APPENDIX

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

NRC Inspection Report: 50-498/90-38 50-499/90-38

Operating Licenses: NPF-76 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: November 20, 1990, through January 1, 1991

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

R. J. Evans, Resident Inspector, Project Section D
Division of Reactor Projects

W. B. Jones, Senior Project Engineer, Project Section D
Division of Reactor Projects

C. J. Paulk, Reactor Inspector
Division of Reactor Safety

Approved: A. T. Howell 1-29-91
A. T. Howell, Chief, Project Section D — Date
Division of Reactor Projects

Inspection Summary

Inspection Conducted November 20, 1990, through January 1, 1991
(Report 50-498/90-38; 50-499/90-38)

Areas Inspected: Routine, unannounced inspection of plant status, onsite followup of events at operating power reactors, followup of previously identified inspection findings, followup on corrective actions for violations and deviations, operational safety verification, engineering safety feature systems walkdown (Unit 2), monthly maintenance observations, surveillance observations, preparation for refueling (Unit 1), and cold weather preparations.

Results: During this inspection period, the licensee performed work activities in a controlled manner and provided documentation which accurately reflected the work activity.

On November 24, 1990, Unit 1 tripped from 100 percent power when a generator running ground fault relay actuated. Subsequent investigation by the licensee revealed that main generator stator damage occurred as a result of harmonic oscillations (paragraph 3.b). An extended outage to repair the main generator was still ongoing at the close of the inspection period.

A notification of an unusual event was declared on December 19, 1990, when a fire occurred in the area of the Unit 2 main turbine Bearing No. 1 (paragraph 3.e). The source of the fire was oil soaked insulation which had not been adequately cleaned up following work on the Unit 2 turbine during the first refueling outage.

One inspector followup item (paragraph 3.d) was identified. This item pertains to licensee actions associated with the sodium contamination of the Unit 1 steam generators and auxiliary feedwater storage tank. The inspectors considered the lack of hydrazine sampling prior to addition to the hydrazine injection tank to be a programmatic weakness.

A second weakness noted during this inspection period involved less than adequate corrective action in addressing the generic implications of failed diesel-generator injector pump hold down bolts (paragraph 3.a). After the failure of four bolts on one injector pump, the licensee did not address the potential failure of the bolts on three other injector pumps that had been removed during the refueling outage. Two days after the first failure, the bolts on another pump also failed.

A strength was identified during the performance of maintenance activities. Maintenance personnel were observed to be conscientious in conducting on-the-job training of electrical helpers (paragraph 8). Another strength identified is the licensee's cold weather preparations that were implemented as a result of last years freezing problems (paragraph 11).

DETAILS

1. Persons Contacted

HL&P

*S. L. Rosen, Vice President, Nuclear Engineering
*S. M. Dew, Nuclear Plant Materials Management
*W. J. Jump, Maintenance Manager
*A. K. Khosla, Senior Engineer, Licensing
*D. J. Denver, Manager, Plant Engineering Department
*J. R. Lovell, Manager, Technical Services
*K. Christian, Unit 1 Operations Manager
*L. Giles, Unit 2 Operations Manager
*G. Weldon, Manager, Operations Training
*M. McBurnett, Manager, Integrated Planning and Scheduling
*A. C. McIntyre, Manager, Design Engineering
*A. W. Harrison, Manager, Licensing
*C. A. Ayala, Supervising Engineer, Licensing
*F. A. White, Supervisor, Plant Operations
*W. A. Randlett, Manager, Nuclear Security Department
*T. J. Jordan, General Manager, Nuclear Assurance
*M. R. Wisenburg, Plant Manager
*R. W. Chewning, Vice President, Nuclear Support
*D. W. McCallum, Manager, Plant Operations Support
*W. L. Mutz, INPO Coordinator
*J. W. Janicki, Supervisor, Work Control Center

Carolina Power & Light Company

*S. M. Shropshire

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

*Denotes those individuals attending the exit interview conducted on January 3, 1991.

2. Plant Status (71707)

Unit 1 began this inspection period operating at 100 percent reactor thermal power. On November 24, 1990, the Unit 1 main generator ground fault relay actuated, which resulted in a Unit 1 reactor trip. The reactor was stabilized in Mode 3 (HOT STANDBY) operation. A subsequent inspection of the main generator by the licensee disclosed a damaged stator cooling coil. The reactor remained in Mode 3 until November 30, 1990, when Mode 4 (HOT SHUTDOWN) was entered. Mode 4 operation was required because of an inadvertent sodium hydroxide contamination of the Unit 1 auxiliary feedwater storage tank (AFST) and steam generators (SGs).

