ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-445/96-01
50-446/96-01

Licenses: NPF-87
NPF-89

Licensee: TU Electric
Energy Plaza
1601 Bryan Street, 12th Floor
Dallas, Texas

Facility Name: Comanche Peak Steam Electric Station, Units 1 and 2

Inspection At: Glen Rose, Texas

Inspection Conducted: January 7 through February 17, 1996

Inspectors: A. T. Gody, Jr., Senior Resident Inspector
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Approved: W D Johnson 3/18/96
W. D. Johnson, Chief, Project Branch B Date

Inspection Summary

Areas Inspected (Units 1 and 2): Routine, announced inspection, including plant operations; maintenance and surveillance observations; engineering; plant support; operations followup; and engineering followup.

Results (Units 1 and 2):

Plant Operations

- Two safety-related inverter failures resulted in a Unit 1 trip with a safety injection on January 17, and a Unit 1 manual trip on January 22 (Section 1).

- Two transients resulted in automatic overpower turbine runbacks on February 14. The first was caused by an instrument and controls technician performing a calibration with an inadequate procedure. The second, which occurred during recovery efforts from the first, was caused by operators not balancing steam loads properly. These overpower events were characterized as an unresolved issue (Section 2.1).

- Miscommunications between operations and other departments resulted in a general misunderstanding of what caused the second runback on February 14 (Section 2.1.2).

- On January 20, at the direction of an instrument and control technician, a licensed operator isolated feedwater to one steam generator contrary to operating procedures. The incident demonstrated that the operator had a lack of knowledge of the function of a control switch on the main control boards. This was a noncited violation (Section 3.2).

- An increasing number of housekeeping and storage of nonplant equipment discrepancies were noted during the report period. Licensee management's response to the observations was appropriate (Section 3.1).

- Operators had not implemented appropriate compensatory measures while performing maintenance on one of the emergency diesel generator starting air banks (Section 3.3).

- An increase in the number and frequency of operations and maintenance-related errors were noted by both the inspectors and licensee management. The inspectors noted that management reemphasized self-verification expectations and trained operators (Section 3.4).

- The licensee had not fully implemented changes to operating procedures to eliminate a potential nonconservative calculation of reactor coolant system leakage. When informed, licensee management responded appropriately (Section 8.1).

Maintenance

- There was an increase in postmaintenance housekeeping problems (Section 3.1).

- A plant transient occurred when an inadequate procedure directed an instrument and control technician to remove a circuit card for calibration which resulted in a turbine runback (Section 2.1.1).

- An instrument and control technician directed an operator to isolate feedwater flow to one steam generator during low power operations contrary to procedure (Section 3.2).

- Inadequate diagnostic testing procedures for the safety-related Elgar inverters left the reverse transfer lockout setpoint out of tolerance on three inverters (Section 9.1.3).

Engineering

- The inspectors observed very good reactor engineering support of plant operations during the Unit 2 coastdown (Section 6.3).

- The inspectors' review of CPSES Unit 1 10kVA Elgar inverter operating history and industry operating experience revealed that inverter failures continued to occur at an increasing rate, particularly since January 1993. The inspectors found that the licensee's diagnostic plan did not ensure that the reverse transfer lockout was within calibration tolerances. The licensee's failure to leave the safety-related 10kVA inverters in a calibrated condition was characterized as a noncited violation (Section 9.1.3).

Plant Support

- The inspectors observed that radiological protection support to plant operations and maintenance was very good. Additionally, the inspectors noted that radiation protection personnel maintained cognizance of changing plant and radiological conditions (Section 7.2).

Summary of Inspection Findings:

- Inspection Followup Item (IFI) 50-445/9602-02 was closed (Section 9.1).
- IFI 50-445/9602-03 was closed (Section 9.1).
- Unresolved Item (URI) 50-446/9601-01 was opened (Section 2.1.4).
- IFI 50-446/9601-02 was opened (Section 6.1).
- IFI 50-445/9601-03; 50-446/9601-03 was opened (Section 6.2).
- Noncited violations were identified in Sections 3.2 and 9.1.3.

