APPENDIX

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

NRC Inspection Report: 50-498/91-01 Operating License: NPF-76
50-499/91-01 NPF-80

Dockets: 50-498
50-499

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

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

Inspection At: STP, Matagorda County, Texas

Inspection Conducted: January 2 through February 12, 1991

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

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

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

D. R. Hunter, Senior Reactor Inspector, Operational Programs
Section, Division of Reactor Safety

Approved: A. T. Howell, Chief, Project Section D 3-14-91
Division of Reactor Projects Date

Inspection Summary

Inspection Conducted January 2 through February 12, 1991 (Report 50-498/91-01; 50-499/91-01)

Areas Inspected: Routine, unannounced inspection of plant status, onsite followup of events at operating power reactors, onsite followup of written reports of nonroutine events at power reactor facilities, operational safety verification, surveillance activities, monthly maintenance activities, refueling activities, and evaluation of licensee quality assurance program implementation.

Results: On January 7, 1991, a Technical Specification-required shutdown was commenced because of a blown fuse associated with Train S of the solid state protection system. The power reduction was stopped at 61 percent reactor power after corrective action was performed (paragraph 3.a).

On January 9, 1991, Unit 2 was manually tripped when a feedwater isolation valve (FWIV) went closed after power was lost to the associated hydraulic pumps. A subsequent review of this event resulted in three inspector followup items, which include the adequacy of the annunciator response procedure, the training received by operators to address a loss of power to the skid, and the philosophy utilized by operations personnel to initiate nonemergency troubleshooting (paragraph 3.b). Inattention to detail also appears to have been a contributing factor of this event.

In addition to the weaknesses associated with the January 9, 1991, partial loss of feedwater flow event, other instances of weaknesses in procedural or other written guidance and inattention to detail were noted. These included: (1) lack of guidance associated with the installation of standby diesel generator injector pump hold down bolts (paragraph 3.c); (2) ambiguities associated with a preventive maintenance activity to verify time delay relays for safety injection reset and reactor coolant system letdown isolation timing (paragraph 3.d); (3) a lack of guidance for reassembly of contaminated vacuum cleaners (paragraph 3.f); (4) inadequate implementation and review of a battery surveillance (paragraph 5.b); (5) a weld repair to the turbine driven auxiliary feedwater pump that was not hydrostatically tested (paragraph 3.e); and (6) the failure to note an out-of-specification log reading for auxiliary feedwater storage tank level (paragraph 3.g).

A weakness was identified in the dedication program for upgrading commercial grade standby diesel generator injector pump hold down studs (paragraph 3.c).

Several self-assessment and correction action strengths were noted as a result of inspection followup of 41 licensee event reports (LERs) (paragraph 4).

An unresolved item pertaining to differences associated with similar procedures was identified (paragraph 7.a).

On February 8, 1991, a meeting was held with licensee managers to discuss the results of NRC's evaluation of licensee quality assurance program implementation (paragraph 9).

DETAILS

1. Persons Contacted

*M. R. Wisenburg, Plant Manager
*S. L. Rosen, Vice President, Nuclear Engineering
*M. K. Chakravorty, Director, Nuclear Safety Review Board
*A. C. McIntyre, Manager, Design Engineer
*W. J. Jump, Maintenance Manager
*J. D. Sharpe, Deputy Maintenance Manager
*C. A. Ayala, Supervising Engineer, Licensing
*S. B. Melton, Supervising Engineer, Project Engineering Department
*S. Timmaraju, Senior Consulting Engineer, Design Engineering Department
*A. K. Khosla, Senior Engineer, Licensing
*A. W. Harrison, Nuclear Licensing Manager
*T. J. Jordan, General Manager, Nuclear Assurance
*J. R. Lovell, Technical Services Manager

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

*Denotes those individuals attending the exit interview conducted on February 15, 1991.

2. Plant Status

Unit 1 was in Mode 5 at the start of this inspection period. The unit has been shut down since the November 24, 1990, reactor trip which was caused by a main generator ground fault. A decision was made to commence the third refueling outage on January 15, 1991. Reactor head stud detensioning started on January 17, 1991, and a full core fuel element offload was completed on January 23, 1991. The unit ended the inspection period with the fuel removed from the reactor vessel and scheduled refueling outage activities in progress.

Unit 2 began this inspection period operating at 100 percent reactor thermal power. On January 7, 1991, a Technical Specification (TS)-required shutdown was commenced. A blown fuse in the Train S solid state protection system prevented resetting an urgent failure of the safety system actuation train. Power reduction was stopped at 61 percent reactor power on the same day after corrective action was performed. On January 9, 1991, the reactor was manually tripped in anticipation of a low steam generator (SG) level trip when a feedwater isolation valve (FWIV) was inadvertently closed during a troubleshooting activity. The unit was returned to service on January 11, 1991, and reached full power on January 12, 1991. On January 18, 1991, a main turbine electrohydraulic control (EHC) system fluid leak on a throttle valve required a load reduction to 79 percent.

Repairs were completed and the unit was returned to full power on January 19, 1991. The unit remained at this power level at the close of the inspection period.

3. Onsite Followup of Events at Operating Power Reactors (93702)

a. Notification of Unusual Event (NOUE) (Unit 2)

At 2:30 a.m. on January 7, 1991, Unit 2 declared a NOUE as a result of a TS-required shutdown. During the performance of Train S reactor trip breaker trip actuating device operational test (TADOT) (Procedure 2PSP03-SP-0006S, Revision 0), an urgent failure alarm on Train S of the solid state protection system (SSPS) would not clear when the B safeguards test cabinet turbine trip block switch was taken to normal. This alarm prohibited the operator from taking SSPS Logic Train S out of inhibit and back to normal, and TS 3.3.2, Table 3.3-3, Action 14, was entered. Action 14 requires an entry into HOT STANDBY in 6 hours and cold shutdown within the following 30 hours.

Operators began ramping down in power, and troubleshooting commenced. Instrumentation and control (I&C) personnel found one of two 10-amp fuses (in series) not functional on electrical Distribution Panel 1203, Breaker No. 8. This is the feeder breaker to the Train B logic test cabinet. The fuse failed during the course of the test and prevented resetting the relays. The licensee replaced the fuse and completed the TADOT satisfactorily. The NOUE was terminated at 4:25 a.m. The power reduction was terminated at 61 percent power. Power was then increased at 6 percent per hour until full power was achieved.

b. Manual Reactor Trip Due To Closure of a Feedwater Isolation Valve (FWIV) During Troubleshooting (Unit 2)

On January 9, 1991, Unit 2 was in Mode 1 at 100 percent power. A manual reactor trip was initiated at 10:07 p.m. in response to the loss of main feedwater flow to SG 2C. FWIV 2C closed because of an interruption of power to one of two FWIV safety grade solenoid dump valves during operational troubleshooting. The energized solenoid valves maintain hydraulic pressure at the FWIV actuator to maintain the FWIV open. SG 2C level started to decrease and the reactor was manually tripped. An automatic reactor trip would have occurred on low steam generator water level. The main turbine tripped as expected. Auxiliary feedwater (AFW) flow initiated on low-low steam generator level and the remaining FWIVs closed on low reactor coolant system (RCS) average temperature. All systems responded as expected, except that the FWIV bypass valve to SG 2C. After closing, the FWIV bypass valve reopened to approximately 30 percent following the feedwater isolation signal. At 10:43 p.m., the plant was stabilized in Mode 3.

The event began at 9:45 p.m. on January 9, 1991, when alarms for low hydraulic and low nitrogen pressure were received in the main control room. The licensee identified at the local FWIV hydraulic skid that the FWIV 2C pneumatic and electrohydraulic pumps were not operating.

Each FWIV is held open against nitrogen pressure by hydraulic pressure maintained by their respective pneumatic and electrohydraulic pumps. The low nitrogen and hydraulic pressure alarms received for FWIV 2C indicated the valve could potentially close. However, the information available to the operators was not sufficient to provide an accurate assessment of the time before the FWIV could be expected to close. Additionally, operations personnel have been sensitized to a history of problems with the FWIV which have resulted in sudden closure and subsequent plant trips. As a result, the operators took immediate actions to locate the cause of the failure believing that immediate actions were necessary to prevent a plant trip.

The unit supervisor joined a nonlicensed operator at the FWIV 2C hydraulic skid unit. The operators determined that a solenoid valve in the air supply line for the FWIV 2C pneumatic and hydraulic pumps was not operating because of a loss of electrical power to the hydraulic skid. The unit supervisor advised the control room to check power supplies for the hydraulic skid unit. The shift supervisor directed operators in the control room, one of which was a reactor plant operator (RPO) trainee (nonlicensed), to assist in determining the applicable power supplies. Several sources of information were used, such as diagrams and operating procedures, to establish a list of potential power supplies. The RPO trainee identified the power supply to the hydraulic pumps and incorrectly identified the Class 1E power supply to one of the two safety grade solenoid dump valves for FWIV 2C as possible power supplies to check. The list was given to a second nonlicensed operator. At approximately 10 p.m., the shift supervisor directed the second nonlicensed operator to check the various power supplies identified on the list.

The shift supervisor did not verify the accuracy of the list prior to dispatching the nonlicensed operator, which is indicative of inattention to detail. At approximately 10:06 p.m., the unit supervisor directed a nonlicensed operator to check the fuse on the hydraulic skid unit. The fuse was removed and verified to have continuity. In the process of replacing the fuse, the circuit was completed. The hydraulic pumps started and the low pressure alarms cleared in the control room. At 10:07 p.m. the unit supervisor reported that the hydraulic pumps had started. The control room operators attempted to contact the second nonlicensed operator by radio who was in the process of checking power supplies in the switchgear room. This attempt was unsuccessful. Within 7 seconds, the nonlicensed operator pulled the fuse to the Class 1E power supply, which deenergized one of the two safety grade solenoid dump valves. FWIV 2C began closing and a manual reactor trip was initiated as feedwater mass flow rate to SG 2C approached zero.

The inspectors reviewed Station Problem Report (SPR) 910006, which was initiated as a result of the event. A review of selected procedures was conducted and selected licensee personnel were interviewed. The inspector's review was directed at the off normal condition (partial loss of feedwater) which resulted in the manual reactor trip. SPR 910006 documented that the specific problem (loss of power to FWIV 2C [FV-7143] hydraulic operating unit) occurred at about 9:50 p.m. on January 9, 1991. The licensee identified that the screws holding the fuse block and lugs were loose on the hydraulic skid, thereby causing an intermittent power loss. The screws were tightened and the remaining fuse blocks on the Unit 2 skids were checked with no problems found. The fuse blocks for the Unit 1 skids were also checked and no problems were noted.

The inspector's review of annunciator procedure, 2POP09-AN-06MA, Revision 0, Windows E2, "FWIV FV-7143 HYD PRESS LO1550 psig Decreasing," and F2, "FWIV FV-7143 N2 PRESS LO-1500 psig Decreasing," revealed that the annunciator procedure did not fully address the loss of power to the nonsafety-related hydraulic unit (e.g., loss of 480 volt AC bus, local breaker or fuse failure, etc.). Interviews revealed that the operations personnel were aware of the locally mounted N2 pressure indicator (PI7143). During the event, the N2 pressure was checked locally and documented at 1650 psig. The operators, however, did not recognize the direct relationship between the N2 pressure (acceptable, sustained pressure), the hydraulic pressure (proportional to the N2 pressure), and valve position (valve not closing).

The use of the readily available N2 pressure gauge was not addressed in the annunciator procedures to assist the operations group in diagnosing the problem and formulating appropriate corrective actions. The licensee's evaluations and actions associated with the apparent weaknesses noted in the annunciator procedure, including the update of the procedures, operator training regarding the procedure changes, and generic implications regarding the lack of procedure scope, is considered an inspector followup item (498/9101-01; 499/9101-01).

The inspectors reviewed the established administrative procedures associated with the conduct of operations and maintenance to ensure that the program and procedures provided an adequate definition of "emergency maintenance." Emergency maintenance was defined as "a condition where an immediate safety hazard to personnel and equipment exists." Document reviews and personnel interviews indicated that the off normal condition encountered did not represent a situation which required "emergency maintenance" to be performed.

