

APPENDIX A

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-498/94-31
50-499/94-31

Licenses: NPF-76
NPF-80

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

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

Inspection At: Matagorda County, Texas

Inspection Conducted: September 11-15, 1994

Inspectors: W. Wagner, Reactor Inspector, Plant Support Branch
Division of Reactor Safety

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Approved: 

W. P. Ang, Chief, Plant Support Branch,
Division of Reactor Safety

10/20/94
Date

Inspection Summary

Areas Inspected (Units 1 and 2): Routine, announced inspection of written reports of nonroutine events at power reactor facilities and followup of previously identified inspection items.

Results (Units 1 and 2):

Twenty-two open items were closed. The licensee provided adequate information to substantiate that these items posed no significant safety issues. One new Inspection Followup item was opened for future followup inspection of the Preventative Maintenance optimization program which had not yet been fully implemented at the time of the inspection.

Summary of Inspection Findings:

- Licensee Event Report 499/9308 was closed (Section 1.1)
- Licensee Event Report 499/93009 was closed (Section 1.2).
- Licensee Event Report 498/93021 was closed (Section 1.3).
- Licensee Event Report 498/93022 was closed (Section 1.4).
- Licensee Event Report 498/94008 was closed (Section 1.5).
- Violation 498/9235-06; 499/9235-06 was closed (Section 4.1).
- Violation 498/9305-02 was closed (Section 3.1).
- Violation 498/9305-03 was closed (Section 3.2).
- Inspection Followup Item 498/9331-38; 499/9331-38 was closed (Section 4.2).
- Inspection Followup Item 498/9331-51; 499/9331-51 was closed (Section 2.1).
- Inspection Followup Item 498/9348-16; 499/9348-16 was closed (Section 3.3).
- Inspection Followup Item 498/9349-13; 499/9349-13 was closed (Section 2.2).
- Inspection Followup Item 498/9349-14; 499/9349-14 was closed (Section 2.3).
- Inspection Followup Item 498/9349-15; 499/9349-15 was closed (Section 2.4).
- Inspection Followup Item 498/9431-01 was opened (Section 2.4).
- Inspection Followup Item 498/9349-16; 499/9349-16 was closed (Section 2.5).
- Inspection Followup Item 498/9349-17; 499/9349-17 was closed (Section 2.6).
- Inspection Followup Item 498/9350-10; 499/9350-10 was closed (Section 3.4).
- Inspection Followup Item 498/9350-20; 499/9350-20 was closed (Section 3.5).

- Inspection Followup Item 498/9351-16; 499/9351-16 was closed (Section 4.3).
- Inspection Followup Item 498/9355-01; 499/9355-01 was closed (Section 3.6).
- Inspection Followup Item 498/9355-02; 499/9355-02 was closed (Section 3.7).
- Inspection Followup Item 498/9419-07; 499/9419-07 was closed (Section 4.4).

Attachment:

- Attachment - Persons Contacted and Exit Meeting

DETAILS

1 LICENSEE EVENT REPORTS (LER) (92700)

1.1 (Closed) LER 499/9308: Failure to Maintain Environmental Qualification

1.1.1 Original Event

This report stated that the environmentally qualified configuration of a motor-operated valve in the residual heat removal (RHR) system had not been maintained after maintenance. A replacement motor for Motor Operated Valve RH-0060B did not contain T-drains which were installed in the motor-operated valve during environmental qualification.

This issue was addressed as a violation in NRC Inspection Report 50-498/93-35; 50-499/93-35. Followup of the report remained open at that time, pending completion of training program enhancements which the licensee had committed to implement as part of their corrective actions.

1.1.2 Licensee Action in Response to this Event

The licensee revised their training programs for initial and continuing training for system engineers, senior reactor operators, quality control inspectors, maintenance planners, and the crafts personnel.

1.1.3 Activity During this Inspection

The inspector reviewed Station Problem Report 931578, which added environmental qualification and configuration management as topics in the continuing training program for quality control inspectors, systems engineers, and maintenance personnel. The inspector reviewed the training module, which the licensee had prepared, and class attendance lists.

1.1.4 Conclusion

The inspectors found the licensee's actions to be adequate. This item is closed.

1.2 (Closed) LER 499/93009: Technical Specification Violation Due to Use of Inappropriate Reference Test Value Data for a RHR Pump

1.2.1 Original Event

On April 26, 1993, while Unit 2 was in a refueling outage, the licensee identified that Technical Specifications 3.5.6 and 4.0.5 had been violated during previous surveillance testing. Surveillance testing of RHR Pump 2A, performed on February 18 and 20 and March 21, 1993, used inappropriate test reference values to calculate pump differential pressure. On January 29, 1993, a field change was generated to the inservice test for RHR Pump 1A, to

add a means to control RHR pressure during inservice testing to prevent a challenge to the relief valves. This field change incorrectly included a RHR Pump 2A data sheet which contained pump differential pressure values from a February 11, 1989, reference value test. This inappropriately changed the RHR Pump 2A differential pressure reference value test data. The appropriate reference value data should have been obtained from a September 3, 1992, test. The cause of this event was less than adequate attention to detail by the preparer and the subsequent reviewers during the preparation, review, and approval of the field change.

A licensee analysis of this event determined that:

- Inappropriate inservice testing did not impact the function of RHR Pump 2A.
- There was no significant impact on RHR Pump 2A flow.
- If challenged, RHR Pump 2A would have performed its safety function.

1.2.2 Licensee Action in Response to this Event

The licensee issued a field change to include the appropriate test reference values in the RHR Pump 2A inservice test procedure. The licensee trained appropriate personnel on the lessons learned from this and similar events involving preparation of procedure changes, along with techniques for precluding recurrence. The licensee also reviewed a sample of other completed field changes to ensure that the reported condition was an isolated incident.

1.2.3 Activity During this Inspection

The inspectors performed an onsite review of the licensee's documentation associated with this event to verify appropriate actions were taken. The inspectors determined that the licensee's identified actions were accomplished by the scheduled dates and that they were adequate to address this issue.

1.2.4 Conclusion

The inspectors concluded that the licensee's actions were adequate to address this item and that they had been accomplished by the scheduled dates. This item is closed.

1.3 (Closed) LER 498/9321: Failure to Provide Backup Overcurrent Protection For Penetration Conductors

1.3.1 Original Event

This report identified that certain safety-related fuses intended to provide backup overcurrent protection for conductors penetrating containment were not actually wired into their associated circuits. This redundant protection was

a required design feature to prevent a single failure of an overcurrent protection device from allowing excessive fault current through the containment penetration conductors, resulting in excessive heat which could degrade the containment penetration seal integrity. The affected circuit provided power to the space heaters for the Train B RHR pump in Unit 1. The space heaters are normally energized when the RHR pumps were not running. The licensee inspected the identical fuses for the space heaters in the Train A and C RHR pumps and found that they had not been wired into their associated circuits, either. No other cases of miswired backup fuses were found during licensee inspections of all other installations of backup fuses in Units 1 or 2. The licensee had installed the backup fuses to meet Regulatory Guide 1.63 in September 1985. Neither startup testing nor periodic surveillance testing had detected the improper wiring configuration.