Attachment:

- Attachment - Persons Contacted and Exit Meeting

DETAILS

1 PLANT STATUS

Unit 1 began the inspection period at 100 percent power. On January 17, Unit 1 automatically tripped from an automatic safety injection actuation, which occurred due to the failure and subsequent reenergization of Bus 1PC2. On January 20, the unit restarted and reached 100 percent power on January 22. On January 22, Unit 1 was manually tripped by operators due to a loss of feedwater flow that resulted from a loss of power to electrical Bus 1EC1. On January 24, Unit 1 entered Mode 5 for inverter testing and repairs due to the inverter reliability problems associated with the reactor trips. The details of the events, which include equipment failures and the licensee's corrective actions are documented in NRC Inspection Report 50-445/96-02. On February 4, Unit 1 restarted and reached 100 percent power on February 6. Unit 1 remained at approximately 100 percent power during the remainder of the inspection period.

Unit 2 began the inspection period at 100 percent power. On February 10, Unit 2 began a coastdown for the refueling outage that was planned to commence on February 22. On February 14, while the unit was operating at 95 percent power, a feedwater heater bypass valve opened causing a partial loss of feedwater heating. The transient caused reactor power to reach 102.5 percent power for several seconds before being reduced by an automatic turbine runback. Within 2 hours, another turbine runback occurred, following a similar transient, which caused reactor power to again increase to greater than 100 percent power. The unit was stabilized at approximately 91 percent power. At the end of the inspection period, the unit was at approximately 90 percent power.

2 PROMPT ONSITE RESPONSE TO EVENTS AT OPERATING POWER REACTORS (93702)

2.1 Turbine Runback Events

On February 14, Unit 2 was operating at approximately 95 percent power near end-of-core life. Normal day shift activities had begun, including routine maintenance. At approximately 8:20 a.m., instrument and control technicians performing a channel calibration of Condensate Pump Discharge Header Pressure Channel 2240, began to cause condensate pump discharge header pressure alarms in the control room. The operators expected to receive the alarms due to the calibration procedure. At 8:30 a.m., the control room received the condensate low pressure heater bypass trouble alarm which was followed by the emergency low pressure heater bypass valve opening. At 8:32 a.m., the main turbine control circuits caused a runback from 1105 megawatts to 990 megawatts. Reactor power reached 102.5 percent by nuclear instrument indication before stabilizing at approximately 97 percent.

At 9:59 a.m., operators were restoring extraction steam to Feedwater Heaters 2A/2B when a level imbalance occurred between the heater drain tanks. The level imbalance caused a reduction in flow from the heater drain pumps which caused a reduction in the feedwater pump suction pressures and led to the automatic opening of the emergency low pressure heater bypass valve. The plant response was similar to the first event. Reactor power again reached approximately 102.5 percent before a second turbine runback occurred.

2.1.1 Cause

Instrument and control technicians were performing a channel calibration of Condensate Pumps Discharge Header Pressure Channel 2240, using Instrument and Control Procedure ICI-4126B, Revision 1, dated April 30, 1991. When the technicians performed Section 8.2 of the procedure to calibrate Analog Mixing Amplifier (NMA) Card PQY-2240, the procedure required the technicians to remove the NMA card, place the card on an extender, make adjustments to the card, and then restore the card to its original position. When the technicians removed the NMA circuit card, they also removed the portion of the circuit that generates the signal for condensate flow through the gland sealing steam condenser.

The gland sealing steam condenser bypass valve, designed to automatically control condensate flow through the condenser, began to close when the flow signal was removed. With increasing condensate flow through the gland sealing and auxiliary gland sealing steam condensers, the differential pressures across the condensers began to increase, reducing the pressure at the condenser outlets and at the main feedwater pump suction. The emergency low pressure heater bypass valve opened when feedwater pump suction pressure dropped below 290 psig.

Bypassing the low pressure feedwater heaters caused the temperature of the feedwater entering the steam generators to decrease which caused the cold leg reactor coolant system temperatures to drop. Because the core was nearing end-of-life, the moderator temperature coefficient had a large effect and caused reactor power to increase. A turbine load reduction of approximately 115 megawatts occurred when the Nitrogen-16 detectors sensed 109 percent power.

