APPENDIX

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

NRC Inspection Report: 50-498/93-55
50-499/93-55

Operating License: NPF-76
NPF-80

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

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

Inspection At: Matagorda County, Texas

Inspection Conducted: December 19, 1993, through January 29, 1994

Inspectors: D. P. Loveless, Senior Resident Inspector
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Approved: W D Johnson 3/30/94
W. D. Johnson, Chief, Project Branch A Date

Approved: T. F. Westerman 3/30/94
T. F. Westerman, Chief, Engineering Branch Date

Inspection Summary

Areas Inspected (Units 1 and 2): Routine, unannounced inspection of plant status, onsite followup of events, operational safety verification, maintenance and surveillance observations, followup on lubrication program issues, review of standby diesel generator reliability, and review of the engineering backlog.

Results:

- Failure to properly control the use of jumpers and provide a second verification of their use resulted in the over-thrust and damage of a pressurizer block valve. This was considered an additional example of Violation 50-499/93054-01 (Details I, Section 2.1).

- A faulty voltage regulator caused the output breaker of Standby Diesel Generator 12 to open inadvertently (Details I, Section 2.2).

- Failure to correctly implement an equipment clearance order caused an electrician to receive a shock because of a temporary power source (Details I, Section 2.3).

- The failure to control the manual clutch on a motor-operated valve caused a safety-related valve to inadvertently open when it was required to remain shut (Details I, Section 2.4).

- Maintenance workers removed a blind flange that was in place in accordance with an equipment clearance order. This violation was not cited because of the extensive corrective actions performed by licensee management (Details I, Section 2.5).

- In general, control room communications and self-verification were considered good although both areas could be improved to provide a more consistent application (Details I, Section 3.1).

- Workers in the plant were not consistently meeting plant management's expectations for self-verification, acceptance of clearance orders, and attention to detail (Details I, Section 3.2).

- The inspector noted that a previously identified leak sealant clamp on a residual heat removal system flange had been removed (Details I, Section 3.2).

- The inspector continued to identify plant deficiencies that were not documented on service requests. This inattention to detail by reactor plant operators was indicative of weak supervision in the field (Details I, Section 3.2).

- The inspector identified that some security response checklists were not of the correct revision. No significant revisions had been made to the checklists (Details I, Section 3.3).

- A minor problem with control of contaminated zones was identified (Details I, Section 3.4).

- Inspectors identified that literal Technical Specification compliance had not been clearly established as a management expectation. Licensed operators appeared to have nonconservative interpretations of some Technical Specifications requirements (Details I, Section 3.5).

- The changing of reset temperature setpoints on Essential Chiller 21C was conducted appropriately. Technicians stopped work when a wiring discrepancy was identified (Details I, Section 4.2).

- The modification of the containment emergency sump manway covers was conducted appropriately and involved oversight by maintenance supervisors (Details I, Section 4.3).

- The refurbishment and replacement of a high head safety injection system valve gear box was conducted in accordance with plant procedures. First line supervision was present and self-verification was utilized (Details I, Section 4.4).

- The inservice test of Component Cooling Water Pump 1A was properly performed and implemented the ASME Code Section II testing program requirements (Details I, Section 5.1).

- The calibration of Nuclear Instrument NI-36 was performed in a professional manner; attention to detail was good; and double verification was properly implemented (Details I, Section 5.2).

- The implementation of lubrication program initiatives should improve the lubrication program. Management support for the program improvements was evident (Details I, Section 2.6).

- One inspection followup item was identified to determine if a reverse power trip of Standby Diesel Generator 12 was considered valid or invalid (Details II, Section 1.7).

- An inspection followup item was identified to track the review of procedures that require prelubrication of fuel injection pump fasteners prior to torquing (Details II, Section 1.8).

- Restart Issue 5 on engineering backlogs was considered resolved for restart (Details II, Section 2.7).

Summary of Inspection Findings:

(Referenced sections are in Details II.)

- Inspection Followup Item 498;499/93055-01 was opened (Section 1.7).

- Inspection Followup Item 498;499/93055-02 was opened (Section 1.8).

- Inspection Followup Item 498;499/93044-04 remained open (Section 1.2).

- Inspection Followup Item 498;499/93044-02 was closed (Section 1.3).

- Inspection Followup Item 498;499/93044-01 was closed (Section 1.4).

- Inspection Followup Item 498;499/93044-03 remained open (Section 1.5).

- Inspection Followup Item 498;499/93020-01 was closed (Section 1.6).

- Inspection Followup Item 498;499/93031-30 was closed (Section 2.1).
- Inspection Followup Item 498;499/93031-41 was closed (Section 2.2).
- Inspection Followup Item 498;499/93031-42 was closed (Section 2.3).
- Inspection Followup Item 498;499/93031-16 was closed (Section 2.4).
- Inspection Followup Item 498;499/93031-18 remained open (Section 2.5).
- Licensee Event Report 499/93-004 was closed (Section 2.6).

Attachments:

- Attachment 1 - Persons Contacted and Exit Meeting
- Attachment 2 - Standby Diesel Generator Actions Deferred

DETAILS I

DIVISION OF REACTOR PROJECTS

1 PLANT STATUS

1.1 Unit 1 Plant Status

At the beginning of this inspection period, the Unit 1 reactor was in cold shutdown. At the end of the inspection period, Unit 1 was in cold shutdown on Day 359 of the forced maintenance outage. Preparations were under way to enter the hot shutdown mode.

1.2 Unit 2 Plant Status

During this inspection period, the Unit 2 reactor remained shutdown and defueled.

2 ONSITE FOLLOWUP OF EVENTS (93702)

2.1 Over-Thrusting of the Pressurizer Block Valve (Unit 1)

On December 20, 1993, two motor-operated valve technicians were performing a modification to the pressurizer power-operated relief Block Valve RC-MOV-00C1B in accordance with Plant Change Form 204750-B. A wire was terminated at the wrong terminal block, resulting in the overthrusting of the valve actuator upon full-stroke testing of the valve.

The modification required physical removal of the torque switch from the valve closing circuit to place the limit switch in service in the closing direction. The work was authorized by Work Authorization Number 93036900. Upon completion of the modification, a diagnostic test was to be performed. The valve would be opened manually and closed electrically.

During the modification, a technician removed the closed torque switch in accordance with Procedure OPGP03-ZM-0021, Revision 4, "Control of Configuration Changes." In order to facilitate removal of the closed torque switch, one lead for the manual protection switch was de-terminated. The manual switch was installed as a protection device to stop the motor, by removing power from the actuator whenever the technician released the switch. The technician did not appropriately document the de-termination of the manual protection switch in accordance with Procedure OPGP03-ZM-0021. The lead in question was an electrical jumper attached by an alligator clip, and the technician stated that documentation was not required for electrical jumpers. Procedure OPGP03-ZM-0021, Revision 4, "Control of Configuration Changes," Section 6.1.5.5, states, in part, that installation and removal of electrical jumpers shall be documented. This failure to follow plant administrative procedures was the first barrier missed in the event.

Upon completion of the modification, the technician determined that the termination point for the manual protection switch was incorrect. He informed a second technician that he was going to relocate the lead from the original Terminal Point 16C to Terminal Point 16. Terminal Point 16 electrically bypassed the closed limit switch, which allowed the actuator to drive the valve into its seat without removing power from the actuator. The second technician did not verify that a proper termination had been made. According to Procedure OPGP03-ZM-0021, Revision 4, "Control of Configuration Changes," Section 6.1.5.4, installation and removal of jumpers shall be verified. Section 2.12 defines verification as the act of checking a condition or activity by an individual other than the person performing the activity. This was a failure to follow procedures and constituted a second missed barrier.

Several days later, the technician modified the original documentation to show the change of termination points, crossed out the "C" in the original Termination Point 16C, initialed the change, and then backdated the change to December 17, 1993. According to Procedure OPGP03-ZA-0090, Revision 7, "Work Process Program," Section 3.7.2.14 the back-dating of any work document is prohibited. The second technician was not aware of the change to the documentation. Thus, another failure to follow procedures occurred and another procedural barrier was breached that could have prevented the event from proceeding further.

The two technicians then proceeded to set up the motor-actuated valve actuator test equipment in preparation for testing the valve. The valve was manually opened and set to close electrically. Upon closure of the valve, the technician noticed a trace that identified that the valve may have been overthrust and immediately released the manual protection switch, removing power from the actuator. The trace was further evaluated, and it was concluded that during valve closure the actuator had overthrust the valve.

Service Request 205711 was initiated to evaluate and repair the valve. The valve was evaluated by plant engineering by Plant Change Form 205711-A. The following components were identified for replacement:

- Worm
- Worm Shaft
- Worm Gear
- Compensator Springs

A postmaintenance test was performed in accordance with Plant Maintenance Procedure OPMP05-ZE-0309, Revision 7, "MOV Diagnostic Testing." The test results were satisfactory and the testing equipment and jumpers were removed from the actuator.

During the licensee's investigation, the technician stated that he did not believe he was in error by not correctly documenting the relocation of the jumper and backdating a recorded entry. The second technician did not independently verify the technician work performance. Plant Maintenance Procedure OPMP01-ZA-0035, Revision 0, "Qualification and Certification of Maintenance Personnel," required contract personnel performing maintenance activities affecting the quality of safety-related structures, systems, and components to be qualified and certified. This procedure was amplified with the issuance of Maintenance Department Standing Order MG - 22, Revision 0, "Contractor Qualification Requirements," that provided interim guidance for determining, evaluating, and documenting maintenance contractor qualification requirements. This procedure was not applied to the motor-operated valve actuator vendor personnel. It had been a year since the technician attended work control training and the second technician had never been trained nor certified in HL&P work control processes.

