APPENDIX B

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

NRC Inspection Report: 50-498/89-11 Operating Licenses: NPF-76
50-499/89-11 NPF-80

Dockets: 50-498
50-499

Licensee: Houston Lighting & Power Company (HL&P)
P.O. Box 1700
Houston, Texas 77001

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

Inspection At: STP, Matagorda County, Texas

Inspection Conducted: April 1-30, 1989

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E. J. Holler, Chief, Project Section D Date
Division of Reactor Projects

Inspection Summary

Inspection Conducted April 1-30, 1989 (Report 50-498/89-11; 50-499/89-11)

Areas Inspected: Routine, unannounced inspection of plant status, followup of events, operational safety verification, monthly maintenance observation, and monthly surveillance observation.

Results: Within the areas inspected, one violation of NRC requirements was identified regarding failure to establish environmental qualification of certain auxiliary feedwater system valves with installed space heaters. Also, the circuitry of the space heaters did not meet the guidance of RG 1.75 (see paragraph 4). A weakness was noted in the controlling of instruction manuals, spare parts, history files, and housekeeping. A violation was noted but not cited regarding maintenance activities (see paragraph 5). Discrepancies were noted between the same procedures used in Unit 1 and in Unit 2 regarding accumulator surveillances (see paragraph 6). Discrepancies regarding proper maintenance of oil level in the essential chillers was also noted (see paragraph 7).

## DETAILS

1. Persons Contacted

*P. L. Walker, Senior Licensing Engineer
*J. E. Geiger, General Manager, Nuclear Assurance
*A. W. Harrison, Supervising Licensing Engineer
*V. A. Simonis, Plant Operations Support Manager
*S. M. Head, Supervising Licensing Engineer
*M. R. Wisenburg, Plant Superintendent
*J. R. Lovell, Technical Services Manager
*W. H. Kinsey, Plant Manager
*M. A. McBurnett, Licensing Manager

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

*Denotes those individuals attending the exit interview conducted on May 4, 1989.

2. Plant Status

Unit 1 operated at full licensed thermal power for the duration of this inspection period. The annual emergency preparedness graded exercise was conducted on April 26, 1989. The results of the exercise are documented in NRC Inspection Report 50-498/89-12; 50-499/89-12.

Unit 2 began this inspection period at 8 percent reactor power. After an initial unsuccessful attempt to synchronize the Unit 2 main generator to the offsite electrical distribution system, the licensee successfully sychronized the generator on April 11, 1989. Toward the end of the inspection period, the licensee shut down Unit 2 to find and correct a noise associated with the main turbine.

3. Followup of Events - Units 1 and 2 (93702)

On April 6, 1989, at 5:54 a.m., with the Unit 1 emergency safety features (ESF) Diesel Generator (DG) No. 11 out of service for scheduled maintenance, ESF DG No. 12 failed to start during an operability test required by Technical Specification (TS) 3.8.1.1. With two inoperable DGs, Unit 1 entered a 2-hour limiting condition for operation (LCO) as required by TS 3.8.1.1(f). Unable to return DG Nos. 11 or 12 to operability status by 7:54 a.m., the licensee began a controlled shutdown of Unit 1 as required by TS 3.8.1.1(f).

The problem with the DG No. 12 was determined to be a failed resistor in the governor assembly. The licensee had received information from the Palo Verde Nuclear Generating Station (PVNGS) that similar problems had

existed with their DGs. Both the STP and the PVNGS DGs were manufactured by Cooper Energy Services. The licensee contacted the manufacturer to discuss the problem and to pursue possible corrective measures that should preclude recurrence of this event.

At 11:46 a.m., on April 6, 1989, DG No. 11 was returned to service. The NRC inspector witnessed the performance of Procedure 1PSP03-DG-0001, "Standby (S/B) Diesel Generator No. 11 Operability Test." Following the replacement of the failed resistor in the governor assembly and after successfully completing the required operability test, the licensee declared DG No. 12 operable at 7:50 p.m. and exited TS 3.8.1.1.