1.3.2 Licensee Action in Response to this Event

The licensee rewired the affected circuits to install the fuses as functional overcurrent protection devices.

The licensee completed their root cause investigation and determined that the miswiring was an isolated incident. The licensee concluded that this probably resulted from unauthorized temporary rewiring during startup testing in 1985, which had not been properly restored. The exact cause and time of the miswiring could not be established from the records maintained during the period.

1.3.3 Activity During this Inspection

The inspector reviewed Plant Change Form 309776A and Service Requests 212715 and 212714. The affected circuit for the RHR pump space heaters were rewired in accordance with these documents. The inspector found that the licensee had completed their corrective actions by November 1993.

1.3.4 Conclusion

The inspector found the licensee actions to be adequate. This item is closed.

1.4 (Closed) LER 498/93022: Deviation from Method of Contaminant Sampling for Diesel Generator Fuel Oil

1.4.1 Original Event

This voluntary report identified that the licensee had not been using the method specified in Technical Specifications for sampling the emergency diesel generator fuel oil. Technical Specification 4.8.1.1.2d specified that samples of the fuel oil in the diesel generator storage tanks obtained for periodic analysis for particulate contamination be obtained in accordance with Standard ASTM-D2276-78. The licensee identified that their method of sampling deviated slightly from the specified standard, introducing a potential conservative bias in their determination of particulate contamination in the

samples. In Standard ASTM-D2276-78, the sample container was required to be rinsed with filtered flushing fluid, then capped. The licensee's method required the sample container to be rinsed in demineralized water, then dried in an oven before capping.

In a letter dated January 31, 1994, the Office of Nuclear Reactor Regulation reviewed the licensee's report and determined that the identified discrepancy had no impact on the licensee's ability to establish fuel quality. The Office of Nuclear Reactor Regulation considered that the licensee's method achieved results which were equal to, or more conservative than, the method specified in the Technical Specifications.

1.4.2 Licensee Action in Response to this Event

The licensee reviewed the particulate contamination results for all samples and found none to exceed the specified limits.

The licensee reviewed their procedures for other instances where the Technical Specification requirements had not been adequately incorporated and found several other minor deviations which were considered insignificant or potentially conservative.

The licensee submitted an amendment to their Technical Specifications to remove the requirements for fuel oil sampling and to establish a new fuel oil sampling program.

1.4.3 Activity During this Inspection

The inspector reviewed Station Problem Report 931281, which identified the deviation from the Technical Specification. The inspector reviewed licensee Procedure OCP05-ZS-0005, "Sampling and Treatment of the Fuel Oil System," Revision 3, dated November 10, 1993.

The inspector found that the licensee's procedure had been revised to conform to the method specified in Standard ASTM-D2276-78, with one exception. The procedure did not utilize the filtered flushing fluid (petroleum ether) specified in the ASTM standard, due to safety concerns. According to the licensee, petroleum ether was extremely flammable and their method was discussed with the NRC, Region IV. The NRC considered this was acceptable to satisfy the ASTM in methodology and intent.

The inspector noted that the licensee's procedure specified 10 ppm (parts per million) as the maximum allowable particulate contamination, while the Technical Specification and the ASTM standard specified 10 mg/l (milligrams per liter). The inspector questioned the equivalency of these units of measure for particulate concentration in fuel oil. The licensee identified that their use of ppm was not an equivalent unit of measure for fuel oil. However, the licensee's calculation did appropriately determine particulate

concentration to meet the required quantitative acceptance criteria. The licensee stated that the inaccurate use of ppm as the unit of measure in their procedures would be corrected. The inspector found the licensee proposed actions to be adequate.

1.4.4 Conclusion

The inspector found the licensee actions to be adequate. This item is closed.

1.5 (Closed) LER 498/94008: Failure to Stagger Reactor Trip Breaker Surveillance Test Intervals

1.5.1 Original Event

The licensee identified that on February 24, 1994, while Unit 1 was in Mode 1 at 7 percent power, a review of the performance history of the solid state protection system surveillance testing determined that the reactor trip breaker surveillances associated with Technical Specifications 4.3.1 and 4.3.2 were not performed in accordance with Technical Specification requirements for staggered test intervals. Although the subject surveillances were individually within their required intervals, they were not within the grace interval associated with the monthly stagger requirement of Technical Specification Table 4.3-1, Note 7, and Table 4.3-2, Note 1. Both of these notes stated that "each train shall be tested at least every 62 days on a stagger test basis." This event occurred during the period in which the normal cyclic schedule was being re-established at the end of a long outage. The causes of this event were determined to be an inadequate surveillance program (in that methods for assuring staggered intervals were restored following an outage were less than adequate) and inadequate training of new divisional surveillance coordinators.

1.5.2 Licensee Action in Response to this Event

The LER stated that a "Technical Specification Stagger Report" would be developed and generated for responsible surveillance coordinator review on a periodic basis (e.g., biweekly). This report would notify the responsible surveillance coordinators of the need to maintain the Technical Specification stagger requirements which were more limiting than the calculated completion date/"Dead Date" for the individual surveillances. As an interim measure, until the implementation of the "Technical Specification Stagger Report," the plant surveillance coordinator was directed to conduct reviews on a periodicity of approximately 2 weeks to ensure that Technical Specification surveillance stagger requirements were maintained. The plant surveillance coordinator conducted training for division surveillance coordinators with scheduling responsibilities for surveillances with Technical Specification stagger requirements. This training addressed details of South Texas Project surveillance program implementation relative to ensuring that Technical Specification surveillance stagger requirements were not exceeded. Conditional surveillance tasks were generated in the surveillance task data base for each division responsible for surveillance tasks subject to Technical

Specification stagger requirements. These conditional surveillance tasks were listed on the mode change reports for mode ascension up to Mode 3. The responsible surveillance coordinators were directed to review the staggered due dates for all surveillances tasks subject to Technical Specification stagger requirements prior to each increasing mode change, as applicable. The LER also stated that an interdepartment task force would be formed to develop recommendations for improving the process for replacing and training new responsible surveillance coordinators.

