APPENDIX

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

NRC Inspection Report: 50-498/92-21 Operating License: NPF-76
50-499/92-21 NPF-80

Dockets: 50-498
50-499

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

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

Inspection At: Matagorda County, Texas

Inspection Conducted: June 7 through July 4, 1992

Inspectors: J. I. Tapia, Senior Resident Inspector
R. J. Evans, Resident Inspector
G. L. Guerra, Radiation Specialist (Intern)
M. A. Satorius, Project Engineer
M. F. Runyan, Reactor Inspector
W. J. Krupp, Senior Resident Inspector, Region III

for A. T. Howell, Chief, Project Section D Date 8/3/92
Division of Reactor Projects

Inspection Summary

Inspection Conducted June 7 through July 4, 1992 (Report 50-498/92-21; 50-499/92-21)

Areas Inspected: Routine, unannounced inspection of plant status, onsite followup of reports of nonroutine events at power reactor facilities, followup of violations and deviations, followup of previously identified items, operational safety verification, monthly maintenance observations, and maintenance program implementation.

Results: Corrective actions for licensee event reports and Notices of Violation were good (Section 3). The licensee's identification and correction of a radiation protection technician working more than 72 hours in a 7-day period (Section 4.1) and a nonconservative error in an Emergency Operating Procedure (Section 4.4) were commendable. The licensee's planned actions to address industry-wide problems relative to solenoid operated valves were extensive (Section 5.4). However, the licensee's lack of timeliness in correcting an emergency diesel generator turbocharger support problem was indicative of a nonconservative approach in correcting a nonconforming condition (Section 4.5.3).

Plant operators continued to be challenged by steam generator feedwater system equipment problems (Section 5.1). The adequacy of recently enhanced alarm response procedures will be assessed during future inspection and will be tracked by an inspection followup item (IFI) (Section 4.2).

Several maintenance concerns and weaknesses were identified. Continuing emergency diesel generator (EDG) problems were noted during this inspection period (Section 4.5.1), and the overall unavailability of EDGs was high. This issue will be tracked by an IFI (Section 4.5.2). The licensee, despite extensive efforts, has not been able to resolve Unit 1 source range monitor reliability problems (Section 5.3), and a Unit 1 alternate charging motor-operated valve had to be leak repaired for a second time (Section 5.2). A lack of preventive maintenance associated with the technical support center chilled water and ventilation systems appeared to have been one of the causes associated with a high temperature condition in the plant computer room (Section 4.3). Several examples of planning and scheduling weaknesses resulted in unnecessary or longer than necessary equipment outages, unnecessary entry into Technical Specification (TS) action statements, and unnecessary actuations of engineered safety features equipment (Section 5.5). Generally, open service requests (OSRs) were being properly prioritized (Section 6.1); however, some weaknesses associated with the OSR backlog were identified (Sections 6.1 and 6.3).

A list of acronyms and initialisms is provided as an attachment to this report.

DETAILS

1. PERSONS CONTACTED

Houston Lighting & Power Company

*C. Ayala, Supervising Engineer, Licensing
*M. Chakravorty, Executive Director, Nuclear Safety Review Board
*M. Coppinger, Maintenance Department
*R. Dally-Piggot, Engineering Specialist, Licensing
*D. Denver, Manager, Nuclear Engineering
*R. Gangluff, Manager, Chemical Operations and Analysis
*R. Garris, Manager, Design Engineering
*R. Hernandez, Manager, Design Engineering
*W. Kinsey, Vice President, Nuclear Generation
*W. Jump, Manager, Nuclear Licensing
*D. Leazar, Manager, Plant Engineering
*A. McIntyre, Director, Plant Projects
*G. Midkiff, Manager, Plant Operations
*G. Parkey, Plant Manager
*R. Rehkugler, Director, Quality Assurance
*S. Rosen, Vice President, Engineering
*T. Underwood, Director, Independent Safety Engineering Group

Central Power and Light Company

*B. McLaughlin, Owners Representative

In addition to the above, the inspectors also held discussions with other licensee and contractor personnel during this inspection.

*Denotes those individuals attending the exit interview conducted on July 6, 1992.

2. PLANT STATUS (71707)

Unit 1 began the inspection period in Mode 1 (power operation) and remained at full power until June 17, 1992. On that day, power was reduced to 80 percent to repair a leaking instrument tube associated with the Steam Generator Feedwater Pump (SGFP) 11 turbine. Power was increased to 100 percent the same day. Unit 1 remained at full power through the end of the inspection period.

Unit 2 also began the inspection period at full power operation. On June 9, 1992, power was reduced to 95 percent to correct plant computer room elevated temperature which resulted in secondary plant equipment high temperature alarms. The alarmed conditions were corrected and the unit returned to full power the same day. Unit 2 remained at full power through the end of the inspection period.

Several organizational changes were implemented on July 1, 1992. The position of Vice President, Nuclear Support was eliminated and the functions of the nuclear support department were reassigned to the other departments. The site facilities organization was transferred to the nuclear purchasing and materials management department. The Nuclear Group Vice President was given oversight of the information resources organization. The industrial safety group was transferred to the nuclear assurance department.

3. INSPECTOR FOLLOWUP

3.1 Onsite Followup of Written Reports of Nonroutine Events at Power Reactor Facilities (92700)

3.1.1 (Closed) Licensee Event Report (LER) 50-498/91-012: Reactor Trip Because of Motor Generator Malfunction

On April 12, 1991, Unit 1 tripped from 40 percent power because of a loss of control rod power to the reactor trip switchgear. The malfunction of a rod drive motor generator (MG) voltage regulator circuit relay apparently caused MG 11 to trip and also caused a loss of MG 12 output voltage. The regulator power relay malfunction was caused by a defective output switch. Corrective actions taken included replacement of the regulator power relay timer and control relay. Additionally, a procedural change to the applicable calibration procedure was made to enhance the detection of relay malfunctions. During the troubleshooting process, the relay was found to be miswired. Although the incorrect wiring of the relay was not clearly identified as a cause of relay malfunction, corrective actions were implemented to prevent recurrence. The miswiring was the result of inadequate wire labelling. Procedures were enhanced to verify that adequate wire labelling exists prior to lifting any wires. The inspectors determined that these corrective actions were accceptable.

3.1.2 (Closed) LER 50-498/91-20: TS Violation Because of Two Missed Surveillances

On September 15, 1991, the licensee determined that two control rod deviation position checks were not performed because the rod deviation monitor was incorrectly declared operable. The cause of the event was attributed to errors by three shift supervisors in implementing procedural requirements, inadequate postmaintenance test requirements, and an inadequate temporary modification request form. Corrective actions taken were appropriate.

3.1.3 Commitment Change to Unit 1 LER 50-498/89-017

On August 14, 1989, an event occurred that resulted in the contamination of the liquid waste processing system, the auxiliary boiler, and the inorganics basin. Corrective actions included reviewing the radioactive to nonradioactive system interfaces. This review resulted in the initiation of two planned modifications to install radiation monitors in selected system interfaces. This LER was reviewed and closed in NRC Inspection

Report 50-498/90-39; 50-499/90-39. Subsequently, the licensee determined that these modifications are no longer necessary. The licensee sent a letter to the NRC, dated April 10, 1992, that described the commitment changes, including the justification for the deletion of the planned modifications. The review of the justification for the commitment changes that were documented in LER 50-498/89-17 will be performed during a future inspection and will be tracked by IFI 498/9221-01.