The second runback was also caused by Nitrogen-16 detectors sensing an overpower condition which occurred when the emergency low pressure heater bypass valve opened due to low feedwater pump suction pressure. However, the low suction pressure was caused by the loss of heater drain forward flow while attempting to restore the 2A/2B feedwater heaters.

2.1.2 Communications

The inspectors responded to the control room when the licensee announced the first runback on the sitewide paging system. The inspectors noted that the operating crew appeared to have the transient under control. The inspectors also noted that support from other departments, including reactor engineering, was apparent. Also, it was evident that reactor engineering understood the importance of controlling the axial flux difference and was providing recommendations to operations. The inspectors concluded that the licensee demonstrated excellent communications during the response to the first runback.

However, the licensee did not make a sitewide announcement concerning the second runback and many individuals were unaware that the transient occurred. The inspectors concluded that the communications on the second runback were not completely effective and did not meet licensee management's expectations. Operations Department Administrative Procedure, ODA-102, "Conduct of Operation," stated that announcements of abnormal conditions should be made using the plant announcing system. The licensee agreed with the inspectors' conclusions.

During that afternoon, the inspectors discussed the causes of the runbacks with licensee management. The licensee had concluded that the first runback was caused when the technician removed the NMA card from the circuit and that the second was caused when the system was restored. The licensee stated that most of the NMA cards do not have an indication function and a control function on the same card. Those that did had been identified in procedures. Procedure ICI-4126B did not indicate that the NMA card also had a control function. The licensee also stated that the procedure originally had been written to be performed during Modes 3, 4, 5, or 6, and that the procedure had been changed to remove the mode restriction in 1993. The licensee stated that all other instrument and control calibration activities had been halted until a review for similar indication/control NMA cards had been completed. The inspectors concluded that this was appropriate.

On February 16, the inspectors met with the technicians to discuss the procedure. The procedure referenced Westinghouse Interconnecting Wiring Diagram 8815D33, Sheets 16 and 19, each sheet referenced the other, and no other function was indicated on the NMA card. The same NMA card on Sheet 20 indicated that the card was assigned another function in addition to condensate pump discharge pressure. The procedure did not caution the technicians that the card controlled another function, as other procedures did.

The inspectors then discussed the timing of events and determined that the technicians had removed the NMA card, placed the card on an extender, calibrated the card, and then restored the card to its original position before the first runback was announced at about 8:32 a.m. The technicians stated that they had later concluded that removal of the NMA card caused the runback and went to inform the unit supervisor shortly after 10 a.m. The inspectors concluded that based on their timing, the licensee had made an incorrect assumption concerning the cause of the second runback and discussed the situation with licensee management. The inspectors again concluded that communications were not completely effective in determining the cause of the second runback. Management agreed with the inspectors' position and concluded that additional investigation was needed.

The licensee had notified the NRC headquarters operations officer of the first time that licensed thermal power was exceeded in accordance with the requirements in the Unit 2 operating license; however, the event text did not explain that the licensed thermal power had been exceeded a second time. The inspectors noted that the alarm printout showed that two of four nuclear instruments exceeded 102 percent power during the second runback. The licensee stated that they had considered the second transient to be a continuation of the first. The inspectors pointed out to the licensee that the second overpower event was separate and required notification. The licensee updated the event notification on February 15 and incorrectly stated that the second event occurred when the technician reinserted the NMA card into the system. The inspectors questioned the licensee regarding the incorrect information. The licensee stated that they intended to update the information by submitting a special report to the NRC. The inspectors concluded that this was appropriate.

2.1.3 Licensee's Initial Conclusions

The inspectors attended the licensee's performance review committee meeting concerning the maintenance activity. The technicians stated that the NMA card had been marked with a permanent marker with both equipment tag numbers that were associated with the card. Tag numbers identify the various functions included on the card. The technicians stated that placing the tag number on the card edge was standard practice but was not a controlled process, and that some cards contain more tag numbers than fit on the card edge.