The licensee decided to start the Unit 1 refueling outage 2 months early because of the time needed to repair the main generator. The third refueling outage is scheduled to occur during the period of January 15, 1991, through March 24, 1991. Unit 1 entered Mode 5 (COLD SHUTDOWN) operation on December 4, 1990, to support the forced outage and maintenance activities. The unit remained in Mode 5 through the end of the inspection period.

Unit 2 was operating in COLD SHUTDOWN at the beginning of the inspection period. The licensee was in the process of completing the unit's first refueling outage. Unit 2 entered Mode 4 on December 1, 1990. Unit 2 startup activities continued through December 6, 1990, at which time the reactor was taken critical. The unit entered Mode 1 on December 9, 1990. The first refueling outage was completed the following day when the main generator output breaker was closed. Unit 2 power was increased in increments to allow for scheduled testing activities. Unit 2 reached 100 percent reactor thermal power on December 19, 1990. A fire in the area of the main turbine Bearing No. 1 occurred on December 19, 1990. The source of the fire was oil soaked insulation which had not been adequately cleaned up during turbine work that occurred during the first refueling outage. Unit 2 remained at full power through the end of the inspection period.

3. <u>Onsite Followup Events at Operating Power Reactors (93702)</u>

   a. <u>Standby Diesel Generator (SDG) No. 23 Valid Failure (Unit 2)</u>

   On November 20, 1990, Unit 2 was in Mode 5 operation. During the performance of a 24-hour load test on SDG No. 23, Injector Pump 5L separated from the engine. The test was terminated and SDG No. 23 was secured. The licensee determined the event constituted a SDG valid failure because of the possibility of fire from the loss of fuel from the damaged injector pump. The licensee's investigation of the injector (jerk) pump failure identified that all four injection pump hold down studs had failed. The injection pump and hold down studs were replaced and retorqued.

   On November 22, 1990, during a post maintenance test run of SDG No. 23, Injector Pump 5R separated from the engine. The licensee determined that the four hold down studs for Injector Pump 5R had also failed. The fuel Injector Pump 5R and studs were replaced. Four injector pumps (1R, 3R, 5R, and 5L) had been removed several days earlier for timing adjustments. All four studs and hold down nuts for each injector pump were replaced at that time. After the second pump (5R) failed, an inspection of the 1R and 3R jerk pump fasteners was performed. One hold down nut on Pump 1R and two hold down nuts on 3R were found to have less torque than required by procedure. All of the studs and nuts for Pumps 1R and 3R were replaced. On November 24, 1990, SDG No. 23 was run for one hour. All hold down nuts on the four affected injector pumps were verified to be satisfactorily torqued. The SDG No. 23 was declared operable several days later following completion of surveillance testing.

The root cause of stud failure was not immediately identified by the licensee. Possible causes may have been related to torquing technique, fatigue failure of the studs, or relaxation of the fasteners. Corrective actions taken included replacement of Pumps 5L and 5R, replacing the studs and hold down nuts for the four affected pumps, performing laboratory analysis of the studs and nuts (fatigue failure of one stud was found), and discussion of the event with the vendor (Cooper-Bessemer). A special report was sent to the NRC in accordance with TS 4.8.1.1.3 and 6.9.2 requirements. Additionally, the licensee committed to submit a supplemental report to the NRC by March 31, 1991.

The inspectors considered that the licensee's initial corrective actions following the first injector pump (5L) failure were not of sufficient scope to determine if a generic problem existed. The licensee did not realize that a generic problem existed until the second pump (5R) failed during a test run 2 days later. The corrective actions following the first pump's failure concentrated on the one pump, and did not consider the other three that had been recently removed. The studs were subsequently sent to a laboratory for analysis. The pump was disassembled for inspection and no evidence of damage was observed. Because of the time associated with obtaining the laboratory results, the licensee replaced the pump and studs for 5L and resumed testing of SDG No. 23. When the second pump failed, the licensee then examined the third and fourth pumps. Discussions with the licensee personnel revealed that generic issues were not considered after the first pump failure because: (1) an injector pump failed in 1987 on SDG No. 12 because of an improper preload which resulted in fatigue failure of two studs and the licensee believed the Pump 5L failure occurred because of the same reason; (2) the 5L injector pump failure was only the second failure since 1987; and (3) the time required for obtaining laboratory results would have delayed the outage.