3.2 Followup on Corrective Actions for Violations and Deviations (92702)

3.2.1 (Closed) Violation 498/9031-01: Inoperable High Head Safety Injection (HHSI) Pump in Mode 3

This violation was documented in NRC Special Inspection Report 50-498/90-31; 50-499/90-31. An enforcement conference was held with the licensee on October 5, 1990. The licensee issued LER 50-498/90-022 in response to the violation of TS 3.5.2 on September 12, 1990. The violation involved a Unit 1 mode change from Mode 4 to 3 without establishing three operable HHSI trains in accordance with the subject TS. The licensee developed a training program emphasizing the attention to detail and self-verification. The inspectors considered these actions to be appropriate. This training was conducted for all employees engaged in the maintenance and operation of the plant.

3.2.2 (Closed) Violation 498;499/9206-02: Motor-Operated Valves (MOVs)

This violation involved the use of unacceptable engineering justifications to establish the operability of several MOVs. The MOVs in question were diagnostically tested and then left with the torque or limit switch set such that the total thrust applied to the valve stem (including control switch repeatability and diagnostic system inaccuracy) exceeded the vendor's maximum allowable thrust. The overthrust conditions were documented on requests for actions (RFAs) and dispositioned "use as is" on conditional release authorizations (CRAs) on the basis of information that was neither available onsite nor evaluated for site-specific applicability.

Prior to the NRC inspection in which this violation was identified, the licensee had recognized that the subject RFAs were unsupportable and had issued one new RFA for each unit encompassing all of the previous overthrust conditions. The new RFAs, however, were classified in such a way that the root cause and generic implications of this problem were not addressed. This concern is discussed further in Section 3.3 of this report.

In response to the violation, the licensee performed a root cause analysis and concluded that the discrepant dispositions resulted from the failure of personnel to adhere to procedures and accurately complete work documents. A second root cause was less than adequate guidance on what constitutes acceptable technical justification for operability determinations.

A memorandum dated May 7, 1992, and issued as required reading for the design engineering staff, delineated instructions on the performance of RFA conditional releases and justifications for continued operation. The memorandum specifically addressed the need to ensure that the site applicability of any information used to form the basis of an operability evaluation must be documented within the record management system as a permanent record.

In the response to the Notice of Violation, the licensee indicated that Engineering Assurance (EA) had previously identified the same finding. The inspectors reviewed the EA associated documentation and found that the problem was identified in a January 24, 1992, memorandum from EA to engineering. However, the documentation of the EA finding by internal memorandum did not result in the review of non-MOV-related RFAs and CRAs. The licensee's review in response to the Notice of Violation found that although there were no operability problems with other RFAs and no cases in which a CRA was not justifiable, RFAs and associated CRAs were identified for which the engineering dispositions were not properly supported by design documentation. These engineering dispositions were found to be deficient in detail or to contain information not properly evaluated for STP applicability. Actions are being taken by the licensee to provide proper design documentation for each of these.

As was previously identified in NRC Inspection Report 50-498/92-04; 50-499/92-04, the licensee had initiated, as a result of a quality assurance audit, a deficiency report to upgrade their corrective action program. It is the inspectors' understanding, based on discussions with the General Manager, Nuclear Assurance, that corrective actions in response to EA findings will be addressed as part of the corrective action program enhancements.

The inspectors concluded that the licensee's corrective actions were comprehensive and timely.

3.3 Followup on Previously Identified NRC Items (92701)

3.3.1 (Open) Unresolved Item 498/499/9206-01: MOV Actuator Stall Thrust and Over Thrust

The unresolved item focused on two technical issues, each potentially affecting the operability of several safety-related MOVs in both units. One of these issues involved the use of Westinghouse stall test data to establish the operability of certain MOVs which, by standard calculational methods, appeared inoperable. The most notable of these valves were the two pressurizer power operated relief valve (PORV) block valves on each unit. When the standard industry MOV sizing equation was applied to these valves, the calculated thrust required to close the valve under maximum dynamic load exceeded the calculated available thrust. In the calculation prepared for the licensee, Westinghouse had supplied a stall thrust value at 80 percent degraded voltage that was well in excess of both the calculated available thrust and the calculated required thrust. The stall thrust value was used to demonstrate that the MOV was capable of operating under design basis conditions. The issue that had remained unresolved was the methodology employed by Westinghouse to determine the degraded voltage stall thrust values.

The inspectors reviewed a letter dated June 9, 1992, from Westinghouse to STP which contained a description of the valve and operator testing performed by Westinghouse to determine valve factors and operator capabilities. This letter in combination with a separate testing summary provided by the licensee established a chronology of the testing performed on the PORV block valves. The same general sequence of testing was stated by the licensee to apply to all Westinghouse-supplied MOVs.

The testing summary provided by the licensee was as follows:

> The testing sequence began at the Electric Power Research Institute (EPRI), where several test valves failed to fully isolate flow under full flow and differential pressure conditions. After several modifications and testing performed at Westinghouse, the valves were retested at EPRI and demonstrated successful isolation. The licensee stated that Westinghouse had informed them that not all valves had to be modified, which included the PORV block valves at STP. Based on these test results, valve factors were determined which were used in individual calculations to predict the thrust required to position the valves under dynamic conditions.
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> In addition, when Westinghouse procured valve operators from Limitorque, each operator prior to shipment was tested with the torque switch bypassed to determine the maximum (stall) thrust available. The stall thrust tests were performed at 100 percent design voltage, after which the resulting thrust measurements were adjusted by calculation to estimate the 80 percent voltage stall thrust capability. If the calculation demonstrated that the 80 percent thrust was not greater than the design thrust required, then another stall test was performed at 80 percent voltage. The stall tests were performed under static conditions.
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> When the operators were received at Westinghouse, they were mated to their respective valves and subjected to a valve functional test. Although these tests simulated differential pressure conditions, they were not true dynamic tests since no flow was provided during the time the valve was in motion.

The inspectors questioned the use of stall thrust test results obtained under static conditions to predict valve capability under design full-flow conditions. The licensee stated that it had been informed by Westinghouse that rate-of-loading and dynamic effects influencing the stall capability of the actuators were fully compensated for by the conservatisms used in establishing the valve factors. These and other questions regarding the stall thrust test results will be addressed during a future NRC inspection at Westinghouse. Pending the results of that inspection, this item remains unresolved.

The other technical issue associated with the unresolved item was the increased thrust ratings applied to approximately 45 valve actuators at STP. After diagnostic testing had been performed, these actuators had been left with the torque or limit switch set such that the total thrust experienced by the valve (including allowances for control switch repeatability and diagnostic system inaccuracy) exceeded 110 percent of the nominal actuator rating established by the actuator vendor, Limitorque. Limitorque permits an unconditional overthrust of up to 10 percent above the nominal rating for all of its actuators.