The instrument and control manager stated that most calibration procedures had been written to be conducted during Modes 3 through 6 even though most did not require a specific mode. The manager also stated that during the early 1990's, a continuing effort was instituted to review the procedures and to remove the mode restraint whenever possible. The manager noted that while the procedure to calibrate the condensate pump discharge pressure did not reference the bypass control valve function of the card, the procedure to calibrate the bypass control valve function did reference the condensate pump discharge pressure function of the card. In response to the event, the procedure was revised to indicate the control function. Additionally, the review also identified two other procedures (one for each unit) that calibrated a card that had both an indication function and a control function without appropriate cautions.

2.1.4 Conclusions

The licensee concluded that the runbacks were caused by a significant personnel error by the technicians in not stopping to identify the function of a second equipment tag located on the card edge. The inspectors agreed that the technicians were the last line of defense, and missed an opportunity to prevent the plant transient from occurring. However, the inspectors concluded that several other errors had a larger contribution to the transient. These included: (1) the failure of Interconnecting Wiring Diagram Sheets 16 and 19 to reference Sheet 20, and vice versa; (2) the failure to identify the dual function of the card during the procedure review to remove mode restraints in 1993; and (3) the failure to identify the problem earlier when the discharge pressure function was noted in the bypass control valve calibration procedure. The inspectors concluded that while the practice of marking the card with a permanent marker with the tag numbers was standard, it was an uncontrolled process and could not be relied upon to verify a card's function. The inspectors concluded that the licensee's actions to correct the procedure and to review the procedures for all NMA cards were prompt and appropriate.

The inspectors concluded that the communications breakdown between departments was significant. The inspectors concluded that the licensee's misunderstanding of what caused the second runback influenced their apparent lack of urgency in resolving its root cause. The inspectors will complete their review once the licensee determines the actual power levels and duration. The overpower events are an unresolved item (URI 50-446/9601-01).

3 PLANT OPERATIONS (71707)

The inspectors conducted daily examinations of plant operations. The inspectors review of control room staffing and access, adherence to procedures, compliance with Technical Specifications, and operator behavior and attentiveness was performed to ascertain if the plant was being operated safely and in accordance with requirements. Logs for shift operations, clearances, and for limiting conditions for operation were reviewed for accuracy and appropriate actions.

3.1 <u>Plant Tours</u>

The inspectors performed daily plant tours to ascertain if activities were being conducted safely and to note the general material condition of the plant. The inspectors noted an increased number of instances where housekeeping was not maintained in accordance with licensee management expectations. Specific examples include untied ladders, unsecured nitrogen bottles, unused hoses, and improperly stored cleaning equipment. Also, the inspectors identified several examples in which work areas were not cleaned after work completion. The inspectors discussed the housekeeping issues with the licensee. The licensee addressed the items appropriately, and reinforced their expectations on housekeeping to the workers.

3.2 <u>Inadvertent Feedwater Isolation During Startup of Unit 1</u>

During a plant startup on January 20, the unit supervisor requested that the prompt team begin maintenance on the Steam Generator 1-04 feedwater bypass valve controller. Power had been raised to approximately 20 percent and feedwater was being supplied through the feedwater control valve and no longer through the bypass valve. The prompt team leader and an instrument and control technician determined that replacing a tracker-driver (NTD) card would probably correct the controller's deficiencies. They also decided that the work could be performed using the authorized work request form using an approved procedure and did not require a work order.

Using data sheets from Procedure ICI-4206A, the instrument and control technician calibrated a replacement NTD card on the test rack. Although the procedure, "Channel Calibration Steam Generator Loop 4, Channels 1-LS-0549," was written for in-place calibration of the loop which required that the plant be shutdown, no mode restriction was required because the card was on the test rack.

The instrument and control technician discussed the proposed maintenance activity with the unit supervisor. Following the discussion, the supervisor was satisfied that the bypass would not open during the replacement of the calibrated NTD card as long as the controller was "in manual" as per Procedure INC-2085, "Rework and Replacement of I&C Equipment." The supervisor authorized the technician to proceed. The reactor operator was not present during these discussions.