These procedures provided guidelines that should have acted as multiple barriers against the assignment of noncertified personnel performing field work. Failure to implement these procedures was considered an additional barrier that should have prevented this event. Less than adequate communications, understanding of work performance expectations, and configuration controls existed in the motor-operated valve contractor field activities.

Immediate corrective action in response to this event was the issuance of a stop work order for all motor-operated valve field activities. A station problem report was initiated. The technician was released from site employment and the second technician was placed on disciplinary status. Remedial training was conducted on the work process program, configuration control, and performance expectations. An additional action in response to this event was to provide HL&P supervision and quality control personnel with each motor-operated valve work crew conducting work in the field.

During this event, as discussed above, several barriers were bypassed in the form of failure to follow procedures that represented a violation of Technical Specification 6.8.1.a. However, this violation of procedures was considered as an additional example of failure to follow procedures associated with the work process program as cited in NRC Inspection Report 50-499/93-54. During this inspection period, the corrective actions associated with this previous violation were still in the process of being developed by the licensee. Corrective actions specific to this event were addressed, and the generic corrective actions for problems with the work process program will be addressed in the licensee's response to Violation 499/93054-01. Therefore, no violation is being cited at this time and no additional response is necessary.

2.2 Reverse Power Trip on Standby Diesel Generator 12 (Unit 1)

On January 13, 1994, Standby Diesel Generator (SDG) 12 tripped on reverse power during the performance of Plant Surveillance Procedure OPSP03-DG-0002, Revision 0, "Standby Diesel 12 Operability Test." The output breaker tripped open from full load after approximately 1 hour. Plant operators placed the diesel in the cooldown sequence and declared SDG 12 inoperable. Station Problem Report 94-0085 was generated to document the trip.

A reverse power annunciator was indicated on the local annunciator panel, but no reverse power relays were found in the tripped condition. A review of the emergency response facility data acquisition and display system computer data indicated that a transient of the voltage regulator had occurred. Service

Request 208114 was initiated for troubleshooting. On January 18, an unloaded test of SDG 12 was performed while monitoring the voltage regulator parameters. Some instabilities were detected in the firing pulses and the decision was made to replace the voltage regulator module.

Unloaded and loaded tests were performed on January 19, and no instabilities were noted. A postmaintenance test was performed after the test equipment was removed, followed by a surveillance test and no anomalies or equipment malfunctions were noted. The diesel generator was then returned to service.

2.3 Work Authorized under Inadequate Clearance Order

On January 17, 1994, an electrician was performing cleaning and inspection of Motor Control Center MCC 2L1. This center had been deenergized and isolated in accordance with Equipment Clearance Order 2-94-5011, and work had been authorized. The electrician verified that the normal electrical supply to the center had been deenergized before he began work. However, the electrician received an electrical shock while cleaning Cubicle N3L. This cubicle had been temporarily supplied power via a jumper from a 277 volt source. The jumper had been installed in accordance with Temporary Modification TZ-JC-92-0022.

Although the electrician was not injured, this was a potentially significant incident. Plant management took action to prevent such extreme personnel hazards. Station Problem Report 940117 was issued to investigate the cause of the event. Corrective actions included reviewing other temporary modifications for conflicts with equipment clearance orders, training of station workers to require verification that circuits were deenergized prior to working with bare hands, and additional training of operators on proper preparation of equipment clearance orders. (This event was reviewed in more detail during the operational readiness assessment team inspection. This review was documented in NRC Inspection Report 50-498/93-202; 50-499/93-202.)

2.4 Inadvertent Opening of Centrifugal Charging Pump Discharge Valve

On January 15, 1994, reactor operators started Centrifugal Charging Pump 1A for in service leak testing. Operators noticed immediately that flow to the reactor coolant pump seal injection increased. After a brief investigation, the operators secured the pump to ensure compliance with Technical Specification 3.1.2.3 requirements. Surveillance Requirement 4.1.2.3.2 allows operators to energize an inoperable charging pump in Mode 5, provided the discharge of the pump has been isolated from the reactor coolant system by a closed isolation valve with power removed from the valve operator.

Reactor plant operators identified that Seal Injection Bypass Valve CV-MOV-8348 was open. This valve had been closed and isolated in accordance with Equipment Clearance Order 1-93-5072. The control board handswitch had been tagged in the neutral position and the valve breaker was in the off position. Licensee engineers determined that the valve disk was hydro-pneumatically lifted to the open position upon starting the charging pump. The valve had last been operated manually and the clutch was still engaged. The licensee determined that the manual gear ratio was low enough that the starting pressure of the charging pump was sufficient to push the valve disk in the open direction.

The licensee's corrective actions included: requiring that all valves of this type be electrically closed when issuing an equipment clearance order, labeling these valves with a caution tag, and revising applicable procedures. (This event was further reviewed during the operational readiness assessment team inspection. This review was documented in NRC Inspection Report 50-498/93-202; 50-499/93-202.)

2.5 Failure to Adhere to an Equipment Clearance Order

On January 21, 1994, maintenance personnel were performing work in accordance with Service Request CC-2-212615 that was issued to remove blind flanges from Valves 1-CC-0418, 1-CC-FV-4565, 1-CC-0416, and 1-CC-0184 following successful completion of local leak rate testing. The mechanical maintenance supervisor inadvertently briefed the crew for the removal of the slip blind from Valve 1-CC-0416 when the work was intended for Valve 1-CC-0418. Additionally, the crew mistakenly went to Valve 1-CC-FV-4565 and removed that blind flange prior to realizing that they were working on the wrong component. Upon realizing their errors, the blind flange was reinstalled at Valve 1-CC-FV-4565 without documentation of work performed, notification of the error, or work stoppage.

The crew then proceeded to Valve 1-CC-0416 and began detensioning the slip blind fasteners even though an Equipment Clearance Order 2-93-7649 danger tag was hanging on the blind. Before physically removing the blind, the Unit 2 control room operators were requested to lift the danger tag and the mechanical maintenance supervisor was notified. The supervisor questioned the location of the work performed, realized that work was occurring on the wrong location, and stopped the job.

Immediate corrective action was to have the crew retorque the flange into place and leave the work area as they found it. The licensee initiated a human performance review board to determine the facts surrounding the event. The board identified the causes of the event as follows:

- Inattention to detail by the maintenance supervisor.
- Failure to use the self-verification program by the workers.
- Failure to follow the equipment clearance order program.

As corrective action for the specific event, licensee management took severe disciplinary action against the individuals involved and their supervisor. A human performance review board was established to fully investigate the event. The results of the board's investigation were published in Lessons Learned Transmittal 94-003 and the workers were trained on the event.

Prior to this event, as documented in NRC Inspection Report 50-498/93-30; 50-499/93-30, the inspectors had identified an adverse trend in the area of equipment clearance order implementation. This trend was documented by the licensee in Station Problem Report 93-2722. The licensee developed an event review team to review the trend. The team evaluated 34 station problem reports that addressed equipment clearance order problems in 1993. The causes of the events were determined to fall into four general categories: procedural noncompliance, management's inattention toward procedural violations, insensitivity of plant personnel toward equipment clearance orders, and inadequate training of plant personnel.

Corrective actions for the generic equipment clearance order problems included: various training activities for all plant workers, revision of the review process for revising equipment clearance orders and increasing the work scope under an existing equipment clearance order, revision of the equipment clearance process to require that individual workers be responsible for their own safety, and revision of the equipment clearance process to require that the removal of a danger-tagged piece of equipment receive equivalent reviews as the removal of a clearance boundary. The inspector determined that the generic aspects of the January 21 event were addressed by the task force's recommendations. However, the corrective actions had not been fully implemented at the time of this event.

The failure of maintenance personnel to follow the requirements of the equipment clearance order program was a violation. However, this violation was not cited because it met the criteria specified in Section VII.B.(1) of the enforcement policy.

2.6 Followup on Lubrication Program Issues

NRC Inspection Report 50-498/93-07; 50-499/93-07 identified concerns related to maintenance and lubrication of the auxiliary feedwater pumps. The maintenance organization subsequently conducted a general review of the lubrication program to identify whether improvements were needed.

Several issues were identified as weaknesses in the program:

- The existing lubrication specifications manual was in hard copy format and the information was not computer data based. This posed a problem when a manufacturer recommended a change in lubricant type. The identification of all equipment using a common lubricant was resource intensive, because it was difficult to sort the data in its existing form.

- Approval by the cognizant system engineers required, in many cases, specialized expertise in the areas of lubrication properties and compatibility between existing lubricants. This process also required a sizable work load on maintenance planning personnel to acquire approvals for a single lubrication change that affected several systems, like those for motor-operated valve actuators.

- The originator of a lubrication change might not have the training to provide an impact statement concerning compatibility of existing lubricants to proposed lubricants.

The lubrication program was maintained by the maintenance manager and controlled by Plant General Procedure OPGP03-ZM-0004, Revision 5, "Lubrication Program." Lubrication specification sheets had been developed for all equipment requiring lubrication. The sheets were contained in a 12-volume controlled document sorted by system designator. The manual was a controlled document maintained by the operations document control center. Each sheet identified the equipment number, manufacturer, vendor manual, subassembly, lubrication method and capacity, frequency of maintenance, vendor recommended lubricant, and approved lubricant. The lubrication specification sheets were approved by the cognizant maintenance lead specialist and the cognizant system engineer. The cognizant system engineer determined that recommended lubricants met or exceeded the manufacturer's recommended product or specification.

The lubrication program procedure required the person submitting a revision to an existing lubrication sheet to include an impact assessment. The assessment was to include justification for a change of lubricants, compatibility between existing lubricant and proposed lubricant to see if cleaning and flushing prior to replacement was required, and identification of affected preventive maintenance actions.