On April 5, 1989, Unit 2 tripped from 11 percent reactor power while attempting to synchronize the main generator to the offsite electrical distribution system. The licensee determined the cause of the reactor trip to be an electrical relay problem associated with the main generator circuit breaker. The licensee determined that improper implementation of changes to the wiring of the generator backup distance relay and negative phase sequence relay by startup technicians, prior to turnover of the generator system to plant operations, caused the Main Generator Circuit Breaker to trip. The problem relays were rewired and tested on April 7, 1989.

The loss of power to 13.8kV auxiliary buses, after the generator circuit breaker tripped, resulted in a loss of power to Reactor Coolant Pumps 2A, 2B, 2C, and 2D. The undervoltage coils on the pump breakers actuated to trip the breakers and generate a low flow reactor trip signal through the Solid State Protection System, which tripped the reactor. All rods inserted normally. The loss of power to ESF bus E2A caused Standby Diesel Generator No. 21 to start. ESF loads sequenced onto the bus as required. After verifying stable conditions, the operators reenergized the auxiliary buses from their respective standby buses which were supplied from the Unit 2 Standby Transformer. When bus 2J was reenergized, RCP 2D restarted because its breaker had failed to trip open on the loss of voltage. The additional flow caused a drop in steam generator water level resulting in an actuation of the Auxiliary Feedwater system. Average coolant temperature continued to decrease due to lack of decay heat, lack of coolant pump heat, and secondary steam loads. A main steam isolation was manually initiated to prevent overcooling of the RCS.

Troubleshooting of the RCP 2D breaker revealed a broken lug on a cable from the undervoltage coil to the breaker trip circuit. The wire connected to the lug had caught on the breaker enclosure, apparently when the breaker was racked in, because of the wire falling out of its harness. The undervoltage coil functioned properly and sent a trip signal to the Solid State Protection System to initiate a reactor trip; however, the RCP breaker did not trip because of the broken lug. The broken lug on the RCP 2D breaker was replaced and the other Unit 2 RCP breakers were checked for other wires which may have fallen from their harnesses.

Plant restart was delayed by a packing leak on a feedwater isolation bypass valve. Mode 1 was achieved on April 11, 1989. On the same day, at 1:26 p.m., initial generator synchronization to the offsite electrical distribution system was achieved.

On April 15, 1989, a Unit 2 reactor trip occurred when the Train S reactor trip breaker opened without receiving a reactor trip signal from the solid state protection system. All systems functioned normally after the trip. The faulty breaker was subsequently replaced but reactor restart was again delayed by necessary repairs to a worsening packing leak on the feedwater isolation bypass valve. Mode 1 was again achieved on April 20, 1989.

On April 21, 1989, a metallic noise was discovered in the area near the No. 8 main turbine generator bearing. HL&P commenced a reactor shutdown to disassemble and inspect the low pressure turbine and bearings. On April 27, 1989, the licensee determined that a bore plug in the main turbine generator jack shaft had backed out and fallen into the hollow bull gear, causing a noise as it tumbled within the bull gear when the turbine was rolled. The inspection period ended with reassembly of the main turbine ongoing.

4. Operational Safety Verification - Units 1 & 2 (71707)

The objectives of this portion of the inspection were to ensure that the facility was being operated safely and in conformance with regulatory requirements, to ensure that the licensee's management controls were effective in discharging the licensee's responsibility for continued safe operation, and to assure that selected activities of the licensee's radiological protection program were implemented in conformance with plant policies and procedures and were in compliance with the approved physical security plan.

The NRC inspectors visited the control rooms on a daily basis when onsite and verified that control room staffing, operator behavior, shift turnover, adherence to TS LCOs, and overall control room decorum were being conducted in accordance with NRC requirements.

Tours were conducted throughout various locations of the plant to observe work and operations in progress. Radiological work practices, posting of barriers, and proper use of personnel dosimetry were observed.

The NRC inspectors verified, on a sampling basis, that the licensee's security force was functioning in compliance with the approved physical security plan. Search equipment such as X-ray machines, metal detectors, and explosive detectors were observed to be operational. The NRC inspectors noted that the protected area was well maintained and not compromised by erosion or unauthorized openings in the area barrier.