During the previous NRC inspection, the licensee had established an interim basis for concluding that the affected valves were operable. For those actuators subject to overthrust in the 110 to 140 percent range, the licensee referenced a January 24, 1992, letter from Limitorque to South Carolina Electric and Gas (which was transmitted by facsimile to STP) stating that thrust ratings for SMB-000, SMB-00, SMB-0, and SMB-1 type MOV actuators could be increased to 140 percent of the currently published actuator ratings. For Westinghouse MOVs and in particular five MOVs in the 141 to 161 percent thrust range, the licensee provided a February 22, 1992, telecopy message from Westinghouse permitting the operation of these valves for an additional six cycles. Westinghouse had qualified these actuators based on testing performed for them by Limitorque. The unresolved item was principally focused on the methodology employed by Limitorque and Westinghouse to establish the higher thrust ratings.

During this inspection, the inspectors noted that the licensee was no longer relying on the two letters cited above to justify operation of the overthrusted MOVs. Instead, two preliminary test reports performed for Westinghouse by Limitorque were being used for that purpose. The inspectors reviewed these reports, entitled as follows:

> "Report on Qualification Testing Program of Limitorque SMB-00 Valve Actuator for Increased Thrust Rating for Use in a Westinghouse Steam Supply System, Report B0335, February 3, 1992 (Preliminary);" and

> "Report on Qualification Testing Program for Limitorque SMB-2 Valve Actuator for Increased Thrust Rating for Use in a Westinghouse Nuclear Steam Supply System, April 8, 1992 (Preliminary)."

The licensee stated that the two test reports had been reviewed and determined to be applicable to STP MOVs. However, this review had not been formally documented. During the inspection, the licensee stated an intent to formally document their review of the test reports. This issue will be reviewed as a followup of the unresolved item.

The licensee stated that Westinghouse had completed their planned testing for SB operators and that the results had been satisfactory. The SB test reports were not yet available. In the interim, the licensee had received correspondence from Westinghouse stating that the SMB test results could be applied to SB operators because of the similarity of design, construction, and operation.

The licensee identified these two reports as being proprietary information. Therefore, the details of the reports are not discussed in this report. The inspectors identified several areas of concern that will be pursued during a future NRC inspection at Westinghouse. This item remains unresolved pending the results of the Westinghouse inspection.

3.3.2 (Open) Followup of 90-Day Response Items Identified in NRC Inspection Report 50-498/92-06; 50-499/92-06

During the NRC MOV inspection (refer to NRC Inspection Report 50-498/92-06; 50-499/92-06) performed February 24-28, 1992, three 90-day response items were identified. The responses to these items are due in mid-July 1992. During this inspection, the inspectors obtained a preliminary status on each of the three items.

The first response item requested the licensee to provide the methodology it plans to use for extrapolating diagnostic test results from test conditions to design basis conditions. The licensee had consulted several other utilities and had developed a linear extrapolation technique to predict the thrust required to successfully operate the valve under design basis differential pressure conditions. The inspectors noted that no allowance had been made in the extrapolation method for rate-of-loading effects. Rate of loading occurs as the differential pressure across the valve increases, which results in the torque switch tripping at a point where progressively less actual thrust is delivered to the valve stem. This rate-of-loading effect and the differential pressure effect on the valve disc as well as the pressure effect on the valve stem must be included in the extrapolation method. The licensee acknowledged the need to include the rate-of-loading consideration into its extrapolation methodology. The licensee stated that a revised methodology may not be available in time to provide it as part of the reply to the response item.

Using the linear extrapolation technique, the licensee identified 45 MOVs that needed additional evaluation to establish whether sufficient margins exist for valve operability. The licensee stated that these evaluations would be completed in time for the 90-day response and that any valves considered inoperable would be handled in accordance with the TS requirements, as appropriate.

In the second response item, the licensee was requested to provide long-term plans for MOVs left in an overthrust condition. The licensee had purchased both the Westinghouse and KALSI test reports for uprating valve actuators and expressed the intent to use the results of these studies to qualify the subject actuators for long-term service. The licensee was using the preliminary Westinghouse test results (performed by Limitorque) to establish the current operability of the overthrusted MOVs. If at any time the KALSI test results were to be employed, the licensee recognized that the fastener torquing criteria associated with this testing would have to be addressed.

The third response item involved an apparent conflict between "Limitorque Technical Update 92-01," and licensee communications with Westinghouse concerning torquing requirements for actuator base and housing cover fasteners. Westinghouse had advised the licensee that the torquing requirements expressed in the technical update were not applicable to its operator testing program, which had not specified any torque values. The inspectors reviewed a concurrence of this position provided to STP from Limitorque dated June 11, 1992. The concurrence, however, reiterated that torquing requirements are applicable if the 92-01 update (based on KALSI testing) is used to support a 40 percent increase in actuator thrust rating.

The issues associated with the three response items will be reviewed further after the NRC is in receipt of the licensee's 90-day response.

4. OPERATIONAL SAFETY VERIFICATION (71707)

The purpose of this inspection was to ensure that the facility was being operated safely and in conformance with license and regulatory requirements. The inspectors visited the control rooms on a routine basis and verified control room staffing, operator decorum, shift turnover, adherence to TS, and that overall personnel performance within the control room was in accordance with NRC requirements. Tours in various locations of the plant were also performed to observe work activities and to ensure that the facility was being operated in conformance with license and regulatory requirements. The following paragraphs provide details of specific inspector observations during this inspection period.

4.1 Overtime Limits Exceeded Without Approval

During the inspection period, a radiation protection technician worked for more than 72 hours in a 7-day period. This incident represents a violation of established procedures and TS because the excessive overtime was not properly authorized by plant management.

TS Section 6.2.2, "Unit Staff," establishes limits on minimum shift crew composition and working hours. It requires that adequate shift coverage be maintained without the routine use of substantial amounts of overtime. The objective is to have operating personnel work a normal 40-hour week while either unit is operating. In the event that unforeseen problems require substantial amounts of overtime to be used, or during extended periods of unit shutdown for refueling, maintenance, or modification, the 40-hour work week can be exceeded on a temporary basis. TS establish the guideline that an individual should not be permitted to work more than 72 hours in any 7-day period, excluding shift turnover time. Any deviation from the guideline has to be authorized by the plant manager, or equivalent, in accordance with established procedures.

Procedure OPGP02-ZA-0060, Revision 4, "Overtime Approval Program," was issued to administratively control the documentation and approval of overtime. Additionally, night orders and standing orders were issued to key departments, including operations, chemical analysis, and radiation protection, to assure that they remained cognizant of the TS 6.2.2 requirements. These administrative controls were strengthened following an NRC identified violation (refer to NRC Inspection Report 50-498/91-11; 50-499/91-11). An NRC audit identified four unit supervisors and two shift supervisors that had exceeded the guidelines established in TS, but did not receive the proper authorization. NRC subsequently concluded that the administrative controls were adequately strengthened and the violation was closed in NRC Inspection Report 50-498/91-22; 50-499/91-22.

On June 16, 1992, the licensee determined that a radiation protection technician worked greater than 72 hours in a 7-day period (June 5-11, 1992). The technician was scheduled to work 3 days, take 1 day off, then work 3 nights. However, the technician was requested to fill in for a person who called in sick. As a result, he came to work on his scheduled day off. The technician then exceeded the 72-hour time limit on the 7th day of work. In addition to Procedure OPGP02-ZA-0060, standing orders were in place to require approval for overtime before limits were exceeded. However, the administrative guidelines were not adhered to because the overtime approval form was not filled out and submitted to management in a timely manner. The technician subsequently stated that no safety-related work was performed during the time frame that the 72 hours was exceeded.