In this instance, the failed injector pumps did not present a challenge to other safety-related equipment. Previous inspections of the licensee's corrective action program has shown that the licensee's reviews are generally sufficient to identify if a generic concern exists. The inspectors are continuing to review the licensee's corrective action program, particularly as it relates to root cause analysis.

b. <u>Reactor Trip Because of a Generator Ground Fault Relay Actuation (Unit 1)</u>

On November 24, 1990, Unit 1 tripped from 100 percent reactor thermal power because of a generator running ground fault relay actuation. All safety related systems responded as expected. The relay actuation resulted from electrical arcing along a failed stator coil end turn to the stator cooling water system manifold.

The licensee formed investigation and recovery teams to evaluate the failure and implement corrective actions. Extensive disassembly of the generator, including rotor removal, was determined to be necessary to replace the failed stator coil. Impact tests were performed on both Unit 1 and 2 generators to determine the natural frequency of the generator end turn assembly with respect to the 120 Hz resonant frequency. Unit 2 turbine end natural frequency was 135 Hz (considered excellent) while Unit 1 was 110 Hz (considered unacceptable). This suggested the Unit 1 end turn had already passed through the natural resonant frequency and was subjected to excessive vibration. The licensee determined additional tests and inspections were necessary before the cause of the failure could be conclusively identified. Licensee Event Report (LER) 1-90-25 was issued describing the event in detail. Additionally, the licensee committed to issue a supplementary report to the NRC by April 30, 1991. Detailed review of the licensee's corrective actions and root cause analysis of this event will be performed during future NRC inspection followup of the LER.

c. Engineered Safety Feature (ESF) Actuation Because of a Partial Loss Of Offsite Power Event (Unit 1)

On December 19, 1990, Unit 1 was in Mode 5 operation. While transferring power from an alternate power supply to the normal power supply, 13.8KV Standby Bus 1G, a loss of power occurred to Standby Bus 1G. Standby Bus 1G was feeding the 4.16KV Class 1E Bus E1B. The loss of power on the safety-related Bus E1B resulted in an ESF actuation of the SDG No. 12 and Train B control room heating, ventilation, and air conditioning (HVAC) systems.

The transient occurred during transfer of load for Standby Bus 1G from the Unit 2 standby transformer (alternate power supply) to the Unit 1 standby transformer (normal power supply). The operator closed the normal power supply breaker and opened the alternate power supply breaker in accordance with the approved procedure. However, the alternate power supply breaker failed to fully open. The normal power supply breaker then tripped open as designed because of the alternate supply breaker failure. Standby Bus 1G subsequently deenergized, resulting in a loss of offsite power to safety-related Bus E1B. The SDG No. 12 autostarted on the loss of power to safety-related Bus E1B. All safety-related system loads sequenced on as designed. Normal power to safety-related Bus E1B was restored within 1 hour.

Corrective actions included troubleshooting the alternate supply breaker to 13.8KV Bus 1G (Tag No. 7E151ESG151G). The investigation revealed the trip arm was hanging up on the inside front cover plate of the breaker. This event is described in LER 1-90-026. Followup of the corrective actions taken will be performed during a future review of the LER.

d. Steam Generator Sodium Intrusion (Unit 1)

On November 30, 1990, Unit 1 was operating in Mode 3 and preparations for a reactor startup were in progress. During routine daily samples of the SGs and AFST, abnormally high sodium concentrations were detected. The concentrations in SGs 1A and 1D were the highest, 3 to 4 ppm. This high concentration resulted from steaming through SGs 1A and 1D power operated relief valves (PORVs) for temperature control. The AFST sodium concentration was 0.15 ppm. The licensee determined the sodium intrusion resulted from the introduction of caustics (sodium hydroxide) into the chemical feed (CF) system. The CF system was used following the reactor trip on November 24, 1990, to add hydrazine and ammonia to the AFST. The licensee had intended to add 40 gallons of hydrazine to the AFST on the afternoon of November 27, 1990, from the 35 percent hydrazine injection tank. Subsequent evaluation disclosed that the sodium hydroxide impurity had been added to the 35 percent hydrazine injection tank late on November 25, 1990, during a normal chemical addition to the hydrazine tank while preparing to place the secondary systems in wet layup following the reactor trip.

HL&P design engineering and Westinghouse chemistry personnel were consulted relative to the cleanup plan and the possibility of performing the cleanup in Mode 4 versus Mode 5. High sodium concentrations can result in accelerated intergranular stress corrosion cracking (IGSCC). Westinghouse agreed that expeditious cleanup of the SG secondary system in Mode 4 was probably no greater risk than reducing the sodium concentrations with the plant in Mode 5. The licensee concluded that IGSCC was not a significant concern for the existing plant conditions since the concentrating effect of sodium would be minimal, even though concentrations were above the established limit of 1 ppm for heating up above 300°F.