The maintenance manager initiated an action plan which identified a goal to improve controls on the use of lubricants. The plan provided for retention of a contractor to review the lubricants in use at the plant and the usage controls and recommended changes. The changes were scheduled for implementation in 1993.

At the time of this inspection, several lubrication program changes were in the final stages of implementation. The licensee's contractor had completed the review of lubricants in use and usage controls. The contractor recommended changes to controls to improve the ease of use for workers and to prevent use of incorrect lubricants. Procedure OPGP03-ZM-0004 was revised to incorporate these recommendations. The staff had been augmented by one permanent employee in order to maintain the lubrication program. A lubricant dispensing point inside the protected area was scheduled to be completed in January 1994. The lubrication program, training, and implementation was scheduled for January and February 1994. These program changes included:

- Lubricant consolidation
- Changes to preventive maintenance procedures
- Lubrication specifications

- Lubricant dispensing building
- Lubricant additions

2.6.1 Conclusions

The inspectors concluded that the appointment of a lubrication engineer who was responsible for the overall administration of the lubrication program provided a well defined ownership. The implementation of these program improvements and enhancements should improve the lubrication program. Management support was evident in this area of inspection, indicating management's receptiveness to identifying and correcting plant problems.

2.7 Conclusions

The inspectors noted that the failure of plant workers to self-verify actions in the field and inattention to detail continued to cause minor plant transients and events. Additionally, examples involving weaknesses in the control of equipment clearance orders continue to occur, although extensive corrective actions have been and are still being taken. Three of the events addressed were reviewed in more detail and were documented in the operational readiness assessment team's inspection report.

3 OPERATIONAL SAFETY VERIFICATION (71707)

The objectives of this inspection were to ensure that this facility was being operated safely and in conformance with license and regulatory requirements and to ensure that the licensee's management controls were effectively discharging the licensee's responsibilities for safe operation. The following paragraphs provide details of specific inspector observations during this inspection period.

3.1 Control Room Observations

Throughout this inspection period, the inspectors observed control room activities on a daily basis. Shift turnovers were of good quality and included a complete review of control panel status. Communications between reactor operators were considered to be good. Repeat backs and verbal annunciator acknowledgement were routine but not completely consistent. The licensee's self-verification program was being utilized during the conduct of procedural implementation. However, during basic operations not specifically requiring procedures be in hand, operator use of self-checking was not as prevalent.

Beginning on January 4, 1994, the control room shift turnover meetings were held in the operations support center for each unit. This helped reduce the number of people in the control room, which reduced the noise level and disturbances placed on the operators. The turnover meetings were well conducted and provided a good basis for turning over the watch. The inspector concluded that this change was positive.

Also on January 4, the inspector found pieces of insulation stored on top of heating, ventilation, and air conditioning ducts above the control room in Unit 2. This condition was brought to the attention of the shift supervisor and the material was removed. This was the second time the inspector has found stored items above the control room, as previously documented in NRC Inspection Report 50-498/93-45; 50-499/93-45.

3.2 Plant Tours

The material condition of the plant continued to improve as Unit 1 progressed toward restart. The service request outstanding backlog continued to decrease in number, age, and significance of the individual requests. Additionally, in general, the station-wide threshold for documenting plant deficiencies decreased. However, the inspectors noted cases of reactor plant operators not meeting licensee management's expectations in identifying deficiencies. Morale of plant workers was improving. The cleanup efforts and improved plant coatings in some areas improved plant general appearance. There was still evidence of general housekeeping deficiencies, including tape, both cotton and latex gloves, booties, tools, etc., found in various places in the plant.

On December 18, 1993, during a night shift tour, the inspector approached two motor-operated valve technicians performing work on Motor-Operated Valve 1-CC-MOV-0032, component cooling water valve to spent fuel pool cleaning and cooling system heat exchanger. The work was conducted in accordance with Plant Maintenance Procedure OPMP05-ZE-0309, "MOV Diagnostic Testing." The technicians were completing the task and clearing the work area. While the inspector was reviewing the work procedures, the technician verified the tag number of the valve and entered it into the data sheet of the procedure in accordance with the licensee's self-verification program. The inspector asked the technician why he verified the component after the work was complete. The technician replied that the verification had been performed earlier, but he had failed to sign the sheet.

This action was discussed with the plant manager who stated that this was not in accordance with management's expectations. Numerous problems have been encountered with the motor-operated valve actuator program work processes and corrective actions have been put in place to ensure that the expectations for the performance of work activities have been defined.

On several other occasions, the inspectors identified minor discrepancies that indicated a lack of attention to detail on the part of the maintenance workers and that management expectations were not being fully implemented in the field. The precise implementation of self-verification, acceptance of equipment clearance orders, and attention to detail, although improved, continued to be an area needing additional improvement. Increased supervision in the field has been noted; however, this has not always been effective. Better emphasis by senior management on direct supervision techniques and feedback systems may be necessary to continue to improve in this area.

During the inspection documented in NRC Inspection Report 50-498/93-45; 50-499/93-45, the inspectors identified that a leak sealant clamp had been installed on the pump discharge flange in Residual Heat Removal System 1C. The clamp had been injected twice and continued to leak. In addition, the documentation was insufficient to determine the extent of mechanical peening that had been performed on the flange. At that time, the plant manager committed to remove the clamp and return the flange to its original condition prior to restart. Following repair to the flange, inspectors observed the as-left condition of the flange and determined that it was in good condition and was free of leaks.

During routine plant tours, the inspectors continued to identify equipment deficiencies that had not been identified and documented on a service request for repair. The following is a listing of a number of these items:

- A cracked gear box on High Head Safety Injection Pump Discharge Valve 1-SI-206A. The repair of this valve was observed and is documented in Section 4.4 of this inspection report.
- A Thermolag brand fire enclosure in Train A electrical auxiliary building ventilation system was cracked.
- Fasteners on safety-related electrical boxes were missing.
- Scaffolding was found resting on top of a safety-related ventilation fan motor termination box. This appeared to be causing inleakage around the box seal. The fan was not required for Technical Specification operability at that time.
- A large number of leaks were identified in the Train A electrical auxiliary building ventilation system.
- A process pressure meter was pegged high.
- The motor operator for Valve 2-MOV-SI-8A was left uncovered and open for an extended period of time (greater than 2 months) while work was suspended.
- There was a lack of proper storage of ladders throughout the plant.

Although none of these items made the equipment inoperable, the lack of identification of these items by reactor plant operators indicated an inattention to detail and was indicative of less than adequate supervision in the field.

On December 18, 1993, during a night shift tour, the inspector found an extended ladder in front of Heat Tracing Panel 9R0027, with no identification tag indicating work in progress. On January 4, 1994, a folded ladder was found stored in the chemical and volume control system valve room with no identification tag. These deficiencies were discussed with the shift supervisor and the ladders were removed.

On January 11, 1994, during a tour of the reactor containment building, the inspector noted that the 52-foot elevation was completely dark in some areas. A reactor plant operator verified that there was not an electrical outage and could not explain why the lights were off. He contacted the electrical department and technicians found the Motor Control Center 1L1 backup breaker open. Operators energized the center and the lights were restored. The inspector was concerned that neither the operator nor technicians performing work in the area questioned the lack of lighting in that area. This industrial safety concern should have been identified by plant personnel.

3.3 Security Observations

On December 20, 1993, the inspector reviewed the electronic security system failure compensatory measures positioning check sheets that were used on December 15, when a security system failure occurred. It was identified that the check sheets used were from Procedure OSDP01-ZS-0010, Revision 12, "Contingency and Compensatory Response," and should have been from Revision 13 of the procedure, which was implemented on October 12, 1993.

The inspector informed the security supervisor, and a station problem report was initiated. There were no changes to the compensatory measures positioning check sheets in Revision 13. Apparently, the check sheets were taken from the procedure, copies were made and stored in a file for easy access. A review of both the central and secondary alarm stations was performed and both contained Revision 12 check sheets in their files.

The inspector expressed concern with the use of improperly controlled copies of procedures and the potential for failure to properly compensate for system outages. Following discussions with the inspectors, security supervisors began developing a system for updating and maintaining current forms within the security department.

3.4 Radiation Protection Activities

On January 13, 1994, work was being performed on the emergency containment sumps inside a contaminated zone. There were extension cords laying across the contaminated zone boundary and into the clean area. The inspector expressed the concern of potentially contaminating the clean area unless the extension cords were taped to the floor. Health physics was informed and the extension cords were taped in place.

3.5 Compliance with Technical Specifications

On December 27, 1993, during a routine evaluation of the control room log, the inspector noted that, on December 23 and 26, licensed operators had closed the reactor trip breakers to perform testing of various plant actuation systems. The inspector questioned these actions because the digital rod position indication system had been out of service during that time interval. Technical Specification 3.1.3.3 states that one digital rod position indicator shall be operable and capable of determining the control rod position within plus or minus 12 steps for each shutdown or control rod not fully inserted. The action statement requires that, with less than these position indicators operable, personnel immediately open the reactor trip breakers.

The shift supervisor discussed the evolution and stated that, as long as they were performing a test, licensed operators were allowed to exit a Technical Specification action statement. Discussions with licensing department personnel determined that this was a general consensus among some of the plant personnel. During discussions with operators on a later shift, the inspector was told that the evolution took place because the motor/generator sets were removed from service and that this was an equivalent action to the Technical Specification requirements. The inspector discussed these responses with senior management. Management personnel stated that during this evolution it was appropriate to close the reactor trip breakers because the control rods remained fully inserted throughout the evolution.