1.5.3 Activity During this Inspection

The inspector performed an onsite review of the licensee's documentation associated with this event to verify that appropriate actions were taken. The inspector determined the following:

- Interim reviews were performed by the plant surveillance coordinator approximately every 2 weeks until the surveillance stagger report program was implemented, to ensure that Technical Specification surveillance requirements were maintained;
- Training of divisional surveillance coordinators was performed on implementation of stagger requirements for surveillances;
- The "Surveillance Stagger Report" program was implemented on April 29, 1994; and
- The interdepartment task force submitted recommendations for improving the process for replacing and training new responsible surveillance coordinators.

1.5.4 Conclusion

The inspector concluded that the licensee's identified actions were accomplished by the scheduled dates and that they were adequate to address this issue. This item is closed.

2 FOLLOWUP OF CORRECTIVE ACTIONS FOR NRC OPEN ITEMS IDENTIFIED IN THE MAINTENANCE AREA (92902)

2.1 (Closed) Inspection Followup Item (IFI) 498/9331-51: Performance of Precision Calibrations of the Component Cooling Water Heat Exchanger Flow Instruments

2.1.1 Original Followup Item

The licensee had committed, in its operational readiness plan, to perform precision calibrations on the installed flow instruments in the component cooling water heat exchanger outlet to the essential cooling water system.

The precision calibrations for the Unit 1 flow instrumentation was reviewed and documented in NRC Inspection Report 50-498/93-39; 50-499/93-39.

2.1.2 Licensee Action in Response to this Item

The Unit 2 precision calibrations of the component cooling water heat exchanger flow instrumentation were completed.

2.1.3 Activity During this Inspection

By review of applicable documentation, the inspectors verified that the calibrations were performed. Service Requests 176274, 176275, and 176276, each dated June 24, 1993, initiated the actions required to perform the calibrations on the flow indicators and flow transmitters in Trains A, B, and C of Unit 2. The instrumentation for Trains A, B, and C was calibrated and returned to service on November 26, 1993, April 20, 1993, and January 14, 1994, respectively. The three work packages each contained the completed (signed off and dated) work instructions, plant change forms, calibration data sheets, test instructions, and test control forms.

2.1.4 Conclusion:

The inspectors concluded that the licensee had satisfactorily completed the precision calibrations for the Unit 2 flow instrumentation in the component cooling water heat exchanger outlet to the essential cooling water system. This item is closed.

2.2 (Closed) IFI 498;499/9349-13: Weakness in Preventative Maintenance - Poor Equipment Performance

2.2.1 Original Followup Item

Weaknesses in the scope and implementation procedures for the preventative maintenance (PM) program contributed to poor equipment performance. These weaknesses were attributed, in part, to poor development of the PM program in terms of scope and procedure accuracy that were not properly addressed.

2.2.2 Licensee Action in Response to this Item

The licensee reviewed this NRC concern and documented the results of their review in a memorandum dated May 6, 1994.

2.2.3 Activity During this Inspection

The inspector reviewed the licensee's documentation associated with this item to verify appropriate actions were taken. The inspectors noted the following:

- Unit 1 PM activities were initially created for each equipment vendor recommendation. In 1989, maintenance management directed that many of the "active" status PM activities be reviewed for possible inactivation. This review was performed, and a large number of PM activities were placed in an "Inactive" status. Unit 2 PMs corresponding to Unit 1 "Inactive" PMs were either not developed or placed in an "Inactive" status at that time (1989).
- All "Inactive" PM tasks were currently scheduled for review under the licensee's South Texas Project Business Plan 1994-1998, "Focus Area Initiatives, F4.2 - Material Condition and Plant Reliability." This activity was scheduled to be completed by the end of 1995. This review would consist of documenting all maintenance recommendations and commitments associated with the equipment listed on a PM, along with determining the applicability and effectiveness of the PM. Based on these findings, the PM would be adjusted to the proper status and frequency. Requirements for Unit 2 PMs were to be addressed as the corresponding Unit 1 PM was reviewed.
- Reliability Engineering, as part of the PM living program, has been tasked to continue to monitor equipment failures and review them for preventability. PM activities or modifications will then be implemented when it is determined that a failure is preventable, and the PM/modification is applicable and effective.

2.2.4 Conclusion

The inspector concluded that the licensee had reviewed this item and had established an action item in their South Texas Project Business Plan 1994-1998, to address and track their actions for this item. The licensee actions which were identified and scheduled for completion by December 31, 1995, provided reasonable assurance that weaknesses in the preventative program would be addressed by the licensee. This item is closed.

2.3 (Closed) IFI 498;499/9349-14: Not Performing Inactive PM Tasks - Instrument Calibration

2.3.1 Original Followup Item

As a result of not performing inactive PM tasks, the following preventable events, equipment failures, and instances of poor assurance of operability (mostly dealing with instrument calibrations) occurred: (1) an uncalibrated lubricating oil pressure switch contributed to a startup feed pump not starting on demand following a reactor trip; (2) a feedwater booster pump was damaged partly because of an uncalibrated lube oil pressure switch; (3) the technical support center chillers failed, resulting in high temperature conditions and corresponding alarms on the plant computer. Only inactive PMs were associated with the technical support center chiller; (4) temperature indicators used to determine the operability of safety-related chillers were

not periodically calibrated; and (5) an uncalibrated level switch in the component cooling water system contributed to an engineered safety feature actuation.

2.3.2 Licensee Action in Response to this Item

The licensee reviewed this NRC concern, and documented the results of their review in a memorandum dated May 6, 1994.

2.3.3 Activity During this Inspection

The inspectors reviewed the licensee's documentation associated with this event to verify appropriate actions were taken. The inspectors noted the following:

2.3.3.1 Inactive PM Tasks

All inactive PM tasks were currently scheduled for review under South Texas Project Business Plan 1994-1998, "Focus Area Initiatives, F4.2 - Material Condition & Plant Reliability." This activity was scheduled to be completed by December 31, 1995. This review would consist of documenting all maintenance recommendations and commitments associated with the equipment listed on a PM, along with determining the failure effects of not performing the PM, and determining the applicability and effectiveness of the PM. Based on these findings, the PM would be adjusted to the proper status and frequency.

Reliability engineering, as part of the PM living program, will continue to monitor equipment failures and review them for preventability. PM activities or modifications will be implemented when it is determined that a failure is preventable, and the PM/modification is applicable and effective.

2.3.3.2 An Uncalibrated Lubricating Oil Pressure Switch Contributed to a Startup Feed Pump Not Starting on Demand Following a Reactor Trip

This problem was documented in SPRs 921619 and 921620. During the investigation of this event, switches were found out of calibration. The analysis of the event noted that the original engineering design established a situation where the startup feed pump start permissive could be defeated prior to the receipt of an alarm in the control room. These SPRs did not assign any specific corrective actions regarding the PM program. LER 92-010-00, "Corrective Action 2," documented the review of this design condition and required revision of the switch scheme. While the SPRs did not assign any specific corrective actions regarding the PM program, specific maintenance feedback forms with due dates of September 22, 1994, were issued to evaluate the need to perform preventative maintenance on these switches.