This incident was determined to be a violation of the licensee's established procedures (OPGP02-ZA-0060), program (health physics department standing orders), and TS administrative controls (TS 6.2.2.f.2). This violation will not be subject to enforcement action because the licensee's efforts in identifying and correcting the violation meet the criteria specified in Section VII.B.2 of the Enforcement Policy. Although a similar violation was previously cited, corrective actions were implemented and were determined to be adequate. This violation was the result of individuals who failed to adhere to established requirements. Corrective actions planned by the licensee included disciplinary action of the individuals involved and reissuance of night orders emphasizing the importance of the time limits on working hours.

4.2 <u>Isolation Valve Cubicle High Ambient Temperatures (Units 1 and 2)</u>

The ambient air temperature in two rooms located in the plant exceeded the TS limits during the inspection period. One room temperature exceeded the temperature long enough to require the licensee to submit a special report to NRC. Once the licensee identified that a problem existed in both units, corrective actions were planned and partially implemented by the end of the inspection period. The planned actions were considered to be thorough. However, the associated room temperature alarm response procedure lacked specific instructions on how to respond to building area high temperature conditions.

The main steam isolation valve (MSIV) cubicle ventilation subsystem in each unit is designed to operate during normal and accident plant operating conditions and to maintain the ambient temperature in the cubicles within TS limits. TS 3.7.13, "Area Temperature Monitoring," establishes limits on temperatures in selected areas of the plant. The area temperature limits ensure that safety-related equipment will not be subjected to temperatures in excess of their environmental qualification temperatures. Exposure to excess temperatures may degrade equipment and can cause a loss of operability. In accordance with TS 3.7.13, Action b, if any area exceeds the temperature limit established in TS Table 3.7-3 for more than 8 hours, a special report is required to be submitted to NRC. For the MSIV cubicles at elevation 10 feet, where the AFW pumps are located, the temperature limit is less than or equal to 101°F.

Although not required by the applicable alarm response procedure, when the high ambient temperature alarm was received in the control room, temporary logs of cubicle ambient temperature were initiated to track the temperature every 4 hours. On June 24, 1992, the Unit 2 MSIV Cubicle D elevation 10 feet ambient temperature was measured at 104°F at 6:25 p.m. TS 3.7.13 was entered and exited 4 hours later when the temperature was measured at 98°F. On June 30, 1992, the MSIV cubicle temperature high alarm energized in the Unit 1 main control room. Temporary logs were initiated to monitor the MSIV Cubicle D temperature. At 3:30 p.m., TS 3.7.13 was entered when the local temperature was measured at about 102°F. TS 3.7.13 was exited at 11:40 p.m. when the alarm cleared and local temperature was verified to be less than 101°F. An NRC special report was required since the area temperature exceeded the TS limit for more than 8 hours.

In response to the high temperatures, the air flow in each of the two MSIV D train cubicles was measured. In both units, the rated flow of the fan was satisfactory, but the flow through the ventilation duct associated with the steam driven AFW pump room was below limits in both units. The required flow rate was 9000 cfm and the minimum allowed flow rate was 8550 cfm (acceptance criteria limit of minus 5 percent). In Unit 1, the measured air flow was 8205 cfm while 8413 cfm was measured in Unit 2. The licensee then cleaned out the duct, which was plated with dust and insects from the outside (system does not have an inline filter), and the flow test was repeated. The removal of the airflow obstructions resulted in the Unit 1 flow rate increasing to 8634 cfm and the Unit 2 flow rate increasing to 9307 cfm.

A review of Alarm Response Procedure 0POP09-AN-22M1, Revision 0, "Annunciator Lampbox 22M01 Response Instructions," was performed. The subsequent actions section for Annunciator F1, "Isolation Valve Cubicle Temperature High," listed the required actions as: (1) investigate cause of room high temperature; (2) take the appropriate action per TS; and (3) initiate a service request for failed components. These actions appeared inadequate to correct an area high temperature. Additional actions that should have been required include: (1) monitoring the airflow and cleaning the duct, if necessary; (2) taking temporary log readings if the temperature is verified to be high, and (3) installing temporary fans to assist in cooling. The inspector noted that this procedure had been enhanced as a result of an Operations Department procedure upgrade program (refer to NRC Inspection Report 50-498/92-15; 50-499/92-15); however, the only substantive change to the procedure was the addition of the requirement to initiate a service request for failed components. The inspector considered this lack of procedural guidance to be a weakness. IFI 498;499/9221-02 will be used to track further reviews of other alarm response procedures in order to assess their adequacy and to assess the effectiveness of the procedure upgrade program.

4.3 Power Reduction Following Loss of Room Cooler (Unit 2)

On June 9, 1992, Unit 2 power was reduced approximately 5 percent for 1 1/2 hours because various computer alarms indicated that some secondary plant equipment temperatures were steadily rising. The cause of these indications was elevated temperature in the plant computer room which affected the reliability of the plant computer. A station problem report was written to investigate the reliability of the computer room cooling and the impact that the cooling system has on plant operations.

Unit 2 was at full power operation on June 9, 1992, when the Feedwater Booster Pump 21 inboard bearing high temperature alarm was received in the main control room. Plant operators observed the temperature displayed on the computer slowly increasing. Standby Feedwater Booster Pump 23 was started and Pump 21 was secured. The thrust bearing temperature alarm on Standby Feedwater Booster Pump 22 was observed to be increasing. Additionally, the stator coil differential temperature was also observed to be increasing. In an effort to reduce the heat load on the unit and because of the possibility of losing the feedwater system, the unit was ramped down in power to 95 percent.

About 20 minutes later, the Proteus (nonsafety-related plant computer) computer room was observed to be about 15°F higher than expected. The plant operators discovered Technical Support Center (TSC) Chiller 21B had tripped off line and Chiller 21A had failed to start. Since the TSC chilled water system provides cooling water to the computer room air handling units, the loss of both chillers resulted in a loss of computer room cooling and room temperature started to increase. Chiller 21A was manually started and the computer room temperature was noted to decrease. The indicated high temperature conditions returned to the normal values when the room temperature was returned to normal (about 65°F). Unit 2 subsequently returned to full power operation the same day.

Temperature sensors in the plant are connected to the computer at cold junction boxes. Thermocouples are located in the junction boxes in order to automatically compensate for changes in junction box ambient temperature. The thermocouples provide temperature compensation to a limit of 104°F in order to maintain accurate temperature inputs from the plant components. The room temperature did not reach or exceed 104°F; however, the higher than normal ambient temperature did result in unreliable computer outputs.

One of the causes of the event was the reliability of the room coolers and TSC chillers. Preventive maintenance was not performed on the equipment because of the low priority levels established for these components. The TSC chilled water and ventilation systems are classified as nonsafety related. The only TSC items in the preventive maintenance program were the chilled water pumps, pump pressure gauges, and system MOVs. All other system preventive maintenance activities, including the chiller inspection and test, were inactivated. Corrective maintenance work orders were issued when defective items were identified. The failure of the cold junction boxes to maintain adequate sensor readings was not clearly identified. A ition problem report was issued to investigate the incident, but the investigation had not been completed by the end of the inspection period. The corrective actions being considered included activation of preventive maintenance activities for selected TSC components.