General housekeeping, cleanliness, and physical condition of safety-related equipment were inspected with particular emphasis on engineered safety feature (ESF) systems.

During the inspection period, the NRC inspectors questioned the licensee about the use of space heaters in safety-related motor operated valves. The licensee identified seven safety-related valves per unit with space heaters. Three valves were associated with the Essential Cooling Water (ECW) system and four were associated with Train D of the Auxiliary Feedwater (AFW) system. Space heaters for the valves were provided by the vendor for use during preinstallation storage and were not considered safety related. After questioning by the NRC inspectors on the safety classification of the motor space heaters, the licensee performed an indepth review of the application of space heaters in the seven valves.

The licensee determined that the space heaters were incorrectly wired into the circuitry of the eight (four per unit) AFW valves but were correctly wired into the circuitry of the six (three per unit) ECW valves. The six ECW valve space heaters were wired with dual circuit breakers, with one breaker designed to shunt trip open on an ESF signal. However, the eight AFW valves had nonsafety-related space heaters wired in parallel to the Class 1E 125V DC motors. The wiring configuration apparently did not meet criteria established by Regulatory Guide (RG) 1.75, "Physical Independence of Electrical Systems." The four AFW valves (per unit) are: AF-MOV0143, AFW turbine steam inlet valve; AF-MOV0514, AFW Pump 14 turbine trip and throttle valve; AF-FV7526, AFW to steam generator 1D regulating valve; and AF-MOV0019, AF turbine Pump 14 isolation valve.

The eight AFW valves were located in the Unit 1 and Unit 2 isolation valve cubicle (IVC) buildings. The area would be subjected to a harsh environment if a design basis accident occurred. The eight AFW valves were environmentally qualified because of their location. Vendor supplied documents (Wyle Laboratories Report No. 47644-05) indicated that the motor operated valves were tested for environmental qualification (EQ) without the space heaters being energized. The licensee operated the eight EQ AFW valves for several months with space heaters wired into the valve circuits, even though the space heaters had not been shown to have been EQ tested.

Paragraph (f) of 10 CFR 50.49 requires that qualification of each component must be based on testing or experience with identical equipment, or with similar equipment with a supporting analysis, to show that the equipment to be qualified is acceptable. Paragraph (k) of 10 CFR 50.49 states that equipment previously required by the Commission to be qualified to NUREG-0588, "Interim Staff Position on Environmental Qualification of Safety Related Electrical Equipment," need not be requalified. Section 5(1) of NUREG-0588, Revision 1, states that the qualification documentation shall verify that each type of electrical equipment is qualified for its application and meets its specified performance requirements. The basis of qualification shall be explained to show the relationship of all facets of proof needed to support adequacy of the complete equipment. Data used to demonstrate the qualification of the equipment shall be pertinent to the application and organized in an auditable form.

The equipment qualification file (Wyle Laboratories Report No. 47664-05) for the eight AFW valves did not adequately support the actual application of the valves with the space heaters installed and energized. The EQ documentation failed to adequately analyze for all possible effects of energized space heaters used within the valve assemblies. Specifically, the areas not analyzed included effect of premature aging of the valve components due to the additional heat supplied by the heater, the effect of heater failure on the valve, and the effect of burn damage on electrical components due to close proximity to the heater elements. Failure to properly qualify the eight AFW valves with regard to their application in the field is an apparent violation of 10 CFR 50.49 requirements (50-498/8911-01; 50-499/8911-01).