2.3.3.3 Feed Water Booster Pump was Damaged Partly Because of an Uncalibrated Lubricating Oil Pressure Switch

This problem was documented in SPR 930445. Corrective Action C2 of the SPR initiated a maintenance feedback form to develop PMs for Unit 2 Feed Water Booster Pumps 21, 22, and 23 lube oil pressure switches. Maintenance feedback forms were issued to develop PMs for the lube oil pressure switches installed on the Units 1 and 2 feed water booster pumps. On April 27, 1994, the licensee verified all the PMs associated with the above pressure switches were in an active status.

PM optimization of the feed pump turbine lube oil system was scheduled for completion prior to the end of 1994. During this review, all lubrication oil system PMs were scheduled to be reviewed to determine their applicability and effectiveness.

2.3.3.4 The Technical Support Center Chillers Failed, Resulting in High Temperature Conditions and Corresponding Alarms on the Plant Computer. Only "inactive" PMs Were Associated with the Technical Support Center Chillers.

This problem was documented on SPR 920247. Corrective Action C1 of the SPR evaluated what preventive maintenance actions were needed and initiated a active PM request. On September 2, 1992, a memorandum was issued identifying 12 PM activities required to maintain the technical support center chilled water pumps and to test and maintain the technical support center chillers. The PMs were issued and in the "active" status.

Preventative maintenance optimization of the essential chilled water system was in progress with mechanical maintenance and instrument control portions completed and the electrical maintenance portions nearing completion. As part of this review, all chilled water system PMs were scheduled to be reviewed to determine their applicability and effectiveness.

2.3.3.5 Temperature Indications Used to Determine the Operability of Safety-Related Chillers were not Periodically Calibrated

This problem was documented in SPR 920250. Corrective action C3 of the SPR reactivated the PMs required to maintain the subject temperature indication instruments associated with the safety related chillers. As of April 27, 1994, 12 PMs had been activated for calibration of the essential cooling water chiller outlet temperature indicators.

PM optimization of the essential cooling water system was scheduled for completion prior to the end of 1994. During this review all essential cooling water system PMs were scheduled to be reviewed to determine their applicability and effectiveness.

2.3.3.6 An Uncalibrated Level Switch in the Component Cooling Water System Contributed to an Engineered Safety Feature Actuation

This problem was documented in SPR 920708. Corrective Action C3 of the SPR required a review of the PMs associated with control room annunciators to determine whether the annunciator instrument loops received a periodic calibration. A list of annunciator input instruments was submitted to the operations department, and they compiled a list of annunciators of sufficient importance to operator performance to warrant calibration of the associated instrument input loop. A PM feedback form for activation/development of PMs associated with the list of annunciators identified by the operations department was generated and entered into the maintenance feedback tracking system. On April 26-27, 1994, a licensee review verified all the subject instruments either had active PMs issued for calibration or active feedback forms issued to activate or develop associated PMs. Actions for these feedback forms were scheduled to complete prior to December 31, 1994.

2.3.4 Conclusion

After reviewing the above information and associated documents the inspectors concluded that the licensee had reviewed these items and implemented satisfactory actions to address, track and resolve the original NRC concerns. Each of these concerns had been assigned a tracking action item in the South Texas Project commitment tracking and control system to track resolution of the concern to completion. This item is closed.

2.4 (Closed) IFI 498:499/93049-015: Appropriate PM Tasks Were Not Developed or Included in the PM Program for Some Important Equipment in the Standby Diesel Generators (SDGs) and Support Systems

2.4.1 Original Followup Item

Relay failures in the voltage-regulating circuit caused inoperable SDGs on two different occasions. The relays that failed had been installed beyond their 10-year service life, but had never been replaced nor scheduled to be replaced. Appropriate PM tasks for these relays were not developed and, therefore, were not included in the PM program for this important equipment in the SDGs and associated support systems.

2.4.2 Licensee Action in Response to this Item

The licensee reviewed this NRC concern and documented the results of their review in a office memorandum dated May 6, 1994.

2.4.3 Activity During this Inspection

The inspectors reviewed the licensee's documentation associated with this concern to verify appropriate actions were taken. The inspectors noted the following:

- SPRs 910318, 910463, and 920072 documented and addressed problems encountered with relays and failures of instantaneous preposition boards in the control circuits of the SDGs.
- Corrective Action C1 of SPR 910318 stated that PMs 90001729 - 90001734 were written to replace the Class 1E relays in the SDGs generator control panels on a periodic basis. Corrective Action C2 of SPR 910318 increased the PM frequency of replacement of SDG generator panel Class 1E relays from every Fuel Cycle 6 occurrence to every Fuel Cycle 3 occurrence, or approximately every 54 months. The original relays have been now been replaced.
- Corrective Action C3 of SPR 910463 stated that a review of the failure mode analysis report from the instantaneous preposition board vendor for preposition boards for SDG Nos. 11 and 22 would be performed, and corrective action specified as required. Preventative Maintenance Items 93000061-93000066 were developed for periodic replacement of these boards.
- SPR 920072 documented similar problems as those identified in SPR 910463.
- The licensee's current PM optimization program included the performance of a review of all maintenance recommendations, commitments, performance history, failure effects, PM applicability, and effectiveness for the equipment listed on a PM. This review was performed on all PM activities for the SDG system and support systems, and is scheduled for completion prior to the end of 1994.
- The licensee stated that reliability engineering, as part of the PM living program, has been tasked to monitor SDG failures and review them for preventability. PM activities or modifications would be implemented when it was determined that a failure is preventable and a PM/modification would be applicable and effective.

2.4.4 Conclusion

The inspector concluded that the licensee had reviewed this item and initiated appropriate initial corrective actions to address this concern. A tracking action item was established in the South Texas Project commitment tracking and control system to track resolution of this item to completion. The results of the PM optimization program will be reviewed during future NRC inspections (IFI 498/9431-01). This item is closed.

2.5 (Closed) IFI 498/93049-16; 499/93049-16: Main Control Board Meters Used During SDG Testing and SDG Monitoring Not in PM Program

2.5.1 Original Followup Item

Main control board meters used during SDG testing and SDG monitoring were not in the PM program and had not been calibrated since startup.

2.5.2 Licensee Action in Response to this Item

The licensee reviewed this NRC concern and documented the results of their review in a office memorandum dated May 6, 1994.