The inspectors reviewed Procedure OPGP03-ZM-0026, "Control of Troubleshooting." Step 2.5, defined "troubleshooting" activities, which included the "pulling of fuses." Regarding troubleshooting activities, Step 1.2.5 provided some exceptions to the performance and documentation requirements of the work process program, including the use of portable test instruments, measuring devices, and general recorder maintenance. Step 1.2.6, however, stated that "This procedure does not apply to operational troubleshooting activities as performed by Chemical Operations and Analysis and Plant Operations Departments." Document reviews and personnel interviews revealed that guidelines regarding the operational troubleshooting activities were not specifically addressed in the administrative programs (Plant Conduct of Operations, Conduct of Maintenance, Control of Troubleshooting, etc.) at STP. The subsequent review of licensee evaluations and actions regarding administrative guidance established to define, control, and document the quality and safety-related operational troubleshooting activities is considered an inspector followup item (498/9101-02; 499/9101-02).

The review of the overall sequence of events revealed that the plant operations group performed extensive operational troubleshooting activities in a relatively short period. Document reviews and personnel interviews revealed that the operations group was concerned that FWIV 2C (FW-7143) valve might drift closed, resulting in a plant trip because of a loss of main feedwater to the SG. The response to the off normal condition, including the operational troubleshooting activities, appeared to require a substantial amount of research on the part of the operations crew. The knowledge level of the operations staff could have been enhanced with regard to the hydraulic operating units and the postulated off normal conditions. Readily accessible indications, including local N2 pressure, FWIV FV-7143 valve position, main feedwater flows, and no apparent hydraulic system failure (e.g., a hydraulic leak) were available to the operations staff during the initial response to the event. A thorough assessment of the information available during the off normal condition should have allowed the shift supervisor to better preplan, control, and verify the subsequent operational troubleshooting activities, possibly preventing the unit trip.

The inspectors reviewed the training lesson plans for licensed and nonlicensed operators regarding the FWIV hydraulic operating units. The lesson plans provided limited information regarding the normal and abnormal operating conditions associated with the hydraulic operating units. Interviews with training personnel revealed that the system normal and off normal procedures, which contained limited information on the hydraulic units, were utilized in the operator training and requalification training program. However, the lesson plans did not address the operator actions associated with a loss of power to the hydraulic units, which is a credible failure mode.

The subsequent review of the licensee evaluations and actions, including lesson plan updates, operator training update, and generic implications associated with the apparent weaknesses noted in the training lesson plans, is considered an inspector followup item (498/9101-03; 499/9101-03).

Interviews with licensee personnel revealed that modifications to the hydraulic operating units will be implemented to improve individual unit reliability. The modifications include the provision for two separate electrical power supplies and an oil cleanup system on each hydraulic unit. These actions as well as the three inspector followup items will be reviewed during future inspection followup of the LER for this event.

c. Standby Diesel Generator (SDG) Fuel Oil Injector Pump Stud Failures (Unit 1)

On January 20, 1991, two of four hold-down bolts for the 2L fuel oil injector pump on SDG No. 13 failed during the 12th hour of a 24-hour SDG run. All the injector pumps for SDG No. 13 had been recently reassembled following the disassembly of SDG No. 13 for inspection. A similar problem occurred in November 1990, when the hold-down bolts failed or became loose for the 5R and 5L injector pumps for SDG No. 23 (Unit 2). These injector pumps also had been recently reinstalled prior to the failure of the hold-down bolts. The licensee replaced the failed bolts and sent them to a laboratory for a failure analysis. The laboratory determined that the studs failed because of excessive fatigue stresses that resulted because of improper stud installation.

The licensee consulted with the vendor (Cooper-Bessemer) and has implemented a new stud bolt installation technique. The hold-down bolts on the three SDGs for Unit 2 were replaced with new bolts utilizing the new installation technique. The 2L injector pump hold-down bolts for SDG No. 13 were replaced and the balance run was completed.

The failure analysis indicated that the installation procedure was the potential root cause. The procedure had been previously modified by the introduction of a stud installation tool. However, since studs on SDG No. 13 failed, it was decided to revise the entire installation methodology to eliminate virtually all sources of uncertainty or potential overstressing. The following measures were taken:

- use of the stud installation tool which appears to have caused an uncertain amount of installation stress has been discontinued;
- the prestressing of the stud against a lock washer was deleted; and
- studs are now installed handtight and held in place by locktight.

The licensee has removed all the studs which were installed with the stud installation tool and replaced them using the new installation process.

d. Safety Injection (SI) Actuation During Preventive Maintenance (Unit 1)

On January 26, 1991, at 8:50 a.m. with Unit 1 shut down, an automatic actuation of SI occurred in one of three trains. Train C SI actuation resulted because of inadequate preventive maintenance (PM) instructions. Operations personnel verified that the appropriate engineered safety feature components operated as required, including heating, ventilation, and air conditioning (HVAC) fans and dampers, containment isolation valves, cooling water systems and the Train C SI accumulator isolation valve.

The purpose of the PM was to verify time delay relays for SI reset and reactor coolant system (RCS) letdown isolation timing and to verify the Actuation Train C, 15-volt power supply adequacy. The PM was approved on December 11, 1990, and was being performed for the first time. The SI reset time delay relay had been tested during a previous refueling outage as part of a design change activity using similar work instructions contained within the work request. The PM instructions were believed to be adequate since they were developed on the basis of a previous, successful work activity and had been reviewed by the system engineer. The PM instructions successfully tested the SI reset time delay relay but did not adequately control the conditions necessary to restore the system to its "as found" condition. Since the unit was shut down, instrumentation channels providing SI actuation signals to the SSPS logic were initially blocked, as expected. However, the PM instructions mistakenly cleared all the blocks. As a result, an unexpected actuation occurred.

The procedure was not explicit as to whether an actuation would be received or not. In the front of the procedure, a caution states that the procedure will unblock SI. Control room personnel, who reviewed the procedure, suspected that an actuation might be received, but I&C personnel stated that an actuation would not occur because the SI signal was blocked further upstream. This assumption was apparently never verified as accurate. During performance of the PM, the actuation subsequently occurred. After the actuation was received, the procedure was suspended pending revision and all actuated components were returned to normal lineup. The inspectors will followup on this event during a future inspection after the LER for this event is submitted.

e. Auxiliary Feedwater (AFW) Pump Weld Repair Not Tested (Unit 2)

On January 31, 1991, the licensee identified that a weld repair, performed on a steam supply flange to the steam driven AFW pump, did not receive the American Society for Mechanical Engineers (ASME) code-required code pressure test (CPT) prior to the AFW pump being declared operable. Work Request (WR) WR-AF-129551 was initiated in November 1990, to repair a steam cut on the face of the pipe flange located upstream of MS-514 (AFW Pump No. 24 Trip/Throttle Valve). The work instructions, which were implemented in November 1990, initially required the detensioning/removal of the flange fasteners to facilitate removal of the flange. The flange face was then to be restored through machining and/or weld buildup. Following reassembly, the postmaintenance test (PMT) required an operational leak test (OLT) and inservice leak test (ISLT).

During the performance of the activity, maintenance personnel noted that the flange could not be removed because of interference problems. Revision 3 of the WR was initiated to allow the flange to be cut out. The revised work package was reviewed by four persons, including operations quality control; however, the required ASME Section XI CPT was not identified. The flange face was repaired and installed in accordance with the revised work instruction. The OLT and ISLT were successfully performed on December 5, 1990, and the system later returned to operable status. The WR document was reviewed for final closeout on January 31, 1991. This review identified that the ASME Section XI weld repair did not receive the required ASME Section XI, Article IWA-4400, system hydrostatic test. WR AF-114170 was initiated to perform a hydrostatic test on the flange field weld. This test was successfully completed on February 3, 1991, and the steam driven AFW pump was returned to operable status.

The inspector reviewed this event in context with an event described in LER 498/89-22, "Technical Specification Violation Due to the Failure to Perform the Required Post Maintenance Test (PMT)." The corrective actions which had been implemented, including the use of separate PMT forms, were properly implemented for the latest event. The corrective actions associated with this event will be reviewed by the inspectors during followup to LER 499/91-02.

f. Skin Contamination From Improperly Reassembled Vacuum

On February 2, 1991, at approximately 3 p.m. a Health Physics contract technician was found contaminated with a 0.5 uCi Co-60 particle on the right lower leg, approximately 1-2 inches above the ankle. A skin dose estimate based on the exposure starting at the time of entry into the contaminated area indicated that the dose may have exceeded administrative and 10 CFR Part 20 limits. The subsequent investigation, which included a review of logs, interviews with personnel, and reviews of survey data, showed that the initial dose rate was overestimated and the actual exposure time was significantly less than initially estimated.

The final skin dose for the individual was calculated to be 1.46 Rem, assuming 2 1/2 hours of exposure with the particle on the exterior of the protective clothing and 0.5 hours on the skin. The exposure time was estimated on the basis of the individual's skin becoming contaminated during undressing. This was the most probable scenario since the individual was wearing protective clothing when he came into contact with the source and the exposed area of the skin was protected with two layers of protective clothing at all times except when undressing. The source of contamination was determined to be an improperly assembled vacuum cleaner that the technician had used.

Subsequent testing of the vacuum cleaner indicated that the vacuum cleaner was faulty and was passing contamination. Contamination survey results of the exterior were also substantially higher than those in the general area. A separate investigation was initiated to determine the reason for the vacuum cleaner failure.

An inspection of the vacuum cleaner identified a missing high efficiency particulate absorber (HEPA) filter. All other vacuum cleaners were immediately removed from service for inspection and evaluation. No other problems were identified. The licensee determined that a need existed to generate a detailed checklist for assembling the vacuum cleaners after performing maintenance activities. In addition, metal wire seals are being placed on all vacuum cleaners to assure control of their disassembly.

g. Auxiliary Feedwater Storage Tank (AFWST) Level Below Limit Specified on Log Sheet (Unit 2)

On February 7, 1991, at 6:45 p.m., the AFWST level was noted to be 97 percent on all three channels of the qualified display processing system (QDPS). The TS limit is 518,000 gallons which corresponds to 98 percent level. Emergency response facility data acquisition and display system (ERFDADS) readings on all three channels indicated 517,000, 515,700, and 513,800 gallons. Control room personnel took immediate corrective action to fill the AFWST to above the required level. This was accomplished at 6:55 p.m.

The AFWST level discrepancy was discovered at the end of an operations crew shift during a review of the safety function checklist. This checklist includes reviewing the control room logs generated during that shift. The control room log entry noted the AFWST level at 97 percent. This shiftly surveillance (required every 12 hours) was taken by a reactor operator trainee earlier in the shift (approximately 3 p.m.). The log was subsequently reviewed and approved by a licensed reactor operator and a licensed senior reactor operator. Neither licensed operator, however, identified the 97 percent value as being out of specification. This resulted from less than adequate attention to detail during their review of the control room log.

An archival file of ERFDADS data disclosed that the tank level went below the TS requirement of 518,000 gallons at 1:01 p.m. on February 7, 1991. However, the licensee subsequently determined that actual tank level is 6000 gallons when indicated level is 0 percent. As a result, no violation of TS 3.7.1.3 occurred.

Conclusion

With the exception of the Unit 2 NOUE, these events were attributed, in part, to inadequate procedural guidance or inattention to detail. The Operational Improvement Plan (OIP) is intended, in part, to reduce the likelihood of future events caused by these types of problems. The implementation of the OIP will be reviewed during future inspections in order to assess its effectiveness in correcting the problems noted above.

4. Inoffice Review and Onsite Followup of Written Reports of Nonroutine Events at Power Reactor Facilities (90712) (92700)

During this inspection, the inspectors reviewed the licensee's evaluation and corrective actions of LERs. The licensee's nuclear safety review board (NSRB) had reviewed the LERs as identified in the associated station problem report (SPR). These reviews were found to be thorough and in many cases, the NSRB caused additional reviews and corrective action to be implemented. The licensee implemented a corrective action review meeting (CARM) in December 1990, to provide an interdepartmental review of corrective actions. This CARM was implemented, in part, because of the questions the NSRB was identifying. The effectiveness of the CARM will be evaluated during a future inspection.

The LERs were reviewed to determine that corrective actions were accomplished and that actions were taken to prevent recurrence. The LERs were also reviewed for trends and contributing root causes. Six general categories were identified. These categories were: personnel error and/or procedural inadequacies, equipment failure, feedwater isolation valve (FWIV) failures, inverter failures, spurious toxic gas analyzer ESF actuations, and isolated events.