The inspector discussed this issue with personnel from the Office of Nuclear Reactor Regulation who concurred with the licensee management's position. The position indication system was only required with one or more control rods less than fully inserted. The inspector stated a concern that operators were apparently utilizing Technical Specifications as guidance and not as a legal requirement. Manager ι personnel agreed that Technical Specifications should be followed literall ıd conducted briefings with senior reactor operators to address this issue.

On January 14, the licensing manager discussed with the inspector that maintenance personnel had completed repairs and calibration of the digital rod position indication system. He stated the licensee's intent to close the reactor trip breakers and withdraw the control rods one bank at a time for further calibration and testing of the digital rod position indication system prior to declaring the system operable. The inspector stated that reactor operators could not withdraw control rods without one digital rod position indication system operable without being in violation of Technical Specification 3.1.3.3. Again, licensee management personnel stated that under these conditions they determined that it was appropriate to exit the action statement to test the position indication. After discussions with appropriate levels of NRC management, the licensee agreed and began to develop an alternate plan of action.

On January 15, licensee management requested a Notice of Enforcement Discretion from the Regional Administrator in order to close the reactor trip breakers while the digital rod position indication system was inoperable. The reason for the request was to test the position indication system following maintenance. This request was granted on January 16, based on the implementation of the following compensatory measures by licensee personnel:

- Reactor operators maintained reactor coolant system boron concentration at refueling levels in accordance with Technical Specification 3.9.1.

- All Technical Specification required instrumentation remained operable.

- Control rod withdrawal was limited to no more than one bank at a time.

- Operators were briefed on the need for heightened awareness to ensure a quick response to any adverse indications.

These measures remained in place until testing of the digital rod position indication system was completed. The regional staff determined that the plant safety would not be unduly compromised by the testing and were satisfied that the actions were in the best interest of the public health and safety. Therefore, the Regional Administrator exercised discretion not to enforce the requirements of Technical Specification 3.1.1.3 during the testing of the position indication system.

The inspectors discussed the need to comply with the letter of the Technical Specification regardless of whether an alternate action may be technically correct. Licensee management agreed to delineate that information and to remove certain confusing Technical Specification interpretation documents from the main control room.

3.6 Conclusions

In general, plant operations were conducted in a safe and conservative manner. Plant material condition had improved substantially as Unit 1 progressed toward restart. However, failure of plant workers and operators to consistently perform self-verification and inattention to detail continued to cause problems. Maintenance workers failed to properly respect equipment clearance orders and reactor plant operators failed to identify plant equipment deficiencies during routine operator rounds. The inspector determined that these problems were indicative of inadequate or lack of direct supervision in the plant. Additionally, licensed operators were willing to test DRPI and open breakers without literal compliance with the Technical Specifications.

4 MAINTENANCE OBSERVATIONS (62703)

The station maintenance activities addressed below were observed and documentation reviewed to ascertain that the activities were conducted in accordance with the licensee's approved maintenance programs, the Technical Specifications, and NRC regulations. The inspector verified that the activities were conducted in accordance with approved work instructions and procedures, the test equipment was within the current calibration cycles, and housekeeping was being conducted in an acceptable manner. Activities witnessed included work in progress, postmaintenance test runs, and field walkdown of the completed activities. Additionally, the work packages were reviewed and individuals involved with the work were interviewed. All observations made were referred to the licensee for appropriate action.

4.1 Postmodification Testing of Essential Chiller 12B

On January 5, 1994, the inspector observed portions of the postmodification testing on Essential Chiller 12B as discussed in NRC Inspection Report 50-498/94-04; 50-499/94-04.

The performance of the tests were satisfactory and the essential chilled water system functioned as expected. The inspector observed a catch basin that was rigged up with a radiological survey mop. The catch basin was set up as a drain for Essential Chiller 11B supplemental cooler. The bottom of the mop was at about shoulder level and the test engineers performing the postmodification test were aware of the mop and worked around it. A reactor plant operator performing his rounds was also aware of the mop, but did not question the proper set up. The catch basin was collecting clean water, but the mop was potentially contaminated. The inspector informed health physics and the catch basin was removed and properly installed.

4.2 Reset Temperature Setpoints on Essential Chiller 21C (Unit 2)

On January 27, 1994, the inspector observed electrical technicians performing Service Request 214022 as part of Modification 93-050 on the 150-ton Essential Chiller 21C. The technicians were licensee personnel who had been trained by the vendor to perform maintenance on the York brand chillers.

While verifying that the modification wiring was correct, the technicians identified a discrepancy between the actual wiring and the print. In accordance with the procedure, work was stopped and their supervisor was notified. Under the supervisor's direct supervision, the covers on the plastic raceways were removed and the leads were traced to determine the termination points. It was found that the lead in question, although shown landed on a different terminal, was electrically correct. The terminal it was landed on provided the same common point as the terminal shown in the drawing. The lead was tagged with a marker to identify it being on the correct terminal.

The inspector noted that the plastic wire ways appeared to be deteriorated from aging such that many of the plastic locking tabs were broken. This problem was pointed out to the electrical supervisor. He stated that they had submitted a request to replace the plastic wire ways during future shutdowns. Although as many as 50 percent of the tabs on some of the wire ways were broken, the inspector noted that enough of the tabs remained to provide the intended function of separation and protection of the wiring harnesses.

The inspector reviewed Equipment Clearance Order 94-5128 to ensure the control panel was properly removed for service. The control panel was properly tagged and the clearance order had been accepted by the craft.

4.3 Modification to Safety Injection Containment Sump Manhole Covers (Unit 1)

On January 27, 1994, the inspector observed maintenance personnel perform a modification to the emergency sump manway cover plates in accordance with Service Request 1-204633. It had been previously identified that a gap between the manway cover and the emergency sump cover plate, when misaligned, exceeded the allowed gap of 1/8 inches. The work instructions had maintenance install bolts on all three manway covers to act as a guide to prevent misalignment. This was done in accordance with Plant Change Form 204633-A.

The work was performed in accordance with "skill of the craft" practices under the direct supervision of the maintenance supervisor. The inspector verified that all parts and materials used were properly qualified. The drilling was performed in the hot machine shop. The inspector verified that the mechanical technicians were conducting work in accordance with the required radiation work permits.

The inspector verified that the work was properly authorized and the equipment clearance order had been accepted. The sump covers were installed and the alignment was satisfactory. The inspector observed a quality control technician verify the positioning of the manway covers upon installation and the housekeeping cleanliness of the sump upon completion of the job. No discrepancies were noted.

4.4 Repair High Head Safety Injection Pump 1A Discharge Isolation Valve

On January 27, 1994, the inspector observed portions of work being performed by mechanical maintenance technicians on High Head Safety Injection Pump 1A Discharge Isolation Valve 1-SI-206A. The work was performed in accordance with Work Authorization Number 94002239. The installed gear box was cracked and required replacement. Since there were no identical actuators in stock, a design change was required for the manufacturer's recommended replacement. Document Change Notice Number MD-308 reflected the change.

The replacement actuator was coated for inside containment in accordance with Plant Change Form 208142-A. The stem nut was removed and the threads were machined to match the threads on the valve stem. The inspector observed this process and verified that the technician was following the vendor manual recommendations. The first-line supervisor observed the maintenance activity both in the field and in the shop.

The original cracked gear box was sent to the plant engineering department for a root cause analysis. When removing the original actuator, the technicians utilized self-checking techniques when verifying the proper component identification. The inspector verified that the work was properly documented and the system was returned to service.

4.5 Conclusions

In general, maintenance was conducted in a manner sufficient to support plant operators. In most cases, procedures were followed and discrepancies identified during the work were properly dispositioned. Effective field supervision was noted on some jobs.

5 SURVEILLANCE OBSERVATIONS (61726)

The inspectors observed the surveillance testing of safety-related systems and components addressed below to verify that the activities were being performed in accordance with the licensee's approved programs and the Technical Specifications.

5.1 Component Cooling Water Pump 1A Inservice Test (Unit 1)

On January 6, 1994, during the night shift, the inspector observed portions of the Component Cooling Water Pump 1A inservice testing. The surveillance test was performed in accordance with Plant Surveillance Procedure 1PSP03-CC-0001, Revision 3, "Component Cooling Water Pump 1A Inservice Test." The test was performed by plant operators. One was located in the main control room and the other was stationed at the pump. The inspector reviewed the procedure and verified that conformance with Technical Specifications was provided. The test was properly authorized for work start. The operators performing the test had good communications and were utilizing the techniques of the self-verification program. The inspector verified that the test results were within the acceptable values.

5.2 Calibration of Nuclear Instrument NI-36 (Unit 1)

On January 5, 1994, the inspector observed the conduct of the 18-month calibration in accordance with Plant Surveillance Procedure 0PSP05-NI-0036, "Intermediate Range Neutron Flux Channel II Calibration (N-0036)." The calibration was performed by two instrument technicians whose progress was frequently reviewed by a first line supervisor.

The inspector verified that the work package was properly authorized and released by operations personnel. The procedure was being followed by the technicians with each step being double verified. The technician stated that they had not seen any component degradation within the nuclear instrumentation circuitry and that very little adjustment was required. All measuring and test equipment being used to perform the procedure were found to be in current calibration.

The calibration process was performed in a professional manner with good attention to detail.

5.3 Conclusions

In general, the surveillance testing program was implemented in a manner that supported plant operations. Workers followed procedures, double verified required steps, and self-verified their actions.