Train B of the Safety Injection (SI) system for Unit 2 was inspected to ensure the system valves, control switches, and electrical power supplies were in their correct positions, as required by the system operating procedure and plant drawings. The SI system Train B was compared to Procedure 2POP02-SI-0002, Revision 2, "Safety Injection System Initial Lineup," and the Piping and Instrument Diagram (P&ID) 5N129F05014 No. 2, Revision 10, "Safety Injection System." All valves, power supplies, and control switches were found to be in the correct position for the mode of operation on the day of inspection. Items observed during the inspection included:

- Labelling discrepancies were observed throughout the system lineups. For example, in the Control Board Lineup 2POP02-SI-0002-5, Valve 2-SI-FV-3957 was labelled "HHSI Tc Upstream" on the panel, but was called "HHSI Pump Cold Leg Test Line Isolation Valv. in the procedure. In the electrical lineup, the field label for Device E2B1-W1L was "Backup Breaker For Compt. C1," but E2B1-W1L was called 2-SI-MOV-0006B in the procedure.

- In Train B Initial Lineup Procedure 2POP02-SI-0002-5, the location of Device 2-SI-0070B was missing the room number (fuel handling building (FHB) RM-5).

- During the review of SI System Vent Lineup 2POP02-SI-0002-16, two Train B valves were noted to be missing from the lineup. The two valves were the Test Vent Valves 2-SI-0138 and 2-SI-0101B.

- The SI System Vent Lineup 2POP02-SI-0002-16 listed Valve 2-SI-0231, which was previously deleted. The valve was not shown on the system P&ID, neither was the valve listed in the system initial lineup. A review of documentation was performed to determine if the valve was shown to be deleted when operations performed the SI system vent lineup. The licensee could not locate documentation to verify that Train B of the SI system was vented per 2POP02-SI-0002-16. However, Train B of the SI system was vented per 2PSP03-SI-0014, Revision 1, "ECCS Valve Checklist," on February 13, 1989.

During the inspection of the mechanical auxiliary building (MAB) in Unit 2, Boric Acid Tank Room 076 was visited. The NRC inspectors observed local Sample Connection Valve 2-CV-0322 leaking excessively. This valve was slowly draining boric acid from Boric Acid Tank 2B onto the floor of the room. The Unit 2 shift supervisor was immediately notified. The licensee fully shut the valve and generated a problem report.

The NRC inspectors observed control room operations, reviewed applicable logs, and conducted discussions with control room operators. The NRC inspectors verified the operability of selected emergency systems, reviewed tag-out records and verified proper return to service of affected components, and ensured that maintenance requests had been initiated for equipment in need of maintenance.

One apparent violation and no deviations were identified in this area of the inspection.

5. Monthly Maintenance Observations - Unit 1 (62703)

Portions of selected Unit 1 maintenance activities were observed to ascertain whether the activities were conducted in accordance with approved procedures. The activities included:

- Maintenance Work Request (MWR) SY46861, Seismic Monitoring System

- Preventive Maintenance (PM) IC-0-EM86007175, Revision 9A, Meteorological Monitoring System Inspection

The NRC inspectors tried to determine through observations whether approved procedures were being used, replacement parts were properly certified, and housekeeping was being maintained. Specific items noted during the observation of PM IC-0-EM-86007175 included:

- Both the Primary and Backup Meteorological (Met) towers had instruction manuals and drawings that were uncontrolled and out of date. Having manuals available for use by the technicians in remote locations, such as the Met towers, can be beneficial. However, having uncontrolled or out-of-date copies of manuals for troubleshooting or maintenance purposes may lead to problems. The manuals and drawings have since been recalled for updating or disposal by the licensee.

- A box inside the primary Met tower contained what appeared to be spare parts. The spare parts were inside zip-lock bags that provided some identification as to what the parts were, however, there were no material issue forms included in the box that identified the date or source of issue. The spare parts have since been returned to the Instrumentation and Control (I&C) shop for dispositioning.

- An uncontrolled history file was being maintained at both Met towers. The information that was gathered as part of the PM was being

transferred to copies of out-of-date data sheets. These data sheets were then being added to the history files. The history files have since been returned to the I&C shop for review to determine their usefulness.

- The primary and backup Met tower electric generator batteries were observed to have standing water on top of them. The potential existed where the water could have shorted out the batteries. The batteries were cleaned by the licensee on the day of inspection.

- The primary Met tower was noted to be in need of cleaning. Housekeeping was not being maintained in an acceptable manner. Loose paper, dirt, dead insects, and other items were noted throughout the room. Prior to the end of this inspection period, the room was cleaned by the licensee.

