APPENDIX B

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

NRC Inspection Report: 50-498/90-34 Operating License: NPF-76
50-499/90-34 NPF-80

Dockets: 50-498
50-499

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

Facility Name: South Texas Project (STP), Units 1 and 2

Inspection At: STP, Matagorda County, Texas

Inspection Conducted: October 13 through November 20, 1990

Inspectors: J. I. Tapia, Senior Resident Inspector, Project Section D
Division of Reactor Projects

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Approved: A. T. Howell 12-31-90
A. T. Howell, Chief, Project Section D Date
Division of Reactor Projects

Inspection Summary

Inspection Conducted October 13 through November 20, 1990 (Report 50-498/90-34; 50-499/90-34)

Areas Inspected: Routine, unannounced inspection of plant status, onsite followup of events at operating power reactors, licensee actions on a previous inspection finding, followup on corrective actions for a violation, onsite followup of written reports of nonroutine events at power reactor facilities, engineered safety feature system walkdown (Unit 1), operational safety verification, maintenance observations, complex surveillance (Unit 2), spent fuel pool activities (Unit 2), and refueling activities (Unit 2).

Results: Within the areas inspected, 2 apparent violations were identified. The first violation (paragraph 3.c) involved a Unit 2 mode change from no mode to Mode 6, refueling, with the A train 120-volt Vital Distribution Panel DP-001 not powered from its inverter power supply as required by Technical Specification (TS). The second violation involved two examples of failure to follow approved procedures. Example 1 (paragraph 3.e) involved an inadvertent deenergization of a Class 1E bus because of a failure to follow a procedure during breaker testing. Example 2 (paragraph 9.d) involved a failure to change an FCR using an approved review process.

One unresolved item (paragraphs 11 and 12) was identified during this inspection. This item pertains to observations made by the inspectors during certain Unit 2 refueling activities. These observations are similar to those noted by NRC in September 1989, and this item will remain unresolved pending future inspection followup of your corrective actions.

Two inspector followup items were also identified as a result of this inspection. These include: (1) licensee actions following an inadvertent spill during the reflood of the Unit 2 reactor refueling cavity because of work control problems (paragraph 3.b); and (2) future licensee actions to smooth away the rubbed areas of a No. 11 diesel generator (DG) bearing (paragraph 8.d).

Weaknesses noted during this inspection period included: (1) a declining trend in the area of procedural compliance, resulting in unnecessary challenges to safety systems during maintenance and surveillance activities; (2) an example of TS noncompliance during a mode change was caused, in part, by inattention to detail by plant operators; (3) problems with the effective control of equipment clearances during certain plant conditions; and (4) a lack of understanding of the affect of an inoperable data processing unit channel on the operability of the core subcooling margin system.

Strengths observed during this period included: (1) Unit 2 Mode 5 entry and mid-loop operations were performed in a careful and systematic fashion; (2) the Unit 2 loss-of-offsite power test and safety injection test on Train B were performed well; and (3) licensee actions to evaluate the Unit 2 steam generator stub tubes was thorough.

DETAILS

1. Persons Contacted

*D. P. Hall, Goup Vice President
*W. H. Kinsey, Vice President, Nuclear Generation
*M. R. Wisenburg, Plant Manager
*M. A. McBurnett, Nuclear Licensing Manager
*A. K. Khosla, Senior Engineer, Licensing
*W. J. Jump, Maintenance Manager
*A. W. Harrison, Supervising Engineer, Licensing
*C. A. Ayala, Supervising Engineer, Licensing
*D. J. Denver, Manager, Plant Engineering Department
*D. W. McCallum, Plant Operations Support Manager
*G. N. Midkiff, Plant Operations Manager
*F. A. White, Supervisor, Plant Operations Support
*J. R. Lovell, Manager, Technical Services
*R. L. Balcom, Director, Quality Assurance
*J. M. MacKay, Staff Engineer, Independent Safety Engineering Group
*D. O. Wohleber, Director, Records Management System
*J. Blevina, Supervisor, Records Management System

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

*Denotes those individuals attending the exit interview conducted on November 20, 1990.

2. Plant Status

Unit 1 operated throughout this inspection period at 100 percent reactor power.

Unit 2 began this inspection period in Mode 6, refueling. Core off-loading began on October 13, 1990, with the removal of the first fuel bundle at 12:45 p.m. After completely unloading the core, major outage activities were commenced. Core reloading was completed on November 10, 1990. Mode 5, cold shutdown, was entered on November 16, 1990, at 5:11 p.m. On November 20, 1990, reduced inventory (mid-loop) operation was entered in order to remove steam-generator nozzle dams. The unit remained in this status at the close of the inspection period.

3. Onsite Followup of Events at Operating Power Reactors (93702)

   a. Inoperable Data Processing Unit (DPU) Results in Past TS Violations (Unit 1)

   On October 11, 1990, during performance of the Unit 1 remote shutdown monitoring and accident monitoring instrumentation channel checks, it was noted that one of two DPUs in the qualified display processing system (QDPS) was inoperable. DPU "C" was inoperable because of a failed power supply. Therefore, only one channel of core subcooling margin was operable. TS 3.3.3.6 requires that the inoperable channel be restored within 7 days or the unit be shutdown within the next 12 hours. However, the DPU power supply was repaired and the DPU was declared operable within the allowable time.

