLLOWUP

3.1 In-Office Review of Written Reports of Nonroutine Events at Power Reactor Facilities (90712)

3.1.1 (Closed) Licensee Event Report (LER) 50-498/90-05: Reactor Trip on Low Steam Generator Water Level

3.1.2 (Closed) LER 50-498/90-18: TS 3.0.3 Entry Caused By Inoperable Feedwater Isolation Valve

3.1.3 (Closed) LER 50-498/90-020: Reactor Trip Caused By Both Trains of Solid State Protection System Being in Test Simultaneously

3.1.4 (Closed) LER 50-498/90-25: Reactor Trip Caused by Generator Ground Fault Relay Actuation

3.1.5 (Closed) LER 50-498/91-07: Engineered Safety Features Actuation Following Switchyard Breaker Fault

3.1.6 (Closed) LER 50-498/91-019: Reactor Coolant System Leak Greater Than TS Limits

3.1.7 (Closed) LER 50-498/91-23: Residual Heat Removal Motor Lead Cracking at Epoxy Interface

3.1.8 (Closed) LER 50-499/91-01: Manual Reactor Trip Following Closure of Feedwater Isolation Valve

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

3.2.1 (Closed) LER 50-499/91-06: Spurious Signals From Toxic Gas Analyzer Resulted in Control Room Ventilation Actuation

On May 16, 1991, Unit 2 was at full power operation. The control room ventilation system actuated to the recirculation mode because of a spurious trip from a toxic gas analyzer. On May 21, 1991, a similar actuation occurred from the same analyzer. The causes of the two events were not clearly determined. Corrective actions taken included extensive troubleshooting, development of additional preventive maintenance tasks, and review of system design to identify additional methods to minimize spurious actuation signals.

The toxic gas analyzers monitor outside air that enters the electrical auxiliary building, for high airborne hazardous chemical concentrations. Concentrations above a predetermined setpoint will generate an Engineered Safety Features actuation signal. The system consists of two analyzers in each unit, with one-out-of-two actuation logic. The licensee has experienced numerous problems with these analyzers. The engineering department performed a review and developed an action plan to resolve the toxic gas monitor reliability issue. The analyzers will be replaced with three state-of-the-art analyzers. The one-out-of-two logic scheme would also be replaced with a two-out-of-three coincident logic scheme. The modifications are scheduled for implementation in the next refueling outage for each unit.

Conclusion

The overall quality of the LERs was good. LER commitments made were completed within the stated time interval. The LERs reviewed satisfied 10 CFR Part 50.73 reporting requirements. No unaddressed generic concerns were identified during the review.

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

4.1 Containment Isolation Valves Fail to Close (Unit 2)

Unit 2 entered TS 3.0.3 when two steam generator (SG) blowdown sample valves failed to close on demand. The cause of the two solenoid-operated valve failures had not been determined at the end of the inspection period. Corrective actions planned by the licensee include removal of the valves for root cause analysis. A task force also has been developed to review the reliability of solenoid operated valves at STP.

Blowdown of the secondary side of the SGs is performed to maintain secondary side water chemistry within specifications, to prevent buildup of corrosion products, to reduce SG radioactivity levels, and to provide the means of draining the secondary side. The SG blowdown system is designed to accommodate the blowdown under a wide range of conditions. Sampling of the blowdown liquid is performed for measurement of radioactive isotopes and for chemistry control purposes. At the primary sample panel nonreactor-grade sample sink, bulk water from each of the four SGs is sampled. Water is provided to the sampling system through two containment isolation valves located outside reactor containment. The two containment isolation valves are Target Rock solenoid operated valves which fail closed on loss of power.

On April 28, 1992, following a sample of SG 2C bulk water, the Unit 2 operators discovered that both Containment Isolation Valves SB-FV-4187 and SB-FV-4187A would not go closed upon demand. TS 3.6.3 (Containment Isolation Valves) action statements could not be met since both valves were inoperable. As a result, TS 3.0.3 (Plant Shutdown) was initiated. At 5:30 p.m., a Notification of Unusual Event (NOUE) was declared and a plant shutdown from full power was begun. The licensee undertook action to close both valves by removal of power and by attempting to cool the valves with portable blowers and ice packs. Valve SB-FV-4187 indicated closed at approximately 6:15 p.m. At 6:35 p.m., TS 3.0.3 was exited, and the NOUE was terminated a few minutes later. Plant operators had reduced power to 93 percent. The power level was subsequently increased to 100 percent after the NOUE was terminated. The licensee subsequently issued LER 50-499/92-04 that describes this event in detail.

At the end of the inspection period, the cause of the April 28, 1992, event was not clearly identified. Limited troubleshooting in accordance with Service Request SB-164211 was performed and the licensee determined that the downstream valve, FV-4187A, was mechanically stuck open. The upstream valve, FV-4187, could not be tested because the manual isolation valve located upstream of the valve is inaccessible during normal plant operation. The licensee plans to install a freeze seal upstream of FV-4187 and remove both FV-4187 and FV-4187A from the sample line. New valves will then be installed. A root cause analysis will be performed on the removed solenoids. The licensee committed in the LER to submit a supplemental report following determination of the failure mechanism.

The licensee has approximately 130 Target Rock valves onsite. There are eight Target Rock Model Number 84DD-003 valves in each unit, including FV-4187 and FV-4187A. Valve SB-FV-4189A, a valve identical to FV-4187, failed to close following a Unit 2 reactor trip on January 22, 1992 (see NRC Inspection Report 50-498/91-34; 50-499/91-34). The cause was attributed to poor seating of the valve disc because of low differential pressure across the valve. In response to Generic Letter 91-015, "Operating Experience Feedback Report, Solenoid Operated Valve Problems at U.S. Reactors," the licensee implemented a solenoid-operated valve task force to review the station's solenoid valves. The licensee plans to develop an action plan by the end of June 1992. The inspectors will continue to monitor the licensee's progress in this area.