The plant was cooled down to approximately 225°F (Mode 4) and draining of the steam generators began late on November 30, 1990. By December 1, 1990, SGs 1A and 1D had been drained and refilled and SGs 1B and 1C were being drained.

The licensee continued to drain and fill the SGs and AFST through the weekend with the goal of decreasing the sodium concentration in the SGs and the AFST to below 0.010 ppm.

By December 3, 1990, the SG sodium concentrations were as follows:

1A: 0.044 ppm   1B: 0.164 ppm   1C: 0.050 ppm   1D: 0.079 ppm

AFST concentration was 0.008 ppm. The chemical feed skid and injection piping were also drained and/or flushed to remove residual sodium hydroxide.

After confirming the 35 percent hydrazine tank had been contaminated with sodium hydroxide, chemical operations supervisory personnel located and impounded the barrels which contained the chemicals that had been most recently pumped into the hydrazine injection tank.

The licensee determined the most recent shipment of hydrazine was supplied by Olin Corporation in black 55 gallon plastic drums. The drums were clearly marked with a vendor label complete with chemical assay. Certificates of Compliance were required with each shipment. Ninety-one drums were used between July 1, 1989, to July 1, 1990.

Warehouse labeling consists of class/bin (HL&P Part No. 501-7733) with a paper adhesive label. Material Received Report (MRR) numbers are also normally included on the drum. Container tags are filled out by chemical operations personnel and affixed to the barrels by site facilities personnel before moving the drums from the warehouse to the protected area. The bungs to the new barrels supplied by a previous vendor and the Olin Corporation were sealed with a plastic protective cap.

The previous supplier, Van Waters & Rogers (VWR), shipped the material in blue drums. Ninety drums were received in 1988 under the VWR purchase order. Four of these drums were found in the rinseout area near the neutralization basin during the initial investigation of this problem. They were all stenciled with "35% Hydrazine" in black lettering on top but only three had container tags. Operators that added the hydrazine to the 35 percent hydrazine tank on November 25, 1990, confirmed that they had added from a blue barrel. Operators verified that the barrel was labeled 35 percent hydrazine and initially thought that they removed the plastic protective cover, however, because of the routine nature of this task, the operators could not be certain.

A subsequent licensee review of the material issued report (MIR) and container tags for the other three blue barrels confirmed that they had been used in Unit 2. The Unit 2 secondary system was sampled in parallel to the Unit 1 investigation. No abnormal sodium levels were identified in the Unit 2 concentrated chemical storage tanks or the associated systems. By process of elimination, the licensee determined the fourth blue barrel appears to have been the most likely source of the impurity. The residual liquid in the rinsed barrels having container tags for the affected time period was sampled and analyzed for sodium. The suspect blue barrel was also sampled and had the highest sodium level. Its sodium concentration was higher that the concentration of the sodium in the service water with which it was rinsed, indicating some level of sodium contamination.

The licensee concluded that one barrel of approximately 50 percent sodium hydroxide was added to the 35 percent hydrazine tank on November 25, 1990. Since no other sodium problems attributed to chemical impurities have been previously identified, the licensee considered that the probability that 1 of the 50 barrels received from VWR in 1988 was tainted or improperly packaged was small. The fact that the barrel in question had no container tag or MIR information indicates that it had been inside the protected area for an extended period of time. As a result, it could have been used for another purpose without proper relabeling or obliteration of the existing label. During interviews, operators indicated that the barrel had been in the storage location for an extended period and was inventoried weekly as 35 percent hydrazine. The chemical operators may have unknowingly retrieved a barrel containing sodium hydroxide along with several other acceptable barrels that were moved by them over the weekend; however, this could not be determined with complete certainty because licensee procedures did not require the chemical sampling of the 35 percent hydrazine barrel prior to addition to the hydrazine injection tank. Training and procedures for transferring the hydrazine to the 35 percent hydrazine injection tank only require verification of the barrel labeling. The inspector considered this lack of sampling to be a procedural weakness.

No other suspect drums were found inside the protected area, indicating that this was an isolated event. A problem report was written and will address and summarize the final conclusions and corrective actions. Immediate corrective actions taken include the following:

- New drums of hydrazine are being sampled prior to addition to the 35 percent hydrazine injection tank.
- Unit 2 systems were sampled to verify that the problem only existed in Unit 1.
- Chemical operations and analysis personnel were made aware of the seriousness of the event and subsequent impact to the plant.