Discussions with licensee personnel revealed that the effect of the DPU on the operability of the subcooling margin channel was not clearly understood. As a result, the licensee reviewed past occurrences when one DPU was not in service in order to determine compliance with the subcooling margin TS. Two occurrences were identified where a DPU had been out of service for more than 7 days, both times in Unit 1. TS actions were not taken to restore the DPU within 7 days or shut down within the next 12 hours. The cause of the events was a less than adequate evaluation of the effect of QDPS component failure on the operability of instruments required by TS. This event, as well as corrective actions taken by the licensee, will be reviewed during future inspection followup of Licensee Event Report (LER) 90-24 for Unit 1.

b. Inadvertent Spill Because of Work Control Problems (Unit 2)

On October 31, 1990, Unit 2 was in a defueled status. During initial attempts to reflood the reactor refueling cavity, a spill of approximately 50 gallons occurred through two open vents and two open drain valves located on the upstream side of safety injection Accumulator 2A discharge check valve. Corrective maintenance had been previously performed on the 2A Accumulator discharge line check valves. The drain and vent valves had been positioned in accordance with the equipment clearance order that was issued to allow work on the check valves. When the reflooding began, the equipment clearance order was released but all the valves were not restored to their required position.

The spill occurred as a result of the accumulator check valve not seating fully because of low differential pressure, thereby allowing water to flow through the check valve and open vent and drain valves into the normal containment sump via a tygon hose. The clearance was not identified as being required to be performed prior to flooding of the reactor refueling cavity. The spill was contained in the reactor containment building (RCB) radioactive drain system. This event appears to have occurred because licensee personnel did not recognize that the 2A Accumulator check valve would not fully seat under a low differential pressure condition. A special problem report was written by the licensee, and corrective actions included, in part, a review of all refueling related clearances. Additional licensee actions will be tracked by Inspector Followup Item (IFI) 499/9034-01.

c. Failure to Comply with TS 3.8.3.2 (Unit 2)

On November 4, 1990, at 2 p.m., Weekly Surveillance 2PSP03-AE-0002, Revision 2, "ESF Power Availability," was being performed on Unit 2. During the surveillance, the A train 120-Volt Vital Distribution Panel DP-001 was found powered from its regulated power transformer. TS 3.8.3.2, which is applicable when the plant is operating in Modes 5 or 6, requires this panel to be powered from its inverter power supply to perform core alterations, movement of irradiated fuel, or positive reactivity changes. Mode 6 was entered on November 2, 1990, at 10:57 p.m. At this time core alterations were commenced for core reload from a defueled or no mode condition. Core reloading had been ongoing since that time when DP-001 was discovered to be powered by its regulated power source. This failure to satisfy a TS requirement is considered an apparent violation (499/9034-02). The licensee investigation of the cause(s) of this apparent violation was still in progress at the end of the inspection period; however, it appears that this apparent violation was caused in part, by inattention to detail by plant operators.

d. Inadvertent Engineered Safety Features (ESF) Actuation During Surveillance Testing (Unit 2)

On November 6, 1990, an inadvertent ESF actuation occurred while Unit 2 operations personnel were performing a Safety Injection/Loss of Preferred Power surveillance test on the No. 21 diesel generator (DG). During the test, the 120VAC power supply to safety-related Inverter 1201 tripped open and inverter load shifted as designed to its 125-volt dc input. The breaker opened during the portion of the test when the 4.16kv Switchgear E2A was deenergized and reenergized. Later in the test, the No. 21 DG was released from the emergency mode of operation and a frequency/voltage transient occurred. This was not unusual and was expected when the "speed droop" governor control was turned on. At this time, an alarm on Inverter 001 was received and the alarm for Inverter 1201 was observed. Several minutes later, operations personnel shut the ac breaker to Inverter 1201.

When the AC breaker was shut, a fluctuation of ac power supply occurred at Distribution Panel DP001 and several engineered safety feature (ESF) actuations occurred. Inverter 1201 and Panel DP001 were electrically connected through 125-volt dc Bus E2A11. The voltage spike caused Radiation Monitors RT-8012, -8033, and -8035 to result in ESF actuations of the control room envelope, fuel handling building (FHB) and RCB ventilation systems. The cause of the AC breaker to open and the cause of the voltage spike that resulted in ESF actuations were still under investigation by the licensee at the close of the inspection period. Licensee actions associated with this event will be reviewed during followup of LER 2-90-18.

e. Inadvertent ESF Actuation Signal Because of Personnel Error During Electrical Breaker Testing (Unit 2)

On November 16, 1990, during the performance of Electrical Maintenance Procedure OPMP05-NA-0001, Revision 9, "General Electric 13.8 kV Breaker Tests," a loss of power occurred on 13.8 kV Auxiliary Bus 2H, which in turn caused an ESF actuation signal on loss of power signal to 4160-volt Vital Bus E2C. The No. 23 emergency DG was tagged-out for maintenance and, therefore, did not start. The residual heat removal (RHR) system was operating on Trains "A" and "B" at the time of this occurrence; therefore, there was no interruption of RHR flow. Subsequent review by the licensee revealed that the electrician did not adhere to a note in the procedure which states, "Do not perform 6.36 on Bus Feeder or Tie breakers unless the bus is deenergized." The licensee's investigation of why the note was not adhered to was still ongoing at the close of the inspection period. Step 6.36 calls for aligning a breaker to the test position and cycling the breaker closed then open. The failure to adhere to the procedure note is considered a failure to follow an approved procedure and is an apparent violation of TS 6.8.1 (498;499/9034-03). This violation is being cited because this example of procedural noncompliance represents a continuing declining trend that has resulted in unnecessary challenges to safety systems.