4.4 Emergency Operating Procedure Setpoint Error (Units 1 and 2)

A training department instructor, who was preparing a lesson plan, identified an error in an emergency operating procedure (EOP). This error resulted in a nonconservative steam generator (SG) level at which the operators must initiate reactor coolant system (RCS) feed and bleed to maintain heat removal following a loss of the secondary heat sink. The correct value was calculated and the respective procedure was revised.

On June 30, 1992, while preparing a lesson plan for a mitigating core damage class, a training department instructor discovered that a calculation was performed using inaccurate information. The error resulted in the wrong steam generator water level in which RCS feed and bleed is initiated. Emergency Operating Procedure (EOP) OPOP05-EO-FRH1, Revision 0, "Response to Loss of Secondary Heat Sink," provided instructions to immediately initiate RCS feed and bleed to prevent core damage if: (1) SG wide range levels in any two SGs are less than 34 percent, or (2) pressurizer pressure is greater than or equal to 2335 pounds per square inch gage (psig) because of loss of secondary heat sink. The licensee determined that the correct SG level setpoint should have been 39 percent. The lower value previously used was nonconservative. The licensee notified the NRC within the 4-hour time limit as required by 10 CFR Part 50.72.

The error was introduced into the EOP setpoint document which was used in the development of the EOPs. The background document for the setpoint document consisted of two reference plants. One was an HHSI plant (3411 megawatts thermal) and the other was a low head safety injection plant (3025 megawatts thermal). The difference depended on whether or not the safety injection pumps injected water into the RCS at normal operating pressures. The value for the high head plant was used and extrapolated to 3800 megawatts thermal.

However, the licensee discovered the value used should have been based on the low head safety injection plant because STP was a low head plant. The result of this was that the SG level used to initiate a feed and bleed operation in EOP 0POP05-EO-FRH1 was 5 percent lower than required.

The setpoint was recalculated using the correct data and a field change request was issued to correct the SG setpoint in the procedure. Remedial actions planned include performing a review of the EOP support documents in an attempt to identify similar errors. The licensee planned to issue LER 50-498/92-06 because of this condition. The inspectors considered the licensee's identification of this deficiency to be a strength.

4.5 <u>EDG Issues</u>

The licensee continues to experience various problems with EDG performance. The following issues were reviewed during this inspection.

4.5.1 <u>Non-Valid Failure (Unit 2)</u>

On June 10, 1992, during a scheduled performance of a TS-required operability test, EDG 22 tripped when released from the emergency mode. Subsequent investigation revealed no alarms on the local annunciator panel and the master trip circuit green trip light was on, indicating that a nonemergency trip was present. Believing that the problem was related to annunciation, the nonemergency trips were reset and the EDG was again started. The green light for the master trip circuit came on again. An attempt to reset the circuit with the engine running was unsuccessful and the engine was shut down.

The licensee commenced troubleshooting and verified the tightness of wire terminations and contacts related to the unit shutdown relay. An attempt to duplicate the event was made and the engine again tripped when it was released from the emergency made. All the trip alarms were received, indicating a problem in the shutdown air system. The cause of the problem was subsequently identified as a defective air regulator valve that did not provide sufficient pressure to reset the nonemergency trip alarms. The air regulator valve was subsequently replaced.

The engineering department is evaluating a design change to improve the reliability of the air regulator valve and to provide additional instrumentation to allow monitoring of the system air pressure. This evaluation is scheduled to be completed by October 1992. Previous events have occurred on EDGs 21 and 23 which involved the engine tripping when released from the emergency mode. The licensee issued Station Problem Reports 91-0456 and 92-0004 to initiate an investigation. The cause of those trips was determined to be the result of foreign material under the seat of the nonemergency trip air system check valve, allowing a decrease in air pressure and thus causing a trip with no apparent indication. The licensee subsequently generated preventive maintenance instructions to clean the check valves periodically and to blow down portions of the air system to remove excess particulates.

4.5.2 EDG Unavailability (Units 1 and 2)

On June 23, 1992, licensee and NRC personnel conducted a conference call to discuss EDG unavailability. The licensee's station trending program has identified a higher than expected level of EDG unavailability. The current adverse trend indicates that the licensee will not meet its 1992 goal of individual EDG unavailability of less than or equal to 2.5 percent. For the period from May 1991 to May 1992, the following values of unavailability were experienced:

	Unit 1		Unit 2
EDG No.	Unavailability (Percent)	EDG No.	Unavailability (Percent)
11	4.1	21	3.3
12	3.7	22	7.5
13	2.9	23	2.6

Unavailable hours are logged against the EDGs when they are removed from service to perform corrective or preventive maintenance. Careful planning of train outages is required to maximize maintenance to assure high reliability but, at the same time, minimize unavailability. The high number and frequency of preventive maintenance activities, as well as planned outages of support systems, has contributed to the unavailability. Planned outages outside of the normal limiting conditions for operation (LCO) train outages to repair essential cooling water system leaks have added significantly to unavailability in early 1992. In addition, troubleshooting of repetitive and long-standing problems required the EDGs to be out of service, and this has contributed to EDG unavailability.

During the conference call, the question of the effect of higher than expected unavailability values relative to compliance with the Station Blackout Rule (10 CFR Part 50.63) was discussed. These discussions were preliminary and the required information was not available to determine whether the values impacted the analysis. The information will be reviewed at a later date and will be tracked by IFI 498;499/9221-03.

4.5.3 Loose EDG Turbocharger Support (Unit 2)

On June 18, 1992, two nuts were found loose and one nut missing on the turbocharger support bracket of EDG 22. This condition was identified during a daily walkdown by maintenance personnel. A total of eight studs and nuts attach the turbocharger support against the engine block. The turbocharger support carries the vertical weight of the turbocharger and the nuts and studs maintain the support against the engine block. The studs and nuts are therefore not carrying a large load. The Cooper Besssemer Manual specifies a torque value of 50 foot-pounds.

The maintenance personnel identified the nonconforming condition to the control room. Control room personnel then issued an RFA to engineering. The

RFA requested engineering to evaluate the condition and recommend an alternate method of attaching the nut to the stud. Engineering issued a conditional release authorization on June 19, 1992, indicating that the engine was operable. The limitations imposed by this document required monitoring the turbocharger support studs and nuts hourly when running the EDG. This conditional release was based on an analysis which considered the effects of an assumed alternating load and the resulting stress levels for five instead of eight studs and nuts. The resulting postulated fatigue diagram indicated that the potential load on the remaining five studs was slightly lower than a safety factor of one. Coincident with the conditional release, a maintenance service request was issued to replace the missing nut and tighten the other nuts before the next monthly engine surveillance was to be performed. The last monthly surveillance had been performed on June 17, 1992; therefore, the service request as written could have allowed this condition to exist until July 17, 1992.

The inspector became aware of this condition on June 22, 1992, during a plan-of-the-day meeting. At this time, the inspector questioned why the licensee chose this course of action instead of simply repairing the nonconforming condition. In addition, the inspector determined that the other five engines had not been inspected to assure that a similar condition did not exist. After discussions between the inspector and the plant manager, the licensee issued a station problem report to assure that a root cause would be investigated to address a lack of timeliness of remedial actions. The inspector considered the licensee's approach to correcting the nonconforming condition to be an example of poor work planning (refer also to Section 5.5 of this report) and a nonconservative approach to correct a nonconforming condition.