Future corrective actions will be tracked by inspector followup item (498/9038-01).

e. Notification of Unusual Event (NOUE) Because of a Fire Near the Unit 2 Main Turbine

On December 19, 1990, the Unit 2 control room received a fire protection computer alarm (turbine generator building thermal detector to Turbine Bearing No. 1 alarm). An operator was dispatched to the vicinity of the bearing, located in an enclosed area. A fire in the vicinity of the Bearing No. 1 was reported to the control room. The onsite fire brigade responded to the fire and extinguished it within minutes. Unit 2 remained at 100 percent reactor thermal power. Turbine bearing temperature and vibration levels were closely monitored and remained within allowable limits. Unit 1 personnel assisted the Unit 2 operators with monitoring the event.

About 45 minutes after the fire was extinguished, the fire reflashed and was again put out by the fire brigade. A NOUE was declared at this time because the fire, located inside the protected area, was not brought under control within 10 minutes. The fire reflashed several times, but each time was extinguished by the fire brigade. The fuel source for the fire was oil soaked lagging (insulation) in the vicinity of Turbine Bearing No. 1. The source of the oil was from lube oil flushing activities conducted during the refueling outage. No safety-related equipment was damaged by the fire. The NOUE was terminated when all oil soaked insulation was removed. A station problem report was written to investigate the cause of fire and spilled oil.

The operators responded appropriately to the fire and properly classified the event as a NOUE. Poor housekeeping activities during the refueling outage, which include the control of flammable materials, was a significant contributor to this event.

4. Licensee Action on Previous Inspection Findings (92701)

(Closed) Open Item (498/8726-11; 499/8726-11): Development and Validation of MPL

This item was opened in NRC Inspection Report 50-498/87-26; 50-498/87-26, to provide for tracking the completion of the master parts list (MPL) as part of Action Item 2.2.1.2 of Generic Letter 83-28 prior to licensing the plant. At the time the item was opened, the licensee had committed, via a letter dated November 4, 1986, to have the MPL completed by August 25, 1991. Subsequent to the inspection, the licensee submitted a response to Supplement 2 of the STPEGS Safety Evaluation Report (SER) dated October 26, 1989. Supplement 2 requested additional information regarding Action Item 2.2.1 of Generic Letter 83-28. The licensee changed its commitment for completion of the MPL to late 1992 and the change was accepted by NRC.

The MPL has been specifically identified as an action item to Generic Letter 83-28. Therefore, redundant tracking of this issue is not necessary and this Open Item 498/8726-11; 499/8726-11 is closed. Action Item 2.2.1.2 of Generic Letter 83-28 will remain open pending completion and inspection of the licensee actions.

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

a. (Closed) Violation (498/8934-03; 499/8934-03): Failure to Ensure Qualification of Electrical Equipment

During an environmental qualification (EQ) inspection conducted in 1989, the inspector identified that:

- A motor operated valve (B1SI-MOV-0039B, ECCS Accumulator Outlet), which could be required to be repositioned following an accident, had electrical cabling for power and indication which was subject to submergence. This cabling had not been qualified for postaccident submergence.

- A failed gasket existed on motor operated Valve D1AF-MOV-0514 as evidenced by the existence of moisture intrusion. In addition, the grease relief on this motor operated valve actuator was broken off. These conditions resulted in the actuator being in an unqualified condition.

The licensee relocated electrical cabling in accordance with WR-SI-85438. The failed gasket was replaced in accordance with the instructions provided in WR 62639. Additional EQ inspections were performed by the licensee with no additional deficiencies were identified. This violation is closed.

b. (Closed) Violation (498/8934-04; 499/8934-04): Failure to Follow Procedures

During the 1989 EQ inspection, the inspectors found that the licensee had failed to follow installation procedures in that:

- Wires connected to the terminal block (TB) inside motor operated Valve A1SI-MOV-0039A were found to be bent greater than the minimum bend radius allowable.

- Wires were connected to adjacent TB points inside motor operated Valve D1AF-MOV-0514 instead of alternate points specified in the vendor's test report. In addition, postinstallation inspections incorrectly documented that the wires were connected in accordance with the vendor's requirements.

- The splice connections for Flow Transmitter N1SI-FT-0901 were not installed using the shims necessary to provide a properly qualified configuration.

The licensee evaluated the use of adjacent terminals and determined that the procedure was too conservative. The licensee revised the procedure to address the use of terminal blocks and the requirements for EQ. This was considered acceptable by the inspector.

With respect to the failure to use shims, the licensee submitted voluntary LER 1-89-18. The inspector reviewed documents associated with the corrective actions addressed in the LER and found the licensee's actions to be acceptable. This violation is closed.