4. Licensee Action on Previous Inspection Findings (92701)

(Closed) Unit 1 Operational Readiness Inspection Observation No. 24: Establishing an Improved Method for Cross-Referencing Surveillance Procedures to Other Affected TS

During the Unit 1 Operational Readiness Inspection (Inspection Report 50-498/87-45), the NRC determined that the licensee needed a cross-referencing system to identify when the failure of one component's surveillance test may require entry into a more restrictive action statement. In response to the observation, the licensee committed (Letter ST-HL-AE-2298) to revise surveillance procedures and the program, as necessary, to ensure that all affected TS are adequately cross-referenced. This commitment was to be implemented prior to the end of full-power testing.

During a followup inspection (NRC Inspection Report 50-498/87-77), the progress of this effort was reviewed. At that time, the licensee's procedure review was incomplete. During a subsequent followup inspection (NRC Inspection Report 50-498/88-17), the licensee provided the inspectors with information about a computerized TS tracking system. The TS management system was determined to be an enhancement to the TS program. However, the system was not being used because of problems with the computer software. This item (Observation No. 24) was previously left open pending resolution of the software problems or the implementation of some other tracking system. The NRC determined that the closure of this issue was not required prior to issuance of the full power license. The licensee then committed to the NRC (Letter ST-HL-AE-2584) that they would operate and maintain this computerized tracking system.

Subsequently, the licensee determined the TS management system did not function as well as expected. The system required significant and costly upgrades to be functional at a usable level of confidence. The licensee then informed the NRC (Letter ST-HL-AE-3599) that the TS management system was not the method of choice to comply with the original commitment.

An alternate means of tracking LLO entries and surveillances was implemented by the licensee to ensure compliance with TS. This new method involved the operability tracking log and the plant surveillance scheduling program. The operability tracking log was a procedurally controlled manual system where all inoperable TS-required equipment is logged and tracked until restoration. All surveillances associated with inoperable equipment were to be listed and tracked separately in the log. These entries are reviewed routinely by the licensed operators. The operability tracking log requirements and responsibilities were described in Procedure OPOP01-ZQ-0030, Revision 8, "Maintenance of Plant Operations Logbooks."

Additionally, all surveillances were to be tracked under the control of Plant Surveillance Scheduling Procedure OPGP03-ZA-0055, Revision 4, "Plant Surveillance Scheduling." This procedure described the administrative structure and division of responsibility for scheduling of periodic TS surveillance requirements. The procedure also provided instructions for establishing and maintaining the surveillance data base (computer program that supports the surveillance scheduling program). The data base cross-references procedures and equipment to the corresponding TS. The licensee stated (Letter ST-HL-AE-3599) that these methods meet the intent of the original commitment of providing a means for cross-referencing surveillance procedures to the TS and ensuring that the procedures are conducted on time. These methods have been in place for some time and have been reviewed during previous NRC inspections.

A review of the TS tracking system was performed during this inspection period, and the system was determined to be performing its intended function. The system was noted to have a low rate of missed surveillances which have been previously reported, as appropriate. At some time in the future, the licensee plans to rewrite the software to make the data base more efficient to use. However, the system now in use was determined to meet the requirements of the original commitment. Operational Readiness Inspection (NRC Inspection Report 50-498/87-45) Observation No. 24 is closed.

5. Followup on Corrective Actions for Violations and Deviations (92702)

(Closed) Violation (498/9008-01; 499/9008-01): Failure To Adequately Implement a TS Surveillance Requirement

During a previous inspection, it was determined by the NRC that procedures did not exist to fully implement the requirements of TS Surveillance 4.7.3.a. Pursuant to 10 CFR 50.73, the licensee submitted Licensee Event Report (LER) 90-003 regarding the failure to perform a TS required surveillance of certain component cooling water (CCW) system valves because of a deficient procedure. The inspectors verified that licensee corrective actions were ad[illegible] The event is described in detail in paragraph 6.c of this in[illegible] report. This violation is closed.

6. <u>Onsite Followup of Written Reports of Nonroutine Events at Power Reactor Facilities (92700)</u>

The inspector reviewed the LERs listed below to determine whether corrective actions were adequate and whether response to the events was adequate and met regulatory requirements, license conditions, and licensee commitments.

a. <u>(Closed) Unit 1 LER 89-14: Inoperable Standby Diesel Generator in Violation of TS Due To Inadequate Procedure</u>

On June 20, 1989, the licensee determined that Standby DG No. 13 had been out of service for more than 72 hours, resulting in a violation of TS 3.8.1.1. The cause of the event was determined to be incorrect work instructions which required the jumper wire to be installed in the Chiller 12C circuitry. The cause of the incorrect work instructions was an inadequate chiller maintenance procedure and an incorrect entry in the master equipment data base. The procedure failed to provide sufficient detail to ensure that applicable steps were performed on specific types of chillers. Also, the master equipment data base incorrectly identified the Chiller 12C as a "semi-hermetic" type of chiller, which is not used at STP.