The inspectors reviewed the corrective actions the licensee had taken with respect to personnel error and/or procedural inadequacies. Two independent safety engineering group (ISEG) reports were reviewed, "ISEG Review of Procedure Use/Compliance," dated November 13, 1989, and ISEG Report 90-45, "ISEG Quarterly Review of Selected Operational Experience Reports and In-House Event Reports," dated January 31, 1991. These reports critically assessed areas including: procedure compliance, procedure use, and the adequacy of the SPR evaluations to ensure procedural complianc. The ISEG was noted to be actively involved in addressing personnel error and/or procedure inadequacy issues and plans additional reviews in this area. A procedural task force report was issued in July 1990. This task force analyzed station procedures and compliance with procedures as they pertained to station incidents. The conclusions and recommendations were then documented in the procedure task force report. This report provided input to the OIP, which was issued in December 1990.

The inspectors reviewed 20 LERs which were evaluated to have resulted, in part, because of personnel error or procedural inadequacy. The OIP was found to address weaknesses which resulted in the LERs. The NRC staff will evaluate the effectiveness of the OIP during future inspections.

The following LERs were reviewed and closed by the inspectors:

a. (Closed) LER 498/88-026: Reactor Trip and Safety Injection Due to Loss of Offsite Power Caused by Personnel Error

On March 30, 1988, with Unit 1 at 7 percent reactor thermal power, a partial loss of offsite power occurred which resulted in a reactor trip. A subsequent low-low compensated T-cold signal initiated an SI sequence.

The partial loss of offsite power resulted during main generator relay troubleshooting. The licensee was testing the main generator current transformers to determine the cause of an earlier generator trip. When a secondary current was injected into the current transformer circuitry, a main generator lockout occurred. This caused an isolation of the transformer and the opening of the supply breakers to 13.8 Kv Auxiliary Buses 1F, 1G, 1H, and 1J and Standby Bus 1F.

The licensee's investigation identified miswiring in five current transformers which supply input to the differential relays and other main generator breaker protective and metering devices. The licensee failed to identify the wiring error prior to troubleshooting the circuit because there was not an adequate review of the work instructions prior to starting the work. The wiring errors appear to have existed since initial installation.

The licensee stopped all troubleshooting activities after the event until the initial analysis was completed. A case study of this event was presented to electrical and I&C technicians, with particular emphasis placed on understanding the consequences of performing each step in the troubleshooting instructions. The licensee requested a TS change to 3/4.3.2 to delete the reference to excessive cooldown protection and the associated items (ST-HL-AE-2626). This request was granted by the NRC on May 24, 1988 (TAC No.-67930), and is identified as Amendment 1 to Facility Operating License No. NPF-76.

b. (Closed) LER 499/89-027: Inoperable Turbine Throttle Valve Limit Switch Resulting in a Technical Specification (TS) Violation

On October 25, 1989, with Unit 2 at 100 percent thermal power, a nonlicensed turbine building reactor plant operator discovered that the closed limit switch on main turbine throttle Valve No. 2 was disconnected. The operator initiated a WR at the time of discovery; however, the maintenance WR was not reviewed by the unit supervisor until approximately 8 hours later. TS 3.3.1 requires that with one turbine throttle valve input to the reactor trip system inoperable, the applicable channel be placed into the tripped condition within 6 hours. The failure of the nonlicensed operator to make a licensed operator aware of the condition resulted in a TS violation.

The licensee determined that the turbine throttle valve had possibly been exposed to high vibrations resulting in the limit switch linkage failure. Design Changes 89-J-0367 (Unit 1) and 89-J-0368 (Unit 2) were initiated to modify the linkage assembly. These modifications are scheduled to be implemented during the third refueling outage for Unit 1 and the second refueling outage for Unit 2. A memorandum was sent to all the operators (licensed and nonlicensed) providing guidance on plant nomenclature that should be considered as safety related and thus any deficiencies immediately reported. A discussion of this event, including each operator's responsibility to ensure effective communications has been given and has been added to the reactor plant operator and chemical plant operator training lesson plans.

c. (Closed) LER 499/89-024: Failure to Restore Essential Chiller to Service Within Technical Specification (TS) Limits

On May 28, 1989, violations of TS 3.7.14 and 3.5.2 occurred because Train C of the chilled water system was inoperable for more than 72 hours. The event occurred because licensee personnel logged the time of inoperability when the system was taken out of service for maintenance rather than the time a support system was removed from service. This decision was based on a miscommunication of system status to management and inadequate logging of a chiller start failure. Factors that contributed to this event included a lack of administrative controls to assist operators in determining the operability of a system when a support system is inoperable, the WR generated following the chiller start failure was incomplete, and guidelines on how to make changes in the operability tracking log did not exist.

Corrective actions taken by the licensee included: (1) holding operations personnel briefings on the event; (2) revising the operability tracking log procedure to provide guidance on making changes to the log; (3) incorporating lessons learned into the operator's requalification training program; (4) providing guidance to assist operators in the determination of operability of TS-required systems when support systems are inoperable; and (5) providing a TS interpretation on the definition of operability.

d. (Closed) LER 499/90-010: Inadvertent Engineered Safety Features (ESF) Actuation Due to Incorrect Connection of Test Equipment

On May 15, 1990, with Unit 2 in Mode 5 for a forced outage, an unplanned ESF actuation of the Train C SDG occurred. A maintenance electrician was performing Surveillance Procedure 2PSP-PK-001, "4.16KV Class 1E Undervoltage Relay Channel Calibration/TADOT-Channel 1," when he connected his test leads to the incorrect relay. This resulted in a sensed undervoltage condition on the Train C safeguards bus. The Train C EDG started and the Train C ESF equipment cycled on as expected. The proper location for the test leads was identified in the the surveillance procedure.

The licensee reviewed the surveillance procedure and determined that the procedure provided the proper guidance for correctly landing the test leads. Control of configuration changes was also reviewed as specified in Procedure 0POP03-ZM-0021, "Control of Configuration Changes." This procedure requires a second individual to verify the connection point of a jumper prior to installation. This procedural requirement is not applicable to measuring and test equipment (M&TE) unless it is being hardwired into the system. On June 29, 1990, the licensee issued training Bulletin MTB-90-028, concerning the importance of preverifying test connections prior to connecting test equipment.

e. (Closed) LER 498/90-04: Inadequate Engineered Safety Features (ESF) Actuation Due to Inadequate Control of Procedure Performance

On March 24, 1990, with Unit 1 in Mode 1 at 100 percent power, an inadvertent start of the Train C SDG occurred during the performance of a surveillance test. A maintenance technician was working with a licensed operator to verify operability of slave relay contacts in the SSPS for starting the SDG. This activity was being conducted in accordance with Surveillance Procedure 2PSP03-SP-0011C, "Train C Diesel Generator Slave Relay Test." The surveillance procedure required that the operator first start the diesel generator and then the maintenance technician was to connect the digital multimeter (DMM) leads to the slave relay to verify that the relay was operating properly. In this instance, the maintenance technician placed the DMM leads on the relay contacts prior to the operator starting the diesel generator. This caused sufficient current flow through the relay to start the SDG.

The licensee reviewed the surveillance procedure and determined that the sequence of steps was correct. However, the procedure did not provide a precautionary statement that identified that a SDG start could occur if the steps were performed in the incorrect sequence. A caution statement has been added to each surveillance procedure applicable to the six SDGs. The licensee also determined that there were some knowledge deficiencies regarding the potential effects of test instruments on plant systems during surveillance testing. A training bulletin was issued on April 27, 1990, MTL-90-019, that discussed each individual's responsibility to correctly utilize test equipment during surveillance activities and that individuals are programmatically prohibited from deviating from surveillance procedure step sequence. A second training bulletin was issued to all operations personnel emphasizing the importance of controlling the sequence of procedural steps.

f. (Closed) LER 498/90-007: <u>A Technical Specification (TS) Violation Due to an Inadequate Procedure</u>

On April 30, 1990, with Unit 1 in Mode 6 and core alterations in progress, the containment ventilation isolation emergency safety feature actuation system (ESFAS) was disabled during the performance of a planned test. The test was being performed in accordance with approved Maintenance Procedure OPMP08-SP-0001, "RPS/ESF System Normalization." The test required that all three trains of the ESFAS be placed in the test position. This rendered the automatic containment ventilation isolation inoperable. TS 3.3.2 required this isolation feature to be operable with the plant in Mode 6 with core alterations in progress.

The licensee determined that the maintenance procedure was inadequate because it did not provide a prerequisite to prohibit performance of this test with core alterations in progress. The licensee has revised the procedure to prohibit the performance of this procedure with the plant in Modes 5 and 6 with movement of irradiated fuel in the containment. Training bulletins have also been issued to operations, maintenance, and procedure development personnel. The training bulletin issued to operation and maintenance personnel emphasized the importance of proper communications between the two groups. The training bulletin issued to personnel responsible for preparation of plant procedures emphasized the the need to ensure that procedure prerequisites were correct.

The inspector noted that the licensee's corrective actions were appropriate to correct the procedure deficiency and to address the communication problem between the maintenance technician and the on duty control room operator. However, the responsibility to ensure that a surveillance or maintenance procedures will not adversely affect plant operations or its response to a challenge lies with the senior reactor operator who authorizes the performance of the work activity. This is accomplished, in part, by the individual being cognizant of what the status of the plant will be during the performance of the activity. Control and authorization of work activities was discussed with the licensee management. The licensee stated that work control was considered during review of the LER. However, the complexity of the procedure required that the senior reactor operator rely on the precautions in the maintenance procedure.

g. (Closed) LER 498/89-018: Voluntary Licensee Event Report (LER) 89-018 Regarding Improper Installation of Regulatory Guide 1.97 Category 2 Instrumentation Due to an Error in the Installation Details

During an NRC team inspection in September 1989 (NRC Inspection Report 50-498/89-34; 50-499/89-34), the inspectors identified violations of equipment qualification requirements contained in 10 CFR 50.49. The licensee subsequently identified that construction installation procedure for Regulatory Guide 1.97 Category 2 instrumentation did not include installation details that would assure the devices were qualified to the requirements of 10 CFR 50.49 and IEEE 323-1974. The licensee identified postaccident monitoring instrumentation which required rework of cable splices. The licensee did determine that the instruments would have remained operable in a harsh environment.

The licensee's corrective actions consisted of reviewing the equipment that was potentially affected for both units and performing rework to bring the instruments into compliance with the Code of Federal Regulations and Institute of Electrical and Electronics Engineers requirements. Plant Maintenance Procedure OPMP02-NZ-0013, "Cable Terminations", has been revised to include a list of nonsafety-related instruments that require environmentally qualified splices to meet Regulatory Guide 1.97 requirements.

h. (Closed) LER 498/89-022: Technical Specification (TS) Violation Due to the Failure to Perform a Required Postmaintenance Test

On December 5, 1989, the licensee identified that two component cooling water (CCW) isolation check valves had not received the required postmaintenance testing. The Train C CCW system containment isolation check valves, CC-0198 and CC-0183, were replaced on August 31 and September 1, 1989, respectively. Following their replacement the local leak rate test and operational leak check were satisfactorily performed on the valves. Because operations was the designated test coordinator, the unit supervisor performed the review of the maintenance packages. The unit supervisor failed to note that the required ASME XI code pressure test had not been performed. The Train C CCW system was subsequently declared operable.

The licensee identified that the test results were summarized such that it was not readily apparent that the required tests had not been performed. The operational leak test, code pressure test, and local leak rate test were identified on one test control form with a common test completed signature block. The test control procedure did not adequately define responsibility for completion of the tests, and operations personnel were not well trained on postmaintenance test control.

The licensee's General Procedure OPGP03-ZM-0025, "Maintenance Testing Program," was revised to require the use of a testing control form for each separate type of test performed. The test coordinator, who is either the work supervisor or the system engineer, must ensure that the test identified on the test control form is completed prior to signing the form. The approving official must have all the signed test control forms prior to signifying the test activity has been completed. Training on the new requirements of this procedure were presented during the hot license requalification training classes and completed in June 1990. Prior to inclusion of this event in the training module, a training bulletin, MTB-90-00-01, was presented to operations and maintenance personnel. This bulletin discussed the failure to perform all the postmaintenance required tests. The valves were tested in accordance with ASME Section XI and found to be operable.

i. (Closed) LER 498/90-06: Manual Reactor Trip Due to Full Closure of a Feedwater Isolation Valve During Partial Stroke Testing

On July 30, 1990, FWIV 1A fully closed during a partial stroke surveillance test. SG 1A level began decreasing because of loss of feedwater flow. The reactor was manually tripped since an automatic trip was imminent because of low SG level. The operators then attempted to stabilize the plant following the trip; however, SG 1A level did not recover as expected. Operations personnel determined that a recirculation valve on the A train of AFW was mispositioned. The recirculation valve was returned to the correct position and SG 1A level was recovered.