6 LICENSEE COMMITMENT MADE AS A RESULT OF THE OPERATIONAL READINESS ASSESSMENT TEAM (ORAT) INSPECTION

During the ORAT inspection, the team identified an inconsistency in the manner that the pressurizer power-operated relief valves (PORV) on both units were stroked to satisfy the requirements of Technical Specifications (TS). TS 4.3.3.5.2 required that the PORV transfer switches, power, and control circuits, including the actuated components, shall be demonstrated OPERABLE at least once per 18 months from the auxiliary shutdown panel (ASP); additionally, TS 4.4.4.1.b required that each PORV be operated through one complete cycle of full travel once per 18 months. This TS requirement did not specify from what location the PORV should be manipulated. Previously, the licensee had only stroked the PORVs from the ASP; however, because these valves were normally operated from the control room, the ORAT considered this practice to be nonconservative. The licensee concurred and committed to revise the procedure that stroked the PORVs, in addition to reviewing other plant surveillances to ensure that other nonconservative testing was not being performed on plant components. The licensee committed to complete this action prior to entry into Mode 4.

The licensee generated Station Problem Report (SPR) 940126 to track the identified problem concerning PORV testing and to review other surveillances to ensure similar examples did not exist. The inspectors reviewed this SPR and independently verified that the appropriate field changes that ensured the PORV was stroked from the main control boards and the ASP had been made to Procedure 1PSP03-RC-0010, "Unit 1 Pressurizer PORV Operability Test." In addition to the field change, the licensee committed to revise a PORV Operability Test procedure common to both Units 1 and 2.

In addition to this review, the inspectors independently reviewed the TS to determine if all plant components tested from the ASP were also tested from the control room. The inspectors determined that the licensee's procedures were currently acceptably testing TS governed components, with the exception of the four steam generator PORVs and the three safety-injection system accumulator discharge motor-operated valves. The procedures governing these components had also been identified by the licensee. Procedure OPSP03-MS-0001 for the steam generator PORVs was revised January 19, 1994; and Procedures OPSP03-SI-0020, -0024, and -0025, for Accumulator A, B, and C, respectively, were revised January 25, 1994.

The inspectors considered the licensee's actions to address the ORAT commitment to be acceptable.

DETAILS II

DIVISION OF REACTOR SAFETY

1 REVIEW OF SDG RELIABILITY (RESTART ISSUE 11)

1.1 Background

Both units at South Texas Project were shut down in early February 1993 and remained shutdown as a result of numerous broad scope problems identified by the NRC and the licensee.

NRC Inspection Report 50-498/93-31; 50-499/93-31 identified 16 restart issues that required resolution prior to the restart of Unit 1. In addition to these restart issues, a number of items related to these restart issues were identified. NRC Inspection Report 50-498/93-44; 50-499/93-44 concluded that sufficient improvements had been accomplished for the Unit 1 SDGs that the restart issues identified in NRC Inspection Report 50-498/93-31; 50-499/93-31 were considered closed.

In addition to the restart issues identified above, the licensee had performed various assessments of the SDG reliability. Recommendations from these assessments were being tracked by system engineering. Some of the recommendations were classified by the licensee as restart restraints and were reviewed by the inspectors. Also during the inspection, the inspectors reviewed open items from NRC Inspection Report 50-498/93-44; 50-499/93-44.

1.2 (Open) Inspection Followup Item 498; 499/93044-04: Tracking and Disposition of All Open Issues Identified in the Licensee's Closure Package

The inspectors reviewed the status of the SDG restart issues which were identified in the licensee's report, "Operational Readiness Closure Package 11, Standby Diesel Generator Reliability." Some of the restart issues were items identified as restart issues from NRC Inspection Report 50-498/93-31; 50-499/93-31. These restart issues were closed in NRC Inspection Report 50-498/93-44; 50-499/93-44. In addition, other restart issues consisted of items identified in three different independent assessments and a self-assessment. The first independent assessment was performed by quality assurance in March 1993, the second was performed by a group of industry and station personnel in October 1993, and the third was performed by the chief control design engineer of Cooper-Bessemer in October and December 1993. The self-assessment was performed by system engineering.

The inspectors reviewed the status of the items identified in each of the assessments to determine the number of items remaining that licensee personnel determined were required to be completed prior to restart of Unit 1. The restart issues consisted of station problem reports, open procedure revisions, open licensing documents, open modifications, and other action items.

The inspectors noted that many of the items identified as restart issues in Operational Readiness Closure Package 11, "Standby Diesel Generator Reliability," had been deferred until after Unit 1 startup. The inspectors reviewed the deferred items and agreed that it would not be necessary to complete them prior to restart. Attachment 2 to this inspection report contains the list of deferred items and their completion dates. A future inspection will review these items to ensure that they have been completed. The licensee agreed to supply the NRC any other startup restraints that were deferred prior to startup.

1.3 (Closed) Inspection Followup Item 498; 499/93044-02: SDG Incorrect Fuse Installations

During troubleshooting of SDG 12, maintenance personnel found discrepancies between actual installed fuses and vendor drawing requirements. The vendor drawing showed a requirement for 3 amp fuses and the actual installed fuses were 2 amp. This fuse installation discrepancy was identified as an inspection followup item in NRC Inspection Report 50-498/93-44; 50-499/93-44.

Station Problem Report 93-2977 was prepared to address the problem. The immediate corrective actions included replacing the 2 amp fuses with 3 amp for SDG 12. Fuses for SDGs 11 and 13 wer inspected by the maintenance personnel and the 3 amp fuses were found correctl, installed.

As additional corrective action, training department instructors held a training session on January 11, 1994, for electrical maintenance department personnel. The training was documented in Office Memorandum Maint-94-1-0006. The subject of the memorandum was electrical maintenance on fuses. The training topics included an overview of Station Problem Report 93-2977 and corrective actions, the method for determining the proper fuse replacement, actions required by the craftsmen and the planner when a discrepancy was found, the requirement for providing accurate documentation when fuses were replaced, and the importance of maintaining configuration control. The inspectors concluded that the training was acceptable for maintenance personnel.

Licensee personnel have undertaken a walkdown of fuses for Units 1 and 2 as a restart restraint which will be completed prior to entering Mode 2 for each unit. The SDGs were included in the systems to be walked down. At the time of this inspection, the three Unit 1 SDGs had been inspected. The system engineer stated that one incorrect fuse had been found in both Trains A and C and none in Train B. The inspectors concluded that the licensee had completed all necessary corrective actions for Unit 1.

1.4 (Closed) Inspection Followup Item 498;499/93044-01: SDG Spurious Starts

Some of the corrective actions were completed and reviewed by the inspectors and documented in NRC Inspection Report 50-498/93-44; 50-499/93-44. This report documents the remaining corrective actions.

Plant engineers determined that the cause of the spurious starts was the failure of the varistors and installation of relays without surge suppression in the control circuitry that caused voltage spikes. The voltage spikes degraded the transistor's operational characteristics and resulted in intermittent transistor operation. In addition, the licensee concluded that the transistor may have degraded because of high control cabinet temperatures and the varistors may have a limited life.

Maintenance personnel installed varistors on the Unit 1 SDG 4X1, 4EX3, and 3UP Allen Bradley brand relays to eliminate coil surges which could cause transient voltages. This was a recommendation made by the vendor. The installation of the relays for the three Unit 1 diesels was accomplished by Plant Change Forms 315217, 315218, and 315219.

A representative of Cooper En-Tronic Controls performed a review of the SDG control panel drawings. The representative concluded that no control panel modifications done by plant personnel would have stopped the SDGs from performing their safety function. The vendor did find some drawing errors which they stated should be corrected. Licensee engineers generated Plant Change Form 208735A to address the various issues.

Licensee personnel sent a number of the varistors to Wyle Laboratory to determine the failure mechanism. The results were not conclusive, but the laboratory did recommend that HL&P institute a surveillance program to monitor the condition of the varistors. Maintenance personnel established preventive maintenance for the varistors which included replacing them every 5 years and testing the replaced varistors to establish an estimated service life for them. In addition, the commercial grade dedication process for the varistors required that the varistors should be inspected upon receipt for part number and that dimensions and DC tested for voltage and current. The inspectors concluded the corrective actions were appropriate and had been completed by the licensee.

1.5 <u>(Open) Inspection Followup Item 498;499/93044-03: Absorbent Material Found in SDG Cam Gallery</u>

During the preventive maintenance inspection for SDG 23, absorbent material was found on the right side of the cam gallery in two different locations. The inspector was informed that the last time the cam covers had been removed was by a contractor and that the new dedicated organization had not been involved.

Maintenance personnel prepared Station Problem Report 93-3473 to revise all SDG preventive maintenance procedures that required disassembly to include a cleanliness inspection prior to assembly. The licensee deferred corrective actions for this problem report until after Unit 1 restart. The scheduled date for completion was February 28, 1994. Management personnel stated that the three Unit 1 diesels had been reinspected using HL&P personnel and all were found satisfactory. This item remained open until revision of the procedures was completed.

1.6 (Closed) Inspection Followup Item 498;499/93020-01 Standby Diesel Generator Failure to Start

During the conduct of a postmaintenance test following an 18-month inspection and maintenance outage on May 24, 1993, SDG 21 failed to start. Technicians found during troubleshooting that the intermediate coupling for the left bank air distributor was broken and the rotor seized in the distributor body. Station Problem Report 93-1835 was issued. This item was identified as an inspection followup item pending analysis and review for generic implications.

On September 16, 1993, design engineering department personnel completed their evaluation of the failure analysis report. The starting air distributor, which was newly installed, was concluded to have seized as a result of the presence of a foreign material between the rotor and the distributor body. Further testing identified the contamination as polyethylene. The failure of the intermediate coupling was considered to be a secondary failure.

The root cause was determined to be the failure of maintenance personnel to perform a proper cleanliness verification on the new rotor prior to installation. Licensee personnel concluded in Station Problem Report 93-1835 that the root cause was the failure of the skill of the craft to maintain the cleanliness level required. The vendor was informed by letter of the contamination in the spare part shipped to the site. Training to discuss the lessons learned from this occurrence was conducted for the diesel crew involved. The corrective action group considered this event appropriate for the constructive discipline program, but no action was taken because it had been 5 months since the event occurred. The failure of the SDG to start was classified as a nonvalid failure because it occurred during a postmaintenance test run.