2.5.3 Activity During this Inspection

The inspectors reviewed the licensee's documentation associated with this concern to verify that appropriate actions were taken. The inspectors noted the following:

- This problem was documented in SPR 910156. Corrective Action C1 of this SPR stated that maintenance would revise or generate PMs to calibrate the applicable main control board meters for each SDG in both Units 1 and 2.
- Maintenance Memorandum Maint-91-1-1680, provided a list of PMs that provide PM instructions for the SDG main control board panel meters. Licensee documentation verified that these PMs were current.
- The licensee was reviewing all other main control board instruments to evaluate what PM activities should be developed for them.
- The licensee stated that reliability engineering, as part of the PM living program, has been tasked to monitor SDG failures and review them for preventability. PM activities or modifications would be implemented when it was determined that a failure was preventable, and a PM/modification would be applicable and effective.

2.5.4 Conclusion

The inspector concluded that the licensee had reviewed this item, and initiated appropriate corrective actions to address this concern. A tracking action item was established in the South Texas Project commitment tracking and control system to track resolution of this item to completion. This item is closed.

2.6 (Closed) IFI 498/93049-17; 499/93049-17: Approximately 150 Main Control Board Instruments Were Not in the PM Program

2.6.1 Original Followup Item

In reviewing the issue of noncalibrated SDG meters, the licensee identified approximately 150 additional main control board instruments that were not in the PM program. Some of these instruments monitored important parameters for the 125 VDC batteries and the battery chargers.

2.6.2 Licensee Action in Response to this Item

The licensee reviewed this NRC concern and documented the results of their review in a office memorandum dated May 6, 1994.

2.6.3 Activity During this Inspection

The inspectors reviewed the licensee's documentation associated with this concern to verify that appropriate actions were taken. The inspectors noted the following:

- During the investigation of SPR 910156, a list was generated of all main control board indications/instruments without periodic calibration scheduling.
- The licensee stated that all control room panel instruments which had been identified by operations as requiring calibration should be reviewed. Those instruments which were not calibrated by a surveillance procedure and did not have a PM for their calibration would be identified and placed on a list. Those instruments which were identified as not calibrated by a surveillance program and that were not identified in Licensee Procedure OPGP03-ZM-0016, "Installed Plant Instrumentation Calibration Verification Program," would be identified in a second list. Actions for these two lists would be tracked in accordance with Maintenance Feed Back Form 73021.
- All instruments identified on the first list would have PMs created for their calibration, and this action would be tracked in accordance with Maintenance Feed Back Form 73022.
- All instruments identified on the second list would be added to Procedure OPGP03-ZM-0016, and this action would be tracked in accordance with Maintenance Feed Back Form 73023.
- The many systems covered by these instruments were scheduled for optimization over the next year and a half; however, all actions associated with these instruments were tentatively scheduled to be completed by September 30, 1994.

2.6.4 Conclusion

The inspector concluded that the licensee had reviewed this item and implemented appropriate corrective actions to address this concern. Along with the identified feedback forms, a tracking action item was established in the South Texas Project commitment tracking and control system to track resolution of this item to completion. This item is closed.

3 PREVIOUS VIOLATIONS (92903)

3.1 (Closed) Violation 498/9305-03; 499/9305-03: Concurrent SDG Inoperability

3.1.1 Original Violation

This violation involved the removal of a SDG from service concurrent with the inoperability of another SDG. During routine maintenance, SDG 12 had been declared inoperable, while SDG 13 was inoperable due to paint clogging the fuel metering rod ports of the engine. The inoperable status of SDG 13 was not known by the licensee at the time SDG 12 was removed from service.

3.1.2 Licensee Action in Response to this Violation

In their June 25, 1993, response to this violation, the licensee identified that the corrective actions for Violation 498/9305-02; 499/9305-02, involving inadequate post-maintenance testing for SDG 12, would prevent recurrence of the simultaneous removal from service of multiple SDGs.

3.1.3 Activity During this Inspection

The inspector verified the licensee's corrective actions in response to Violation 498/9305-02; 499/9305-02.

3.1.4 Conclusion

The inspector found the licensee actions to be adequate. This item is closed.

3.2 (Closed) IFI 498/9348-16; 499/9348-16: Inadequate Computer Information Systems

3.2.1 Original Followup Item

In June 1993, an NRC diagnostic evaluation team inspection identified a weakness in the ability of the engineering staff to support other organizations. One of the indicators of this engineering performance deficiency identified by the team was that computer information systems and software programs developed by the licensee's engineering organization were not adequate to support the licensee's operations staff. Specifically, the team identified that the Technical Specification action statement program

could not be used by the operations staff because operations did not perform the required tasks, and the program was difficult to use.

Due to the lack of engineering support, the operations department had informally developed their own computer information system to aid in such functions as work control, equipment clearances, and reactor coolant system leak rate calculations. However, the operations computer systems had not been developed with appropriate quality assurance controls and/or procedural guidance. Configuration control problems eventually resulted from the use of the informal operability tracking log computer information system.

Due to weaknesses identified in Section 2.3.5 of the diagnostic evaluation team report, this issue was identified for followup after restart.

3.2.2 Licensee Action in Response to this Item

The licensee initiated a project to validate that the software and associated data bases used by operations complied with software quality assurance requirements. Furthermore, the licensee initiated development of a new procedure for assuring the quality of computer software used in the station.

3.2.3 Activity During this Inspection

The diagnostic evaluation team had identified that the Technical Specification action statement program provided by engineering could not be used by operations. Through discussions with licensee personnel, the inspector found that the nuclear information systems group had taken action to become more customer oriented. The licensee had established a task force working group with representatives of all the user groups to improve the design and development of their computer information systems.

The inspector reviewed licensee Procedure OPGP07-ZA-0014, "Software Quality Assurance Program," Revision 0, dated September 6, 1994. The inspector found that the licensee had developed the procedure to control the quality of software subsequently developed or procured.

The inspector reviewed the closure reports for completion of the licensee's validation of existing software and data bases. The licensee had conducted their validation using a draft of their new software control procedure. According to the licensee, no configuration control problems related the use of the engineering software and data bases had been encountered subsequent to the licensee's validation activity.

3.2.4 Conclusion

The inspector found the licensee's actions to be adequate. This item is closed.

3.3 (Open) IFI 489/9350-10; 499/9350-10: Plant Modifications Not Effective Improvements

3.3.1 Original Followup Item

In June 1993, the NRC diagnostic evaluation team inspection had identified that the licensee's installation of plant modifications to effect plant improvements were not always successful. The team observed that temporary modifications were not aggressively pursued to closure. A large number of temporary modifications had been outstanding for over 2 years. The team also observed that temporary modifications were not thoroughly evaluated. Dose impact was not evaluated for temporary modifications involving manual actions.