5. <u>OPERATIONAL SAFETY VERIFICATION (71707)</u>

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 control room staffing, operator decorum, shift turnover, adherence to TS, and that 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 <u>Unexpected Engineered Safety Features Actuation Signal (Unit 2)</u>

During the performance of a routine surveillance test, a containment ventilation isolation (CVI) occurred. The CVI signal was generated by a radiation monitor that was not part of the test procedure. This event was the second time that a CVI occurred during the performance of a surveillance test. The cause of the event has not been clearly identified by the licensee. The results of the investigation of this event will be discussed in LER 2-92-005.

Process and effluent radiation monitors are used to monitor, record, and control the release of radioactive materials that may be generated during normal operation, anticipated operational occurrences, and postulated accidents. Located in the fuel handling building (FHB) ventilation exhaust are two spent fuel pool exhaust monitors. In the event of high radiation, the spent fuel pool exhaust monitors initiate emergency operation of the FHB ventilation system, causing the exhaust air to be filtered prior to release. Two additional radiation monitors are installed in the reactor containment building (RCB) purge lines to monitor purge exhaust. In the event of high radiation, the RCB purge isolation monitors send a signal to the solid state protection system for containment ventilation isolation.

This event was at least the sixth time that a radiation monitor has spuriously actuated with no known cause. A similar event occurred during the Unit 1 third refueling outage. On January 22, 1991, a CVI actuation occurred during a calibration of the SG Blowdown Radiation Monitor RT-8022. RCB Purge Radiation Monitor RT-8013, which is physically located above RT-8022, unexpectedly generated a CVI signal. The cause of the CVI signal was not determined and was assumed to be the result of a spurious actuation. The monitor that actuated the CVI (RT-8013) was also in the same train (Train C) as the monitor being tested (RT-8022). The two events indicated that a potential common cause failure mechanism existed, but the licensee was unable to identify such a mechanism. The licensee believed, however, that the events were not related and were random in nature. Approximately 12 related surveillance tests were being performed each week, and several spurious actuations have occurred while no work activity was in progress. Additionally, the only known correlation between the monitors are the power supplies. If the power supplies were affected during the surveillances, then more than one monitor would actuate.

A preliminary review of the nuclear plant reliability database indicated that other nuclear plants have also experienced numerous unexpected radiation monitor actuations in which the cause could not be determined. The inspector will continue to monitor the licensee's progress in resolving this problem.

5.2 Inadvertent Transfer of Local/Remote Switch (Unit 1)

On April 30, 1992, during the performance of a maintenance activity in the ECW intake structure, maintenance workers apparently bumped a Unit 1 transfer switch. The transfer switch for Travelling Screen 1C was changed from the remote to the local position. Plant operators quickly responded to the event and restored the switch to the correct position within 11 minutes. The licensee determined that ECW Train 1C was operable (capable of performing its intended function) during the period that the switch was not in the preferred position. Operations personnel performed well in response to the event; however, maintenance personnel inattention to detail caused the event.

During the time that the transfer switch was in the local position, the ECW Train C subsystem and, subsequently, EDG 13, were conservatively considered inoperable and the licensee complied with the applicable TS requirements. On the next day (within 24 hours of the event), the licensee determined that Travelling Water Screen 1C was not inoperable while the transfer switch was in the local position. The travelling screens normally operate intermittently based on ECW screen wash booster pump discharge pressure. The licensee assumed that a sufficient time interval would exist between an emergency start signal of an ECW pump and a high differential pressure condition, even under accident conditions, such that an operator could be sent to investigate the problem. During the event on April 30, 1992, the control room immediately responded to the indications and restored the switch within 11 minutes. The licensee concluded that the ECW travelling screens were capable of performing their intended function, and therefore, were not inoperable.

A design change request will be submitted to the modification review board for adding a protective device to prevent inadvertent manipulation of the transfer switch at the ECW intake structure. This change request was not approved by the end of the inspection period.

5.3 Reactor Trip Near Miss (Unit 2)

A reactor trip near miss occurred in Unit 2 when two main steam pressure low bistables actuated, one after the other. If both bistables had been energized simultaneously, a reactor trip and safety injection (SI) signal would have been generated. No correlation between the two bistable trip signals was identified.

On June 4, 1992, the power to Class 1E 120 volt-alternating current (VAC) Distribution Panel DP1201 was transferred from the normal source, the inverter/rectifier, to the alternate source, the regulated voltage transformer. This transfer was made to allow electrical maintenance to replace the transformer in the inverter. The work was successfully completed the same day. As Panel DP1201 was being transferred from the alternate power supply to the normal inverter supply, the panel was deenergized (break before make circuit breaker transfer logic). Several Channel I bistables actuated, including the Channel 1 Loop 2 Low Steam Line Pressure SI. This was an expected response. When DP1201 was re-energized, the Loop 2 Low Steam Line Pressure SI bistable cleared several seconds later. Approximately 80 seconds later, the Loop 2 Channel II Low Steam Line Pressure SI bistable actuated because Loop 2 Steam Pressure Transmitter PT-525 failed to 600 pounds-per-square-inch gage (psig) (normal pressure is 1090 psig). Had the Loop 2 Channel 1 bistable still been actuated, a reactor trip and SI signal would have been generated.

A minor feedwater flow transient occurred because of the event. SG water level is controlled by a system that monitors steam flow, feedwater flow, and SG level. A drop in Loop B steam pressure caused the control system to sense a reduced steam flow demand because the steam flow signal is pressure compensated. This caused a reduction in feedwater flow and SG levels dropped from 59 percent to 52 percent. Operators then took manual control of feedwater flow and restored SG level to normal.

Service Request MS-166557 was issued to troubleshoot Channel 2 Steam Pressure Transmitter D2-MS-PT-0525. The transmitter output was found to be erratic and the transmitter was replaced. The pressure transmitter loop was returned to service 3 days later. Both the Channels I and II instrument loops are Train A components; however, they receive power from different inverters and motor control centers. A station problem report (SPR) was issued to investigate the event.

5.4 Inoperable Unit Vent Gaseous Effluent Monitor (Unit 1)

The unit vent radiation monitors sample the plant vent stack effluent prior to release to the environment. The monitors sample for particulates, iodine, and noble gas activity and have no control function. One of the two unit vent gaseous activity monitors was found not to be updating for about 5 days. This event was initially considered a violation of TS because the compensatory actions required by TS were not taken. The licensee subsequently determined that the monitor was operable, and that a violation of TS had not occurred. The monitor malfunctioned again during the inspection period. Corrective actions taken the second time the monitor was out of service were more thorough than the first time. Long-term corrective actions were not identified by the end of the inspection period.