6. Operational Safety Verification (71707)

The objectives of this inspection were to ensure that the facility was being operated safely and in conformance with license and regulatory requirements, and to ensure that the licensee's management controls were effectively discharging the licensee's responsibilities for safe operation. This inspection also 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.

The inspectors conducted control room observations on a routine basis and verified that control room staffing, operator decorum, shift turnover, adherence to TS LCOs, and overall control room operation was in accordance with requirements. The inspectors conducted tours in various locations of the plant 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 certain observations identified during this inspection period.

a. Leaking Pressurizer Spray Valve (Unit 2)

During testing of pressurizer spray valves on December 13, 1990, one of two pressurizer spray valves did not close completely when the control room control switch was placed in the close position. The resulting spray caused one bank of backup heaters to remain energized. The licensee entered the reactor containment building to investigate the cause of the slightly open spray valve. The licensee lubricated the valve stem and was subsequently able to stroke the valve closed such that the backup heaters no longer remained energized. The licensee attributed the failure of the spray valve to fully close to the extended period the valve was in dry layup during the recent outage.

b. Conoseal Leak (Unit 2)

On November 22, 1990, Unit 2 was in Mode 5 with the reactor coolant system (RCS) at 100°F and at atmospheric pressure. When the RCS was filled and vented following completion of the first refueling outage, a reactor vessel instrument port column assembly conoseal began leaking excessively. At the time the RCS was at atmospheric pressure with pressurizer level stabilized at about 62 percent. Leakage past the conoseal was estimated to be about 2 gpm. The RCS water that leaked out accumulated in the lower internals storage area. Approximately 3 inches of water accumulated in the lower internals storage area. The RCS was drained down to Elevation 41 (top of vessel flange) to stop the leak. The lower internals storage area was drained to the reactor containment building (RCB) normal sump.

The conoseal was tightened and this stopped the leak. However, engineering conducted an investigation into the installation practices used for the conoseals. From this review, engineering determined that the conoseal upper gasket may have been installed incorrectly. This assumption was based on the fact that the installation procedure, OPMP04-RX-0018, Revision 2, "Non-Rapid Refueling Mechanical Support," states that when placing the upper and lower gaskets, "ensure that the apex of the cone formed by the gasket points toward the top of the vapor container." The problem with this instruction is that the vapor container is not identified in the work instructions or drawings provided to the installers. The licensee is revising the procedure to include caution notes to ensure that the conoseals are installed correctly. The conoseal as installed is performing correctly.

Engineering personnel will witness the conoseal disassembly during the next outage to determine that exact orientation of the conoseal and inspect the seating surfaces. This effort will help to determine the impact of an incorrectly installed conoseal and to see if the conoseal was in fact assembled incorrectly. Westinghouse was consulted and concurs with the licensee's decision to continue operating with the nonleaking conoseal even though the licensee did not determine whether the conoseal was incorrectly installed.

c. <u>Auxiliary Shutdown Panel Qualified Display Parameter System (QDPS) Displays Out of Service (Unit 2)</u>

During a routine tour of the auxiliary shutdown panel room in Unit 2, maintenance technicians observed the C Train QDPS plasma display out of service. The screen would only display the diagnostic menu page and would not change screens upon demand. The other QDPS display (Train A) was already out of service for corrective maintenance. The C Train QDPS screen was displaying a time and date that was several days old. Upon discovery of the inoperative C Train display, the operators entered TS 3.3.3.5 action statement (7 days to repair one train of QDPS or be in Hot Shutdown within the next 12 hours). The QDPS C Train display was repaired using parts from Unit 1 and was returned to service within 2 days.

The licensee was questioned as to when the TS action statement was entered. The Unit 2 shift supervisor started the 7-day clock at the time the display froze up. However, the QPDS display was returned to service prior to the end of 7-days.

The NRC questioned the licensee about the incident in terms of surveillance requirements since the auxiliary shutdown panel instruments are only surveyed on a monthly basis. The licensee stated that TS commitments were being met but would further review the incident in order to ensure continued compliance with TS 3.3.3.5.

d. AFW Pump Turbine Mechanical Overspeed Trip (Unit 2)

On December 2, 1990, during surveillance testing, the Unit 2 steam driven auxiliary feedwater pump mechanical overspeed trip mechanism could not be reset. A maintenance work request (MWR) was written to disassemble the mechanical overspeed trip mechanism. Upon disassembly, the tappet ball of the mechanical overspeed trip mechanism was found broken. This prevented the associated emergency weight from providing sufficient force to operate the linkage of the trip and throttle valve. The tappet ball was manufactured out of polyurethane plastic material and the tappet shaft was machined cut of aluminum. The licensee replaced the tappet ball with one manufactured from brass. The condition of the Unit 1 tappet ball was similar to the Unit 2 tappet ball. It was also replaced with one manufactured from brass. In addition, the licensee revised the preventive maintenance procedures to include disassembly and inspection of the mechanical governor assembly internals every refueling outage.