Conclusions

A radiation protection technician worked for more than 72 hours in a 7-day period without proper approval. Procedural guidance was not adhered to by a select number of licensee representatives. However, this was considered an isolated incident, and this failure to comply with an administrative procedure resulted in a noncited violation.

An EOP setpoint was found to be incorrect. NRC was properly notified and the setpoint was corrected in the procedures. The inspector considered the licensee's identification of this problem to be a strength.

Isolation valve cubicle high ambient temperatures, in excess of TS limits, were measured in both units. The alarm response procedure for area high temperatures lacked sufficient guidance even though it recently had been reviewed and revised as part of a procedure upgrade program. Further inspection followup of other alarm response procedures will be tracked by an IFI.

Unit 2 power was reduced in response to erroneous plant computer output readings. The event occurred because of a loss of cooling to the room air coolers. One apparent cause of the event was inadequate preventive maintenance of the subject equipment.

EDG problems continue to exist. These problems pertained to continuing EDG nonvalid failures during the cooldown cycle, high EDG unavailability, and poor work planning to correct a nonconforming condition. EDG unavailability will be tracked by an IFI.

5. MONTHLY MAINTENANCE OBSERVATIONS (62703)

Selected maintenance activities were observed to ascertain whether the maintenance of safety-related systems and components was conducted in accordance with approved procedures, TS, and appropriate codes and standards. The inspector verified that the activities were conducted in accordance with approved work instructions and procedures, that the test equipment was within the current calibration cycles, and that housekeeping was being conducted in an acceptable manner. All observations made were referred to the licensee for appropriate action.

5.1 Replacement of SGFP Turbine Instrument Tubing (Unit 1)

On June 17, 1992, Unit 1 power was reduced from 100 percent to 80 percent. The power reduction was needed to allow for the repair of a leak on a section of instrument tubing on SGFP Turbine 11, which had to be taken out of service. Service Request FW-155442 was issued to replace a leaking section of braided flex hose. The leak was approximately 1 gallon per minute. Hose failure could have caused the feed pump to trip on simulated low suction pressure (instrument failure). SGFP Turbine 11 was returned to service following repair, and Unit 1 rated thermal power was returned to 100 percent the same day. Although this maintenance activity was performed well, the inspectors noted that continuing SGFP problems and other SG feedwater system problems continue to challenge plant operators.

5.2 Valve Body-to-Bonnet Leak Repair (Unit 1)

An MOV was found leaking in the reactor containment building, which caused elevated radiation levels. This valve previously had been found leaking and was repaired during a maintenance outage in April 1992. The licensee plans to permanently repair the valve seat during the next refueling outage in September 1992.

On June 21, 1992, during a Unit 1 reactor containment building inspection to locate the source of an increase in containment radiation levels, a leak was found on the RCS alternate charging valve (CV-MOV-6). A steam plume approximately 5 feet long was observed. Previously, this valve had been leaking in February of 1992. RFA 92-0261 was issued and the leak was repaired on April 12, 1992, during a planned Unit 1 maintenance outage that began on April 4, 1992. A seal ring (bolted clamp type assembly) and pressure injected sealant (Furmanite) were initially used to stop the leak. The subsequent leak was stopped by the addition of more Furmanite on June 25, 1992. No problems were noted during this inspection activity.

The disposition planned for a final repair is to remove the sealant material. If the seating surface is found to have steam cut damage, the licensee will machine the surface and reassemble the valve. A 10 CFR Part 50.59 screening evaluation was performed for both the Furmanite addition and final repair by machining and no changes were found to be required to the Updated Safety Analysis Re- -t.

5.3 Troubleshooting of Source Range Monitor (Unit 1)

During the inspection period, problems with a neutron flux source range monitor continued to be identified by the licensee. Corrective actions were taken to repair the monitor, which was experiencing electrical noise interference problems. The actions were unsuccessful and the monitor remained out of service at the end of the inspection period. Although the monitor was not needed for power operation, monitor operability would be required prior to startup following any unit shutdown or trip.

Two source range nuclear instrument channels are provided in each unit. The monitors are designed for use in detecting reactor neutron flux levels during shutdown and initial phases of reactor startup. Source range monitor NI-31 had been inoperable, on a intermittent basis, since November 1991. The cause of the inoperability was electrical noise in the power supply cables. Extensive corrective actions were taken in the spring of 1992 (refer to NRC Inspection Report 50-498/92-14; 50-499/92-14), and Monitor NI-31 was returned to service on June 5, 1992.

On June 9, 1992, however, Monitor NI-31 was again removed from service. The monitor display was indicating elevated counts per second with the detector voltage removed. The display would indicate several hundred counts per second on an intermittent basis. Corrective actions taken in accordance with Service Request 175726 included change out of a cable located between the control room electronics and the preamplifier and the installation of noise suppressing ferrite beads. These actions were not fully successful because the monitor malfunctioned again at a later date. Monitor NI-31 remained out of service at the end of the inspection period. Corrective actions being considered include the use of a vendor. The vendor would be used to assist in the detection and elimination of the noise interference.

5.4 Containment Isolation Valves Fail to Close (Unit 2)

On April 28, 1992, two containment isolation valves (CIV) in the SG 2C bulk water sample line failed to close upon demand. During this inspection period, one of the two valves was removed and disassembled to determine the root cause of the failure. Debris was found lodged inside the valve. Corrective actions were being formulated to prevent similar occurrences. A solenoid operated valve (SOV) task force was developed to address the generic issues involved with SOVs.

Blowdown of the secondary side of the SG is performed to maintain the secondary side water chemistry within specification, to prevent buildup of corrosion products, to reduce SG radioactivity levels, and to provide the means of draining the secondary side. Sampling of the blowdown liquid is performed for measurement of radioactive isotopes and for chemistry control purposes. Water is provided to the sampling system through two CIVs located in series outside the reactor containment. The two CIVs are Target Rock SOVs which fail closed on loss of power.

On April 28, 1992, following the collection of a sample of SG 2C bulk water, Unit 2 operators discovered that CIVs SB-FV-4187 and SB-FV-4187A would not close upon demand. Since both valves were considered inoperable, entry into TS 3.0.3 was required (refer to NRC Inspection Report 50-498/92-14; 50-499/92-14 for a complete description of the event). The cause of the event was not clearly identified. Limited troubleshooting was performed because the manual isolation valve located upstream of the CIVs was inaccessible during normal plant operation and could not be used to isolate the valves.

On June 18, 1992, Valve SB-FV-4187A was removed and replaced with an identical valve by Service Request SB-164211. A freeze seal was installed on the upstream piping to assist in the safe removal of the mechanically stuck open SOV. The new SOV was satisfactorily tested in accordance with postmaintenance and surveillance test procedures. At the end of the inspection period, SB-FV-4187A was out of service because the valve had to remain de-energized and shut in order to isolate the penetration.