The inspector had no further questions and this item was considered closed.

1.7 SDG 12 Output Breaker Trip

On January 12, 1994, the SDG 12 output breaker tripped after being at 100 percent for 1 hour and 21 minutes as discussed in Details I, Section 2.2, of this report. Plant Surveillance Procedure OPSP03-DG-0002, "Standby Diesel 12 (22) Operability Test," was being conducted at the time. Station Problem Report 94-0085 was issued and SDG 12 was declared inoperable.

The inspector was informed that the following indications and conditions were observed:

- Reverse power alarm at local annunciator;
- 67/32 and 67/50D (reverse) directional overcurrent relay flagged at 4160; and

- SDG 12 continued to operate 4160v, 60hz with no local relays flagged. Stop and cooldown sequences were conducted with no abnormal indications.

Licensee operators concluded from their review of plant computer data that there had been a momentary overload of Engineered Safety Features Transformer E1B caused by a load transient created by a switchyard or grid voltage fluctuation or a transient created by the voltage regulator.

There were no data to support that a grid disturbance had occurred; therefore, troubleshooting efforts were directed to the voltage regulator. The technicians identified no problem during static testing. The 3AM relay (automatic/manual mode control relay) was damaged during the testing. It was concluded that, because the test probe tip had melted, the electrician had inadvertently shorted two adjacent contacts. A loose lead was found in a portion of the control circuitry. Maintenance personnel stated that this lead had not been disturbed since construction and would not have contributed to the problem observed. The inspector was present when direction by the plant manager was given to inspect the other SDGs for loose leads.

On January 18, 1994, an unloaded test of SDG 12 was conducted. Some instability of the firing pulses was indicated and, after 34 minutes, a noticeable sporadic changing of field amperage was observed with an accompanying change in output voltage of 300 volts peak to peak while the operator was raising voltage to the top of the tolerance band. This lasted for about 30 seconds. This instability was believed by the licensee to have created current flows in excess of the 67/32 and 67/50D relay setpoint. The voltage regulator and/or power-driven potentiometer were identified as the principle suspect components. Testing of the potentiometer revealed a smooth trace and no apparent problem. The voltage regulator module card was replaced, and successful unloaded and loaded tests were conducted.

The regulator module card was sent to the vendor for a failure analysis. Part of this analysis will be to check for the degree of instability and to verify the endurance capability of the regulator. The results of this testing were to be utilized to determine event reportability and the need for industry notification.

This event was reviewed with Region IV and the Office on Nuclear Reactor Regulation personnel by a telephone conference call on January 25, 1994. The staff agreed with the licensee's actions. In review of Plant Surveillance Procedure OPSP03-ZQ-0025, Revision 0, "Diesel Generator Starting Classification," for determining valid and nonvalid SDG start failures, the inspector noted that the procedure indicated that, as long as the SDG operated in excess of 1 hour during a test, it was considered to be a valid test and, therefore, there was no valid start failure. The inspectors stated that the intent of Regulatory Guide 1.108 was that a test would have to run at least for 1 hour with no trip of the SDG to be valid, but that a trip was a start failure that would need to be evaluated in terms of the requirements of Regulatory Guide 1.108 to determine if it was a valid or nonvalid start failure. In this case, the failure analysis being performed by the vendor should demonstrate if the voltage regulator would have affected operation of the SDG in the emergency mode.

The results of the vendor testing of the voltage regulator card and the licensee actions with regard to Procedure OPSP03-ZQ-0025 to clarify valid/nonvalid start failures for tests in excess of 1 hour were considered an inspection followup item (498;499/93055-01).

1.8 Fastener Prelubrication Prior to Torquing

During review of Plant Surveillance Procedure OPSP04-DG-001, Revision 9, "Standby Diesel Generator 18-month Inspection," the inspector found that prelube of the fasteners for components other than the fuel injection pump hold down bolts had not been included in the procedure. As an example, Section 6.1M for installation of the fuel injector assemblies included no prelubrication requirements. The failure to prelubricate in accordance with vendor recommendations had been determined to be the root cause of the numerous failures of the fuel injection pump hollow hold down bolts as documented in Section 2.4 of NRC Inspection Report 50-498/93-44; 50-499/93-44.

In response to the inspector's finding, Station Problem Report 94-0154 was issued. A 24-hour operability determination was performed. It was the engineering personnel's judgement that, although the fastener stress was less without lubrication, the successful completion of the postmaintenance tests and surveillance tests on the SDGs without other reported fastener failures demonstrated the operability of the SDGs. As part of the corrective action, the licensee indicated that prerequisite prelubrication requirements would be incorporated into the applicable procedures.

The inspectors concluded that some fasteners were understressed without the prelubrication recommended by the vendor; however, these fasteners were of solid construction and not as susceptible to fatigue failure as the hollow hold down bolts. Pending review of the licensee procedures to include prelubrication of fasteners prior to torquing, this issue was considered an inspection followup item (498;499/93055-02).

1.9 Conclusions

The SDGs were ready to support Unit 1 restart upon proper completion and/or disposition of the current outage scope items. The licensee committed to inform the resident inspector staff should any of the outage scope work on the SDGs be deferred.

2 REVIEW OF THE ENGINEERING BACKLOG (RESTART ISSUE 5)

NRC Inspection Report 50-498/93-31; 50-499/93-31 identified 16 restart issues that required resolution prior to the restart of Unit 1. In addition to these restart issues, a number of items related to these restart issues were identified. NRC Inspection Report 50-498/93-45; 50-499/93-45 documented the review of the licensee's effectiveness in resolving Restart Issue 5, involving the backlog of engineering items. Additional inspection was deemed necessary to fully evaluate the licensee's readiness to restart, based on the area of engineering backlog and work loads. Therefore, Restart Issue 5 remained open. The purpose of this inspection was to perform the additional inspection that was deemed necessary to fully evaluate the issue.

The following sections document the review of specific items related to this issue concerning the manner in which the licensee had implemented their corrective actions. Some of these items were broad scoped and covered numerous licensee systems and programs. These items were closed based on this inspection effort and on the inspection findings documented in NRC Inspection Report 50-498/93-45; 50-499/93-45. Overall, the inspectors concluded that Restart Issue 5 was closed based on the discussion below.

2.1 (Closed) Inspection Followup Item 498;499/93031-30: Additional Backlog Reduction Goals for Resumption of Power Operation Established for Engineering Evaluations

This item was left open in NRC Inspection Report 50-498/93-45; 50-499/93-45 pending the licensee meeting its commitments in this area. On December 31, 1993, the licensee met its goal of having no items greater than 1 year old without an engineering evaluation.

This item was closed based on the licensee's corrective action described above and the licensee's corrective action described in NRC Inspection Report 50-498/93-45; 50-499/93-45.

2.2 (Closed) Inspection Followup Item 498;499/93031-41: Additional Backlog Reduction Goals

This item was left open in NRC Inspection Report 50-498/93-45; 50-499/93-45 pending the licensee meeting its commitments in this area. On December 27, 1993, the licensee met its goal of reducing plant change forms greater than 30 days old to less than 50, and on January 21, 1994, the licensee met its goal of reducing the number of temporary modifications greater than 6 months old by 15.

This item was closed based on the licensee's corrective action described above and the licensee's corrective action described in NRC Inspection Report 50-498/93-45; 50-499/93-45.

2.3 (Closed) Inspection Followup Item 498;499/93031-42: Carryover Items from Past Programs

This item was left open in NRC Inspection Report 50-498/93-45; 50-499/93-45 pending the licensee meeting its commitments in this area. On December 31, 1993, the licensee met its goal of having no carryover items from past programs.

This item was closed based on the licensee's corrective action described above and the licensee's corrective action described in NRC Inspection Report 50-498/93-45; 50-499/93-45.

2.4 (Closed) Inspection Followup Item 498;499/93031-16: Configuration Control Weaknesses Adversely Affected Safety-Related Equipment and the Quality of Design Documents

Several conditions reduced the ability of the engineering staff to support other organizations. Neither the plant nor the design engineering staff had sufficient resources to appropriately support the site. This caused engineering to be slow in identifying deficient conditions and hasty in performing investigations or root cause evaluations, resulting in many engineering solutions or products that corrected the symptom but not the root cause. Approved corrective actions generally took a long time to implement because of schedule or financial considerations. The system engineering program was comprehensive, but was not effectively implemented because of insufficient resources and management oversight. Engineering work backlogs were large, rapidly increasing, poorly tracked, and not well managed. Industry and site operational experience was not effectively used, which led to avoidable site events, repetitive equipment failure, and additional engineering time expenditures. The engineering staff was not sufficiently trained and lacked the analytical tools for some tasks. Information databases were often inaccurate or not current, and computers for system-level trending were very limited in number. Improvement programs often did not help improve the efficiency of engineering support, and resultant corrective actions were often delayed or cancelled because of low priority or high cost.

Many business plan focus areas were designed to resolve these problems, both in the short- and long-term. The business plan action plans clearly defined activities to be taken and the associated schedules for completion. To clarify the responsibilities and management expectations of the system engineer, the action plan defined responsibilities and station expectations of system engineers and budgeted for the addition of nine system engineers in 1994. To improve managerial and supervisory practices, and priorities to enhance system engineering organization performance, the action plan highlighted the evaluation and management of system engineer performance, citing the balance of baseline and emergent work, task tracking, scheduling, planning, accountability, and self-assessment methods. The activities evaluated by this plan were recommended to the plant engineering department managers for implementation. To evaluate and revise the plant priority system and establish emergent work criteria for current schedule impact and to determine departmental scheduling needs and establish a support plan, the action plan addressed improving managerial and supervisory practices and more clearly communicating priorities to facilitate system engineering organization performance.