Due to the weaknesses identified in the diagnostic evaluation team report, this issue was identified for followup after restart.

3.3.2 Licensee Action in Response to this Item

The licensee had committed to restore 15 aged temporary modifications in Unit 1 which were identified as greater than 6 months old. A similar commitment was made for Unit 2. The licensee completed their activities to reduce outstanding temporary modifications prior to restart of both units. The licensee considered that, with increased management attention and changes in supporting processes, no programmatic changes were required to minimize the installation time of temporary modifications.

The licensee changed their temporary modification procedure to require that the preparer consider dose impact of operation in the development of the temporary modification.

3.3.3 Activity During this Inspection

The inspector reviewed the status of the licensee's temporary modifications as of September 12, 1994. The inspector found 21 temporary modifications outstanding in Unit 1, and 13 temporary modifications in Unit 2.

None of the temporary modifications had been installed for over 2 years. The inspector considered the current number of temporary modifications and the period of their installation to be adequate.

The inspector reviewed licensee Procedure OPGP03-ZO-0003, "Temporary Modifications," Revision 15. The inspector found that the procedure had been revised to include dose impact assessment.

3.3.4 Conclusion

The inspector found the licensee actions to be adequate. This item is closed.

3.4 (Closed) IFI 498/9350-20; 499/9350-20: Inaccurate Equipment Maintenance History

3.4.1 Original Followup Item

In June 1993, an NRC diagnostic evaluation team identified that the equipment maintenance history data base was not accurate nor current. The team considered this inadequacy to be caused by the poor quality of the information loaded into the system by the licensee and the large backlog of outstanding entries.

During a subsequent NRC inspection of the weaknesses identified in Section 2.3.5 of the diagnostic evaluation team report, this issue was identified for followup after restart.

3.4.2 Licensee Action Taken on this Item

The licensee eliminated the equipment history backlog by December 31, 1993.

Responsibility for the equipment history program was transferred from the maintenance department to the plant engineering department. The plant engineering department staff was increased to perform data entry, review, analysis and trending.

Responsibility for nuclear power reliability data system was transferred to reliability engineering and incorporated into the equipment history program.

All of the required equipment history data was stored in the plant computer system.

Procedure OPGP03-ZA-0090 was changed to delete equipment history requirements and add instructions for work documentation. A new station procedure was developed for the equipment history program. These procedures were completed by August 15, 1993.

3.4.3 Activity During this Inspection

The inspector reviewed licensee Memorandum "Equipment History Program," dated June 28, 1994, which described the licensee actions to reduce the equipment history backlog and establish a program to analyze and effectively trend repetitive component degradation and failures. The inspector found that the licensee's plan had initially been put into place in March 1993, and was completed in August 1993.

The inspector reviewed new Station Procedure OPGP03-ZA-0503, "Equipment History Program," Revision 0.

The inspector reviewed the current backlog of outstanding equipment history data and found that the licensee had reduced the data entry backlog consistent with stated program goals.

The inspector sampled data bases for several pieces of equipment and found them to be accurate and current.

3.4.4 Conclusion

The inspector found the licensee actions to be adequate. This item is closed.

3.5 (Closed) IFI 498/9355; 499/9355-01: Vendor Testing of Voltage Regulator

3.5.1 Original Followup Item

During a previous NRC inspection of the licensee's troubleshooting activity for a failure of SDG 12 during surveillance testing, review of the results of vendor testing of a removed voltage regulator card was identified as an IFI. A malfunction of the regulator module card had been identified by licensee troubleshooting as a probable cause for the unexpected trip of the SDG after starting and operating loaded for 1 hour and 21 minutes.

The inspector had also noted that the licensee's SDG Test Procedure OPSP03-ZQ-0025, Revision 0, would not have designated the test as a "failure" since the engine had started and operated loaded for at least an hour. The inspector was concerned that the licensee's categorization may not meet the intent of Regulatory Guide 1.108, regarding the definition of a failure during testing.

3.5.2 Licensee Action in Response to this Item

The vendor conducted 40-hour endurance performance testing, including humidity testing, on the suspect voltage regulator. The licensee found no significant problems in performance stability or endurance. The licensee evaluated the vendor testing of the suspect voltage regulator card and found it to be inconclusive because the vendor had not tested the as-found condition of the voltage regulator card. The vendor had reset the voltage regulator control settings during their laboratory testing.

After eliminating all other possible failure mechanisms, the licensee concluded that a malfunction of the voltage regulator card was the most probable root cause of the SDG test failure. Corrective actions to replace the voltage regulator showed improvement in the stability of normal voltage control with no repeat of the spurious trip during subsequent testing.

The licensee revised SDG Surveillance Test Procedure OPSP03-ZQ-0025 to clarify the acceptance criteria regarding test failures occurring after 1 hour of operation.

3.5.3 Activity During this Inspection

The inspector reviewed the vendor test reports and the licensee evaluation of the results of the vendor testing. The inspector found that the licensee had discredited the vendor testing as not representative of the as-found condition

of the voltage regulator. No further failure analysis was performed by the licensee. Due to the improved voltage stability with the new voltage regulator and the lack of repeat observations of stability problems during subsequent loaded and unloaded testing for up to 4 hours, the inspector considered licensee actions to be adequate.

The inspector reviewed licensee Procedure OPSP03-ZQ-0025, "Diesel Generator Starting Classification," Revision 1. The inspector found that the procedure had been revised to include an additional acceptance criteria as part of the starting classification flow chart in Addendum 1. The licensee had added the requirement that, in addition to operating loaded for 1 hour, the test must be successfully completed to be classified as a successful, valid test.

3.5.4 Conclusion

The inspector found the licensee actions to be adequate. This item is closed.

3.6 (Closed) IFI 498/9355-02: 499/9355-02: Lubrication of SDG Fasteners

3.6.1 Original Followup Item

During a previous NRC inspection, the inspector had noted that licensee Procedure OPSP04-DG-001, "Standby Diesel Generator 18-month Inspection," Revision 9, did not incorporate vendor instructions to prelubricate fasteners. In response to the inspectors concern, the licensee had committed to incorporate the vendor recommended prelubrication requirements for fasteners in inapplicable SDG procedures.

3.6.2 Licensee Action in Response to Item

The licensee revised the affected procedures to include the vendor recommended prelubrication recommendation.

3.6.3 Activity During this Inspection

The inspector reviewed the following licensee procedures and found that the licensee had added prelubrication requirements:

- . OPSP04-DG-0001, "Standby Diesel Generator 18-month Inspection," Revision 12;
- . OPSP04-DG-0002, "Standby Diesel Generator 5-year Inspection," Revision 1;
- . OPSP04-DG-0003, "Standby Diesel Generator 10-year Inspection," Revision 1; and
- . OPMP04-DG-0019, "Standby Diesel Generator Fuel Injection Pump and Nozzle Assembly Maintenance," Revision 11.