Observations noted during the review of MWR SY-46861 included:

- Technicians were noted to be troubleshooting the circuitry of Seismic Monitor Channel Sensor XT0002A. Troubleshooting activities included removing the sensor for testing, lifting leads for a wire check and meggering, and reterminating the lifted leads. All troubleshooting activities were performed using verbal instructions provided by the foreman of the task. A review of the MWR was performed. Authorization to troubleshoot the circuitry was not a part of the MWR.

  Instructions on troubleshooting activities were provided in OPGP03-ZM-0021, Revision 1, "Control of Configuration Changes During Maintenance or Troubleshooting." Section 6.2.1 of the procedure requires, in part, that troubleshooting is to be performed using approved work instructions and as part of an MWR. The technicians, following the instructions of their foreman, appeared to exceed the authorization allowed for troubleshooting per OPGP03-ZM-0021 without revising MWR SY-46861.

  TS 6.8.1 requires written procedures to be established, implemented, and maintained, including applicable procedures recommended in Appendix A of Regulatory Guide 1.33, Revision 2, "Quality Assurance Program Requirements (Operation)." Written procedures required per Appendix A of RG 1.33 included procedure adherence and performing maintenance.

  Contrary to the above, on April 27-28, 1989, technicians apparently violated TS 6.8.1 by performing maintenance activities that did not adhere to requirements established by OPGP03-ZM-0021. Although the seismic monitoring system is considered nonsafety related, their operability is required by TS 3.3.3.3.

  This apparent violation (498/8911-02; 499/8911-02) of TS 6.8.1 will not be cited because the criteria specified in Section V.A. of the

enforcement policy were satisfied. Corrective actions taken by the licensee subsequent to the apparent violation included personnel training and performing a review of current procedures to determine and clarify the scope of troubleshooting activities.

- During the performance of MWR SY-46861, an inspection of the Unit 1 tendon gallery was performed. Housekeeping was not being maintained, as indicated by grease on the floor of the tendon gallery. Approximately 2-3 gallons of grease was located in the center of the floor. A tendon in the tendon gallery was leaking grease significantly. The sheathing filler grease cap was leaking grease on Tendon V222. After the condition was reported to the licensee, a second tendon (V209) in Unit 2 was noted by the licensee to be leaking grease. Nonconformance reports were written for the two tendons. The licensee advised that each unit has 96 vertical tendons and all will be inspected at least every 6 weeks for signs of additional leakage. Containment structural integrity is required by TS 3.6.1.6. The licensee stated that the leakage of grease from the two tendons did not affect the structural integrities of the two reactor containment buildings.

- The ladder area leading to the Unit 1 tendon gallery was inadequately illuminated. The area from the top of the first ladder to the second ladder was observed not to be illuminated, and was considered to be an obvious safety hazard. The tendon gallery is an area of the plant that is not traversed by plant personnel on a regular basis.

One apparent violation and no deviations were identified in this area of the inspection.

6. Monthly Surveillance Observations - Units 1 and 2 (61726)

An inspection of Unit 1 licensee surveillance activities was performed to ascertain whether the surveillance of systems and components was being conducted in accordance with TS and other requirements. The following surveillance tests were observed and reviewed:

- 1PSP02-SI-0953, Revision 1, "Accumulator 1B Level Group 2 ACOT (L-0953)"

- 1PSP02-SI-0963, Revision 1, "Accumulator 1B Pressure Group 2 ACOT (P-0963)"

The NRC inspector verified that testing was performed using approved procedures, final test data was within acceptance criteria limits, and test equipment was within required calibration cycles. A technical review of the procedures was also performed.

During the review of 1PSP02-SI-0963, Section 7.5 was noted to be misnumbered. Section 7.5 had two steps numbered as 7.5.3. Step 7.5.2

instructed the technician to go to Step 7.5.4 if a computer point was unavailable. Due to the misnumbered steps, the potential existed of referring a technician to the wrong step (7.5.4). Verbatim compliance with Step 7.5.2 would have sent the technician to the wrong step.