The instrument and control technician discussed the maintenance activity with the reactor operator. The technician reviewed Procedure ICI-4206A, and noted that prerequisite Step 6.5 required that operators verify "SG 4 FW BYP & CTRL VLV," Handswitch 1-HS-2165 was in the closed position. The reactor operator assumed that the unit supervisor had approved the step and then placed the handswitch in the closed position and both the bypass and the control valve began to close. Shortly thereafter, the steam flow/feed flow mismatch annunciator sounded for Steam Generator 1-04 and alerted the operator to the mistake. The reactor operator restored feedwater flow to the steam generator.

3.2.1 Requirements

Instrument and Control Procedure INC-2085 did not direct that Handswitch 1-HS-2165 be repositioned prior to removing the NDT card. The procedure only required that the mannual/automatic station be placed "in manual." A prerequisite for Instrument and Control Procedure ICI-4206A required that, "operations verify SG 4 FW BYP & CTRL VLV Handswitch 1-HS-2165 is in the closed position." Another required that, "the plant is in Mode 3, 4, 5, or 6." Since the plant was in Mode 1, Procedure ICI-4206A was not the appropriate procedure.

3.2.2 Assessment

The licensee documented the incident in ONE Form 96-0063. The inspector reviewed the ONE Form, discussed the event with one of the individuals involved with the evaluation, and discussed general knowledge questions with licensed operators not involved with the incident. The inspector concluded that the licensee was addressing the issue thoroughly and that the licensee's planned corrective actions were appropriate.

While the licensee's evaluation was not complete by the end of the inspection period, the licensee concluded that four barriers failed and allowed the incident to happen. These barriers were:

- instrument and control technicians did not review Procedure ICI-4206A for use during Mode 1 operation,

- the unit supervisor did not clearly understand the actions that were going to take place,

- the reactor operator lacked an understanding of the function of Switch 1-HS-2165, and

- human factors weakness of the switch label.

Based on the previous conclusions, the licensee intended to review and correct, as deemed necessary, the following:

- operator training/knowledge,

- human factors enhancements to the switch label,

- supervisors' responsibility to review/understand the complete job,

- use of procedures by all parties, and

- expectations for understanding the complete job impact and scope changes.

The inspector performed a limited survey of licensed operators concerning Switch 1-HS-2165. All operators knew that the switch operated both the feedwater control valve and its bypass. The inspector concluded that a general knowledge problem did not appear to exist. The inspector questioned the operators concerning the use of the nomenclature for the valves. Some operators stated that they referred to the feedwater control valve as the "feed reg. valve," and the feedwater bypass valve as the "feed bypass control valve." Other operators used the proper nomenclature "feedwater control valve" and "feedwater bypass valve." The inspector concluded the inconsistent use of nomenclature and human factors in switch labeling may have contributed to the event.

3.2.3 Conclusions

The inspector concluded that the mistake represented a weakness in the operator's knowledge and that performance of a step from Procedure ICI-4206A with the unit in Mode 1 was a violation of Technical Specification 6.8.1. This licensee-identified and corrected violation is being treated as a noncited violation, consistent with Section VII.B.1 of the NRC Enforcement Policy.

3.3 Lack of Compensatory Actions

On January 10, the inspector observed that the "Diesel Generator 1-02 Disabled" annunciator was lit due to maintenance on one of the starting air banks. The inspector questioned the unit supervisor to determine whether compensatory measures had been established to ensure that the diesel was still operable since the alarm had no reflash capability. The unit supervisor knew that the alarm resulted from planned maintenance, but was not aware whether compensatory measures had been established and did not know whether the alarm had reflash capability.

The licensee later determined that the annunciator had alarmed several hours earlier during the previous shift and that no compensatory measures had been established. The inspector reviewed Alarm Response Procedure 1-ALB-10B and verified that the caution for performing the compensatory actions was in place. The licensee had revised the procedure following a similar observation in July 1995 (see NRC Inspection Report 95-14). The caution stated that, "due to [the alarm having] no reflash capability, the operator actions should be performed four times per shift as compensatory actions to ensure [that the] diesel generator remains operable."

The inspector discussed the issue with licensee management. Management stated that the crew's actions did not meet their expectations. The inspector noted that it did not appear that the crew had reviewed the alarm response procedure when the alarm was received. The inspector noted that the alarm had been received late on the previous shift and that the diesel was still operable. The inspector concluded that the licensee's actions based on the July observations had not been fully effective.