The failed SOV was disassembled with a Target Rock vendor representative present to provide technical assistance. Following valve disassembly, foreign material was found lodged under the piston ring and on the main disc and sleeve. The inlet, equalize, and pilot seat ports were found plugged. The licensee concluded that the debris, coming from the SG blowdown line, caused the valve to malfunction. Although the debris sample has not yet been analyzed, the licensee suspected that the debris was corrosion products. The disc, rod disc assembly, and piston ring were replaced. The valve internals were cleaned, and the SOV was reassembled. The refurbished valve was returned to the warehouse for future use.

Corrective actions being considered include valve replacement with an air operated or manual valve, cleaning all similar valves during future refueling outages, changing the downstream valve from normally open to normally closed, and installing an inline filter.

In response to Generic Letter 91-015, "Operating Experience Feedback Report, Solenoid Operated Valve Problems at U.S. Reactors," the licensee initiated an SOV task force in March 1992 to review the station's valves. STP currently has 3054 SOVs but only 208 safety-related process SOVs. The SOV task force plan of action was developed in June 1992 and submitted to licensee management for review. The plan of action recommended that an SOV reliability and enhancement program be developed. This program would include three phases, the Target Rock SOVs, the Valcor and Asco SOVs, and all non-class 1E process SOVs. The specific planned actions include: (1) developing a list of all SOVs, (2) comparing field data to design specification database information to verify proper SOV application, (3) comparing field data to environmental qualification requirements, (4) evaluating the use of diverse manufacturers and upgraded reed switch assemblies, (5) reviewing the SOV maintenance and surveillance procedures, (6) forming dedicated teams to perform field work, and (7) providing additional training for maintenance and engineering personnel. The inspectors considered the planned actions resulting from the SOV task force to be a positive initiative.

5.5 Work Planning (Units 1 and 2)

During this inspection period, several problems were identified that indicated less than effective work planning activities. The examples resulted in unnecessary or longer than planned equipment outages, unnecessary entry into TS action statements, and unnecessary actuations of engineered safety features (ESF) equipment. The following are examples of work planning weaknesses:

- Planned maintenance was started on EDG 21 (Train A) prior to ensuring that surveillances due on equipment in Trains B and C would not be performed during the time EDG 21 was out of service. A surveillance for a radiation monitor was performed during the EDG 21 outage. The surveillance activated all trains of Control Room Envelope (CRE). During the surveillance, the makeup damper failed and, as a result, a 2-hour shutdown TS action statement had to be entered. This condition appeared to have resulted in additional pressure on licensee technicians to restore EDG 21 to operable status within 2 hours in order to preclude a TS-required shutdown of Unit 2.

- There were two examples in which the same ESF equipment was activated for different surveillances within days of each surveillance. For example, the CRE trains were activated for a surveillance for verifying operability of a radiation monitor and within 48 hours, the CRE heating, ventilation, and air conditioning was again actuated to perform a 10-hour TS surveillance. Also, EDG 12, after maintenance work, was run for 1 hour for the monthly TS surveillance and 2 days later was started for a TS surveillance for verifying slave relay operability. The inspectors noted that a single actuation of each system could have accomplished both of the applicable surveillances.

- An LCO was entered for the 2B SG PORV to implement two service requests. The LCO was exited after 8 hours when it was determined that work on one service request had already been attempted without success and the other service request was not ready to be worked.

- On July 3, 1992, the Unit 1 anticipated transient without scram mitigation system actuation circuitry was out of service for 24 hours to perform a preventive maintenance procedure. The normal out of service time for this procedure is approximately 1 hour.

These issues were discussed with licensee management. On the basis of these discussions, the inspectors determined that licensee management was already aware of work planning and scheduling weaknesses and were in the process of determining corrective actions.

Conclusions

Unit 1 power was reduced to allow for repairs on SGFP 11. The power reduction was a conservative action to minimize the potential of a unit trip, but was indicative of continuing problems with the SGFPs. Valve 1-CV-MOV-6 required rework to eliminate a steam leak. Maintenance was previously performed on this valve to repair a steam leak during the April 1992 maintenance outage. Unit 1 continued to experience problems with Source Range Monitor NI-31. The monitor has been intermittently out of service since November 1991. Corrective actions taken have been extensive yet marginally successful. The stuck open SG Bulk Water Sample Valve 2-SB-FV-4187A was disassembled and debris was found in the valve. Corrective actions will be taken to prevent similar recurrence. The formation of an SOV task force was a positive licensee initiative. Several examples of less than adequate work planning were identified.

6. MAINTENANCE PROGRAM IMPLEMENTATION (62700)

The inspector reviewed the status of the licensee's OSRs, the efforts to reduce the number of OSRs, and the impact that the number of OSRs were having on the material condition of the plant.

6.1 Prioritization and Timeliness of Closure

The licensee's Procedure NGP-120, "Nuclear Program Priorities," is the procedure that implements the prioritization of all site work. This procedure specifies the criteria for assignment of one of four priorities. These are:

- Priority 1 - performed immediately to avert or correct situations that could lead to [illegible]ing the health or safety of employees or the public;

- Priority 2 - performed as soon as possible (within 72 hours) to maintain safe, reliable, and efficient plant operation;

- Priority 3 - performed as soon as possible to prevent degraded plant operation by reducing availability, capacity, or inhibiting completion of plant events or milestones; and

- Priority 4 - performed on a routine basis (these items will not adversely impact plant operations or prevent accomplishment of plant events or milestones).

The inspector reviewed the OSRs for the AFW system, standby diesel generator system (i.e., EDGs), and containment spray system for both units. These OSRs were reviewed to determine whether appropriate priorities were assigned to OSRs and that the identified OSRs were worked and subsequently closed in a time frame appropriate to the priority. In addition, the inspector walked-down several of the systems to determine whether identified deficiencies that are documented in the OSRs were accurately characterized when compared to field observations.

The inspector concluded that, generally, the licensee was appropriately prioritizing the deficiencies identified in the OSRs. The inspector identified, however, that several deficiencies that would be considered for outage work, were inappropriately categorized as nonoutage OSRs. The result of this practice was that the work was not scoped into outage planning, which caused these deficiencies to be carried as open because plant conditions could not be established to work the OSRs. AFW OSRs Nos. MWR:AF-131351 and MWR:AF-153548 are two examples. Both of these OSRs encompassed work that appeared to be appropriate for outage work scheduling; however, both were contained in the nonoutage OSR list. MWR:AF-131351 had been assigned a priority 2 on March 7, 1991, with no action planned until September, 1992. MWR:AF-153548 had been assigned a priority 4A on November 16, 1991, with a scheduled work date of September 27, 1992. On the basis of the description of these OSRs, the priority appeared appropriate; however, their categorization as nonoutage OSRs appeared to have resulted in the licensee [illegible]bility to correct these deficiencies in a timely manner. The inspector considered the disposition of MWR:AF-131351, a priority 2 OSR with 18 months from identification to scheduled action, as not meeting the intent of Procedure NGP-120. The inspector considered this to be a weakness.

The inspector discussed with licensee management this apparent inappropriate categorization of outage versus nonoutage OSRs. Based on this discussion, the inspector determined that the licensee was aware of isolated examples of inappropriate categorization and prioritization. In addition, the licensee indicated that internal processes were in place to review and update OSRs with respect to categorization and prioritization.