Corrective actions taken by the licensee included immediate removal of the temporary jumper wire, revising the master equipment data base, and reviewing similar procedures to determine if they required clarification. The chiller maintenance procedure was also revised to clearly identify which chiller units were considered "open-drive" versus "hermetic-sealed" units. During this inspection period, corrective actions taken were reviewed by the inspectors. All corrective actions were incorporated into their maintenance program. All actions taken appeared appropriate to the circumstances. This LER is closed.

b. <u>(Closed) Unit 1 LER 90-01: Engineered Safety Features (ESF) Actuation Due to Loss of Power to a Radiation Monitor Relay</u>

On January 3, 1990, a containment ventilation isolation (CVI) actuation occurred because of a loss of power to the Radiation Monitor RT-8012 actuation relay. The event was initiated when licensee technicians performing a modification lifted a power lead which was not called for by the work instructions. The causes of the event were determined to be: (1) failure of the work planner to identify the power interferences and incorporate those interferences into the work instructions; (2) failure of the technicians to follow work instructions provided by performing work that exceeded the scope of the work instructions; and (3) a change to the work instructions (perform modifications on three systems separately) was not appropriately considered when replanning the work activity.

Corrective actions taken by the licensee included: (1) revising the original work instructions to preclude inadvertent ESF actuations; (2) retraining and counseling the radiation monitor technicians on procedure compliance; (3) revising the work planning procedure to clarify the necessity to identify work interferences; and (4) issuing a training bulletin to incorporate lessons learned.

During this inspection period, implementation of the corrective actions was verified to have been completed. The technicians involved received counseling. Procedure OPMP02-ZG-0005, Revision 0, "Work Planning," was revised via Field Change Request (FCR) 90-433. A training bulletin was issued on the event and training was then completed and documented. The corrective actions taken were appropriate for the event. Additionally, the licensee recently implemented a self-verification training program in response to several incidents caused by less than adequate attention to detail. All site personnel will receive training on self-verification. This LER is closed.

c. <u>(Closed) Unit 1 LER 90-003: Failure to Perform a TS-Required Surveillance Due to a Deficient Procedure</u>

During a review of surveillance procedures by an inspector, it was discovered that selected valves in the component cooling water (CCW) system were not subjected to a TS-required position verification once per 31 days. This was an apparent violation of TS 4.7.3.a, which requires that each outside containment valve in the CCW system serving safety-related equipment which is not locked, sealed, or secured in position be verified to be in the correct position at least once every 31 days. The valves that were omitted from the surveillance procedure supply CCW to the centrifugal charging pumps and the spent fuel pool coolers. On the basis of discussions with the NRC, this condition was determined to be a reportable event.

The cause of the event was determined to be a misinterpretation of the requirements of TS 4.7.3 during initial procedure development and subsequent reviews. Corrective actions taken by the licensee included: (1) verifying that the missing valves were in their correct positions; (2) revising the deficient procedure; and (3) reviewing other procedures which verify valve lineups to satisfy TS requirements.

During this inspection, a review of the corrective actions taken by the licensee was performed. All corrective actions have been completed, including: (1) revising Procedure 1PSP03-CC-0011, Revision 4, "CCW Valve Checklist," to include all missing valves;

(2) reviewing and updating (as required) procedures similar to the CCW valve checklist procedure; and (3) performing the surveillances within the required time intervals. A review of selected TS surveillance requirements and surveillance procedures did not reveal any additional NRC concerns. This LER is closed.

7. <u>Engineered Safety Feature (ESF) System Walkdown - Unit 1 (71710)</u>

A walkdown of a Unit 1 ESF system was performed to independently verify the status of the system. The system walked down was the No. 13 emergency DG and its support systems. Specific attributes inspected included the assurance that: (1) power supplies, control switches, and valves were in the correct positions to support DG operation; (2) support systems were operational; (3) system equipment was properly labelled and lubricated, and no leaks existed; (4) flammable materials were not in the vicinity of the equipment; and (5) housekeeping was being maintained. A review of the system operating procedure (1POP02-DG-0003, Revision 9, "Emergency Diesel Generator #13"), and procedure references, including system piping and instrumentation diagrams (P&IDs), was performed. A field walkdown was also performed using the operating procedure and P&IDs to ensure that system lineup was correct in the plant.

All safety-related components were in position to support system operation. Housekeeping was being maintained in the vicinity of the equipment inspected. No prohibited ignition sources or flammable materials were present in the vicinity of the No. 13 DG. The inspector made some observations which were of minor significance and these observations were reported to the licensee for appropriate action.

8. <u>Operational Safety Verification and Sustained Control Room Observations (71707 and 71715)</u>

The purpose of this inspection was to ensure that the facility was being operated safely and in conformance with license and regulatory requirements. This inspection included verifying that selected activities of the licensee's radiological protection program were being implemented in conformance with requirements and procedures and that the licensee was in compliance with its approved physical security plan. In addition, the inspectors conducted sustained control room observations during reduced inventory operation.

The inspectors visited the control rooms on a routine basis and verified that control room staffing, operator decorum, shift turnover, adherence to TS limiting conditions for operation (LCOs), 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 operations and to ensure that the facility was being operated in conformance with license and regulatory requirements.