7. Engineered Safety Feature (ESF) System Walkdown - Unit 2 (71710)

A walkdown of two Unit 2 engineered safety features (ESF) systems was performed to independently verify the status of the systems. The two systems walked down were the containment spray system and the Class 1E DC electrical distribution system. In addition to walking down the systems, a detailed review of the system operating procedures and drawings was also performed. All observations madr were presented to the licensee for resolution or for incorporation into the procedures during future revisions.

The DC electrical distribution system was found to be properly aligned in accordance with the requirements of Procedure 2POP02-EE-0001, Revision 2, "ESF (Class 1E) DC Distribution System." Additionally, an inspection of the DC batteries was performed. No corrosion was found and the electrolyte levels were acceptable.

The containment spray system was found to be properly aligned in accordance with the Procedure 2POP02-CS-0001, Revision 2, "Containment Spray Standby Lineup," requirements. The walkdown included portions of the system located inside the Unit 2 reactor containment building (RCB). The following items were observed:

- Three minor piping and instrument diagram errors were noted.
- Two valves (2-CS-0041A, Pump 2A Discharge Line Test Connection, and 2-CS-0035B, Pump 2B Test Connection) were required to be locked closed. The valves were found shut with cables and locks installed on them. However, the two cables were found to be loosely installed on the valve handles. Therefore, the locks were not performing their intended functions. These valves were reported to the operations shift supervisor who initiated corrective actions. A safety concern

did not exist because the valves were shut and were located in a vital area of the plant (keycard required for entry).

- A tour of the Unit 2 RCB was performed. The RCB was in the process of being cleaned up following completion of the maintenance and refueling outage activities. One radiation boundary was found to be improperly maintained. The area in RCB (20 foot elevation, southwest corner) had radiation boundary tape installed on the floor, but the actual boundary (identified with use of rope) was in a different location. This discrepancy was reported to the on-duty health physics supervisor who initiated corrective actions to fix the boundary markers. This area of the RCB was not an area that was routinely traversed by plant personnel.

In conclusion, the systems were found to be in the correct positions to support plant operation. Housekeeping was being maintained, including the Unit 2 RCB. No problems that affected system operability were identified.

8. Monthly Maintenance Observations (62703)

Selected maintenance activities were inspected to ascertain whether the maintenance of safety related systems and components was being conducted in accordance with approved procedures and TS. Specific items inspected included ensuring approved procedures were adhered to, test equipment was within required calibration cycles, and the equipment was properly returned to service. The activities observed included the following:

- Refueling Water Purification Pump Motor Inspection and Lubrication, Preventive Maintenance (PM) EM-1-FC-87015333

  PM EM-1-FC-87015333 is an 18-month maintenance activity that was performed by electrical technicians on the Unit 1 refueling water purification pump motor. The work consisted of motor inspection, cleaning, and lubrication. No concerns were identified during the inspection of the work and review of the work documents.

- 48 VDC Battery Quarterly Inspection PM EM-2-DE-87016666

  PM EM-2-DE-87016666 was performed by electrical technicians on the Unit 2 plant computer 48 VDC battery. The work consisted of battery inspection, voltage measurements, and specific gravity measurements. Individual cell voltages were measured as a part of the PM. Two battery cells failed to meet the minimum cell voltage requirement, and the total battery voltage was found to be out of the acceptance criteria tolerance range. Therefore, the licensee performed an equalizing battery charge. The inspector observed, however, that the PM did not provide instructions to perform an equalizing charge if the total battery voltage was found out of tolerance.

  The technician was assisted by a new helper during the performance of the PM. The technician performed the work slowly and explained the job to the helper as it was being performed. The technician appeared to be doing a good job of training the helper about the work being performed.

The licensee's maintenance program was implemented in accordance with the procedures. The methods used by the technician to explain the work to the electrical helper reflected positively on the licensee's on the job training program.

9. Surveillance Observations (61726)

Selected surveillance activities were observed to ascertain whether the surveillance of safety significant systems and components had been conducted in accordance with TS and other requirements.

The following surveillance tests were observed and the documents reviewed:

° OPSP02-FW-0519, Revision 0, "Steam Generator A Narrow Range Level Set 2 Analog Channel Operational Test."