The FWIV closure was caused by a technician inadvertently contacting the wrong terminal with a test jumper. During the test, the jumper slipped off the correct connector point. In the process of relanding the jumper, contact was inadvertently made with an adjacent terminal, causing FWIV 1A to close.

Corrective actions planned by the licensee included issuing a training bulletin, reviewing the procedures for possible enhancement, and evaluating the circuitry design to determine if an alternate design could be developed which would allow testing without the use of jumpers. Corrective actions taken included adding the lessons learned for the event to the operator training program. Also, engineering change notice packages were issued to install two single-pole, switch terminal blocks in each of four auxiliary relay panels to allow easy means to perform the test of the FWIV solenoid dump valves (eliminates need to use jumpers). The surveillance procedures were reviewed and no enhancements were determined to be necessary.

An enforcement conference was held and a Notice of Violation was issued for the mispositioned AFW valve. The corrective actions taken for Violation 498/9028-01 that were listed in LER 498/90-06 will be reviewed during closeout of the violation.

j. (Closed) LER 499/89-016: Reactor Trip Due to a Deficient Turbine Steam Inlet Valve Test Procedure

On June 2, 1989, Unit 2 tripped from 76 percent power during the performance of the main turbine steam inlet valve operability test. The unit was stabilized in Mode 3 following the trip and no unexpected posttrip transients were noted. During the valve operability test, Valve TV-1 was cycled from open to closed and back to open. At this time, one of two limit switches on Valve TV-1 remained in the valve-closed position. Valve TV-1 was verified opened at the main control board and locally; however, the operator did not notice the "Turbine Steam Stop Valve Reactor Pretrip" alarm and bistable indication for the valve had not cleared on the main control board. A second valve, TV-3, was then cycled closed per the procedure. This action completed the two-out-of-four turbine inlet throttle valve closed logic, resulting in turbine/reactor trip.

Two causes of the event were identified by the licensee. First, the test procedure was determined to be deficient because it did not require the operator to verify that the alarm and bistable had cleared following completion of the valve cycle. The second cause was a defective limit switch on Valve TV-1 which remained in the valve-closed position after the valve was opened. Corrective actions completed by the licensee included: (1) the defective limit switch was replaced and satisfactorily tested, (2) Units 1 and 2 main turbine steam inlet valve operability test procedures were revised to ensure that alarms and bistable indication lights had cleared prior to testing other valves, (3) a review of other surveillance procedures for similar weaknesses was performed (only one procedure was identified and revised), and (4) all other NAMCO Model EA740 limit switches for the turbine throttle inlet valves were replaced as necessary on both units.

k. (Closed) LER 499/90-003: Inoperable Fuel Handling Building Exhaust Filter Due to a Wiring Error

On February 14, 1990, with Unit 2 at 100 percent reactor thermal power, the licensee discovered that the Train "B" fuel handling building (FHB) exhaust air filter outlet damper would not open. A control room operator was performing Surveillance Test 2PSP03-HF-0002 when he identified this condition.

The licensee began troubleshooting the event and identified that a control wire lead had been improperly landed on a terminal block. The lead should have been landed on Terminal Block 7, but was found landed on Terminal 8. The licensee noted that PM IC-2-HF-89001037 had been performed on January 30, 1990. This PM required that the specified lead be lifted during the maintenance activity.

The licensee landed the control wire on the correct terminal and verified that the damper was operable. The individuals responsible for performing the PM were counseled regarding procedure compliance. Training Bulletin MTB-90-10 was issued on March 8, 1990, to reaffirm the licensee's requirements for procedure compliance.

l. (Closed) LER 498/87-013: Control Room Ventilation Actuation to Recirculation Mode Due to Inadvertent Switch Operation

On November 2, 1987, prior to initial criticality, the Unit 1 control room ventilation system transferred to the recirculation mode because of a momentary loss of power to the toxic gas monitoring system. An engineer working adjacent to the switch inadvertently operated the switch causing the momentary loss of power.

The licensee initiated the plant operability task force to identify plant equipment features which could contribute to unintentional outages such as the trip of a switch or breaker. This task force provided recommendations to add switch covers or install warning signs to guard against inadvertent operation of equipment. The recommendations from this task force were reviewed and the final recommendations were implemented for Units 1 and 2. The switch which the engineer actuated has been relocated.

m. (Closed) LER 498/90-022: Violation of Technical Specification Due to Exceeding the Allowable Temperature in Reactor Coolant System With One High Head Safety Injection High-Head Safety Injection (HHSI) Pump Inoperable

This LER documented a violation of TS 3.5.2 on September 12, 1990, involving a Unit 1 model change from Mode 4 to 3 without establishing three operable HHSI trains within the associated action statement RCS temperature limitations.

This event was the subject of 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 discussed this event with the operators following the event. A training module was developed and has been included in the operator training emphasizing the attention to detail and self-verification. The effectiveness of these and other corrective actions will be evaluated during the NRC staff followup to the Notice of Violation documented in NRC Inspection Report 50-498/90-31; 50-499/90-31.

n. (Closed) LER 498/90-019: Violation of Technical Specifications Due to Exceeding the Specified Time Interval for the Daily Power Range Nuclear Instrumentation (NI) Channel Calibration Surveillance

On July 8, 1990, with Unit 1 at 100 percent reactor thermal power, the operators identified that the daily, 24-hour, power range NI channel calibration had not been performed. The operators initiated the surveillance in accordance with OPSP03-NI-001, "Daily Power Range

NI Calibration"; however, the surveillance was not completed until 38 minutes after the 25 percent allowable time extension. The power range NIs were found to be in calibration.

The licensee revised 1PSP03-ZQ-0002, "Control Room Logs," and 2PSP03-ZQ-0002, "Control Room Logs," for Units 1 and 2, respectively. The logs now specifically track the performance of 0PSP03-NI-0001 on the third shift. Other required surveillances were reviewed and found to be adequately tracked.

o. (Closed) LER 498/89-024: Technical Specification Violation Due to the Failure to Perform a Required Accumulator Boron Sample

On December 26, 1989, with Unit 1 in Mode 3, SI Accumulator 1C was filled by greater than 1 percent total volume to clear a low level alarm. TS 4.5.1.1(b) required sampling of the accumulator boron concentration within 6 hours of the water addition. The control room operator notified the chemical technician supervisor that the sample was required. A chemical technician was notified that the sample was required, however, the technician did not have time to obtain the sample prior to shift turnover. The technician documented the surveillance requirement in his turnover log and informed the oncoming technician that the surveillance was required. The chemical technician supervisor did not inform the relief supervisor or note it in his shift turnover checklist. Operators subsequently requested that RCS pressurizer boron samples be taken every 15 minutes because of the reactor startup and RCS boron dilution that was in progress. The accumulator sample requirement was not performed.

The licensee included a discussion of this event in Chemistry Training Cycle 90-01, which was completed March 23, 1990. Chemical Sampling Procedure 0PCP01-ZA-0014, "Chemical Laboratory Sample Schedule," has been revised to include surveillance sample requirements which are not regularly scheduled samples. Each surveillance that is now performed by chemistry technicians is identified in accordance with Operating Procedure 0POP01-ZT-0001, "Tracking of Conditioned Surveillances and LCO Actions." The inspector observed chemistry sampling in Unit 2 and noted that the surveillances were identified and being tracked.

p. (Closed) LER 498/89-016: Technical Specification Violation Due to Inadequate Procedural Control Over a Plant Modification

On July 13, 1989, with Unit 1 at 100 percent reactor thermal power, the licensee discovered that the rod position deviation monitor would not alarm in the main control room. The alarm capability had been inoperable since May 11, 1989. A modification to alter the configuration of the control room rod deviation alarms had been implemented on May 11, 1989 (ECNP 88-E-0103).

The licensee's review identified that the 10 CFR 50.59 review of the modification did not identify that the TS would be affected. At the time the modification was developed, General Procedure OPGP03-ZE-0001, "Database and I/O List," allowed changes to computer software without requiring an adequate level of design and operations review by the cognizant engineer. This procedure has been revised to allow it to be integrated with the facility modifications program. The licensee has reviewed other software modification and no other similar examples were identified.

q. (Closed) LER 499/89-002: Failure to Properly Restore Control Room Ventilation System Following Testing

On January 7, 1989, with Unit 2 in Mode 6, prior to initial criticality, the licensee discovered that the Train C control room envelope heating ventilation air conditioning (HVAC) system was inoperable. A test performed on December 29, 1988, on the HVAC system required that the makeup filter inlet be covered with plastic sheeting. Following the test, the plastic sheeting was not removed resulting in the Train C control room envelope HVAC system being inoperable.

The licensee's review identified that the test procedure did not provide positive procedural control and independent verification of the altered HVAC configuration. The procedure involved a one-time Halon concentration test, which has been deleted from the plant procedures manual. A training bulletin was issued to plant personnel responsible for procedure preparation. Interim training was provided on the existing requirements for positive procedural controls and independent verification of actions which alter the configuration of plant systems. The above bulletin and interim training program were formalized and presented to plant personnel as part of their continuing training. This item was completed by July 1990.

r. (Closed) LER 499/90-007: Potential Flooding of the Standby Diesel Generator 22 Room

On April 26, 1990, with Unit 2 at 100 percent reactor thermal power, SDG 22 room high pump level alarm actuated in the control room. An operator subsequently noted 5 inches of rain water had accumulated in one end of the SDG 22 room. The water was noted to be coming from under the SDG 22 bay removable missile doors. The sealing area was caulked to eliminate the leakage by the missile shields.

The licensee identified that procedural controls were not in place to ensure that the SDG bay removable panels were reinstalled in accordance with design requirements. There were no procedural controls for other missile shields such as in the mechanical auxiliary building. Sealing requirements have been added to the applicable drawings to replace the shield gasket and caulk all joints if the panels are removed. Quarterly testing of the sump pumps is also being performed.

Temporary modifications are being reviewed to provide backup sump pumps for the SDG bays or provide an alternate power supply for the existing sump pumps. Operating Procedure OPOP04-ZO-0002, "Severe Weather Guidelines," has been revised to include the lessons learned.

s. (Closed) LER 498/88-49: Reactor Trip/Turbine Trip Due to Defective Startup Cooling Water Trip Circuit Fuse Block

On August 26, 1988, the Unit 1 reactor tripped from full power because of a turbine trip. The cause of the turbine trip was not immediately identified. During recovery activities following the trip, an SI actuation occurred on low main steam pressure because of misoperation of the main steam isolation (MSI) controls by a licensed control room operator. The plant operator failed to follow an approved procedure by placing the MSI switches to OPEN position with the main steam isolation valve (MSIV) switches not in the CLOSE position. The operator was attempting to open the MSI bypass valves; however, the MSIVs opened (the MSIV nonsafety-related solenoids were still in auto-open mode of operation) resulting in a SI on low steam pressure. The operators terminated the event in accordance with the applicable procedure. No injection into the RCS occurred because RCS pressure was greater than the SI pump discharge pressure.

Monitoring equipment was installed in order to locate the source of the spurious trip signal. Two days later, the Unit 1 turbine tripped from 23 percent power. The reactor did not trip because thermal power was less than 50 percent (permissive P-9). Again, the cause of the trip could not be determined. On September 2, 1988, Unit 1 turbine tripped off-line a third time at the 46 percent reactor power level. Troubleshooting identified the cause of the trips to be a defective fuse block in the stator cooling water trip circuit. The fuse holder was making intermittent contact with the fuse. This resulted in a deenergization of the stator cooling water low differential pressure time delay relay and initiation of a turbine trip signal. The cause of the inadvertent SI signal was the failure of an operator to follow the applicable plant procedure.