On May 17, 1992, the licensee determined that the Unit 1 unit vent wide range Gas Monitor N1RA-RT-8010B process flow rate indication was locked up at a constant value and not representative of actual plant exhaust conditions. The monitor was declared inoperable and TS 3.3.3.11.b (take flow samples every 4 hours and noble gas samples every 12 hours) was entered. A historical review indicated that the problem had existed for about 5 days prior to discovery. The control room operators had continued to record the value displayed each shift because they did not realize that the indication was not updating. However, identical values can occur if fans are not manipulated.

Chemical analysis personnel discovered the problem during a routine (usually weekly) evaluation of the flow rate historical data.

Since the required TS actions were not complied with for 5 days, the licensee reported to NRC the apparent TS violation within the required 24-hour period. The licensee traced the problem to the local microprocessor. The microprocessor was reset, the database was reloaded, and the monitor was returned to an operable condition. The exact cause of the malfunction was not determined because the reset erased the memory. This effectively prevented a thorough diagnostic evaluation from being performed to determine a root cause of the failure. The process flow rate for the redundant monitor, RT-8010A, functioned correctly during the same period. Monitor RT-8010B was returned to service the next day.

The licensee subsequently made the determination that the monitor was operable between May 12-17, 1992. TS 3.3.3.11 requires that the monitor be capable of alarming to prevent exceeding TS-required dose limits. The unit vent monitor's primary function is to monitor offsite dose and dose rate. The Monitor RT-8010B release rate reading is a product of the process flow rate and the monitor activity. Although the indicated process flow locked up at one value, the indicated value which was used in the computer calculations was considered a reasonable and conservative substitute value (the higher the flow rate, the higher the calculated dose rate). The process flow rate on Monitor RT-8010A was approximately 4000 standard cubic feet per minute (scfm) less than the steady state value displayed on Monitor RT-8010B. Additionally, the Monitor RT-8010B release rate channel did respond to containment purges, indicating proper response of the release rate channel and sample pump. The licensee, therefore, concluded that Monitor RT-8010B would have performed its intended function if required and that it was operable throughout the event. The event was considered nonreportable and the NRC was informed of the retraction on May 27, 1992.

On June 2, 1992, Monitor RT-8010B was declared inoperable. The process flow indication was again locked up at a specific value. Diagnostics were performed on the monitor that were not performed when the monitor malfunctioned in May 1992. The cause of the malfunction was suspected to be the result of problems with the computer software. The corrective actions included "re-initialization" of the monitor, a process that did not result in a memory loss. Monitor RT-8010B was returned to service 3 days later. The monitor display was caution tagged, to ensure verification that the monitor was trending prior to recording data. Long-term corrective actions were not identified by the end of the inspection period since troubleshooting of the monitor was still in progress. A request for assistance form was generated to develop an engineering resolution of the issue and an SPR was written to investigate the cause of the monitor malfunction.

The inspectors identified that the process flow indication associated with Monitors RA-8010B in both units have previously locked up. An SPR was written in 1991 on the subject; however, it focused on a lack of system knowledge, with additional training being identified as the corrective action. The new

SPR (still in draft) will focus on monitoring the point and ensuring the display is trending. The inspectors considered the licensee's inability to prevent recurrence of this problem to be a weakness.

5.5 <u>Unplanned Engineered Safety Features Actuation (Unit 2)</u>

On May 22, 1992, the component cooling water (CCW) to residual heat removal Heat Exchanger 2C outlet valve (CC-FV-4565) failed opened for no apparent reason. This caused the CCW header pressure to decrease to the point that caused the automatic start of CCW Pump 2A, as designed. This event was reportable to the NRC as an engineered safety features (ESF) actuation. At the end of the inspection period, the cause of the event was not known. The licensee planned to issue an LER which will describe all corrective actions taken and planned.

Since the valve is located inside the containment, an RCB entry was made. At 10:35 a.m., a visual inspection was made of the valve. No abnormal conditions, such as loose leads or air leaks, were identified. The valve was tested in accordance with the applicable surveillance test procedure, 2PSP03-CC-0009, Revision 0, "CCW System Train 2C Valve Operability Test." Valve CC-FV-4565 was successfully tested. As a result, the valve was returned to service. The automatic, unplanned start of an ESF component (CCW Pump 2A) was considered a reportable event, and the NRC was informed of the event at 7:01 p.m. the same day.

The cause of the event was not known at the end of the inspection period. Service Request (SR) CC-166553 was issued to perform further troubleshooting but was on hold pending plant engineering department action. The licensee plans to submit LER 50-499/92-06 as the result of the event. Corrective actions taken will be reviewed by NRC as part of the LER review process.

5.6 <u>Inadvertent Excess Boration (Unit 1)</u>

On May 27, 1992, at 9:44 a.m., the Unit 1 Primary Reactor Operator (PRO) initiated steps to borate the reactor coolant system (RCS) to compensate for xenon burnup. The reduction in xenon would have added positive reactivity to the reactor core, therefore, boron (a neutron absorber) was required to be added to the RCS to control power and temperature. The chemical volume and control system (CVCS) was placed in the borate mode and the integrator was set for 35 gallons. The integrator automatically terminates the boration process when the desired amount of boration is achieved, in this case 35 gallons. The boric acid pump controls were adjusted to give a maximum flow rate of about 100 gallons per minute (gpm). After the boration was started, the PRO left the CVCS boration controls to monitor the difference between RCS average temperature and the reference average temperature. During this time, the integrator was still "[illegible]ing," which indicated that the CVCS system was still borating. When the PRO went back to the flow integrator, the integrator indicated 138 gallons. The PRO then immediately secured boration. The PRO took action to compensate for the unplanned excessive boration (that would cause a lower average RCS temperature) by: initiating manual dilution, pulling control rod bank "D," and reducing turbine load. The effects on the RCS were minimized, with reactor power stabilized at approximately 97 percent. The licensee had not completed the investigation of this event by the end of this inspection period.