A second ramification of inappropriately categorizing outage versus nonoutage OSRs was that deficiencies requiring an outage for resolution, but improperly recorded as a nonoutage OSR, reduce the system availability if the component is removed from service for work during power operations. Although the inspector could find no specific examples of safety system outage OSR work being conducted in nonoutage conditions, system availability for the standby diesel generator, high head safety injection system, and AFW system, were exhibiting higher unavailability than the licensee's goal.

6.2 OSR Backlog Reduction Effort

The inspector reviewed the licensee's OSR backlog. Although the rate of closure remained relatively constant, the rate of OSR oper[illegible] continues to increase and the OSR backlog continues to grow. In conv[illegible]ions with licensee management, the inspector was informed that the [illegible] no data that would indicate when the OSR backlog would cease to increa[illegible] stabilize, and start to decrease. The inspector also reviewed the impact of engineering support relative to the size of the OSR backlog and determined that engineering support activities did not appear to significantly contribute to the size of the backlog.

6.3 OSR Impact on The Material Condition of the Plant

6.3.1 Maintenance Coordination

The inspector noted several examples of poor coordination of maintenance and surveillance activities. Some of these examples are addressed in Section 5.5 of this report. Other coordination problems appeared to result from a lack of insight into considering the cumulative effect that a number of lower priority OSRs might have on the overall reliability of plant equipment. The inspector observed an example of this cumulative effect during the walkdown of EDG 12 room on June 10, 1992. The inspector noted that Starting Air Compressor (SAC) 13 was danger tagged and removed from service in order to correct a problem with blow-by of the first stage of the SAC. First stage blow-by was a phenomena characterized by the inability of the SAC's first stage to provide rated pressure increase to the suction of the SAC's second stage. Troubleshooting efforts involved disassembly of the SAC, and inspection to determine the cause. While out of service, SAC 13's associated air accumulator was depressurized and not available to start EDG 12.

While observing the work area, the inspector noted the other SAC associated with EDG 12 (SAC 14) had a significant air leak on its associated air dryer. The air dryer was located downstream of the SAC's air cooler and upstream of the accumulator and the accumulator isolation check valve. The leak was of such a magnitude that as the accumulator approached the charged condition of 250 psig, the SAC was required to operate excessively in order to fully recharge the accumulator. After the accumulator was pressurized to 250 psig and the SAC secured, the leak did not stop, which indicated that the accumulator isolation check valve was also leaking. The result was that the accumulator contents discharged, the pressure setpoint that started the SAC was attained, and the charging cycle was reinitiated. The inspector timed the cycle from SAC start-to-start and determined that in a given hour, the SAC operated 45 minutes and was idle for 15 minutes. The dryer air leak deficiency was documented with an OSR that was approximately 2 days old. The accumulator check valve did not have an OSR assigned. In addition, the inspector noted that an OSR had been initiated in November 1991, on the SAC 14 motor, indicating that the outboard bearing was rough.

These issues were discussed with the licensee, and an OSR was initiated to repair the leaking check valve. Although the inspector did not consider the leaking check valve alone safety significant, that deficiency, in conjunction with the leak on the air dryer, resulted in increased SAC cycling and a greater potential for subsequent SAC failure. During discussion with the licensee, the inspector also questioned the level of system engineer involvement with respect to maintenance conducted on their responsible equipment. The inspector was informed that system engineers were not specifically directed to walkdown their systems at any specific periodicity, but that they were familiar with the material condition of their equipment. It did not appear that system engineers were making input into the prioritization of maintenance activities. The inspector considered this a weakness because appropriate system engineer input could improve maintenance coordination activities.

While the repair of the deficiency identified on SAC 13 was assigned a higher priority than either of the OSRs on SAC 14, the cumulative effect of the two identified deficiencies and the one unidentified deficiency impacted significantly on the SACs' reliability and, therefore, the overall reliability of the air start subsystem and EDC 12.

6.3.2 Control Room Indications

In addition to maintenance coordination, the backlog size has impacted main control board indications for safety-related equipment. This impact was demonstrated to the inspector while walking down the main control boards in both Unit 1 and Unit 2 control rooms. The inspector noted that boric acid tank hi/lo level annunciator alarms were illuminated in both control rooms. When questioned by the inspector, the control room operators stated that the actual level was within the required specified level band and informed the inspector that the reading was available on the main control board. The operator further stated that the alarm routinely cleared and came in, and that it was not unusual for the alarm to be locked in for a period of time. This deficiency was documented in both control rooms with an OSR that had been open in excess of 1 month. In addition, the inspector noted that a similar situation was present on a Unit 1 standby diesel generator day tank, in which the hi/lo level alarm was locked-in. The explanation given to the inspector was similar to that given for the boric acid tank alarm. This deficiency was also documented with an OSR. A similar example was documented in NRC Inspection Report 50-498/92-16; 50-499/92-16. Although the significance of these annunciators OSRs did not appear to warrant high prioritization, their presence and acceptance by the control room operators indicated that the main control board OSR reduction effort was not fully effective. In addition, the practice of operators routinely accepting control room annunciator indications could challenge operators during a future plant event. The inspector noted that, while the overall number of main control board deficiencies had been significantly reduced in recent months, the overall number of open deficiencies at the end of May 1992 remained above the licensee's goal for Unit 1 but significantly less than the Unit 2 goal.

Conclusions

Generally, OSRs were being properly prioritized by the licensee. Examples were discovered which indicated that some OSRs were not adequately differentiated between outage and nonoutage work, which resulted in untimely closure of OSRs and possibly a decrease in safety system availability.

While the licensee was closing OSRs at a constant rate, the backlog continues to increase because the deficiency identification rate has increased. There was no indication when the backlog will peak and start to reduce in number. Engineering support activities did not appear to be a significant contributor to the overall size of the OSR backlog.

The example of SAC reliability indicates that the licensee does not appear to have an effective means to assess the overall cumulative effect that open OSRs (low priority) may have on equipment reliability. System engineer input to prioritization of maintenance activities was considered a weakness.

Two examples of operators accepting control room annunciator deficiencies was viewed as a practice that could operationally challenge the operators during a future plant event. The number of main control board deficiencies had been signficantly reduced, but the overall number of open deficiencies remains high on Unit 1.

7. EXIT INTERVIEW

The inspectors met with licensee representatives (denoted in paragraph 1) on July 6, 1992. The inspectors summarized the scope and findings of the inspection. The licensee did not identify as proprietary any of the information provided to, or reviewed by, the inspectors.

ATTACHMENT

LIST OF ACRONYMS

AFW	auxiliary feedwater
CIV	containment isolation valve
cfm	cubic feet per minute
CRA	conditional release authorization
CRE	control room envelope
EA	Engineering Assurance
EDG	emergency diesel generator
ESF	engineered safety feature
EPRI	Electrical Power Research Institute
EOP	emergency operating procedure
HHSI	high head safety injection
IFI	inspection followup item
LCO	limiting conditions for operation
LER	licensee event report
MOV	motor operated valve
MSIV	main steam isolation valve
MG	motor generator
NRC	U.S. Nuclear Regulatory Commission
PORV	power operated relief valve
psig	pounds per square inch gage
OSR	open service request
RCS	reactor coolant system
RFA	request for assistance
SAC	starting air compressors
SG	steam gererator
SGFP	steam generator feedwater pump
SOV	solenoid operated valve
STP	South Texas Project Electric Generating Station
TS	Technical Specifications
TSC	technical support center