Corrective actions planned included replacing the defective fuse block, resetting the time delay relay setpoint to allow additional time for operators to take corrective actions in the event of low stator cooling water flow, reviewing the reliability of the stator cooling water trip circuitry for possible improvements, and conducting operator training on the proper sequence of operation of the MSI and MSIV switches. Corrective actions completed included: (1) replacement of the faulty and redundant trip circuit fuse blocks, (2) changing the time delay relay setpoints from 25 to 40 seconds, (3) providing training of operations personnel on details of the event, (4) revising the stator cooling water trip circuitry from a one-out-of-two logic to a two-out-of-three logic, and (5) approving an engineering change notice package to allow for modification of the nonsafety-related portion of the MSIV circuitry. This change would remove the auto-open feature of the nonsafety-related MSIV solenoids. This change was incorporated on Unit 2 MSIVs during the first refueling outage. The modification is scheduled for Unit 1 implementation during the third refueling outage.

t. (Closed) LER 499/89-22: Reactor Trip Due to Actuation of the Overtemperature Delta Temperature (OTDT) Turbine Runback Circuit

On September 19, 1989, with Unit 2 at 100 percent reactor thermal power, an OTDT turbine runback occurred during the cross calibration of the incore and excore nuclear instrumentation. The reactor tripped on a subsequent OTDT reactor trip. During the calibration, the operators were controlling the neutron flux distribution and RCS temperature with manual rod control and boron addition and dilution. When the RCS average temperature (Tavg) exceeded the reference temperature (Tref), an OTDT turbine runback occurred. This caused a further Tavg-Tref disparity and a reactor trip on OTDT occurred.

The licensee found that the OTDT turbine runback time delay setting was improperly set and caused an excessive turbine runback. The time delay had been set in accordance with the drawings instead of the governing setpoint document. The turbine runback setpoint did not provide sufficient operating margin. The turbine runback on OTDT was subsequently defeated for both units. This feature was intended for use with the control rods in automatic control. The accident analyses described in the Final Safety Analysis Report (FSAR) are not mitigated by the turbine runback on OTDT. A subsequent station problem report was initiated to determine corrective actions necessary to preclude the use of incorrect documents for instrument settings. Engineering Procedure OPSP10-II-0001, "Incore Excore Detector Calibration," has been revised to reduce the time the plant is in a transient condition, and to further define the procedure prerequisites.

The inspectors reviewed 10 LERs which resulted from equipment failures. The licensee's evaluations were thorough to evaluate the root cause of the event. Corrective actions have been identified to prevent recurrence. The following LERs were reviewed:

u. (Closed) LER 499/90-05: Reactor Trip Due to Failure of a Main Turbine Electrohydraulic Control (EHC) Line

On April 14, 1990, Unit 2 tripped from full-power operation because of low turbine electrohydraulic control (EHC) fluid pressure. The plant was brought to a stable shutdown in Mode 3 following the plant trip. The cause of the event was failure of the EHC supply line to main turbine governor Valve GV-4. The EHC supply line failed because of fatigue stress of a weld caused by governor valve-induced vibration. The cause of the governor valve vibration has been determined to be valve plug rotation.

Corrective actions taken at the time of the event included repairing and rewelding the failed supply line. Several days later, following restart of the unit, the new weld was inspected and a new linear indication was identified. Inspections of other welds in the Unit 2 EHC piping identified additional linear indications. All Unit 2 linear indications were repaired as required. As a temporary measure, temporary supports were added which reduced the vibration amplitude. Additionally, the governor valve control logic was changed to maintain Valve GV-4 full open during power operation to minimize vibration. Valve GV-1 was maintained in an intermediate position to vary turbine load. This temporary modification has since been cleared.

Longer-term corrective actions included modifying the governor valve to add antiswirl baffles and antirotation pins on the plug to stem connections. The modifications were incorporated in Unit 2 during the recent refueling outage. Valve GV-4 was replaced with a "ruggedized" design valve. The difications for Unit 1 are planned for the next refueling outage.

v. (Closed) LER 498/90-15: Reactor Trip Due to a Electrohydraulic Control System Line Rupture

On June 28, 1990, the Unit 1 reactor tripped from 76 percent power because of a turbine trip. The turbine trip resulted from low EHC system pressure. Prior to the reactor trip, turbine generator power oscillations of up to 50 megawatts were experienced. Governor Valve No. 1 (GV-1) was determined to be cycling, which caused the power oscillations. The valve oscillations caused the EHC fluid supply line to GV-1 to rapidly vibrate. The EHC piping eventually sheared at a support clamp located next to throttle Valve TV-3, resulting in a loss of EHC fluid.

The cause of the turbine trip was low EHC system fluid pressure caused by the failed EHC supply line. The GV-1 oscillations were caused by a loose connection in the valve's control circuit. The reason for the loose connection was not positively identified, but may have occurred as a result of valve replacement during the last refueling outage. Further investigations revealed that the EHC system piping contained a number of less than adequate supports and that portions of the nonsafety-related piping had less than the required wall thickness.

Corrective actions taken by the licensee included: (1) repairing the GV-1 loose connection, (2) inspecting all other governor valves for loose connections (none were found), (3) replacing all incorrect supports with supports that include grommets, (4) replacing the EHC piping that did not meet the specified wall thickness requirements, (5) inspecting Unit 2 EHC piping to ensure the wall thickness requirements were met (Unit 2 piping was determined to be acceptable), and (6) issuing a training bulletin to reinforce the need to ensure that leads are tightened appropriately. Additionally, engineering change notice packages were initiated to add flex hoses to the EHC supply lines to each turbine governor and throttle valve. This change was identified as a long term enhancement to help preclude recurrence of this type of event. The change was incorporated into Unit 2 during the unit's last refueling outage. The change was incorporated into Unit 1 during the current refueling outage.

w. (Closed) LER 498/89-020: Engineered Safety Features (ESF) Actuations Due to an Inverter Failure

On October 11, 1989, the inverter which feeds the Unit 1 Channel IV Class 1E vital AC distribution Panel DP002 failed. This caused ESF actuations of the control room, reactor containment building, and FHB HVAC systems because of a loss of power to their respective radiation monitors. Unit 1 remained in Mode 3 during the event. The cause of the event was a failure of a bridge rectifier circuit on inverter DC to DC converter board. The most likely cause of circuit failure was excessive output voltage that was applied over an extended period of time, which resulted in overheating the components.

Corrective actions taken included: (1) replacing the inverter's DC-to-DC converter board, (2) checking the other inverters for proper DC-to-DC converter board output voltage, (3) performing thermographic examinations to assist in detecting excessive component temperatures, and (4) revising the PM instructions to adjust the DC-to-DC converter board output when it is found out-of-tolerance.

The voltage was found to be high during performance of a PM procedure in January 1989. A work request was written to adjust the voltage to the correct value. This adjustment was made in October 1989, about 4 hours prior to board failure. The combination of high voltage applied over time and the disturbance of the board prior to failure may have contributed to the failure. An internal review of the event was performed by the licensee to determine why the voltage adjustment took about 9 months to complete. Originally, the WR had a Priority 2, established by the shift supervisor, but was later downgraded to Priority 3 by work control center (WCC) personnel. Under the new work process control program, the issuing authority assigns the priority and WCC is not allowed to routinely change the priority. The revision made to the inverter's PM procedure has eliminated the need to write a WR if the voltage is found out of tolerance.

x. (Closed) LER 499/89-23: Reactor Trip Due to a Turbine Trip Caused by an Inverter Failure

On September 22, 1989, a Unit 2 reactor trip occurred from 94 percent power because of a turbine trip. The turbine trip occurred on loss of power to the four main turbine auto stop valve solenoids. The unit was stabilized in Mode 3.

The cause of this event was the failure of a capacitor on the DC to DC converter board in the nonsafety-related Inverter V002. This inverter supplies 120VAC power to vital AC distribution Panel DP002. An automatic transfer switch transferred power to an alternate power source for DP002; however, the transfer switch logic is a "break-before-make" logic. This resulted in a momentary power loss to the emergency trip cabinet, which also affected all four auto-stop solenoids. The deenergization of the auto-stop solenoids caused the turbine to trip. The reactor tripped because power was above 50 percent (permissive P-9 trip setpoint).

The root cause of the event was determined to be an inadequate design of the auto-stop solenoid power supplies. A loss of power to the emergency trip cabinet resulted in a turbine trip because there was no redundant power to the cabinets. Corrective actions taken included repairing the inverter, testing the TSCDG, and rewiring the emergency trip cabinet's power supplies. A modification was incorporated in both units to provide backup power to the emergency trip cabinets. This was part of an overall program implemented by the licensee to improve the reliability of the plant's secondary side.

y. (Closed) LER 499/90-12: Engineered Safety Feature Actuation Due to a Failed Open Feedwater Regulating Valve

On July 13, 1990, the SG 2D main feedwater regulating valve failed open while Unit 2 was at 8 percent power. This resulted in a high-high water level in the SG 2D. The high-high water level resulted in a feedwater isolation signal, which is an ESF actuation. Operations personnel decreased power to 4 percent and manually initiated the AFW system to supply feedwater to the SG. One contributing factor to the event was the control room indication that the feedwater regulating valve was fully closed, when it was actually fully open. Since the controller demand for the valve was zero, the operators thought the valve was closed. No direct position indication is provided for the feedwater regulating valves. In accordance with the power ascension procedure, the operators opened the feedwater regulating valve block valves. When the feedwater block valves were opened, the feedwater flow into the SG 2D was at maximum.

The licensee's investigation of this event identified that the feedwater regulating valve position feedback linkage arm had become detached from the valve. With this linkage arm detached, the position feedback would indicate zero position while the valve was actually full open. The arm became detached when a connecting screw became loose and fell off. The licensee was unable to specifically identify why the screw had fallen out, except that the screw may not have been properly torqued during a previous maintenance activity.

The licensee subsequently verified that the attachment screws for each feedwater regulating valve position feedback linkage arm were properly installed. The attachment screws were replaced with longer screws to provide more thread engagement. A training bulletin was issued to all maintenance personnel on the importance of ensuring that all fasteners and termination points are properly secured.

The licensee performed an evaluation on the feasibility of providing direct feedwater regulating valve position. This evaluation was reviewed by the Modification Review Committee and subsequently determined not to have a net benefit when the relative benefit and costs were compared. Many operators also indicated that the modification was not needed because of the feedwater flow indications that correspond to a valve position. These indications included SG level, mass flow rate, and feedwater pump discharge pressure.

z. (Closed) LER 499/90-004: Reactor Trip on Low Steam Generator Level Due to a Feedwater Regulating Valve Failure

On March 26, 1990, a steam flow/feedwater flow mismatch alarm was received in the Unit 2 control room. Attempts to control feedwater flow manually were unsuccessful. Unit 2 tripped from full-power operation on low SG 2C level. Following the reactor trip, the plant was brought to a stable condition with no unexpected posttrip transients.

The cause of the event was subsequently determined to be mechanical failure of the SG 2C main feedwater regulating valve. The valve stem-to-plug connection became loose and later separated. The valve plug fell into the flow stream blocking flow to SG 2C. The failure may have been caused by inadequate tightness in the valve stem-to-plug assembly or slack in the locking pin hole. All other feedwater regulating valves were inspected and were found to have tight connections. Corrective actions taken by the licensee included welding the valve stems to the plugs to prevent rotation and separation. All four valves for each unit have now been welded to prevent the stem from disconnecting from the plug.

aa. (Closed) LER 499/89-005: Partial Loss of Offsite Power Due to a Lightning Arrester Failure

On March 20, 1989, a partial loss of offsite power occurred when a switchyard bus relay actuated and tripped the 345kV power to Standby

Transformer 2. Deenergizing the transformer resulted in a loss of power to the 13.8kV Standby Busses 2G and 2H. The loss of power to the standby buses resulted in a loss of preferred power to 4.16kV ESF Busses E2B and E2C. SDG 22 and 23 autostarted on loss of power to Busses E2B and E2C. The SDGs then restored power to Trains B and C. About half an hour later, offsite power was restored to the busses through standby Transformer 1. The event occurred during a thunderstorm while Unit 2 was in Mode 2 for low-power physics testing.

The most probable cause of the event was the failure of the lightning arrester on standby Transformer 2 because of moisture intrusion of the internal insulator. Corrective actions taken by the licensee included replacement of all three lightning arresters on Standby Transformer 2. The transformer was reenergized following satisfactory completion of testing. The damaged arrester was returned to the manufacturer (Ohio Brass) for failure analysis. The vendor recommended replacing all similar arresters with metal oxide type arresters. Engineering change notice packages were issued to replace the arresters. The replacement of the arresters is currently planned for 1992.

bb. (Closed) LER 498/88-039: Entry Into Technical Specification (TS) 3.0.3 on June 16, 1988

On June 16, 1988, with the unit at 25 percent reactor thermal power, a planned inspection of the Train B 480V load center breakers was in progress. During that period, the Essential Services Chiller (ESC) 12C lube oil pump seal failed, resulting in an inoperable chiller. With equipment in two trains inoperable, the licensee entered TS 3.0.3. The 480V load center was restored to operable and TS 3.0.3 was exited after approximately 1 hour. While repairs were underway on the lube oil pump seal, a maintenance electrician bumped the local trip button on Load Center E1B, resulting in a loss of power to NMCC E1B2 and various Train B components. This again placed the unit into TS 3.0.3. The feeder breaker was closed within 3 minutes and TS 3.0.3 exited.