On the basis of the review of a preliminary SPR, the inspectors raised additional questions. These questions pertained to the failure to initiate a maintenance work request to document a problem with the integrator that occurred the day before the event, May 26, 1992, and the lack of entries in the Unit 2 control room log and the shift turnover sheet concerning the problem with the integrator on May 26, 1992. The licensee stated that the final SPR would address these questions. The inspectors were also concerned with the lack of sensitivity to closely monitor the function of the integrator. Since problems had been recently identified with the integrator and since the time of boration (based on the amount (35 gallons) and flow (100 gpm)) should have been automatically terminated by the integrator in approximately 20 seconds, a heightened sensitivity should have precluded this event. Pending the review of SPR 920215 by NRC, this matter is considered an inspection followup item (498/9214-01).

5.7 Pressurizer Level Channel Checks (Unit 2)

During a Unit 2 main control board walkdown, the inspectors noted that there was an approximate 4 percent pressurizer level difference between Channels RC-LT-466 and RC-LT-465. Upon reviewing the Unit 2 Control Room Logsheet OPSP03-ZQ-00028-1, Revision 3, page 24, the inspectors identified that the acceptance criteria for pressurizer level channel checks was 5 percent, except for Channel RC-LT-466, which was allowed to be 10 percent by Justification for Continued Operation (JCO) 900137. The inspectors determined that the previous problem with RC-LT-466 noted in JCO 900137 had been resolved during the last Unit 2 refueling outage. JCO 900137 expired on November 15, 1991, which then required the acceptance criteria for the Channel RC-LT-466 to be changed to the 5 percent value. The inspectors expressed concern about the apparent lack of administrative controls to ensure that requirements imposed by JCOs are removed when the JCO expires. The inspectors considered this a weakness. The inspectors did not identify any periods, after the JCO expired, when the acceptance criteria for RC-LT-466 exceeded 5 percent. The licensee issued SPR 920228 to document the failure to revise the control room logsheet for the acceptance criteria for pressurizer Channel RC-LT-466 when JCO 900137 expired.

5.8 Inoperable Make-Up Control Damper (Unit 2)

At 11:30 a.m., on June 3, 1992, with EDG 21 out of service for planned maintenance, the control room envelope (CRE) make-up (M/U) flow control damper (FCV-9585) was declared inoperable. With EDG 21 already inoperable, Unit 2 entered TS Limiting Condition for Operation (LCO) 3.8.1.1.d, which requires returning either the EDG 21 or the M/U control damper to an operable status within 2 hours or place the unit in hot standby within the next 6 hours. EDG 21 was returned to service and declared operable at 1:29 p.m. on June 3, 1992, and LCO 3.8.1.1.d was exited. The inspectors witnessed the postmaintenance test of EDG 21, which consisted of verifying that the EDG would achieve the required voltage and frequency in 10 seconds and then accept a subsequent loading of 5500 kW. The inspectors reviewed the activities that resulted in declaring Damper FCV-9585 inoperable. The inspectors determined that the Damper FCV-9585 did not function as expected when the CRE system was restored during a surveillance of Radiation Monitor 2RA-RT-8033.

On June 3, 1992, at 8:15 a.m., a surveillance of Radi[illegible]on Monitor [illegible] 8033 was initiated in accordance with Surveillance Procedure OPSP02-RA-8[illegible] Revision 0, "Control Room/Aux Building Vent Monitor." The surveilla[illegible] verifies that Radiation Monitor 2RA-RT-0833 will alarm with a valid signal and that the CRE ventilation system actuates and realigns to the required emergency configuration. No problems were noted with the equipment during the actuation of Train B of the CRE, but a problem was noted during the restoration of the system. Discussions with the reactor operator (RO) who performed the restoration from the main control board, determined that when M/U Fan B was stopped, M/U Control Damper FCV-9585 indicated full open instead of closed on the main control board, as expected. However, the RO noted Step 7.1.53 of Procedure OPSP02-RA-8033, Revision 0, "Restored Control Room Emergency Ventilation and TSC HVAC Systems Lineup," on Form (-1) as satisfactory, and the surveillance was exited at 9:51 a.m. Even though the RO had a nonlicensed reactor plant operator locally check the status of Control Damper FCV-9855 during the performance of the surveillance, the inspectors were concerned that the surveillance was exited even though FCV-9855 did not perform as expected during system restoration.

The M/U control damper was eventually declared inoperable at 11:30 a.m. when troubleshooting by the operators could not achieve the required TS flow through the damper. The inspectors reviewed the maintenance history of Damper FCV-9585 and noted that SR 147487 had been issued on January 30, 1992, and was still open. There was no SR tag attached the M/U damper control switch on the main control board. This SR was initiated because the damper would not go to and stay in a full closed position. The damper would cycle between 95-100 percent closed.

Procedure OPGP03-ZE-0004, Revision 10, "Plant Surveillance Program," paragraph 4.4.6, states that if surveillance results are unsatisfactory or do not meet the acceptance criteria, as specified by the surveillance procedure, then the surveillance is considered failed. Compliance with this procedural requirement is considered an unresolved item (499/9214-02) pending further NRC review of open SR 147487 and of the failure to identify restoration Step 7.1.53 as unsatisfactory when FCV-9585 did not reposition closed after stopping the M/U fan in accordance with Surveillance Procedure OPSP02-RA-8033.

Conclusions

Spurious radiation monitor actuations continue to occur. The cause of these actuations has not been fully determined.

Inattention by maintenance personnel resulted in an inadvertent transfer of control for an ECW travelling screen from remote to local. Operations personnel responded well to the event.

A reactor trip near miss and a minor feedwater flow transient occurred because of an erratic steam line pressure transmitter. Operators responded well to the event.

A malfunction of the unit vent gaseous activity monitor went undetected for 5 days. This event was similar to two previous events, and corrective actions did not preclude recurrence. The inspectors considered this to be a weakness. Troubleshooting activities were inadequate because they prevented a thorough diagnostic evaluation from being performed. As a result, the root cause was not identified. A subsequent malfunction occurred and corrective actions were more thorough; however, complete resolution of this problem has not been achieved.

An unplanned ESF actuation of a CCW pump occurred, but the cause was undetermined at the close of the inspection period.