3.4 Personnel Errors

During the inspection period, the inspectors noted an increase in personnel errors. The inspectors questioned the licensee on the increased trend, and found that the licensee independently identified the trend, and was in the process of evaluating the personnel errors. The licensee indicated that the error rate approximately doubled in the operations and maintenance departments. Several of the errors involved operation of the wrong component because of inadequate self-verification. None of the errors were significant. Licensee management reemphasized the seven steps of self-verification and conducted self-verification training. The licensee stated that operator feedback indicated that the training was useful.

4 SURVEILLANCE OBSERVATIONS (61726)

The inspectors reviewed the effectiveness of surveillance activities by direct observation in order to ascertain that testing of safety-significant systems and components were being conducted in accordance with technical specifications and other regulatory requirements. Specific surveillances observed are listed below and detailed observations follow.

4.1 Turbine-Driven Auxiliary Feedwater System Tests

On January 10 and 11, the inspectors observed OPT-206A/B, "Auxiliary Feedwater System," which was performed on Units 1 and 2 in accordance with Work Orders MM-4-95-095702-00 and MM-5-95503171-00, respectively. The test was placed on an increased frequency due to previous problems associated with the governor. The inspector attended the prejob briefing that was conducted in the control room and noted that it was adequate. During the performance of the test, the inspector found a steam leak on a steam supply orifice isolation Valve 2MS-0279. The inspector informed the auxiliary operator, who contacted the prompt team. The prompt team responded and repaired Valve 2MS-0279 and others identified by the system engineer before the surveillance was completed. The inspectors verified that the tests were performed within the required frequency. The system engineer monitored the governor valve stems for binding, and determined that no binding was evident. Mechanics performed packing adjustments on the pumps and exercised appropriate safety precautions. Vibration data was obtained subsequent to the packing adjustments with satisfactory results. The inspector concluded that the tests were performed in accordance with procedural requirements, and that the responsiveness of the prompt team to correct the steam leaks was appropriate.

4.2 Unit 1 - Analog Channel Operational Test on Steam Pressure Channel 0524

On February 13, the inspectors observed instrument and control technicians perform an analog channel operational test on steam pressure Loop 2, Channel 0524 for Protection Set I in accordance with Work Order 5-96-501206-AA. The inspector verified that the surveillance was performed in the appropriate work week in accordance with the operations schedule. The technicians appropriately requested permission from operations to enter the Protection Set I cabinet. Self-verification techniques were utilized by the technicians to determine the location of the test connections for Channel 0524. All test equipment was within its specified calibration date. The inspector verified that the as-found data was within the required calibration range. The inspector concluded that the test was properly controlled and conducted in accordance with the procedural requirements and management expectations.

5 MAINTENANCE OBSERVATIONS (62703)

To ensure safe operation of the plant and plant equipment, the inspectors conducted a review of the licensees' safety-significant maintenance activities. This review entailed the visual inspection of plant structures, systems and components, as well as interviewing maintenance personnel, to ensure reliable safe operation of the plant and compliance with regulatory requirements. The maintenance observed during the report period is listed below and inspector observations follow.

- Unit 2, 125 Vdc Battery Charger BC2ED1-1 preventive maintenance in accordance with Work Order EM-3-95-328175-01.

- Unit 2, Emergency Diesel Generator 2-01 fuel oil storage tank sampling in accordance with Work Order MM-5-96-503294-AA.

- Unit 2, inspection of Emergency Diesel Generator 2-01 room ventilation Fan 2-26 in accordance with Work Order EM/MM-3-95-326869-01.

- Unit 2 Fuel Receipt Inspections in accordance with Work Order 4-96-095625-00.

5.1 Unit 2 - 125 Vdc Battery Charger BC2ED1-1 Maintenance

On February 12, the inspector observed a preventive maintenance activity on the 125 Vdc Battery Charger BC2ED1-1 on Unit 2. The purpose of the activity was to remove the Westinghouse breakers and test them in accordance with Procedure MSE-SO-6303, "Molded Case Circuit Breaker Test and Inspection." The electricians appropriately removed the breakers from the battery charger. Leads that were lifted and landed were properly documented and independently verified in accordance with the licensee's procedure. Electricians inspected the breakers and found no damage. The thermal overcurrent trip test and the instantaneous overcurrent trip test was performed on each breaker. The inspector verified that the values for the test currents were calculated correctly, and that the as-found data revealed that both breakers tripped within the required time limits. The inspector concluded that the preventive maintenance on the battery charger was conducted satisfactorily.