  Procedure OPSP02-FW-0519 was performed by instrumentation and controls technicians on the Steam Generator 2A Hi-Hi and Lo-Lo level trip circuits. All setpoints were found and left within acceptance criteria limits. No concerns were identified with this surveillance.

° 2PSP06-PK-0001, Revision 2, "Undervoltage Relay Channel Calibration/Trip Actuating Device Operational Test."

  Procedure 2PSP06-PK-0001 was performed by electrical technicians on the Channel 1 undervoltage relay. All setpoints were found and left within acceptance criteria limits.

° 2PSP06-PK-0005, Revision 2, "Degraded Voltage Relay Channel Calibration/Trip Actuating Device Operational Test."

  Procedure 2PSP06-PK-0005 was performed by electrical technicians on the Channel 1 degraded voltage relay. All setpoints were found within acceptance criteria limits, except Timer 62XE which was found out of procedural tolerance (conservatively low) but within TS required limits. The relay was subsequently readjusted and all as left setpoints were within the required limits.

Licensee personnel performed well in this area while being observed by the inspectors. The persons who performed the activities appeared knowledgeable and competent, used the correct test equipment, adhered to approved procedures, and were careful while performing the assigned tasks.

10. Preparation for Refueling (60705)

A review was conducted of the Unit 1 third refueling outage, scheduled to begin on January 15, 1991. The review assessed the adequacy of the licensee's administrative requirements for control of refueling operations and for control of plant conditions during refueling activities.

The scope of the outage was reviewed and found to include the following:

- Integrated Leakage Rate Test
- Steam Generator Sludge Lancing
- Core Reloading
- Turbine Inspections
- Sequential Train Outages

The outage scope and actual work performed will be evaluated and the results documented in a subsequent inspection report.

11. Cold Weather Preparations (71714)

An inspection of the licensee's cold weather preparations was performed to determine whether the licensee effectively implemented the program of protective measures for extreme cold weather. Specific items inspected included verifying: (1) selected thermostats were properly set, (2) heat tracing and space heating circuits had been energized, (3) Unit 1 (cold shutdown mode of operation) was properly prepared for the cold, and (4) modifications made during the previous year were completed.

A walkdown of the freeze protection and heat trace systems panels and power supplies was performed. All panels were noted to be energized; however, a high number of local alarms (overtemperature, undertemperature, and circuit failure) were observed on selected panels. Only one TS-related circuit alarm (overtemperature) was observed. This alarm was associated with the Unit 1 heat trace system for the Train B boric acid system. A concern did not exist because the circuit was a nonsafety-related secondary circuit and the TS limits for boric acid were for minimum temperature rather than maximum temperature.

STP had previously designed the heat trace systems to protect plant systems to minimum temperatures of 11°F. During December 1989, the local ambient temperature dropped to 8°F. The licensee then decided to protect the plant to 3°F, prompting the need for plant modifications. It was determined that most problems that occurred during the 1989 freeze were attributed to inadequate heat trace; heating, ventilation and air conditioning (HVAC) systems being inoperable; or cooling fans being left on. About 400 work requests were issued to implement design changes, including adding heat trace circuits, providing additional insulation, or repairing existing heat trace and insulation already installed. Most of the work requests were completed by December 1990. Additionally, a new Procedure OPGP03-ZO-0037, "Cold Weather Guidelines," was developed and Procedure OPOP01-ZO-0004, "Extreme Cold Weather Conditions Guidelines," was upgraded to include actions such as removing fans from service.

As part of cold weather preparations for 1990-91, all unnecessary Unit 2 systems were drained on the secondary side. The systems drained included the deaerators, seal water systems, and auxiliary boiler. The temperature dropped to around 20°F in December 1990. The results of the freeze included: (1) essential cooling water (ECW) pond temperature dropped below 54 degrees, requiring the operators to throttle ECW flow to selected components, (2) the mechanical auxiliary building (MAB) chiller cooling coils (nonsafety-related) in the Unit 1 MAB HVAC system froze, (3) a nitrogen regulator to the demineralized water storage tank froze open resulting in an excessive use of nitrogen, (4) the caustic system froze but was later thawed out, and (5) several secondary side pressure and level gauges were damaged. No safety related components were adversely affected.

The licensee's actions to prepare the plant for cold weather appeared adequate. The number of changes made to the plant was indicative of the licensee's commitment to upgrade previously existing cold weather protection measures in order to improve overall plant reliability.

12. Exit Interview

The inspectors met with licensee representatives (denoted in paragraph 1) on January 3, 1991. 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.