An excess boration event occurred as a result of a malfunctioning integrator. Problems had previously occurred with this integrator and the licensee had failed to initiate an SR or document the occurrence in the appropriate log. This failure to document a known problem appears to have resulted in insensitivity by a licensed operator to potential problems in the operation of the integrator. A final review of licensee actions relating to this event will be tracked by an inspection followup item.

A control room surveillance log sheet was not revised following the expiration of a JCO. This was indicative of a weakness in the administrative controls associated with JCOs.

An unresolved item was identified. During future inspection followup, the inspectors will determine whether a licensed operator complied with Procedure OPG-P03-ZE-0004, "Plant Surveillance Program."

6. <u>MONTHLY MAINTENANCE OBSERVATIONS (62703)</u>

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 Troubleshooting of Source Range Monitor (Unit 1)

During the inspection period, Unit 1 continued to experience problems with a neutron flux source range monitor. Extensive corrective actions were taken to repair the monitor which was experiencing electrical noise interference problems; however, problems affecting the reliability of the source range monitor were still evident at the end of the inspection period. Similar corrective actions were planned for the redundant source range monitor, which also malfunctioned during the inspection period.

Two source range nuclear instrument channels are provided in each unit. The source range monitors are designed for use in monitoring reactor neutron flux levels during shutdown and initial phases of reactor startup. Source Range Monitor NI-31 had been inoperable on an intermittent basis since November 1991. The licensee suspected that the cause of the inoperability was electrical noise in the power supply cables. Extensive correction actions were taken following the Unit 1 trip on March 14, 1992, to restore the monitor to an operable condition. The actions had limited success because the monitor again malfunctioned on April 16, 1992. An action plan was developed by the licensee which included a request for vendor assistance. The licensee procured the services of a contractor that specialized in the detection and isolation of electrical noise sources.

On May 4, 1992, a vendor representative arrived onsite to assist in the troubleshooting process. Source Range Monitor NI-31 would occasionally provide a false indication of neutron activity without application of power to the associated neutron detector. The noise source was suspected to be caused by spikes in the alternating current (ac) power distribution system. The vendor representative, with the licensee's assistance, connected a noise generator to the Source Range Monitor NI-31 signal cable. A controlled source of electrical noise was generated on the cable and the location that the noise penetrated the cable was identified. The noise appeared to be entering the system near the detector itself. The noise was then being amplified by the preamplifiers and a false neutron signal was being generated. Ferrite beads were used to reduce the electrical noise. The beads are a magnetic material composed of nickel zinc bound in iron oxide. The ferrite beads presented a high electrical impedance to the noise. The beads were installed in selected triaxial cables located in the associated inboard and outboard electrical penetration boxes. These locations were chosen to prevent electrical noise from reaching the detector from the surface of the signal cable. Additionally, a short between the inner and outer cable shields (triaxial cables consist of a center conductor and two shields) at the preamplifier was installed to prevent all other noises from reaching the input to the preamplifier. Source Range Monitor NI-31 was subsequently returned to service on May 29, 1992.

On June 1, 1992, Source Range Monitor NI-31 was again removed from service because of noise interference. The source of the noise was determined to be at a signal cable inside the inboard penetration box. The connector on the cable was not sufficiently shielded because noise was entering the circuitry at this point. Corrective actions taken included the installation of more ferrite beads. The count rate on Monitor NI-31 in the control room was observed to drop from 120 counts per second (cps) to zero as the ferrite beads were added. Monitor NI-31 was returned to service on June 5, 1992.

On May 28, 1992, Source Range Monitor NI-32 was declared out of service. The monitor was observed to be displaying 35 cps with no detector voltage present and with Emergency Diesel Generator 11 operating and loaded to the associated 4.16kv bus. For a period of time, both the Source Range Monitors NI-31 and NI-32 were out of service. At the end of the inspection period, the SR for Monitor NI-32 was still in the work planning stage. Corrective actions taken for the restoration of Monitor NI-31 were scheduled to be implemented on Monitor NI-32 also.

6.2 ECW System Maintenance Activities (Units 1 and 2)

The ECW system is designed to supply cooling water to various safety-related systems for normal plant operation as well as during and after postulated accidents. The licensee has experienced numerous material condition problems with the system, including weld cracks, dealloyed flanges, and other sources of leakage. During this inspection period, selected components were reworked and a new indication was identified. Despite the material condition of the ECW system, the licensee has aggressively pursued these problems. Besides making necessary repairs, the licensee has developed short- and long- term strategic plans for the resolution of these issues.

On May 5, 1992, the Unit 2 control room received an ECW "Bypass/Inop" status annunciator indication because the Train B self-cleaning strainer was not working properly. The strainers are designed to prevent debris greater than 1/16 of an inch from entering the ECW system. The strainer is located downstream of the pump and is required to operate in all modes of system operation. The strainer motor was reported to be hot and not rotating. The power supply breaker had tripped because of the strainer binding. ECW Pump 2B was declared out of service because of the inoperable outlet strainer. Service Request EW-163868 was issued to replace the reducer (gearbox) located on the strainer shaft. The reducer was replaced and the strainer was postmaintenance tested and returned to service the next day. The reducer was not disassembled or inspected but was impounded pending further analysis.

During an ECW Train B outage, ECW Self Cleaning Strainer 2B was disassembled and inspected for potential damage. A port seal (provides seal between the backwash arm and inner surface of a straining drum) was noted to have come loose inside the strainer. Damage to the drum occurred when the port seal studs wore a groove in the drum assembly. Since the radial clearance is required to be 0.015 inches, slight misalignment will result in the backwash arm rubbing and drum wear. Previous examples of arm-to-drum assembly contact that were thought to be the result of internal component misalignment have been observed in Strainer 2A. Corrective actions taken included replacement of the drum and port seal. The cause of the loose seal was not clearly identified.

Modification Packages 92-15 and 92-16 were generated to install upgraded retrofit packages in the strainers. The changes (currently only proposed) include replacement of the copper-nickel drum and straining elements and would not affect the pressure boundary. This change was proposed in part because of a lack of vendor supplied copper-nickel drum and backwash arm spare parts and the need for a more rigid support assembly. The licensee planned to install the ECW strainer modifications during 1993.