The following paragraphs provide details of certain observations identified during this inspection period.

a. Mode 5 TS Requirements (Unit 2)

Prior to entry into Mode 5, a review of selected Mode 5 restraints was performed. The review verified that selected TS-required equipment was operable prior to entry into Mode 5. The specific TS requirements verified included: (1) Reactor Makeup Water System Isolation Valve 2-CV-0198, which limits dilution flow rate, was locked in place to limit flow (TS 3.4.1.4.1); (2) the required number of standby DGs were operable (TS 3.8.2.2); (3) the required number of dc electrical power sources were operable (TS 3.8.2.2); (4) overpressure protection for the reactor coolant system existed (TS 3.4.9.3); and (5) all high head safety injection pumps were inoperable (TS 3.5.3.2).

b. Reduced Inventory (Midloop) Operation (Unit 2)

The procedure requirements for entry into reduced inventory operation were reviewed by the inspector. These requirements are listed in Procedure OPOP03-ZG-0009, Revision 3, "Midloop Operation." The entry into reduced inventory operation was subsequently witnessed. The activities witnessed were performed in a systematic and cautious manner. The transition to reduced inventory operation was accomplished as expected. The modifications implemented in accordance with Generic Letter 88-17, to monitor reduced inventory operation, performed well. The following attributes were satisfied prior to the unit entering reduced inventory: (1) at least two independent, continuous indications of core exit temperature were operable; (2) at least two independent, continuous reactor coolant system water level indications were operable; (3) at least two additional means of adding inventory to the reactor coolant system were available; (4) a vent path was established on the reactor vessel; and (5) contingency plans to repower vital busses from an alternate source, if necessary, was available.

c. Steam Generator Stub Tubes (Unit 2)

During this inspection period, the licensee informed NRC Region IV and the Office of Nuclear Reactor Regulation (NRR) of the discovery of 106 Unit 2 steam generator (SG) stub tubes which were capped approximately 6 inches above the tube sheet. These 106 stub tubes represent a total of 53 SG cut and capped U-tubes located in three of four Unit 2 SGs. This configuration does not exist in any of the Unit 1 SGs.

Because the licensee originally believed these tubes to be plugged at the tube sheets, they were not included in the preservice inspection program (PSI) or the inservice inspection program (ISI). A detailed evaluation was performed by the licensee, and they concluded that not performing ISI on these tubes has no safety significance for continued operation with the stub tubes in their present configuration until the next refueling outage. The NRC staff reviewed the licensee's evaluation and concurred with their results. The licensee committed to mechanically plug the stub tubes at the tube sheet during the next Unit 2 refueling outage (Fall 1991). This commitment is described in an HL&P letter dated November 26, 1990 (ST-HL-AE-3638).

d. No. 11 DG Bearing Clearance and Lube Oil Sample Analysis (Unit 1)

On November 12, 1990, the as-found condition of the generator end outboard bearing clearance on the No. 11 standby DG equaled 0.013-0.015 inches. The vendor manual (Cooper-Bessemer Manual 4041-01010) requires approximately 0.020-0.026 inches of clearance. An investigation was initiated to verify and ensure that sufficient clearances existed on all similar bearing installations to allow for adequate lubrication.

Subsequent discussions between HL&P and Cooper-Bessemer disclosed that the measurement technique utilized by HL&P on November 12, 1990, differed with the method used by Cooper-Bessemer in the establishment of their specified value. HL&P measured the outboard bearing clearance using lead wire at the top of the bearing with the plunger bolt torqued. Cooper-Bessemer did not torque this bolt prior to taking their measurement. The vendor also indicated that tightening the plunger bolt may introduce some deflection in the bearing ner and that the values measured by HL&P were satisfactory, considering the method of measurement. The values measured by HL&P are consistent with the standard industry practice of providing from 0.001 to 0.0015 inches of running clearance per 1-inch of diameter. The generator shaft is 9 inches in diameter.

In addition to the clearance issue, babbit was identified in the oil beneath the bearing. This was determined to have been caused by rubbing between the oil ring and the outside diameter of the bearing. This was not considered a significant problem because this was attributed to normal wear. The licensee determined that the bearing was acceptable for continued use; however, the licensee plans to remove the bearing during the next outage in order to blend away or smooth the rubbed areas. This action will be tracked as an inspector followup item (498/9034-01).

e. Feedwater Isolation Valve (FWIV) Solenoid Dump Valves (Unit 1)

On November 10, 1990, at 10:23 p.m., with Unit 1 in Mode 1 at 90 percent power, Feedwater System Valve Operability Test 1PSP03-FW-0001 was performed on the Train A Feedwater Isolation Valve (FWIV) to satisfy TS surveillance requirements. During this test, the test light failed to illuminate as required. The alternate operability test, 1TEP07-FW-0018, was performed as required and it was determined that the A train solenoid dump valve, 1AFW-FY-7141, was not repositioning. The FWIV was declared inoperable and the action statement for Modes 1 and 2 was entered in accordance with TS 3.7.1.7, which requires restoration to operable status within 4 hours.

Subsequent troubleshooting determined correct operation of control circuit relays and relay contacts. To determine if the problem was pressure dependent, the FWIV was partially stroked with the test switch while decreasing hydraulic fluid pressure from the initial 2150 psig by 100 psi increments. At 1800 psig, the test light illuminated to indicate operability of both the A train and B train solenoid dump valves and the 90 percent partial stroke limit switch. A normal operability surveillance test and an alternate operability test were performed and verified as satisfactory. The FWIV was declared operable at 12:15 a.m. on November 11, 1990, and the TS action statement was exited.

Initial investigations focused upon two potential causes. One investigation was concerned with the connection of this event with Fyrquel hydraulic fluid degradation as experienced on March 29, 1990. The second investigation examined the pressure dependency associated with solenoid dump valve operation. Chemical analysis of the hydraulic fluid for this FWIV revealed that the total acid number had increased from March to July (0.01 to 0.15) and had remained level (0.14) thereafter to October 1990. The total acid number is the best indicator of hydraulic fluid (Fryquel GT) degradation. As part of a routine sampling program initiated after the identification of potential degradation, a hydraulic fluid sample was collected on November 8, 1990, 2 days prior to this event. An aging test analysis of this sample indicated no increase in fluid viscosity that could have affected valve operation and the total acid number indicated that the fluid in the orifice region would not have been significantly degraded. On November 11, 1990, hydraulic fluid within the reservoir was regenerated by bleeding and feeding with new Fyrquel GT.