5.2 Unit 2 Fuel Receipt Inspections

The inspectors observed portions of the new fuel receipt inspections in accordance with Work Order 4-96-095625-00 and licensee Procedure RFO-201, "Receipt, Inspection and Storage of New Fuel and Insert Core Components." The inspectors noted that maintenance appropriately manipulated the fuel building crane to remove the fuel assemblies individually from the fuel bundle casket. Auxiliary operators ensured proper placement of the fuel assemblies into the inspection stands. Prior to handling of the fuel, radiation protection technicians performed swipes on the assemblies and found them free of contamination. Quality control was present and inspected the fuel assemblies for cleanliness, rod finish, rod spacing, and rod straightness. No significant discrepancies or deficiencies were identified on the fuel assemblies. The inspectors noted that reactor engineering provided good oversight of the fuel inspection activities. The inspector concluded that the new fuel receipt inspections were performed in accordance with the final safety analysis report and procedural requirements.

6 ONSITE ENGINEERING (37551)

The inspectors assessed the effectiveness of the onsite engineering organization in identifying, resolving, and preventing plant problems. This assessment was accomplished through a review of licensee corrective actions, root cause determinations, safety committee involvement, and self-assessment in engineering.

6.1 Unit 2 Refueling Water Storage Tank Degradation

On October 9, 1993, the licensee analyzed white deposits which were discovered on the outside of the Unit 2 refueling water storage tank. The licensee's gamma spectrographic analysis showed low levels of Cesium-134 and Cesium-137 in the same proportions as the water contained in the refueling water storage tank. The measured activity was sufficiently low to prevent it from being detected with a portable frisker. ONE Form 93-1790 was initiated by the licensee. The leakage rate was too small to quanitfy.

Design Change Notice (DCN) 7384, dated February 14, 1995, provided details of an action plan, which included the performance of core drills of the Unit 2 refueling water storage tank, to determine if crystalline deposits were forming inside the concrete. DCN 7384 also specified a grout to be injected into the cracks to provide sealing. During implementation of DCN 7384, the licensee found that no significant crystalline deposits were in the concrete and the grout injection process appeared to be somewhat effective.

The inspectors concluded that the licensee's actions, to date, were appropriate. The inspectors were concerned about two issues: (1) the potential for an unmonitored release path, and (2) the potential for long-term degradation of refueling water storage tank rebar from boric acid corrosion. The inspectors will follow the licensee's continued efforts to resolve the issue as an inspection followup item (IFI 446/9601-02).

6.2 Station Service Water Leakage Investigation

On September 20, 1995, the licensee initiated ONE Form 95-913 because ground water seepage from a location outside the protected area fence, approximately 20 feet from the service water intake structure, appeared to have increased. The inspectors reviewed the licensee's initial efforts to identify the cause of the increased ground water seepage.

6.2.1 Licensee Investigation

The licensee's investigation focused on quantifying and determining the source of the ground water seepage. On September 21, 1995, the licensee installed a weir at the seepage location to quantify the flow which was approximately 40 gallons per minute. Initial temperature readings indicated that the seepage water temperature was slightly higher than any potential natural source. Tritium concentrations in the seepage were found to be comparable to the levels found in the service water impoundment lake. This indicated that the water source was, most likely, from the service water system. By September 26, 1995, the licensee had determined that the most likely source of leakage was the service water discharge canal. Another leakage path from a storm drain in the parking lot near the primary access point was discovered, and the licensee quantified the leakage at approximately 30 gallons per minute. By November 1995, the licensee noted that following an extended dry weather period, flow rates at both leakage paths decreased by about 5 to 10 gallons per minute. The licensee attempted to locate the source of the leak by drilling a number of wells and injecting dye into wells to monitor groundwater flow. Based on chemical analysis, well recovery rates, and dye testing, the licensee believed that the ground water seepage was from the service water discharge canal.