On May 9, 1992, a leak in the ECW piping at the outlet of Unit 1 CCW Heat Exchanger 1B was identified. A 1-inch test connection was welded to 30-inch Pipe EW1205WT3 and a leak developed at the weld fillet. A visual observation indicated a defect length of about 1/4 inch. Ultrasonic testing estimated the subsurface crack length to be 1 1/4 inches. A conditional release authorization was issued that stated that the allowed defect length for weld operability was 1/4 inch. This conditional release was documented in the response to Request For Assistance 92-0534. Corrective actions planned included cutting the 1-inch pipe below the upper toe of the fillet weld and installing a pipe plug/cap

On May 15, 1992, Unit 1 Train B ECW was removed from service for repairs. Service Request EW-157436 was issued to implement the requirements of Request for Assistance 92-0534. The section of piping was removed and a 1-inch aluminum bronze pipe cap/plug was butt welded in place.

During the Train B ECW outage, other work activities were performed, including performance of radiography and rework on two instrument pipe connections. An ECW 14" X 30" piping tee, located in Supply Line EW1202 to the essential chillers, was found to have a defect in March 1992. This tee had a through-wall leak in the heat affected zone of the weld, but the seepage was not measurable. In order to determine the type of repair or rework, Service Request EW-157415 was issued and a radiograph was performed on May 15, 1992. The radiograph failed to identify an observable through-wall indication. The flawed area is scheduled for repair no later than the end of the Unit 1 refueling outage, which is to start in September 1992.

Station Problem Report 89-078 documented the concern about the phenomena with dissimilar welds between aluminum bronze metal and stainless steel. The dissimilar welds were associated with the connections between aluminum bronze piping and stainless steel instrument tubing. Service Requests EW-157413 and EW-157412 were issued to rework two pipe interfaces. The work consisted of replacing the existing welded stainless steel pipe-to-tube adapters with fabricated aluminum bronze inserts. Twelve pipe-to-tube adapters and three thermowells have through-wall leakage in the Unit 1 ECW system. The licensee planned to repair all dissimilar metal pipe-to-tube adapters and thermowells in Unit 1 during train outage weeks and all remaining items are scheduled for completion by the end of the next refueling outage. The work was previously performed and completed in Unit 2 during the last refueling outage.

During the inspection period, a 7/16-inch linear indication was discovered in the base metal of the 30-inch outlet nozzle of the CCW 2B heat exchanger.

Preliminary investigations revealed that the defect was most likely induced during the fabrication of the nozzle when the plate was rolled into a pipe. No evidence of leakage or seepage was identified. Repairs were scheduled for completion no later than the end of the next Unit 1 refueling outage.

6.3 Emergency Diesel Generator (EDG) Cooldown Trips (Unit 2)

The Unit 2 EDGs tripped during the cooldown cycle several times. Corrective actions have been taken, but they have not been fully effective.

The onsite standby electrical power systems of Units 1 and 2 each consist of three independent EDGs supplying power to three associated ESF busses and the loads connected to each bus. Each EDG automatically starts on loss of offsite power (LOOP) to the respective bus or an SI signal. The EDG may be operated in either the emergency mode (LOOP, SI, or manual) or the test mode. During the test mode of operation, there are 13 conditions, such as high jacket water temperature, that will trip the engine. However, during emergency operation of the EDGs, all but three trips (overspeed, generator differential, and low lube oil pressure) are automatically bypassed. Actuation of a shutdown device will cause the air pressure in the pneumatic control header to be vented. This will allow the fuel control cylinder, which also connects to the governor, to shut off the fuel supply. The exception is the overspeed device, which will shut off the fuel and combustion air simultaneously.

The test mode trips can be isolated from the emergency mode trip air header by two emergency mode fuel oil solenoid control valves located in series in the pneumatic header. The two fuel oil solenoid valves energize (closed) during the emergency mode and isolate the test mode air header. This prevents the EDG from tripping when a test mode shutdown is present during emergency operation. If the EDG is released from the emergency mode, the EDG will continue to run in the test mode. The two emergency mode fuel oil solenoid valves will de-energize (open) and the test mode fuel control valve (in series with the two fuel oil solenoid valves) will remain shut to keep the air header pressurized. The presence of any trip signal in the test mode will cause the test mode fuel control valve to reposition open and trip the EDG.

Each time the control room switch for the EDG is placed in the STOP position, the engine enters a cooldown cycle. The generator output breaker opens but the engine continues to run unloaded. During the cooldown cycle, an engine self-check process is initiated. The primary items checked are the operability of the emergency mode fuel oil solenoid valves and the integrity of the pneumatic header. At the start of the cycle, one emergency mode solenoid valve is energized from the nonemergency circuitry and the test mode trip air header is isolated from the air supply regulators. About half way through the cooldown cycle, the second emergency mode solenoid valve will energize and the first valve will de-energize. If the EDG trips during the cooldown cycle (without an actual test mode trip), the cause of the trip could be the result of a pneumatic header air leak or malfunction of one of the two solenoid valves. If an air leak was present, the EDG would trip in the cooldown cycle when the header pressure drops to the low pressure trip setpoint.

During the inspection period, the EDGs tripped during the cooldown cycles several times. On May 6, 1992, EDG 23 was started to satisfy TS 3.8.1.1 requirements for verification of EDG operability. The EDG was then placed in cooldown, but tripped prior to completion of the 5-minute cooldown cycle. Also on May 6, 1992, EDG 21 was started to verify operability in accordance with Surveillance Procedure 2PSP03-DG-0001, Revision 1, "Standby Diesel 21 Operability Test." The EDG did not go into the cooldown cycle when the handswitch was placed in the STOP position. On May 14, 1992, EDG 22 was started to verify operability in accordance with Procedure 2PSP03-DG-0002, Revision 1, "Standby Diesel 22 Operability Test." The EDG did not go through its cooldown cycle when the handswitch was placed in the STOP position. On May 21, 1992, EDG 23 was started in emergency to allow maintenance personnel to adjust the voltage instantaneous prepositioning board. When the EDG was released from emergency and placed in cooldown, the EDG did not go through the cooldown cycle. On June 3, 1992, EDG 21 was started to allow for adjustment of a prepositioning board. Again, the EDG did not go through a complete cooldown cycle. On June 5, 1992, EDG 21 was started in accordance with Procedure 2PSP03-SP-0011A, Revision 1, "Train A Diesel Generator Slave Relay Test." The EDG did not complete the cooldown cycle.