3.6.4 Conclusion

The inspectors found the licensee actions to be adequate. This item is closed.

4 FOLLOWUP ON CORRECTIVE ACTIONS FOR NRC OPEN ITEMS IDENTIFIED IN THE PLANT SUPPORT AREA (92904)

4.1 (Closed) Violation 498/92035-06; 499/92035-06: Two Examples of Failure to Meet Requirements of the Fire Protection Program

4.1.1 Original Violation

A notice of violation was issued for two examples in which the requirements of the licensee's fire protection program were not being satisfied. This notice of violation was documented in NRC Inspection Report 50-498/92-35; 50-499/92-35, dated March 3, 1993. Specifically, a fire door sill clearance did not satisfy the national fire prevention association (NFPA) requirements, and transient combustibles were located in a diesel generator room without the required combustible fire load permit. The example of a failure to meet the fire protection program by not providing proper control of transient combustibles had been previously inspected and was considered closed (NRC Inspection Report 50-498/93-37; 50-499/93-37).

4.1.2 Licensee Action in Response to Violation

In response to the violation on the fire door clearances, the licensee took corrective actions to ensure that all fire doors were in full compliance with the fire door sill requirements. These actions included a 100 percent survey of all the fire doors in both units to determine compliance with a revised clearance criteria; updating applicable drawings to reflect revised door clearance criteria; approving Change Notice 1836, incorporating an exception to NFPA for door clearance criteria; and revising fire protection procedures to require inspection of fire door frame and sill clearances.

4.1.3 Activity During this Inspection

The inspector reviewed Station Problem Report (SPR) 921449, dated December 9, 1992. This SPR documented the problem that Appendix R Fire Door Nos. 023-EAB1 and 436-EAB1 had gaps between the bottom of the doors and the floor, which exceeded the 3/4-inch permitted by NFPA 80 ("Standard for Fire Doors and Windows"), 1974 Edition. The SPR included the corrective actions the licensee committed to do in their response to the notice of violation.

The inspector reviewed the fire door examination data sheets which were used to document the results of the fire door survey. This survey identified 34 deficient fire doors in Unit 1, and 11 deficient fire doors in Unit 2. There were 180 Appendix R fire doors in each Unit and 2 common fire doors in the fire pump house. The deficient fire doors, the fire barrier breach

number, and the service request was initiated by the plant engineering department to repair each door. The inspector conducted an inspection Units 1 and 2 fire doors. The inspector measured the gap clearances for 20 fire doors. Seven of the 20 fire doors inspected, including the 2 identified in the violation, had been previously repaired. The inspector found all the fire door clearances to meet the required acceptance criteria.

The inspector reviewed Document Change Notice CD-00210, which was written to change the design drawing to incorporate a 1-inch gap at the bottom of the door. The design drawings affected were Nos. 9A-49-1-A-1087, Revision 17; and 9A-49-2-A-1087, "Architectural Door Detail," Revision 10. The document change notice added a note to the drawings for fire door configurations, installed in conformance with NFPA 80, that increased the maximum clearance from 3/4 inch to 1 inch at the bottom of the door. This change increased the maximum allowable clearances in accordance with a fire test for doors that exceeded the NFPA 80 criteria. Technical justification for this change was based on two fire test reports conducted for the Palo Verde Nuclear Generating Station that involved single and double door test assemblies. According to documents reviewed by the inspectors, these fire tests were conducted in conformance with NFPA and Underwriters Laboratories, Inc criteria and demonstrated a 3-hour rating as a fire barrier. The licensee utilizes equal make and model fire doors to those in the fire test assembly. Licensee documents also show that the American Nuclear Insurers found the single and double fire doors with gaps in excess of those allowed by NFPA and Underwriters Laboratories, Inc to be acceptable as 3-hour rated doors for South Texas Project (Letter L2010104). A 10 CFR 50.59 safety evaluation was performed by the licensee, since this change required a revision the fire hazards analysis report. The evaluation indicated that the change to the fire hazards analysis report did not involve an unreviewed safety question.

The inspectors also verified that Fire Protection Procedure OPEP03-PR-0127 was revised to require periodic inspection of fire door frame and sill clearances to verify compliance with the fire hazards analysis report. This was accomplished on June 30, 1993.

4.1.4 Conclusion

The inspectors concluded that the licensee had taken appropriate corrective actions to assure that fire doors sill gaps were in compliance with their required acceptance criteria. This item is closed.

4.2 (Closed) IFI 498/9331-38; 499/9331-38: Service Requests Below 850 for the Unit 2 Power Block

4.2.1 Original Followup Item

During review of licensee maintenance program, the NRC identified a concern with the number of outstanding service requests in the maintenance area. The NRC noted that Section 3 ("Backlog Reduction Goals") of the licensee submittal of the "Houston Lighting & Power Company (HL&P) Operational Readiness Plan,"

Revision 0, to the NRC on August 28, 1993, identified that the current goal for Unit 2 service requests was below 850, prior to the next resumption of power operation in Unit 2. The NRC identified that the licensee performance in this area would be a followup item.

4.2.2 Licensee Action in Response to this Item

The licensee submitted a "Houston Lighting & Power Company (HL&P) Operational Readiness Plan Unit 2," Revision 0, to the NRC on March 18, 1994, to cover Unit 2, specifically. Section II.A.2. ("Performance Measures Used to Monitor Maintenance Effectiveness for Unit 2") of this plan identified that "A desired target was to reduce and maintain each units total open service requests to less than 1000 power production system preventative and corrective service requests."

4.2.3 Activity During this Inspection

The inspectors reviewed the following:

- "Houston Lighting & Power Company (HL&P) Operational Readiness Plan Unit 2," Revision 0;
- The NRC review of Unit 2 Restart Issue No. 3, "Service Request Backlog," was discussed in Section 2.2 of NRC Inspection Report 50-498/94-20; 50-499/94-20. This report noted that at the time of the inspection, May 9-13, 1994, the licensee's Unit 2 staff had reduced the service request level to fewer than 1000 open service requests. This NRC review concluded that as of the May 13, 1994, the licensee was effectively and responsibly tracking and trending the service request backlog. Further, the licensee was maintaining control of service request backlog levels and had implemented sufficient actions to control the service request backlogs in the foreseeable future. Restart Issue No. 3 was closed out in this report; and
- The September 13, 1994, Unit 2, "Daily Communication & Teamwork Meeting" reports, which identified that there were only a total of approximately 760 open Unit 2 power production service requests.