Step 7.6.3 of 1PSP02-SI-0953, instructed the technician to verify that an annunciator alarmed when a comparator tripped. The comparator was reset in the next step. Step 7.6.7 verified the same alarm energized when a second circuit was tripped. There were no steps between 7.6.3 and 7.6.7 that verified that the annunciator alarm cleared. The same procedure for Unit 2 (2PSP02-SI-0953) included Step 7.6.6, which verified that the alarm was clear. The same observation also applied to Procedure 1PSP02-SI-0963.

An inspection of Unit 2 licensee surveillance activities was performed to ascertain whether the surveillance of systems and components were being conducted in accordance with TS and other requirements. The following surveillance tests were observed and reviewed:

- 2PSP02-SI-0931, Revision 0, "RWST Level Set 2 ACOT (L-0931)"

- 2PSP02-SI-0952, Revision 0, "Accumulator 2B Level Group 4 ACOT (L-0952)"

During the review of 2PSP02-SI-0952, the procedure was compared to the same procedure for Unit 1 (1PSP02-SI-0952, Revision 1). Differences were noted between the two procedures. The differences included:

- The Unit 1 procedure additionally had Step 6.1 which referred the technician to TS action statements for LCO requirements. The Unit 2 procedure did not have a similar step.

- The Unit 2 procedure had three additional steps in Section 7.6 to verify that an annunciator was clear before, during, and after testing. The Unit 1 procedure did not perform these steps.

- Steps 7.7.1 (remove all test equipment) and 7.7.3 (ensure annunciator deenergized) were double signoff steps for independent verification of actions in the Unit 1 procedure. The same steps in the Unit 2 procedure were single signoff steps, with no independent verification of the steps required.

Additionally, the NRC inspector noted the terminal strips in the Unit 1 Relay Cabinet ZRR-012 had protective covers, but the terminal strips in the Unit 2 Relay Cabinet ZRR-010 did not have protective covers. The terminal strips were noted to be nonsafety related, however.

In conclusion, testing was performed using approved procedures, final test data was within acceptance criteria limits, and test equipment was within required calibration cycles. None of the observations were considered

safety significant concerns. The discrepancies were referred to the licensee for resolution. No violations or deviations were identified in this area of the inspection.

7. Monthly Maintenance Observations - Unit 2 (62703)

The NRC inspectors observed portions of selected Unit 2 maintenance activities to ascertain whether the activities were conducted in accordance with approved procedures. The activities included Work Request CH-78095, "Add Oil to Essential Chiller 21B." The essential chillers provide cooling to selected safety-related equipment during upset and faulted conditions.

The problem description on the work request was, "Essential Chiller 21B upper oil sightglass is empty when chiller is running, add oil as required." The work observed included postmaintenance testing of Chiller 21B following maintenance. The following items were noted during the inspection:

- Procedure OPMP05-CH-0001, Revision 1, "York Chiller Inspection and Maintenance," Section 6.5.5, provided instructions on how to check the oil level with the chillers either operating or shut down. With low oil level (as written on Work Request CH-78095), Addendum 4 was required to be performed. Addendum 4 provided instructions to start the chiller (Step 1), install a jumper to energize a solenoid (Step 2), allow the solenoid to remain energized for approximately 5 days (Step 3), and monitor oil level every 4 hours (Step 4).

  Step 3 was not completed in its entirety before Step 4 was performed. The chiller did not run for 5 days prior to maintenance performing Step 4 and postmaintenance testing. Steps 3 and 4 of Addendum 4 should be adhered to or revised by the licensee to clarify how long the chiller is required to operate prior to performing oil level checks.

- Discrepancies were noted to exist between the essential chilled water (CH) system operating procedures, maintenance procedures, and the vendor manual with respect to proper chiller oil level.

  Step 8.1.1 of Operating Procedure 2POP02-CH-0001, Revision 1, "Essential Chilled Water System," stated "Verify the operating oil level is above the top of the lower sight glass to the middle of the upper sight glass for (Chillers) 22A, 22B, and 22C. The oil level is visible in the sightglass for (Chillers) 21A, 21B, and 21C. If oil level is out of range contact maintenance for correction."