The cause of several cooldown cycle trips has been identified to be the result of an inoperable starting air subsystem. Each EDG is provided with two starting compressed air systems, either of which is capable of starting the engine. Each starting air subsystem consists of a motor-driven air compressor, air dryer, air receiver, starting air valve and associated valves, piping, fittings, and controls. Each receiver is designed to provide sufficient air for five start attempts without recharging. One receiver (odd number) is connected to the right bank starting air supply, while the other (even number) is connected to the left bank. The licensee has determined that if the right bank air receiver is depressurized (usually the result of the associated air compressor or dryer being out of service) the EDG will not go through a cooldown cycle. This situation occurs because the right bank starting air pressure switch is not in the required position to energize a specific relay. Because of the design of the electrical circuitry, an incomplete start signal is generated and the cooldown cycle is inhibited. Although these circuits are nonsafety-related, the failure of the EDG to go through a cooldown cycle if the right bank is not pressurized is considered a design weakness. Short-term corrective actions taken included adding a note to the EDG operating procedure about this condition. Longer-term corrective actions planned include development of a design change to revise the circuitry to prevent these undesired EDG trips during cooldowns.

Although the licensee continues to troubleshoot and document these trips, not all of the causes of the cooldown cycle problems experienced have been identified and resolved. The effect of these problems on EDG availability is considered an inspection followup item (498/9214-03; 499/9214-03).

6.4 Replacement of Battery Cell (Unit 2)

A battery cell was replaced in the Battery E2D11 bank during the inspection period. A maintenance weakness was identified when the inspectors determined that the cell was not sufficiently charged to ensure that the cell voltage was above the TS minimum required value after installation.

The Class 1E 125 volt-direct current (vdc) battery system of each unit consists of four independent busses, each energized by two battery chargers and one battery. Each battery has 59 lead-calcium type cells. Emergency power required for plant protection and control is supplied by the batteries when power from ac sources is not available. Each battery system also supplies power to its associated inverter system, which converts the direct current (dc) power to ac power for the vital instrumentation and protection systems. The ampere-hour capacity of each battery is sufficient to provide, for a minimum of 2 hours, the power required by emergency dc controls and the vital ac instrumentation and protection systems.

On November 25, 1991, a 2-hour load profile test was performed on Battery E2D11. During the test, the post on Battery Cell 7 failed and the test was terminated. A temporary modification was authorized to jumper the cell out. The cell was left in the battery bank for seismic purposes. A calculation was previously performed in October 1991 which determined that Battery E2D11 could have three cells out of service and still be operable. Cell 7 failed as a result of inadequate procedural guidance. Maintenance activities prior to the battery failure were not adequate to verify that sufficient battery cell post-to-interconnecting-cell bar contact was available (see NRC Inspection Report 50-498/91-30; 50-499/91-30). An SPR was written in response to the inspector's findings. The SPR investigation determined that the applicable procedures needed to be upgraded. The procedure enhancements were scheduled to be completed in June 1992.

On May 27, 1992, Cell 7 was replaced in accordance with SR DJ-152652. Additionally, the temporary modification, which jumpered out Cell 7, was removed. The maintenance technicians verified that adequate post-to-cell bar contact existed prior to final torquing. Several days prior to cell replacement, the cell was placed on an equalize charge. The cell was charged to 2.39 volts. About a day prior to cell replacement, the charger was removed from the cell. A drop in voltage was expected because of the presence of excess internal cell gases. As these gases dislodge from internal cell components, the cell voltage was expected to gradually rise. A decision was made to install the cell into the battery bank because cell voltage was expected to increase when electrically connected to the float voltage.

Following battery cell installation, a postmaintenance test was performed on May 27, 1992, in accordance with Procedure 2PSP06-DJ-0002, Revision 2, "125 Volt Class 1E Battery Quarterly Surveillance Test." The Cell 7 measured cell voltage was 2.10 volts, which is below the TS minimum value of 2.13 volts. In accordance with TS 4.8.2.1.b, the battery may be considered operable provided that the out of tolerance parameters are restored to within limits within

7 days. To restore the battery cell to operable, the battery was placed on an equalize charge in accordance with Procedure OPMP05-DJ-0010, Revision 4, "1E Battery Equalizing Charge." The procedure required the battery to be charged for 166 hours (almost 7 full days); however, the charge was suspended to allow the licensee to comply with TS 4.8.2.1.b (verification that Cell 7 was restored).

On June 1, 1992, Battery E2D11 and Cell 7 were retested in accordance with the 7-day and quarterly surveillance procedures. The test was successfully completed, with a measured voltage reading of 2.27 volts. Following test completion, the equalize charge was resumed and subsequently completed.

Discussions were held with the licensee following work completion. The inspectors questioned the licensee as to why a cell, which was not within TS Table 4.8-2, Category B limits (greater than or equal to 2.13 volts), was installed in the battery bank. Licensee representatives acknowledged that the cell was not properly charged prior to installation into the battery bank, and the battery cell charger should have been installed on Cell 7 up to the time of the cell replacement. The installation of a cell with a marginal voltage level is considered an example of inadequate maintenance implementation. Long-term corrective actions were being formulated by the licensee.

Conclusions

The licensee continued its efforts to correct long-standing problems affecting neutron flux source range monitor operability.

The licensee continues to experience problems with ECW leaks. However, the licensee has aggressively pursued the technical issues. Repairs have been made and strategic plans have been formulated to provide resolution of these long-standing problems.

Troubleshooting and corrective maintenance associated with EDG trips during the cooldown cycle have increased EDG unavailability. Corrective actions taken have not been fully successful in resolving these problems. This issue will be tracked as an inspection followup item.

The inspectors identified additional safety-related battery maintenance weaknesses. An inadequately charged battery cell was installed in a safety-related battery.

7. BIMONTHLY SURVEILLANCE OBSERVATIONS (61726)

Selected activities were observed to ascertain whether the surveillances 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.