Pressure dependent repositioning of the dump valve was the cause of the July 7, 1990, unusual event (UE) when both dump valves for the A train FWIV failed to operate at 2800 psig. These valves did operate in the normal 2000 psig hydraulic pressure range but could not be made to operate at the higher pressure. Both valves were removed from service, examined for evidence of fouling and sent to Paul Munroe-Enertech for root cause failure analysis. This vendor's analysis disclosed no evidence of degraded hydraulic fluid. After deforming the plunger spring of one of the valves outward, the reassembled solenoid valve started to operate to its original design requirements.

An investigation for a spring deficiency was initiated. The solenoid valve manufacturer, Valcor, ruled out annealing of the steel spring. Valcor has not experienced problems with these springs in valves at 400°F, well above the temperature seen by the

FWIVs at STP. Further measurement on both plunger springs by Paul Munroe-Enertech revealed that the spring constants were within 5 percent of each other (62.8 and 59.8 pounds per inch). These values are within the allowables of the Valcor design specification. The investigation also revealed no material incompatibility between the hydraulic fluid and the polyimide pilot seal or the pilot assembly lubricant, Bel Ray 6523. The results of the investigation did not support a 10 CFR Part 21 required report.

The reason the dump valve failed to operate is believed to be associated with a fouled pilot valve assembly. The pilot valve uses the solenoid and system pressure to act against the plunger spring and hold the fluid in the orifice region at high pressure. System pressure is, therefore, a variable for pilot valve operation. The higher the system pressure, the harder the plunger spring must work to unseat the poppet and open the dump valve. When the pilot valve is activated, magnetic force is induced by the solenoid coil onto the plunger to overcome the plunger spring. The licensee suspects that some binding occurred in the orifice region, at the pilot seal, on November 10, 1990. The cause of the binding was overcome by decreasing the pressure force component on the pilot seal and flushing the hydraulic fluid out of the valve. The interval of valve flushing was changed in mid-October from weekly to monthly by Revision 1 to the Justification for Continued Operation that was issued after the March 29, 1990, experience.

As a result of this event, the operability test for all FWIVs has been increased from monthly to weekly. In addition, an engineering evaluation of the failure of the pilot valves within the dump valves is in progress. It is expected that this evaluation will be completed by December 19, 1990. The inspectors will review the results of that evaluation upon its completion.

9. 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, the test equipment was within the current calibration cycles, and housekeeping was being conducted in an acceptable manner. All observations made were referred to the licensee for appropriate action.

a. Work Request (WR) RC-93015, Reactor Coolant Pump (RCP) 2C Underfrequency Relay Replacement

WR RC-93015 was issued to replace obsolete underfrequency Relay ITE-81 for RCP 2C in accordance with Engineering Change Notice Package 89-L-0064. The old relay previously failed the time delay surveillance test (in a conservative direction) and could not be readjusted. The work instructions consisted of determinating and removing the obsolete relay, installing the new relay, and revising the wiring to the new relay. The new relay was also tested in accordance with Procedure OPMP05-ZE-0050, Revision 2, "Calibration of ITE-81 Relay."

During the work implementation, the following items were observed:

- The relay wire terminations were handwritten on the wall in ink inside the RCP 2C switchgear cubicle. However, when the relay was rewired, the written terminations were no longer accurate. The handwriting on the wall required removal to avoid a potential mistake because of the change in wiring terminations.

- The WR RC-93015 did not provide clear instructions for the applicable steps of Procedure OPMP05-ZE-0050 to be performed. As a result, the technicians utilized those procedural steps that they deemed appropriate to accomplish the work. No problems were noted by the inspector.

b. Preventive Maintenance (PM) EM-0-EM-86008090, Backup Meteorological Tower Emergency Generator Battery Monthly Test/Inspection

The generator is used to provide power to the tower upon loss of normal AC power. PM EM-0-EM-86008090 is a monthly activity that was performed to ensure that the battery was operable and capable of starting the generator.

The work consisted of checking the electrolyte level of the battery, measuring output voltage, and measuring specific gravity and temperature for each cell of the battery. The as-found electrolyte level was found to be unsatisfactory and water was added. The PM failed to provide instructions, however to check the specific gravity after adding water. After questioning by the inspector, the technicians remeasured the specific gravity of one cell, and it failed to meet acceptance criteria. A technician stated that he would initiate a PM change request to revise the work instructions.

c. Preventive Maintenance (PM) Proceuure EM-2-RS-88008834, Rod Drive Power Supply Control Cabinet Inspection/Test

PM Procedure EM-2-RS-88008834 was performed by electrical technicians on the Unit 2 rod drive power supply control cabinet. The cabinet was cleaned and selected relays were tested, including the motor generator exciter field and bus overvoltage relays. The work was accomplished using instructions provided in Procedure OPMP05-RS-0002, Revision 1, "Switchgear Maintenance Reactor Trip Switchgear Train R and S Control Buses." The relays associated with the motor generator exciter field and bus overvoltage were found out of tolerance during performance of the procedure. These out-of-tolerance relays did not affect the ability of the reactor trip breakers to open following a reactor protection system actuation signal. It appears that these relay setpoints were incorrectly set in a conservative manner. The technicians readjusted the relay setpoints. The licensee had not determined the cause of the incorrectly set relay setpoints by the end of the inspection period.

d. Preventive Maintenance (PM) Procedure EM-1-DG-86004190, Standby Diesel Generator Control Panel ZLP-105 Cleaning, Inspection and Test

PM Procedure EM-1-DG-86004190 was performed on DG No. 13, Control Panel No. ZLP-105 and relays located in the panel. The inspector witnessed the calibration of the varmeter in accordance with Procedure OPMP05-ZE-0107, Revision 0, "Varmeter Calibration."