4.2.4 Conclusion

The inspector concluded that the licensee had maintained the Unit 2 power production service requests below their new goal of 1000 prior to the resumption of power operation in Unit 2, and was effectively tracking and trending the service request backlog. Further, the licensee was maintaining control of service request backlog levels and had implemented sufficient actions to control the power production service request backlogs for both units below their latest identified goals of less than 1000.

4.3 (Closed) IFI 498/9351-16; 499/9351-16: Corrective Action Group Personnel not Adequately Trained

4.3.1 Original Followup Item

The diagnostic evaluation team report issued on June 10, 1993, documented that several individuals outside of the corrective action group, who performed root cause analyses, had not been adequately trained. Also, in the case of engineering, individuals performing root cause analyses often were not knowledgeable on the system or component of concern.

4.3.2 Licensee Action in Response to this Item:

Licensee Business Plan Initiative F3.1 was developed to address several diagnostic evaluation team-identified weaknesses in hardware failure root cause analysis. Equipment failure root cause analysis training was conducted for the engineering staff. An advanced team leader course was scheduled to be conducted during September of 1994 for selected supervisors and key root cause investigation personnel. A project owner was established to guide and direct the equipment failure root cause process in systems engineering and to provide coaching and continuing training in failure analysis techniques. The licensee was in process of revising their corrective action process. The corrective action program was described in Station Procedure OPG03-ZX-0014, Revision 0, dated September 13, 1994. This procedure required determination of root causes to be performed by a person, or group of persons, trained in root cause analysis. The new corrective action program, scheduled for implementation in October 1994 as Revision 6 to Procedure OPG03-ZX-002, will require individuals performing corrective action investigations to be certified investigators trained in the techniques of root cause analysis.

4.3.3 Activity During this Inspection

The inspector reviewed the course attendance record for the equipment failure root cause analysis course. This 3-day course was presented to the system engineering department from June 13-15, 1994. The inspector also reviewed the lesson plan for an advanced equipment root cause analysis course to be presented for selected plant staff. This advanced course will be presented over a 5-day period, covering a wide range of subjects related to solving plant problems, root cause techniques, overload failures, vibration induces failures, fatigue, and corrosion mechanism. This particular training course was designed for training root cause team leaders utilizing "case studies" and "qualification tests" to learn the techniques and pitfalls of root cause analysis techniques. These training courses were intended to be qualification requirements for certification as a investigator under the new corrective action program.

4.3.4 Conclusion

The inspector concluded that the licensee had initiated appropriate actions to ensure that any person involved in determining reasons for equipment failure are adequately trained in failure root cause analysis. This was evident to the inspectors from reviewing the training plans and records, and by review of procedures intended to be incorporated into the new corrective action program. This item is closed.

4.4 (Closed) IFI 498/9419-07; 499/9419-07: Review of Completed Evaluation of a Station Problem Report Required

4.4.1 Original Followup Item

During retrieval of surveillance test records requested by NRC inspectors, the licensee representative identified a condition in which surveillance credit had been incorrectly taken for the partial performance of Surveillance Test Procedure IPSP03-CS-0001, "Containment Spray Pump 1A - Inservice Test," Revision 4, on March 15, 1994. All procedure test attributes with the exception of vibration velocity data had been tested, measured, and recorded. The vibration velocity data elements had been marked "N/A." The inspectors were not informed as to the reason(s) for not measuring the vibration velocities. Even though all test attributes were not performed, the inservice test database showed that the inservice test surveillance test had been completed.

4.4.2 Licensee Action in Response to this Item

The licensee staff initiated SPR 941120 to address and evaluate this problem. The corrective actions included revising the surveillance procedure writer's guide so that the inservice test database will accurately indicate whether a Technical Specification inservice test surveillance test had been completed.

4.4.3 Activity During this Inspection

The inspector review of SPR 941120 revealed that the cause for not measuring the vibration velocities was attributed to a less than adequate evaluation of the surveillance test results by the operational work control group surveillance coordinator. Apparently the operational work control group surveillance coordinator completed a test completion notification form, requesting credit for the vibration test, without being aware that the test performers did not intend to take credit for this test as being a Technical Specification periodic surveillance test. Surveillance Procedure No. IPSP03-CS-0001, "Containment Spray Pump 1A Inservice Test," was being used to recirculate the refueling water storage tank for chemistry to sample; therefore, credit should not have been taken for a periodic surveillance test. To prevent this from reoccurring, the licensee revised Station Procedure OPGP03-ZE-0005, entitled "Plant Surveillance Procedure Preparation." This procedure defined the requirements for surveillance procedure content and format and was revised to include a checkoff on the performance data sheet,

denoting whether or not the procedure was being performed for surveillance credit. Corrective actions also had plant operations do a sampling of completed surveillances for systems in which surveillances were used for evolutions other than surveillances (such as recirculating the refueling water storage tank or the auxiliary feed water storage tank) to ensure similar events have not occurred. Since no similar events could be found in the SPR database, the licensee concluded that this appeared to be an isolated event.

4.4.4 Discussion and Conclusion

The inspector concluded that the licensee had adequately addressed this issue and taken appropriate corrective actions to ensure that the Technical Specification surveillance tests were performed within the required frequency. This item is closed.

ATTACHMENT

1 PERSONS CONTRACTED

1.1 Licensee Personnel

- *A. Aldridge, Supervisor, Engineering Programs
- *J. Blevins, Supervisor, Records Management
- J. Boothroyd, Engineer, Fire Protection
- *J. Calloway, Staff Consultant, Participant Services
- *T. Cloninger, Vice President, Nuclear Engineering
- *W. Cottle, Group Vice President, Nuclear
- *M. Coughlin, Engineer, Nuclear Licensing
- *D. Daniels, Administrator, Corrective Action Group
- *R. Ferguson, Engineer, Nuclear Licensing
- *S. Head, Supervisor, Nuclear Licensing
- *J. Johnson, Supervisor, Quality Assurance
- A. Kent, Manager, Mechanical Fluid Systems Division
- J. Labudo, Supervisor, Fire Protection
- B. Mackenzie, Engineer, Corrective Action Group
- *M. Meier, Manager, Engineering Programs
- K. Taplett, Consulting Engineer, Nuclear Licensing

1.2 NRC Personnel

- * D. Garcia, Resident Inspector

In addition to the personnel listed above, the inspectors contacted other personnel during this inspection.

* Denotes personnel that attended the exit meeting on September 15, 1994.

2 EXIT MEETING

An exit meeting was conducted on September 15, 1994, during which the inspectors summarized the scope and finding of this inspection. The licensee did not express a position on the inspection finding documented in this inspection report. The licensee did not identify as proprietary any information provided to, or reviewed by the inspectors.