The licensee reviewed the operating history of the ESC lube oil pump seals. This review concluded that a generic problem with the pump seals did not exist. However, the licensee noted three recommendations which were incorporated into the instruction manual (4310-00180-BYD) for the 300-ton essential chiller. These changes were: increase the oil change frequency, do not touch the sealing surface during replacement, and ensure the shaft is free of abrasions and defects during seal replacement.

This event was also reviewed by the plant operability task force which subsequently identified equipment controls that should be covered or special cautionary tags provided at the switch. These recommendations have been implemented for both units.

cc. (Closed) LER 499/90-02: Reactor Trip Due to Spurious Activation of Reactor Trip Breaker

On February 2, 1990, with Unit 2 at 100 percent reactor thermal power, the Train S reactor trip breaker spuriously opened. This initiated a reactor trip and the actuation of the Train R reactor trip breaker. The licensee reviewed the Proteus and ERFDADS computer data and noted that the Train S reactor trip breaker had not received a trip signal. The licensee then performed troubleshooting of the Train S reactor trip breaker and system. Troubleshooting activities, however, did not result in the identification of the cause of the spurious trip.

A spurious Train S reactor trip breaker also occurred on April 15, 1989. This event is documented in LER 499/89-13. At that time, the licensee replaced the reactor trip breaker. The undervoltage trip device was exchanged with Train R.

Following the last spurious trip, the licensee installed instrumentation on the undervoltage trip device and shunt trip coil (Temporary Modification TZ-ST-900008) to try to identify the source of the spurious trip.

dd. (Closed) LER 498/89-23: A Technical Specification (TS) Required Shutdown Due to a Diesel Generator Valid Failure and Essential Services Chiller Failure

On December 16, 1989, with Unit 1 at 100 percent reactor thermal power, SDG 12 failed its TS operability test. A later attempt to secure the ESC 12C was unsuccessful and had to be secured locally. The chiller was restored to operable prior to completing the reactor shutdown.

Troubleshooting of the ESC 12C identified contact oxidation and light pressure on the 69X relay in the chiller control circuit. The relay was cleaned and adjusted and the chiller returned to service. The remaining 4.16 kV chiller control circuits were inspected during their subsequent planned train outage.

The licensee identified a problem with the SDG 11 voltage regulator chassis which caused the SDG to fail its operability test. The voltage chassis was replaced and the SDG successfully tested. Subsequent testing of the voltage chassis identified that the age of the component led to its eventual failure. The SDG 12 voltage chassis was identified to be of the same vintage and will be replaced during the ongoing refueling outage. The remaining voltage chassis have not experienced any type of similar problems.

Surveillance testing of the SDGs verifies operability of the voltage regulator. Normal operation of the chillers verifies the operability of the 69X relays and control circuit.

The licensee has experienced feedwater isolation valve (FWIV) failures on both units. These failures have resulted in automatic or manual reactor shutdowns. Modifications have been made to the FWIVs to prevent recurrence of specific failures. Further modifications to the FWIVs will be implemented during subsequent refueling outages. The following two LERs were reviewed relative to FWIV failures:

ee. (Closed) LER 499/89-019: Reactor Trip Due to Full Closure of a Feedwater Isolation Valve During Partial Stroke Testing

On August 23, 1989, FWIV 2C fully closed during a partial stroke surveillance test. Feedwater flow to SG 2C was lost, resulting in a rapid decrease in SG water level. Unit 2 operators attempted to restore flow to the SG 2C, but the level reached the low SG trip setpoint before flow could be restored. The Unit 2 reactor tripped from full power because of the low SG 2C level. The unit was stabilized in Mode 3 with no unexpected posttrip transients.

The cause of the event was determined to be the failure of a limit switch which was designed to prevent closure of the FWIV beyond 90 percent during testing. Corrective actions planned included replacing the defective limit switch, performing FWIV 2C troubleshooting during a scheduled maintenance outage, and reviewing the control circuit design to determine if modifications were necessary.

Corrective actions completed by the licensee included incorporating a design change to add a time delay relay to the testing circuit that would reopen the FWIV after the test was started if the 90 percent limit switch failed to reopen the valve. This change was implemented on both units' valves. A procedure change was made to increase operator awareness of a potential plant trip that could occur during valve stroke testing and a training bulletin was issued. Another design change, scheduled for implementation at a later date will move the hydraulic fluid dump valves outside the FWIV yoke into an accessible area for maintenance. This change would also place the dump valves in a cooler operating environment.

ff. (Closed) LER 498/90-002: TS 3.0.3 Entry Due to Failure of a Feedwater Isolation Valve (FWIV) Solenoid

On January 3, 1990, an operability test was performed on the Unit 1 FWIV 1C to satisfy TS surveillance requirements. The valve stroked as required by the test; however, one of the two redundant solenoid valves associated with the FWIV failed to actuate. The FWIV was declared inoperable. A NOUE was declared because of the required plant shutdown. The plant was taken to Mode 2 (STARTUP) and the NOUE terminated.

The cause of the event was failure of the FWIV solenoid valve because of excessive particulate buildup in the hydraulic fluid of the FWIV. An analysis of the hydraulic fluid was performed. Silica and minerals (indicative of dirt) were found, but corrosion products were not found. The licensee determined that the source of the contamination was external to the valve. The contaminants were being drawn into the fluid reservoir through a breather cap each time the valve was stroked. The cause of the excessive contamination buildup was the lack of a program for routine sampling and analysis of the hydraulic fluid. A contributing cause may have been related to the higher than anticipated ambient temperatures that the hydraulic fluid was subjected to.

The solenoid dump valves for FWIV 1C were replaced and satisfactorily retested. The remaining Unit 1 FWIV solenoid valves were reworked and tested satisfactorily. The hydraulic fluid of all FWIVs was flushed and filtered. A program for quarterly analysis of the hydraulic fluid was implemented. The hydraulic fluid sampling frequency was later changed to a monthly interval. A TS change was made to 3.7.1.7 to clarify the actions required when one FWIV is declared out of service. Modifications were implemented to help limit moisture as a potential source of fluid contamination. Long-term corrective actions included reviewing the need to install cleanup subsystems for the hydraulic skids. Additionally, procedure changes were made to require testing of FWIVs during startup in addition to regular surveillance testing. The changes were made to Procedure 1POP03-ZG-0005, Revision 7, "Plant Startup to 100%."

After the corrective actions of the LER 498/90-02 were implemented, additional problems with the FWIVs occurred. On March 29, 1990, two FWIVs (1A and 1D) fa[illegible] to fully close within the required time intervals (subject o[illegible] 1-90-05) because of hydraulic fluid problems. A 10 CFR [illegible] eport regarding the FWIV solenoid dump valve failures was submitt[illegible] the NRC on April 11, 1990. On July 7, 1990, FWIV 1A failed to operate properly because the dump valve pilot assemblies failed to lift at elevated pressures (498/90-18). Most recently, on November 10, 1990, FWIV 1A failed a routine surveillance test, prompting entry into TS 3.7.1.7.

LER 498/90-02 is closed. The NRC inspectors will review the subsequent failures during review of the 10 CFR 21 report and LERs 498/90-05 and 498/90-18.

The licensee has experienced several ESF actuations as a result of spurious toxic gas analyzer actuations. A toxic gas analyzer subcommittee was formed in 1988 to discuss causes of control room HVAC automatic actuations from the toxic gas analyzers. The inspector noted the subcommittee was active and held a meeting the week of February 11, 1991.

Several toxic gas analyzer subcommittee recommendations have been implemented. These recommendations included:

- Using nitrogen instead of ambient air for zero gas;
- remove the channels for hydrochloric acid, naphtha, and acetic acid from the ESF actuation circuitry;
- provide separate control room alarms for TS and non-TS gases; and
- provide a means for control room personnel to determine the type and magnitude of the alarms received.

The following LERs relative to the toxic gas analyzers were reviewed:

gg. (Closed) LER 499/89-28: Control Room Ventilation Actuation to Recirculation Mode Due to a Spurious Signal From a Toxic Gas Analyzer

On November 30, 1989, the Unit 2 control room ventilation actuated to the recirculation mode (engineered safety features actuation) as a result of a spurious signal from a toxic gas analyzer. The unit remained in Mode 5 operation during the event. The redundant analyzer did not actuate. The cause of the spurious signal was not conclusively identified. The most likely cause of this condition is fluctuations of AC power supplied to the analyzer. This resulted in a memory error which caused the analyzer micro processor to incorrectly energize the high toxic gas concentration relay.

Corrective actions taken by the licensee included: (1) clearing and reloading the analyzer's memory, (2) verifying the analyzer's calibration was within allowed limits, (3) performing additional troubleshooting in an attempt to locate the apparent defect in the power supply circuit or components, and (4) installing a new power cable for the analyzer in accordance with an engineering change notice package in an attempt to reduce noise induced voltages in the cable. Several other events have been attributed to the toxic gas analyzers. Numerous corrective actions have been implemented in an attempt to improve the reliability of the analyzers.

hh. (Closed) LER 498/88-47: Control Room Ventilation Actuation to Recirculation Mode Due to High HCL Trip on Toxic Gas Analyzer

On August 2, 1988, with Unit 1 at 66 percent thermal power, an automatic actuation of the control room ventilation to recirculation mode occurred. A momentary high hydrochloric acid (HCL) spike was sensed by one of the two toxic gas analyzers. No reason for the sensed high HCL could be determined. This event has been reviewed by the toxic gas analyzer subcommittee, and the ESF actuation on HCL has been removed by modification.

ii. (Closed) LER 499/90-06: Control Room Ventilation Actuation to Recirculation Mode Due to a Failure of a Toxic Gas Analyzer

On April 26, 1990, with Unit 2 at 100 percent reactor thermal power, the control room ventilation system actuated to the recirculation mode. The actuation occurred on a high level trip of the vinyl acetate channel. The licensee identified that the electro-mechanical position failed. This mechanism positions an infrared light filter to analyze each of the five toxic gases. The gas analyzer was subsequently replaced. The licensee is reviewing, through the toxic gas analyzer subcommittee, modifications to the analyzer to improve analyzer reliability.

The following LERs were also reviewed and closed.

jj. (Closed) LER 498/88-52: Effects of Westinghouse Generic Reactor Coolant System Flow Anomaly

In 1987, Westinghouse identified that a thermal-hydraulic flow instability existed in some four-loop plants as described in WCAP-11528. This flow anomaly was noted to cause increased coolant temperatures, local reductions in power, and a reduction in the departure from nucleate boiling (DNB) margin. During startup testing of Unit 1, the licensee noted that the flow anomaly may exist at STP. Westinghouse subsequently evaluated RCS flow data collected at 100 percent reactor power and determined that the flow anomaly did exist. Analysis of the data also indicated that the generic DNB margin would not fully offset the flow anomaly penalty.

The RCS flow requirements as specified in the license were required to exceed 395,000 gpm. Westinghouse evaluated that sufficient DNB margin would exist with RCS flow rate greater than 402,000 gpm. For RCS flows between 395,000 and 402,000 gpm, the power levels should be restricted to 99 percent reactor thermal power. The licensee subsequently revised Surveillance Procedure 1PSP03-ZQ-0002, "Modes 1, 2, 3, and 4 Operator Logs," to require RCS flow rate above 402,000 gpm with the reactor at 100 percent thermal power. Westinghouse performed a plant specific analysis of the flow anomaly. This plant specific analysis demonstrated that sufficient DNB margin existed at 395,00 gpm. The above procedure was again revised to reflect the later analysis. The later design analyses were submitted to the NRC staff for inclusion in the TS design basis through Letter ST-HL-AE-3040. These design basis analyses were then accepted by the NRC staff as documented in Letter ST-HL-AE-92257 (SPR 880353).

kk. (Closed) LER 498/88-014: Reactor Protection System (RPS) Actuation Due to a Software Problem in QDPS

On February 4, 1988, with Unit 1 in Mode 3, RPS actuation occurred because of an erroneous RCS hot leg temperature calculated by the qualified display processing system (QDPS) temperature averaging system (TAS). A software error in the QDPS TAS failed to accept a resistance thermal detector (RTD) RCS hot leg temperature as valid during a cooldown from Mode 3 to 4. The QDPS TAS input a no load RCS hot leg temperature when the RTD measured temperature decreased below 530°F. The erroneous hot leg no load temperature value caused an over-temperature/delta-temperature trip on Channel 2 of the RPS. Because Channel 4 was in the trip condition for maintenance activities, a RPS actuation occurred.