The design engineering organization had more clearly defined engineer responsibilities through their realignment. Design engineering has also augmented its staff to reduce backlogs to a manageable size.

Another significant tool to improve engineering's effectiveness and efficiency was the implementation of positive time reporting that was being put in place the first quarter of 1994. These near-term interim departmental performance measures were expected to increase the accuracy and efficiency of engineering planning and scheduling.

To foster an understanding and appreciation of the appropriate balance between short-term cost and investment for long-term performance, the action plan developed a means to balance attitudes and decision making. The desired results included assuming and maintaining a proactive posture regarding effective and efficient problem anticipation and resolution. To demonstrate a commitment to long-term improvement by investment in programs that have long-term benefits, the action plan sought increased long-range productivity through quick and accurate problem resolution and prevention, more application of new technologies and methods, and more efficient use of resources.

To standardize a process for establishing and communicating goals, standards, responsibilities, expectations, and measurements of success, the plan began by conducting an industry survey for processes that have been effective. As part of the process to develop a sound methodology, management intended to develop a baseline of employee knowledge regarding goals, standards, and expectations in the first quarter of 199'. The management team planned to develop a lesson plan and train line managers to implement the desired process after developing and implementing a pilot program.

The inspectors concluded that the licensee's actior had shown significant improvement related to engineering backlog and star y diesel generator generic issues. Inspection Followup Item 498;499/9 31-16 was closed for engineering backlog Restart Issue 5 and the SDG Restart Issue 11.

2.5 <u>(Open) Inspection Followup Item 498;499/93031-18: The Engineering Departments Gave Weak Support in Resolving Plant Problems</u>

The engineering departments gave weak support in resolving plant problems. The root cause analyses and resulting corrective actions were often ineffective in preventing repetitive equipment problems. The following specific issues were reviewed:

2.5.1 <u>Startup Feedwater Pump Start Failure</u>

After a reactor trip, the startup feedwater pump failed to start upon demand because of low oil pressure. Repeated occurrences of moisture intrusion had caused the oil filters to become clogged, reducing the lube oil pressure. A previous pump trip on low lube oil pressure had not been properly evaluated, resulting in the failure to recognize design deficiencies.

The licensee's solution to the lubricating oil moisture problem was multi-faceted and various modifications were being or had been made to resolve the problem. The modifications had been designed to remove all possible moisture from the startup feedwater pump lubricating oil system and remove internal and external sources of recontamination. These modifications included:

- Reinstallation of the original manufacturer's particulate filters. These filters had been installed and were being flushed.

- Addition of a side stream oil filtration system that operates independently from the lubricating oil system and will not prevent startup of the pump if the filters become saturated with water. These filters had been installed and were being flushed.

- Construction of a roof over the entire pump skid to provide protection from the elements. Construction had been started but was not expected to be completed until after plant startup.

- Addition of a mechanical seal cooling system to the pump to prevent degradation of the seals and prevent loss of moisture from the seals to the lubricating system. The system had been installed and was to be tested during startup prior to entering Mode 3.

- Addition of vents to the pump seal housing and bearing oil pedestals to help remove moisture from the seal area before it becomes entrained in the lubricating oil. These vents had been installed.

The inspectors reviewed the licensee's associated corrective action documentation and determined that the licensee's actions were adequate to address this issue. This specific line item was closed.

2.5.2 Steam Generator Feed Pump

During oil pump transfers, the steam generator feed pump turbine tripped repeatedly because the oil pressure decreased rapidly. Engineering personnel mistakenly accepted the recommendation of a vendor to drill holes in the pump casing to prevent air binding, which, when implemented, exacerbated the problem.

The licensee modified the steam generator feedwater pump turbine automatic trip headers by adding an accumulator and check valve. The accumulator added additional volume to the header and acted as a mechanical time delay which allowed the standby main oil pump to come up to full operating pressure without tripping the turbine. This modification has been operated successfully in both units.

The inspectors reviewed the licensee's associated corrective action documentation and determined that the licensee's actions were adequate to address this issue. This specific line item was closed.

2.5.3 Technical Support Center (TSC) Diesels

The TSC diesel generator was not reliable, as evidenced by repeated failures to start and load during testing. Contributing to the poor reliability was exposure to the environment, design weaknesses, and poor circuit breaker reliability. The licensee only partially implemented proposed resolutions to these problems.

Recent completion of open work requests has improved the material condition of the TSC diesel generator equipment. Reliability of the power distribution breakers and exposure to the environment of the skid-mounted equipment was addressed by planned modifications to the equipment. Modifying the diesel generator to improve environmental protection required enclosing the skid area and was scheduled to be completed within 18 months.

Licensee personnel have initiated an enhancement program to further improve the reliability of the TSC diesel generator. A diesel generator project team, headed by a team leader and including the system engineer, has been formed. The team was conducting more frequent walkdowns to inspect for material and equipment degradation. The team was also establishing more detailed system performance indicators. Future installation of load banks to permit full-load testing and increased frequency of functional testing from a quarterly basis to monthly should further improve reliability. The status of the TSC diesel was to be evaluated as part of the assessment process prior to the resumption of power operation.

The inspectors reviewed the licensee's associated corrective action documentation and determined that the licensee's actions were adequate to address this issue. This specific line item was closed.

This inspection followup item was closed for Restart Issue 5 based on the licensee's corrective action described above and the licensee's corrective action described in NRC Inspection Report 50-498/93-45; 50-499/93-45.

2.6 <u>(Closed) Licensee Event Report 499/93-004: Reactor trip caused by Failure of Steam Generator Feedwater Pump because of Water in the Oil</u>

This item was closed based on the licensee's corrective action on Inspection Followup Item 498;499/93031-18 described in Details II, Section 2.5.2, of this report.

2.7 <u>Conclusions</u>

Restart Issue 5 involving the backlog of engineering issues was considered resolved. Most of the inspection effort on this issue was documented in NRC Inspection Report 50-498/93-45; 50-499/93-45. However, the remaining open items were closed or dispositioned for restart as documented above.

ATTACHMENT 1

1 PERSONS CONTACTED

C. Albury, Principal Engineer
D. Bize, Licensing Engineer
H. Butterworth, Manager, Plant Operations (Unit 1)
J. Calloway, Staff Consultant
T. Cloninger, Vice President, Nuclear Engineering
J. Cook, Section Supervisor, Nuclear Steam Supply System
M. Coughlin, Senior Licensing Engineer
W. Dowdy, Manager, Plant Operations (Unit 2)
R. Gangluff, Effluent and Waste Management
J. Groth, Vice President, Nuclear Generation
S. Head, Senior Consultant Engineer
R. Helton, Senior Staff Specialist, Maintenance
J. Johnson, Senior Licensing Engineer
D. Keating, Director, Integrating Safety Engineering Group
F. Mallen, Manager, Nuclear Engineer
F. Mangan, General Manager, Plant Services
L. Myers, Plant Manager (Unit 1)
M. Oswald, Supervisor, Nuclear Steam Supply System/Projects Engineer
G. Parkey, Plant Manager (Unit 2)
J. Pinzon, Senior Engineer
J. Sheppard, General Manager, Nuclear Licensing
S. Thomas, Manager, Design Engineering Department
W. Waddell, Manager, Operations Support
G. Walker, Manager, Public Information
D. Wohleber, Manager, Records Management Systems and Administration

The personnel listed above attended the exit meeting. In addition to the personnel listed above, the inspectors contacted other personnel during this inspection period.

2 EXIT MEETING

An exit meeting was conducted on February 3, 1994. During this meeting, the inspectors reviewed the scope and findings of the report. The Vice President, Nuclear Generation acknowledged that worker attention to detail and self-verification continued to need attention. Also, management personnel agreed that Technical Specifications would be followed literally during future operability decision making. Additionally, the Licensing Manager committed to provide the Senior Resident Inspector with the documentation to support any SDG items that are deferred from the outage scope. The licensee did not identify as proprietary any information provided to, or reviewed by, the inspectors.

ATTACHMENT 2

SDG ACTIONS
DEFERRED

SOURCE	DESCRIPTION	ACTION	DUE DATE
IR.1	INDEPENDENT REVIEW	REVISE ENGINE LOADING GUIDELINES/PROC AND ACCELERATED TESTING VALUE TO RG 1.9 AND NUMARC 8700 - TS AND UFSAR REVISION	6/15/94
IR.14	INDEPENDENT REVIEW	REVIEW PARTS FOR OBSOLESCENCE	6/1/94
IR.17	INDEPENDENT REVIEW	DEVELOP STANDARDIZED PROCEDURES FOR ALL DEFINABLE TASKS	12/31/94
IR.18	INDEPENDENT REVIEW	DEVELOP STANDARDIZED TROUBLESHOOTING PROCEDURES FOR RAPID RESPONSE	12/31/94
IR.20	INDEPENDENT REVIEW	CONSOLIDATE DUPLICATE TRAIN MAINT AND SURV PROCEDURES	12/31/94
IR.24	INDEPENDENT REVIEW	CHECK WEB DEFLECTION/ALTER FOUNDATION TORQUE CHECK PERIODICITY IAW SECTION 15; REVISE PROCEDURES TO REFLECT	6/15/94
IR.25	INDEPENDENT REVIEW	OBTAIN PRECISION ELECTRON WEB DEFECT GAGE	6/15/94
IR.26	INDEPENDENT REVIEW	INCLUDE CBOG RECOMM ON EXPANSION JOINT INSTALLATION IN STP PROCEDURES	6/15/94
IR.27	INDEPENDENT REVIEW	INITIATE 10 YR REPLACEMENT PM FOR EXPANSION JOINTS	6/15/94
IR.31	INDEPENDENT REVIEW	OBTAIN AND TREND AIR RECEIVER DEW POINTS	4/15/94
IR.34	INDEPENDENT REVIEW	CENTRALIZE/STANDARDIZE SDG SYSTEM FILES	6/15/94
IR.39	INDEPENDENT REVIEW	REVISE OPMP04-DG-0019 TO CURRENT DESIGN	6/15/94