  Step 6.5.5.1 of OPMP05-CH-0001 stated "Verify operating oil level is from the top of the lower sightglass to the middle of the upper sightglass." Step 6.5.5.2 stated "Verify shutdown oil level to be at

least at the top of bottom sight glass to the middle of upper sight glass." Both steps applied to both sizes of essential chillers, the 300-ton units (22A-C) and the 150-ton units (21A-C).

The vendor manual for Chillers 21A-C indicates proper operating oil level is from the lower sight glass to the middle of the upper sight glass.

A vendor representative informed the NRC inspector that proper oil level for all chillers exists when oil is visible in the upper sight glass with the unit operating, and oil level can be reliably checked only during chiller operation.

Discrepancies noted with the above statements included:

- Step 8.1.1 of 2POP02-CH-0001 implied that Chillers 21A-C have only one sightglass to verify oil level, but the chillers actually have two sightglasses, an upper and lower one.

- Vendor instructions were not located by the NRC inspector or licensee personnel for proper oil level for the "open drive" type chillers, 22A-C. The oil reservoir is physically different between the "open drive" and "hermetic" chillers. Vendor instructions were provided only for hermetic chillers.

- Step 6.5.5.2 of OPMP05-CH-0001 indicated shutdown oil level should be no higher than the middle of the upper sight glass. Actual shutdown level will vary, depending on purge drum (removes noncondensable gasses from chiller) level at shutdown, length of shutdown and chiller temperature. Also, actual shutdown oil levels for the open drive chillers (22A-C) were noted to be above the top of the upper sightglass (disagrees with requirements of Step 6.5.5.2). Additionally, Step 6.5.5.2 disagrees with vendor instructions (provided verbally) that oil level could only be reliably checked during chiller operation.

- MWR CH-78095 was written to add oil to Chiller 21B. Per wording of the vendor manual, the chiller had sufficient oil, therefore, the MWR was an unnecessary but conservative action.

- Step 8.1.1 of 2POP02-CH-0001 instructed the operator to verify operating oil level of a chiller, but the chillers are not started until Step 8.1.8 of the procedure. Step 8.1.1 should be revised to verify the oil level of a shutdown chiller is above a certain level, or Step 8.1.1 should be placed after Step 8.1.8.

This subject area will be tracked as an open item (499/8911-03) until all procedures in question have been revised to agree on how to check essential chiller oil level, and operations personnel are trained on the proper way to check operating and shutdown oil levels.

No violations or deviations were identified in this area of the inspection.

8. Preparation for Refueling Observations - Unit 1 (60705)

The NRC inspectors observed the testing of a carbon arc cutting device and the generation of the basic requirements for a procedure to which it is qualified and used. The device was tested on a mockup of the bottom half shell of a steam generator; the shell included one primary loop nozzle and the manway cover and flange.

The purpose of the equipment is to extract a broken bolt/stud in the manway flange if that event occurs during the first Unit 1 refueling outage. (The center of the bolt is cut out and the sides are collapsed.)

The overall unit encompasses: a fixture which can be bolted to the manway flange, a positioner which will align the cutting head to the bolt hole, a cooling unit, power control, and the graphite electrode cutting tool. The unit is operated by positioning the device in the hole with the broken bolt/stud, starting the cooling system (the system provides coolant to the electrode and washes away the residue), and energizing the power unit to the cutting electrode. When the cut has been made, the electrode is withdrawn and the resultant "shell" of the bolt can be collapsed inwardly and removed from the flange. Once set up, the operation can be performed remotely, thereby reducing or keeping personnel exposure to penetrating radiation to a minimum. The NRC inspectors did not have any concerns in the development of the process.

No violations or deviations were identified in this area of the inspection.

9. Exit Interview

The NRC inspector met with licensee representatives (denoted in paragraph 1) on May 4, 1989. The NRC 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 NRC inspectors.