The automatic bias calculation has been disabled and the bias values are manually input into the calculation by plant personnel. The licensee has reviewed other QDPS calculations for similar anomalies; however, no other signals exist which use either values with a preset default or substitution values to initiate safety actuations or control functions.

ll. (Closed) LER 498/89-015: Reactor Trip Due to a Failed Relay in the Generator Breaker Control Circuit

On July 4, 1989, with Unit 1 at 100 percent thermal power, the main generator output circuit breaker opened. The reactor subsequently tripped on OTDT. The generator breaker opened because of the failure of a 125 VDC rated auxiliary relay (KZ) which was incorrectly used in the 250 VDC generator circuit breaker trip circuit. There were two of the 125 VDC KZ relays, in parallel, to provide redundant protection to the control circuit. Both relays should have been rated at 250 VDC.

The licensee's investigation determined that the relays were received on site in March 1986 and receipt inspected. The receiving documentation addressed the relays by the identification number and not the model or part number. When the parts were requisitioned, they were addressed by the identification number. The material was requisitioned for use in the control room panels. These panels utilize the 125 VDC relays. The generator circuit trip breaker circuit was tested during the startup scheme verification prerequisite test. The circuit was tested satisfactorily. The use of the 125 VDC relay in the 250 VDC circuit caused its degradation and eventual failure.

The licensee replaced the relay with the correct 250 VDC relay. The Unit 2 generator circuit breaker circuit relays were verified to be the correct model. Nuclear Purchasing and Materials Management is evaluating the purchasing, procurement, and material practices at the time the event occurred and comparing them to the current practices.

mm. (Closed) LER 499/89-015: Technical Specification (TS) 3.0.3 Entry Due to Two Inoperable Channels of the Pressurizer Level Indication

On May 12, 1989, with Unit 2 at 30 percent reactor thermal power, an operator noted that one channel for pressurizer level was inoperable.

Because one other channel had been removed from service for maintenance, the licensee was required to enter TS 3.0.3 and perform a reactor shutdown.

The licensee identified that the kerotest right angle diaphram isolation valve in the pressurizer level transmitter reference leg was stuck in the closed position. The stem on the kerotest valve is not directly connected to the plug. When the stem is backed away from the plug, the differential pressure across the valve should cause it to open. The licensee determined through radiographic examination that the valve plug had not come away from the seat. The reference leg was subsequently vented which caused the valve to open.

The licensee has completed a review of the use of kerotest valves in this type of low differential pressure application. The licensee concluded that although their use is appropriate, the valve may adversely impact the design intent by restricting steam flow to the condensing pot. Modification travelers have been prepared to redesign the reference leg condensing pot layout to the pressurizer. However, the licensee indicated that any new design which utilizes isolation valves between the pressurizer and the condensing pot will not be right angle valves.

nn. (Closed) LER 499/90-09: Discovery of Incorrect Wiring in the Solid State Protection System (SSPS)

On May 12, 1990, with Unit 2 in a forced outage, the licensee identified an extra wire in Logic Train "R" of the SSPS. The licensee evaluated this extra wire and determined that it would not have prevented the fulfillment of any safety functions. The extra wire was removed and the SSPS was successfully tested. An inspection of the remaining SSPS logic cabinets and the Unit 1 SSPS logic cabinets did not identify any other extra wires.

The licensee's investigation concluded that the wire was inadvertently installed by Westinghouse during assembly or continuity testing of the SSPS. The extra wire was identified through troubleshooting activities.

oo. (Closed) LER 498/90-16: Reactor Trip on Over Temperature Delta Temperature (OTDT) Due to Reduction in Reactor Coolant System (RCS) Pressure Coincident With One Channel in Test

On July 2, 1990, with Unit 1 at about 100 percent reactor thermal power, a reactor trip occurred on OTDT. The unit was in power ascension with Loop 4 OTDT in the trip condition to support surveillance testing. A subsequent decrease in RCS pressure resulted in a trip of the Loop 3 OTDT channel and satisfied the 2 out of 4 coincident logic for an OTDT reactor trip. The decrease in RCS pressure resulted from reducing spray flow in the pressurizer and securing a pressurizer heater following equalization of boron concentrations within the RCS. The decrease in RCS pressure lowered the OTDT setpoint. However, the selected pressurizer pressure control channel was reading higher than the others. This allowed the RCS pressure to decrease to Loop 3 OTDT setpoint and cause a trip on that channel.

The licensee has revised Operating Procedure OPOPO3-ZG-0005, "Startup to 100%," to monitor the OTDT margin to trip from 90 to 98 percent reactor thermal power. Power ascension may only proceed if there is a greater-than or equal-to 5 percent margin. Any deviation from this margin must first be approved by management. This procedure also requires that all channels of OTDT be operable prior to exceeding 90 percent thermal power. The OTDT setpoint is logged daily in power operation in accordance with (1) 2PSPO3-ZQ-0002, "Operator Logs." This event was discussed during licensed operator requalification Module 90-04.

Conclusion

The inspectors found overall LER quality to be good. Licensee management was extnesively involved in identifying causes of events as well as identifying corrective actions for events.

5. 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. This inspection included verifying that selected activities of the licensee's radiological protection program were being implemented in conformance with requirements and procedures and that the licensee was in compliance with its approved physical security plan.

The inspectors visited the control rooms on a routine basis and verified that control room staffing, operator decorum, shift turnover, adherence to TS limiting conditions for operation (LCOs), and 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 operations and to ensure that the facility was being operated in conformance with license and regulatory requirements.

The following paragraphs provide details of certain observations identified during this inspection period.

a. Emergency Boration Flowpath Verification

A walkdown of the emergency boration flow paths for Units 1 and 2 was performed to verify that each valve in the main system flow path was in its correct position. All components and flow paths were found in the correct positions to support plant operations. During the walkdown, Unit 2 mechanical auxiliary building Room 76 (boric acid tank room) was noted to have boric acid on the floor. Unit 1 Room 76 was noted to be clean. This condition was reported to the licensee.

A review of Procedure OPOP04-CV-0003, Revision 0, "Emergency Boration," was performed. Section 2.1 of the procedure listed the conditions that required emergency boration. Step 2.1.1 listed the bank insert Low Low alarm on Panel CP-005 as one of the conditions.

A review of the alarm response Procedure 1(2)POP09-AN-05M3, Revision 2(0), "Annunciator Lampbox 1(2)-05M-3 Response Instructions," was performed. The bank insert Low Low alarm response instructions did not cross reference Procedure OPOP04-CV-0003. It appears that the alarm response instructions should have included the emergency boration procedure in the immediate actions section. This discrepancy was reported to the licensee who stated that the alarm response instructions would be updated in the near future.

b. <u>Class 1E Battery Electrolyte Levels Incorrectly Recorded</u>

On January 21, 1991, the safety-related Battery E2A11 was tested by Surveillance Procedure 2PSP06-DJ-0001, Revision 2, "125 Volt Class 1E Battery 7 Day Surveillance Test." The electrical technician recorded the wrong value for Pilot Cell No. 18 electrolyte level on the data sheet. Neither the shift supervisor nor the electrical shop foreman noted the incorrect data during their required reviews. The following day, the same technician performed Procedure 2PSP06-DJ-0001 on Battery E2B11. This time, the wrong values for Pilot Cell Nos. 2 and 33 electrolyte levels were recorded on the data sheet. The incorrect values were again missed by a different shift supervisor and electrical foreman. In all three cases, the value of +1/4 inch was measured and recorded. The acceptance criteria for the electrolyte level was "above the bottom line (shown as mark on the battery) and <u>less</u> than 1/4 inch above top line." The incorrect data was also missed by the electrical system engineer during a review several days later.

These errors were discovered approximately 1 week later when the electrical division surveillance coordinator was performing the final review. The shift supervisor was informed and a station problem report was issued. This event appeared to be a violation of TS Table 4.8-2 surveillance requirements which required additional testing within 24 hours if the weekly results were unsatisfactory. The 24-hour time limit was missed by approximately 1 week. The licensee reported this to the NRC operations center on January 30, 1991. The licensee later determined, however, that the electrical crew performing the two surveillances incorrectly read the electrolyte level. The procedure required the measurement to be taken from the top of the two lines, but the technicians recorded the level from the middle of the top line. The line is approximately 1/8-inch thick. Additionally, some safety-related battery electrolyte levels are read from the midpoint of the lines (a contributing factor to the incorrect readings).

Corrective actions taken by the licensee included discussing the event with the responsible technicians and revising the battery surveillance procedures. Changes were made to: the step that provided the instructions on recording the level, the addendum that shows a picture of how to take the reading, and the data sheet that the data was recorded on.

Discussions with the licensee revealed that this event did not meet the requirements for an LER because the batteries were operable throughout the time frame in question. The electrolyte level was within limits, therefore the batteries were not inoperable. The NRC determined that the procedure was less than adequate because the instructions provided were not detailed enough to ensure that the technician performed the step correctly. The steps have since been revised. Additionally, a lack of attention to detail was observed in the review process. The shift supervisor, test performer, electrical foreman, and system engineer missed the incorrect readings. Proper attention to detail was demonstrated by the final reviewer who discovered the error prior to the data sheets being sent to the document control vault for long-term storage.

6. 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, the test equipment was within the current calibration cycles, and housekeeping was being conducted in an acceptable manner. All observations made were referred to the licensee for appropriate action.

a. Preventive Maintenance (PM) EM-1-PK-87016096, Load Center Transformer E1A1 Feeder Breaker Relay/Device Calibration

PM EM-1-PK-87016096 was performed by electrical technicians on the ground fault relay 50G at Switchgear E1A, Cubicle 12. The relay was tested in accordance with Maintenance Procedure OPMP05-ZE-0033, Revision 3, "Calibration of ITE-GR5 Relays." A pick-up amperes test and a time delay test were performed on the relay. The as-found and as-left setpoints were within acceptance criteria limits. The procedure was noted to be well written with detailed instructions on how to perform the test.

b. PM EM-1-PK-86008559, Centrifugal Charging Pump (CCP) 1A Feeder Breaker Inspection/Test

PM EM-1-PK-86008559 was a 5-year maintenance activity performed by electrical maintenance personnel on CCP 1A feeder breaker. This breaker was tested in accordance with Maintenance

Procedure OPMP05-NA0002, Revision 3, "4160V Gould Breaker Tests." The maintenance consisted of an inspection, cleaning, resistance check, opening and closing timing tests, and dielectric test. The breaker was found and left in an acceptable condition. The procedure was reviewed and compared to the vendor manual. One observation was made with respect to the breaker opening and closing timing test section (Section 6.11). Section 6.11 of the procedure did not provide clear instructions on what to do if the times were out of tolerance and when to measure and record the as-left data. This discrepancy was reported to the licensee. Otherwise, the procedure conformed to the vendor manual recommendations.

c. PM IC-1-CV-86004815, Reactor Coolant Pump (RCP) 1D Loop 4 Seal No. 1 Differential Pressure Calibration

PM IC-1-CV-86004815 was performed by I&C personnel on the RCP 1D Seal No. 1 differential pressure channel. The channel was tested in accordance with Procedure OPMP08-CV-0155, Revision 0, "RCP D Seal No. 1 Delta Pressure Channel Calibration."

d. PM IC-1-RH-86008643, Residual Heat Removal (RHR) Pump 1C Discharge Flow Calibration

PM IC-1-RH-86008643 was performed by I&C personnel on the RHR Pump 1C discharge flow channel. The channel was tested in accordance with Maintenance Procedure OPMP08-RH-0869, Revision 1, "RHR Pump C Discharge Flow Calibration." During the test performance, Section 7.11 (calibration of square root extractor) was suspended because the wrong reading was received by the technicians. The technicians apparently were taking the reading at the wrong terminal points because of unclear procedural guidance.