Field Change Request (FCR) 90-1891 was issued to make changes to Procedure OPMP05-ZE-0107. FCR 90-1891 was noted to have several errors and was not fully incorporated into the procedure. For example, two signoffs were missing and the wrong steps were referenced three times. Additionally, Step 6.4.23 was not clear as to whether a retest for as-left values was required. Three observations were made by the inspector:

- As the technicians began to perform the test in accordance with Procedure OPMP05-ZE-0107, the inspector noted that his copy of page 7A of 20 was different from the technicians working copy (a controlled document). The inspector's copy of page 7A was stamped "Corrected Original" and Step 6.4.16 was revised. The revised step stated "If a wattmeter is not available, connect an ammeter in series with the current input leads to the device being tested." The inspector observed that a wattmeter was not available and, therefore, this revised step was pertinent to the performance of the PM activity. When informed of the FCR 90-1891 problems, the technicians suspended the test to revise the procedure and FCR.

- In accordance with plant Procedure OPGP03-ZA-0002, Revision 18, "Plant Procedures," the onsite document control (DC) department was responsible for notifying holders of working copies within 24 hours of a procedure field change. DC also had responsibility for distribution of FCRs to each individual assigned a controlled copy of a revised procedure. A working copy (issued to technicians on green paper) was a controlled document. One of the responsibilities of work performance was for the technicians to ensure that the procedures used were up to date. Technicians have no way of knowing if an original FCR was "corrected" because the plant procedure tracking system used did not specify whether an FCR was updated. Additionally, the changes made were technical in nature, and a new FCR should have been issued. It was subsequently determined that the technicians had both versions of page 7A in their work document, the old one and the corrected one, but they were not aware of the updated page until a page-by-page review of the working copy procedure was performed.

° The practice of issuing "corrected originals" was not described in the licensee's plant procedures. This process was, apparently, used by contractor personnel in order to make minor changes (e.g. typographical errors, etc.) that did not affect the intent of the procedure. This process was then, apparently, used by the licensee even though it did not conform to the requirements of Procedure OPGP03-ZA-0002, Revision 18, "Plant Procedures." Procedure OPGP03-ZA-0002 requires, in part, that FCRs to quality-related procedures shall be reviewed and approved by a technical reviewer, an authorized individual listed in the addendum to the procedure, and the on duty shift supervisor. Apparently, these reviews were not performed for the "corrected original" FCR 90-1891. Failure to comply with OPGP03-ZA-0002 is the second example of apparent Violation 498/9034-03; 499/9034-03. Although the licensee took corrective actions to revise the affected procedure prior to performing it and stopped the issuance of "corrected originals," this violation is being cited because it was NRC identified and was potentially more safety significant than the particular instance observed by the inspector.

e. Work Request (WR) SP-112893, Solid State Protection System Pressurizer Power Operated Relief Valve (PORV) Control Relays K-925 and K-926 Test

Previous routine channel calibrations of the PORVs did not include the verification of the control relay contact movement. Therefore, WR SP-112893 was performed to test the control relay contacts of Relays K-925 and K-926. No specific concerns were identified during performance of this WR.

The technicians appeared knowledgeable and competent, adhered to the procedures, and their activities were conservative in nature. However, the use of "corrected original" FCRs is significant because procedure changes can be made without the appropriate level of review.

10. Complex Surveillance - Unit 2 (61701)

An inspection of selected complex surveillances was performed to ascertain whether the functional testing of the more complex safety-related systems was in conformance with regulatory requirements, industry standards, TS, and approved procedures. The surveillance tests witnessed included the Unit 2, Train B, loss of offsite power (LOOP) test and combination LOOP-ESF actuation test. Specific attributes inspected included assurance that the test was performed using approved procedures, test prerequisites were completed, test data taken was within acceptance criteria limits, and system restoration was accomplished upon completion of testing.

a. B Train LOOP Test (Unit 2)

The LOOP test was performed on Train B equipment using Procedure 2PSP03-DG-0008, Revision 1, "Standby Diesel 22 LOOP Test." The test consisted of deenergizing the 4.16kv Switchgear Bus E2B, ensuring that the No. 22 DG started upon loss of bus power signal, verifying that loads were shed from the deenergized bus, and ensuring that loads required for a LOOP condition were restarted upon reenergization of the bus by the DG. The test was performed by Unit 2 operators, system engineers, and technicians. All components functioned as designed during test performance. A review of the procedure and preliminary test data was also performed. Minor observations not affecting the validity of the test were made and reported to the licensee.

b. Combination LOOP-ESF Test (Unit 2)

The combination LOOP-ESF test was performed using Procedure 2PSP03-DG-0014, Revision 0, "Standby Diesel 22 LOOP-ESF Actuation Test." The test simulated a LOOP in conjunction with a safety injection (ESF) test signal. This resulted in a deenergization of Bus E2B, shedding of loads from the bus, No. 22 DG start signal, and reconnection of selected loads. The verification that nonessential trips would not trip the DG was also performed. The test was performed by Unit 2 operations personnel, system engineers, and technicians. A pretest briefing was held by the shift supervisor prior to test performance to ensure that all participants were aware of their responsibilities.