SOURCE	DESCRIPTION	ACTION	DUE DATE
IR.40	INDEPENDENT REVIEW	REVISE OPSP04-DG-0001 WITH RECOMM ON PAGE 36 OF REPORT	6/15/94
IR.6	INDEPENDENT REVIEW	MOD FOR ADDITIONAL CONTINUOUS DRAIN VALVE IN AIR INTAKE	2/1/94
IR.7	INDEPENDENT REVIEW	ESTABLISH DEDICATED SDG WORK CREWS	6/15/94
IR.8	INDEPENDENT REVIEW	ESTABLISH DEDICATED OPS PERSONNEL TO COORDINATE SDG WORK AND OPS ISSUES	6/15/94
IR.9	INDEPENDENT REVIEW	ESTABLISH DEDICATED EN AND IC PLANNER	6/15/94
NRC EXIT	OUTSTANDING NRC CONCERNS	INVESTIGATE ENGINE BALANCE TRENDS TO DEMONSTRATE BALANCED CONDITIONS FOR SUPPORTING THE 18 OF 20 CYLINDER JCO USED TO JUSTIFY SEVERAL NON-VALID FAILURE DECLARATIONS (TED FRYAR) PERFORM A CRITICAL REVIEW OF RCM PRODUCT *GAH*	2/1/94 3/16/94
OTH 86-004	A REVIEW OF ISSUES RELATED TO IMPROVING NUCLEAR POWER PLANT DG RELIABILITY	PREPARE AND SUBMIT ADDITIONAL POAS/EOCS TO RMS AS A SUPPLEMENT TO ORIGINAL PACKAGE	6/15/94
SDER 83-001	DG FAILURES SUMMARIZES REVIEW OF OVER 450 LERS CONCERNING DGS, DISCUSSES KEY AREAS OF CONCERN WITH RECOMMENDATION IN PMS, TESTING, TRAINING, AND DESIGN	PREPARE MANAGEMENT REVIEW	6/15/94
SPR 930887	QA REVIEW, D.15	ADD DCM MM-1046 TO VENDOR MANUAL CONCERNING PRECAUTION ON CAM LOBE, VERIFY DONE AND CLOSE; TEJ TO CLOSE BY 2/1/94	4/15/94
SPR 931772	DISCOVERED TWO SMALL LEAKS AT CASTING PLUGS ON HEADS	C3) EVALUATE THE RESULTS OF THE VENDOR ANALYSIS AND DETERMINE WHAT FURTHER ACTIONS ARE REQUIRED TO PREVENT FURTHER RECURRENCE, WAITING REPORT FROM NPMN	4/15/94

SOURCE	DESCRIPTION	ACTION	DUE DATE
SPR 932050	REPLACEMENT HEAD FROM VENDOR IMPROPER	INVESTIGATION	3/1/94
SPR 932331	REVERSE POWER RELAY POTENTIAL WINDINGS POLARITY WRONG	C2) ENGINEERING SUPPORT WILL ISSUE A BULLETIN TO ADDRESS REVISIONS TO OPG03-ZG-0001, REV 8, "MATERIAL CONTROL" FOR ALL DESIGN, SYSTEM, PROCUREMENT AND FIELD ENGINEERS	2/14/94
SPR 932331	REVERSE POWER RELAY POTENTIAL WINDINGS POLARITY WRONG, TRIP ON REVERSE POWER, RELAY HAD BEEN REPLACED, AND WAS FOUND WITH DIFFERENCES IN POLARITY OF VOLTAGE WINDINGS SDG 23 TRIPPED ON REVERSE POWER DUE TO REVERSE POTENTIAL WINDINGS	C8) ALL THE SPARE SDG REVERSE POWER RELAYS WILL BE MODIFIED FOR THE NON-STANDARD PHASING AT STP. (THIS ACTION WAS COMMITTED TO THE NRC IN ST-HL-AE-4633 11/24/93)	6/30/94
		C3) A SAMPLE REVIEW SHALL BE PERFORMED FOR THE PURPOSE OF DETERMINING THE ECNP/MOD PROGRAM EFFECTIVENESS WITH RESPECT TO REPLACEMENT PARTS CONTROL	2/25/94
		C4) A REVIEW OF THE PROGRAMMATIC TRAINING PROVIDED FOR TECHNICAL SUPPORT ENGINEERS WILL BE CONDUCTED TO DETERMINE WHETHER OTHER AREAS OF DEFICIENCY EXIST	2/15/94
		C6B) ENGINEERING WILL REVIEW THE ELECTRICAL POWER DISTRIBUTION SYSTEMS TO DETERMINE IF THERE ARE OTHER NEGATIVE PHASE SEQUENCE RELAYS WHICH MAY BE AFFECTED	3/18/94
		C7) AN INTEGRATED REPLACEMENT PARTS PROG WILL BE DEVELOPED TO ENHANCE THE OVERALL ENGINEERING NOTIFICATION AND ENGINEERING HOLD PROGRAM. IMPROVE THE PLANT PERSONNEL UNDERSTANDING OF THE PROCESS AND PROVIDE TIMELY SUPPORT	5/31/94

SOURCE	DESCRIPTION	ACTION	DUE DATE
SPR 933107	ELECTRICAL AND I&C TRAINING PROGRAMS INADEQUATE (DG CLOSURE PACKAGE)	C1) REVIEW ELECTRICAL, MECHANICAL, I&C LESSON PLANS AGAINST UPGRADED DG VENDOR MANUAL, REVISE AS APPROPRIATE	12/17/94
SPR 933108	DG SYSTEM DRAWINGS IMPAIR ABILITY TO TROUBLESHOOT DG	C1) ENHANCEMENT OF SDG CONTROL CIRCUITRY DRAWINGS (INITIATED)	1/31/94
SPR 933154	RESPONSE TO SDG RELIABILITY WITH RESPECT TO STATION BLACKOUT MAY NOT BE MET	REVISE OPEP07-DG-0001, PERFORMANCE MONITORING OF ESF STANDBY DIESEL GENERATORS, SO THAT SHOULD TECH SPECS BE REDUCED, THE NUMARC 8700 REQUIREMENTS WOULD NOT BE LOST	7/8/94
SPR 933267	PROBLEM TEMPERATURE SWITCH REPLACEMENT AND INSTRUCTIONS	OPERATIONS QUALITY CONTROL WILL DEVELOP A PROCEDURE WHICH DETAILS THE USE OF THE REVIEW MATRIX. THIS WILL BE ADDED TO THE PLANNERS GUIDE FOR USE DURING WORK PACKAGE PREPARATION	6/30/94
SPR 933267	PROBLEM WITH TEMPERATURE SWITCH REPLACEMENT AND INSTRUCTIONS	THE CURRICULUM REVIEW COMMITTEE (CRC) WILL EVALUATE THIS EVENT FOR INCLUSION INTO CONTINUING TRAINING	3/1/94
SPR 933366	S/D SOLENOID HAD BEEN CHANGED WITHOUT DCN	INVESTIGATION; TO COMPLETE ON 1/14/94 PER TEJ	2/3/94
SPR 933375	MANUAL SHUTDOWN LEVER WOULD NOT STOP ENGINE	MAINT SUP WILL DEVELOP NEW PROCEDURE, OR REVISE EXISTING, TO PROVIDE WORK INSTRUCTIONS FOR FUEL ROD LINKAGE ADJUSTMENTS TO ENSURE CONTINUED OPERATION OF EMERGENCY SHUTDOWN LEVER AFTER MAINTENANCE	6/15/94
SPR 933408	CFAR REPORT CONCERNING SAC RELIABILITY	MODS 93062 AND 93063 HAVE BEEN APPROVED FOR EVAL IN 1994. RESULTS OF THE EVAL WILL BE PRESENTED TO MANAGEMENT	12/31/94
SPR 933421	SAC AIR DRYER DESICCANT SIGHTGLASSES CRACKING	INVESTIGATION (M. BALKAR) WORK SD-313300, SD-313295, SD-313296, SD-313297	2/15/94

SOURCE	DESCRIPTION	ACTION	DUE DATE
SPR 933473	DIAPER WIPE FOUND INSIDE CAM GALLERY	C2) REVISE ALL SDG PMS THAT REQUIRE DISASSEMBLY, TO INCLUDE A QNP TO PERFORM CLEANLINESS INSPECTION PRIOR TO REASSEMBLY	2/28/94
SPR 940025	NO PM ACTIVITY BEING PERFORMED ON SDG JW ROCKWALL NORDSIROM VALVES. TO DATE, THERE HAVE BEEN THREE VALVE FAILURES	INVESTIGATION, ACTION	3/7/94
PR 940031	NON-CLASS SAFETY VALVES INSTALLED DUE TO MISINTERPRETATION INVESTIGATION OF P&ID DRAWING	INVESTIGATION	3/4/94
SPR 940059	LSHL-5696 NOT WIRED PER SCALING AND VENDOR DRAWING, CAUSING CRANKCASE OFF-NORMAL ANNUNCIATOR TO ALARM WITH NORMAL LEVEL IN CRANKCASE	INVESTIGATION	3/9/94