The test was suspended, the procedure was revised, the foreman was consulted, and the test was subsequently completed. One observation was reported to the licensee concerning the Calibration Data Package OPMP08-RH-0869-1. This package gave the acceptance criteria for Flow Indicator N1RH-FI0869A in units of tenths (1/10) of gallons. For example, the tolerance at 2000 gpm was plus or minus 63.2 gpm. The Meter FI0869A increments were in units of 100 gpm and half units were 50 gpm.

e. Maintenance Work Request (WR) DG 115104, Replacement of Injector Pump Studs

The replacement of hold down studs for four fuel injector pumps on SDG 23 was observed. The work was accomplished in accordance with MWR DG 115104 and was a continuation of similar replacements on SDG 21 and 22 on previous days. A total of 32 studs were replaced. The licensee determined that the previous installation technique, using a stud installation tool, had the potential to overstress the studs. The studs are now being installed in accordance with document Change Notice MM-949 and Field Change Request 91-0204 to Procedure OPMP04-DG-0019 which do not utilize the stud installation tool. The new installation process requires hand installation with Lock-tight applied to the stud threads. The inspector verified the current calibration of the torque wrench used on the Nylok nut and also verified torquing to the required 50 foot-pounds.

During the stud installation, a quality control (QC) inspector noted that one stud had thread damage, another had an uneven bottom which had been ground, and several of the studs showed discoloration. The QC inspector rejected the use of the studs. Subsequent review disclosed that the rejected studs were all from a batch of 16 that were purchased from Pennsylvania Power & Light under Purchase Order No. RS21979. A review of Receipt Inspection Report No. 91-0163-QC disclosed that the studs had been purchased as commercial grade and subsequently dedicated to safety-related usage by onsite inspection and chemical analysis.

The inspector reviewed the spectromobile alloy analysis and dimensional inspection reports which supported this dedication. It was noted that the inspection attributes did not address the adequacy of the threads and that the alloy analysis resulted in grinding of one stud end which was not subsequently subject to engineering disposition. These observations are considered weaknesses in the dedication process that resulted in less than adequate material being issued to the field. Subsequent discussions with quality assurance personnel confirmed these observations. The licensee will provide quality control receipt inspection personnel with additional training and acceptance criteria for inspecting threaded fasteners. Additionally, the licensee representative indicated that all material tested to provide a basis for dedication will now be subject to engineering disposition for assurance that it is still useable prior to going back into stock.

Conclusion

The technicians appeared knowledgeable and competent, adhered to the procedures, and their activities were conservative in nature. Procedural quality was generally good. One procedure (OPMP05-ZE-0033) was observed to be well written with a high level of detail. A weakness was identified in the dedication of SDG injector pump hold down studs; however, the studs were not installed because of good QC coverage during the maintenance activity.

7. Surveillance Observations (61726)

Selected surveillance activities were observed to ascertain whether the activities were being conducted in accordance with TS and other requirements. Specific items inspected included verifying that test instrumentation used was within its current calibration cycles, test results were within acceptance criteria limits, and personnel performing the test were knowledgeable and competent. All observations were reported to the licensee.

a. <u>1PSP05-CG-9970, Revision 1, "Containment Hydrogen Recombiner Channel 3 Calibration"</u>

Procedure 1PSP05-CG-9970 is an 18 month surveillance that was performed by I&C technicians on the Train B hydrogen recombiner. The surveillance verified the accuracies of the temperature indicator, test switch, wattmeter, and power adjustment potentiometer. A review of Surveillance Procedure 1PSP05-CG-9970 was performed, including a comparison of the procedure requirements to the vendor manual recommendations.

Procedure 1PSP05-CG-9970 was compared to Unit 2 Procedure 2PSP05-CG-9970, Revision 1, "Containment Hydrogen Recombiner Channel 3 Calibration." The Unit 1 procedure was different from the Unit 2 procedure in several places. For example, Steps 7.7.1.a and 7.7.2.a were added to both procedures with field change requests (FCRs). The steps provided instructions to land, then lift, a temporary jumper. The steps were double signoff steps (verification required) in the Unit 2 procedure but not in the Unit 1 procedure. Step 7.5.6 of the Unit 2 procedure instructed the test performer to skip several steps if no indicator adjustments were required. Step 7.5.6 in the Unit 1 procedure incorrectly sent the performer to Step 7.6, skipping Step 7.5.9, which was a double signoff step to turn power off. The Unit 2 procedure was previously corrected by an FCR.

Administrative control of procedure changes was governed by Procedure 0PGP03-ZA-0002, Revision 19, "Plant Procedures." Step 11.3.2.3(a) stated "consistency between similar procedures for Unit 1 and Unit 2 <u>SHALL</u> be maintained." Procedures 1PSP05-CG-9970 and 2PSP05-CG-9970 were similar, but consistency was not being maintained. Although the two procedures were not consistent, the differences had minor safety significance. Additionally, this inconsistency between procedures appeared to be an isolated incident and not indicative of a programmatic problem. Corrective actions planned by the licensee include updating the procedures. The inconsistency between the two procedures will be tracked as an unresolved item (498/9101-04; 499/9101-04) pending completion of corrective actions and further NRC review of other procedures to determine whether this is an isolated example.

b. <u>Procedure 1PSP03-DG-0015, Revision 4, "Standby Diesel 13 LOOP-ESF Actuation Test"</u>

Procedure 1PSP03-DG-0015 was an 18 month surveillance that was performed by operations personnel and supported by maintenance personnel. The test simulated a loss of offsite power (LOOP) in conjunction with an ESF test signal. This resulted in a deenergization of Bus E1C, shedding of loads from the bus, an SDG No. 13 start signal, and reconnection of selected loads. Prior to the test, the shift supervisor and test coordinator held a briefing to ensure that all performers knew what their assignments were.

Operations personnel then aligned Train C for the test, starting pumps as necessary. During test performance, operations personnel attempted to simulate a LOOP signal and ESF signal at the same moment. The LOOP occurred as planned; however, the ESF signal was not generated and selected components did not operate as expected. The test was terminated and troubleshooting activities began. Two SSPS test switches (S143 and S-146) were found to be working intermittently and were subsequently replaced. However, before the switches were replaced, a one-time-only FCR was written to allow simulation of the ESF test signal in a different manner. The LOOP-ESF actuation test was then reperformed. The test and all components worked as expected. The test performance appeared well coordinated by operations personnel.

Conclusion

Two surveillance activities were witnessed, the Unit 1 containment hydrogen recombiner calibration and SDG 13 LOOP-ESF actuation test. Unit 1 and 2 procedure consistency will be further reviewed during a future inspection. The personnel performing the procedures were knowledgeable and competent. The LOOP-ESF actuation test was performed well by Unit 1 operations personnel and good communications were used between test participants.

8. Refueling Activities - Unit 1 (60710)

Unit 1 ended the inspection period in "no mode" operation with the core fully off loaded to the spent fuel pool. Seventy-six new fuel assemblies have been transferred from the new fuel vault to the spent fuel pool in preparation for core reload. Major activities completed to date included: (1) replacing the Reactor Coolant Pump 1B and 1D seals, (2) plugging selected Steam Generator 1C and 1D tubes and installing the primary manway covers, (3) completing steam generator eddy current testing, (4) completing Train C SDG No. 13 24-hour operability run and subsequent surveillance testing, and (5) completing the reactor containment building (RCB) integrated leak rate test. Major activities in progress at the end of the inspection period included low pressure main turbine reassembly, main generator repairs, local leak rate tests, snubber inspections, and ESF Train A maintenance activities.

Routine tours of the Unit 1 RCB were performed throughout the inspection period. Housekeeping was being maintained, including areas where maintenance activities were ongoing. Radiologically controlled areas were properly posted. Health physics and security personnel appeared to have strict control over personnel and equipment entering and leaving the reactor containment building (RCB). The licensee's ability to control housekeeping and other attributes associated with an outage continues to improve with each outage.

9. Evaluation of Licensee Quality Assurance Program Implementation (35502)

In December 1990, the Region IV and NRR staff reviewed the licensee's performance for the previous 8 months in order to identify performance trends. This review was conducted to gain insights of the quality assurance program implementation effectiveness at STP. On February 8, 1991, a meeting was held at the STP with Region IV, NRR, and licensee management to discuss the NRC's evaluation of the licensee's performance. The results of this evaluation, which were presented to the licensee, is provided in the Attachment of this report.

10. Exit Interview

The inspectors met with licensee representatives (denoted in paragraph 1) on February 15, 1991. The inspectors summarized the scope and findings of the inspection. The licensee did not identify as proprietary any of the information provided to, or reviewed by, the inspectors.

ATTACHMENT

PERFORMANCE REVIEW

SOUTH TEXAS PROJECT

FEBRUARY 8, 1991

PLANT OPERATIONS

- PROFESSIONAL ATTITUDE BY PLANT OPERATIONS STAFF
- ONSHIFT OPERATIONS STAFF RESPONDED WELL TO PLANT EVENTS
- ONSHIFT OPERATIONS STAFF WERE NOT ALWAYS CONSISTENT IN THEIR IMPLEMENTATION OF PROCEDURES AND TS REQUIREMENTS
- AS A CONTRIBUTOR TO THE ABOVE, SOME PROCEDURES DID NOT PROVIDE SUFFICIENT GUIDANCE
- EQUIPMENT FAILURES HAVE CHALLENGED OPERATIONS STAFF
- REFUELING ACTIVITIES WERE GENERALLY WELL IMPLEMENTED
- HOUSEKEEPING IS GOOD OVERALL AND IMPROVING (SOME EXCEPTIONS)

RADIOLOGICAL CONTROLS

- IMPLEMENTATION OF RADIOLOGICAL CONTROLS PROGRAM HAS IMPROVED
  - Radiological environmental program well implemented and could serve as an industry standard
  - Good radiological practices implemented during refueling outages
  - ALARA program improving and expanding
  - Excellent management involvement and oversight
  - QA audits were comprehensive and performance based
  - INPO accredited July 1990
  - Good response to previous SALP recommendations

MAINTENANCE/SURVEILLANCE

- THE MAINTENANCE PROGRAM WAS GENERALLY WELL IMPLEMENTED
- BACKLOG OF BOP MAINTENANCE REQUESTS MAY BE AFFECTED BY UNAVAILABILITY OF SPARE PARTS, INADEQUATE WORK INSTRUCTIONS, AND PROBLEMS WITH COMMUNICATIONS AMONG WORK GROUPS

- THERE WERE SOME INDICATIONS OF INACCESSIBILITY OF EQUIPMENT AND OTHER PERSONNEL SAFETY ISSUES WHICH MAY HAVE ADVERSELY INFLUENCED PERSONNEL PERFORMANCE (BASED PRIMARILY ON DISCUSSIONS WITH PLANT PERSONNEL)
- SOME EXAMPLES OF LESS THAN ADEQUATE MAINTENANCE ACTIVITIES
- ILRT AND CILRT WELL CONTROLLED
- ISI PROGRAM GENERALLY WELL IMPLEMENTED
- PERSONNEL ERRORS DURING MAINTENANCE/SURVEILLANCE ACTIVITIES RESULTING IN UNNECESSARY CHALLENGES TO PLANT SAFETY SYSTEMS
- TS SURVEILLANCE REQUIREMENTS NOT ALWAYS COMPLETED

EMERGENCY PREPAREDNESS

- NUMEROUS FINDINGS DURING APRIL 1990 EXERCISE
- EMERGENCY PLAN GENERALLY WELL IMPLEMENTED
  - Operators implemented plan effectively
  - Staffing and facilities activation appropriate and timely
- MARKED IMPROVEMENTS SINCE APRIL 1990

SECURITY

- SECURITY PROGRAM WELL IMPLEMENTED

ENGINEERING/TECHNICAL SUPPORT

- GOOD SUPPORT FOR OPERATIONAL ACTIVITIES
- IMPROVEMENTS NEEDED IN PROCEDURES AND DRAWINGS
- CONTINUED IMPROVEMENT IN PROCUREMENT PROGRAM

SAFETY ASSESSMENT/QUALITY VERIFICATION

- GOOD AT IDENTIFYING PROBLEMS
- SAFETY ASSESSMENT/QUALITY VERIFICATION PROGRAMS NOT COMPLETELY EFFECTIVE
- RESPONSES TO NRC BULLETINS AND GENERIC LETTERS ARE GENERALLY TECHNICALLY COMPLETE AND TIMELY
- CONSERVATIVE APPROACH IN IMPLEMENTING 10 CFR 50.59 SCREENING CRITERIA