The first time the licensee attempted to perform the surveillance test, the test was suspended because of CCW Pump 2B problems. The pump tripped on overcurrent following an attempt to manually start the pump. Trip values for the 50/51 (overcurrent) relays were found to be at the low end of the acceptance scale. The pump starting currents were verified to be within specifications. The relays were reset to normal values and the pump started without tripping. However, the overcurrent alarms (alarms set at a value lower than trip setpoints) actuated twice during the surveillance test. Maintenance work requests (MWR) were written to troubleshoot the pump and alarm relays (high vibration was suspected as the cause of the alarms). Additionally, Reactor Containment Fan Cooler (RCFC) 22B power supply breaker malfunctioned just prior to the test. The RCFC 22B breaker was replaced with the RCFC 22A breaker. An MWR was written to rework the inoperative breaker, and the test was continued. None of the above items had an effect on final test results.

A review of the preliminary test results and the procedure was performed. The inspector informed the licensee of the following observations: (1) the nomenclature of the relays in Sections 6.22, 6.23, and 6.25 were different from the nomenclature for the corresponding relays in the plant; (2) the local fuel oil pressure meter was reading above 100 percent scale (60 psig), apparently because nonsafety-related fuel oil pump discharge pressure relief valves (regulates line pressure) were set too high; and (3) the local emergency supply kit seal lock was found broken for no apparent reason.

In conclusion, all components worked as designed during test performance. The test was well run by licensee personnel. Test data reviewed was within acceptance criteria limits, and the systems were left in positions to support plant operation.

11. Spent Fuel Pool Activities - Unit 2 (86700)

Inspections of spent fuel pool activities were performed to ascertain whether the licensee's spent fuel handling activities were in conformance with requirements of TS and approved procedures. The inspection consisted of verifying that spent fuel pool parameters were being maintained within limits and that the FHB ventilation system was operating as required. Observation of fuel movement was also performed and compared to procedural requirements.

Spent fuel pool parameters verified within required limits included: (1) water level was above TS lower limit; (2) pool temperature was below USAR limits; (3) pool chemistry was within procedural limits; and (4) building ventilation parameters were within procedural limits. Tours of the FHB were performed. Housekeeping was generally being maintained. Radiological barriers were properly posted.

Fuel movement was observed on several different occasions. Activities witnessed included operation of the fuel handling machine and fuel transfer system. The procedures used were verified to be the most current procedures available. On one inspection, three bags (one empty, two containing gloves), one box of surgeons gloves, and two rags were found unsecured on the fuel handling bridge. On a second inspection, one roll of tape, one box of surgeons gloves and one rag was unsecured on the bridge. The inspector noted, however, that these items were at a location on the bridge where the items could not easily fall into the pool. Because these items could not easily fall into the pool, this condition was of minimal safety significance. However, this condition is similar to a previous condition observed by the inspectors in September 1989 during a Unit 1 refueling outage. As a result, this issue will be tracked by an unresolved item (499/9034-04) pending further inspection followup of the licensee's corrective actions.

In conclusion, the spent fuel pool was being maintained within required limits, housekeeping was being maintained in the FHB, and radiological controls were being maintained.

12. Refueling Activities - Unit 2 (60710)

An inspection of refueling activities was performed to ascertain whether the activities were being controlled and conducted as required by TS and approved procedures. Activities inspected included fuel handling operations, housekeeping, and assurance that an accurate map of fuel location changes was being maintained.

Routine tours of the Unit 2 RCB were performed. Housekeeping was noted to be generally good, even in areas where work was in progress. Posting and placement of radiologically controlled boundaries were being maintained. Health physics personnel were noted to be routinely walking down the RCB.

Fuel handling operations were witnessed and compared to procedural requirements. Procedure 0POP08-FH-0001, Revision 0, "Refueling Machine Operating Instructions," provided guidance on how to operate the core refueling machine. The inspector watched fuel movement from the refueling machine bridge and observed the following unsecured items on the bridge: several rubber grommets, several rubber gloves, one pair of binoculars, and a manual handwheel (used to manually move the bridge back and forth). None of the items appeared to be in a location such that they could easily fall into the cavity. This is the second example related to Unresolved Item 499/9034-04.

Fuel movement between the RCB and FHB was observed during both core off-load and core reload. Procedure 0POP08-FH-0003, Revision 0, "Fuel Transfer System," provided instructions for the transfer of fuel between the buildings. Operator activities at both the FHB and RCB control consoles was witnessed and their operation of the fuel transfer system was compared to procedural requirements. On several different occasions, the FHB and RCB operators were observed to be turning the upender hydraulic pump on and off and manipulating the traverse control switches in a sequence not specified by the procedure. This was of minimal safety significance because operating the equipment out of sequence had no effect on the accomplishment of the refueling activities. A similar observation was made by the inspectors in September 1989. As a result, this represents the third example of Unresolved Item 499/9034-04.

In conclusion, RCB housekeeping and radiological controls were being maintained and the first Unit 2 refueling was completed without any significant events occurring.

13. Exit Interview

The inspectors met with licensee representatives (denoted in paragraph 1) on November 20, 1990. 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.