7.1 Surveillance of Pressurizer Heaters (Unit 2)

A quarterly surveillance of the Unit 2 Pressurizer Heater Groups 2A and 2B was performed. The two heater groups were verified to have capacities greater than the minimum required by TS. No concerns were identified. However, a technician made a calculation error but discovered the error through the process of self-checking his work. This was a positive example of the self-verification process.

7.2 Emergency Diesel Generator Operability Test (Unit 2)

On May 6, 1992, EDG 21 was started during a routine test in accordance with Surveillance Procedure 2PSP03-DG-0001, Revision 1, "Standby Diesel 21 Operability Test." The EDG started and came up to rated speed, voltage, and frequency within the required time interval. Several minutes later, EDG 21 was released from emergency and the EDG continued to operate normally for over 1 hour. The EDG was then unloaded and the handswitch was then placed to the STOP position. The EDG tripped immediately and failed to go through the 5-minute cooldown cycle (see also Section 6.3). Since the cooldown cycle circuitry is nonsafety-related and since the EDG would have performed its intended function in an emergency, EDG 21 was considered operable.

Conclusions

A positive example of the self-verification process was identified when a technician was noted to have checked his work and discovered a calculation error. An EDG was successfully tested, but failed to go through the cooldown cycle. The licensee continues to experience problems with the cooldown function of some EDGs.

8. ENGINEERED SAFETY FEATURES SYSTEM WALKDOWN (UNIT 2) (71710)

A walkdown of a Unit 2 ESF system was performed to independently verify the status of the system. The system walked down was the Train A essential chilled water system. All components were found in positions to support plant operation. Two control switches were found in positions other than the positions required by the procedure that governs the system lineup; however, this had no effect on system operability.

The essential chilled water system is designed to provide chilled water to selected air handling units (AHU) under normal and emergency conditions. This safety-related system consists of three 50 percent capacity trains, powered by three redundant, independent, ESF buses. Each train is composed of two water chillers, a chilled water pump, an expansion tank, a chemical addition tank, and associated piping and valves. The lineup of the system valves, electrical power supplies, and control switches were compared to the positions established in the system operating Procedure 2POP02-CH-0001, Revision 5, "Essential Chilled Water System." All components were found in the positions required by the operating procedure except for two flow control valve control switches.

The cooling coils of the electrical auxiliary building control room envelope AHU and electrical auxiliary building main supply AHU are provided with cooling water from the essential chilled water system. Chilled water flow through the two AHUs is controlled by two temperature control valves. One valve controls the outlet flow through each AHU and a second valve controls bypass flow around the AHU. The valve positions are normally controlled by ventilation system temperature controllers located in the plant. The bypass flow around the cooling coils is designed to be isolated upon receipt of an SI signal. One control switch is located on Control Room Panel 2-CP-022 for each set of control valves. The switches have two positions, modulate or bypassed/closed. Checklist 7 of Procedure 2POP02-CH-0001 listed the required switch positions as modulate. The two switches for Train A (and the four switches for the other two trains) were found in the bypassed/closed position. Although the switches were out of position the valves were in the fail safe positions if an SI signal had been received. The positions of the switches were discussed with the plant operators. The switches were in the bypassed/closed positions to maximize the cooling (by eliminating bypass flow) through the AHUs. The operating procedure did not specifically authorize or prohibit this mode of operation. The licensee has experienced problems in the past by not being able to maintain the chillers fully loaded. Eliminating bypass flow assists in keeping the chillers loaded. This alignment was determined to have any safety-significance because the system would have performed its intended safety function if a safety injection signal had been received.

Conclusions

Train A of the Unit 2 essential chilled water system was properly aligned to support plant operation.

9. MANAGEMENT MEETING (30702)

On Thursday, May 14, 1992, a meeting was held in the NRC Region IV office between representatives of the licensee and NRC. The purpose of the meeting was to discuss the Reactor Trip Prevention Plan, the Operational Improvement Plan, and selected maintenance issues.

Following the March 14, 1992, trip of Unit 1 because of a maintenance technician error, the licensee developed additional plans to reduce reactor trips (see NRC Inspection Report 50-498/92-08; 50-499/92-08). The trip prevention policy includes an increased accountability for quality work, increased oversight of activities that could challenge the plant, and methods to reduce the likelihood of reactor trips during the performance of surveillance activities. Also discussed was a brief summary of previous reactor trips (41 total to date) and their causes.

The status of the Operational Improvement Plan was also discussed. A total of 151 of 177 original actions items have been completed.

Selected maintenance issues were presented to the NRC by the licensee's maintenance manager. The issues discussed included the status of the open service requests (corrective maintenance backlog), methods planned to reduce the maintenance backlog, the impact of the open service requests on the plant, material condition challenges, and overall actions taken and planned within the maintenance area.

A final item presented at the meeting by the Group Vice President, Nuclear was the performance of STP between 1989 and 1992. Statistics were presented which demonstrated that the overall plant capacity factor improved each year between 1989 and 1992.

10. EXIT INTERVIEW

The inspectors met with licensee representatives (denoted in paragraph 1) on June 8, 1992. The inspectors summarized the scope and 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
AHU	air handling units
CCW	component cooling water
CFR	Code of Federal Regulations
CRE	control room envelope
CVCS	chemical volume and control system
CVI	containment ventilation isolation
dc	direct current
ECW	essential cooling water
EDG	emergency diesel generator
ESF	engineered safety features
FHB	fuel handling building
gpm	gallons per minute
HVAC	heating, ventilation and air conditioning
JCO	justification for continued operation
LCO	limiting conditions for operation
LER	licensee event report
LOOP	loss of offsite power
M/U	make-up
NOUE	Notification of Unusual Event
NRC	U.S. Nuclear Regulatory Commission
psig	pounds-per-square-inch gage
PRO	primary reactor operator
RCB	reactor containment building
RCS	reactor coolant system
RO	reactor operator
SAC	starting air compressor
scfm	standard cubic feet per minute
SG	steam generator
SI	safety injection
SPR	station problem report
SR	service request
STP	South Texas Project Electric Generating Station
TS	Technical Specifications
TSC	Technical Support Center
VAC	volt-alternating current
VDC	volt-direct current