6.2.2 Inspector Concerns

The service water system leakage posed 3 concerns: (1) the service water system leakage could potentially reduce safe shutdown impoundment inventory; (2) the leakage could be from service water supply piping and be indicative of degraded safety system supply piping; and (3) the groundwater leakage could be negatively affecting the plant backfill by washing away particulates.

The licensee answered the inspectors questions as follows: (1) all the identified leakage from the service water system was being returned to the safe shutdown impoundment and hence, was not reducing impoundment inventory; (2) all well investigations performed indicated that the service water system leakage was from the vicinity of the service water discharge canal, the licensee postulated that since the service water canal is not lined, service water may be permeating the slopes of the canal over a general area and saturating the surrounding backfill; (3) seepage water contained very little suspended solids and little dissolved limestone; therefore, no evidence existed to support the concern of unstable soil conditions establishing.

The licensee also indicated that further analysis is planned. The inspectors were satisfied that no immediate safety concerns existed. Nevertheless, the inspectors planned to monitor the licensee's continued efforts to identify the exact source of the leakage and any significant changes in the seepage characteristics. This is an inspection followup item (IFI 445/9601-03; 446/9601-03).

6.3 <u>Reactor Engineering Support of Unit 2 Coastdown</u>

The inspectors observed reactor engineering support of Unit 2 coastdown operations and discussed reactor engineering's preparation efforts for the anticipated coastdown. The inspectors found that reactor engineering had provided detailed guidance on where to maintain the average coolant temperature and how much effect a specified change in power would have on average coolant temperature. Reactor engineering also reemphasized the need to maintain the axial flux difference within the required band and provided graphs of the expected core response to changes in power.

The inspectors also noted that reactor engineering provided nearly continuous support to the control room during the coastdown and other transients which occurred at the end of the cycle (Section 2). The inspectors concluded that reactor engineering provided good support to plant operations during the scheduled Unit 2 coastdown.

6.4 System Engineering Action Plan

The inspectors observed the licensee's efforts to improve the effectiveness of the system engineering program. Several efforts were in progress, one of which involved the development of a detailed system health plan. The licensee indicated that the proposed system health plan would: enhance the performance monitoring list; revise the system engineering handbook to include troubleshooting expectations, the maintenance rule program, enhance performance monitoring, describe the system health plan details, and describe department goals; purchase and incorporate computer software for system engineers; define system split and develop teams for systems; incorporate a self-assessment program; and formalize a task team to track full implementation of the program.

7 PLANT SUPPORT ACTIVITIES (71750)

The inspectors observed licensee activities in the areas of plant security, chemistry sampling, and radiological protection to ascertain if the licensee took appropriate measures to protect the plant, its staff, and the public.

7.1 Chemistry Sampling

On February 14, the inspector observed chemistry technicians perform sampling from reactor coolant Loop 3 in accordance with licensee Procedure CHM-513B, "Operation of the Unit 2 Process Sampling System." The inspector verified that the prerequisites were met, and that the reactor coolant system sampling lines were properly lined up to obtain the grab samples. Self-verification techniques were utilized prior to initiating the samples, and proper controls were practiced to prevent any potential loss of primary water. The appropriate technical specification related samples for dissolved oxygen, chloride, fluoride, hydrogen, and boron concentration were obtained and tested satisfactorily. The inspector concluded that the evolution was properly controlled and that the grab samples were well within the respective technical specifications and procedural limits.

7.2 Radiological Controls

During plant tours, the inspectors verified the use of locks to control access to radiologically controlled areas and reviewed selected surveys to check their consistency with postings within the surveyed areas. The inspectors verified that licensee activities within radiologically controlled areas were well controlled and followed appropriate radiation worker practices. The inspector questioned several radiation protection technicians on changing radiological conditions, and noted that radiation protection workers were cognizant of the current dose levels in the plant where conditions have changed.

8 FOLLOWUP - PLANT OPERATIONS (92901)

8.1 Review of Reactor Coolant System Water Inventory Procedure

In NRC Inspection Report 50-445/95-29; 50-446/95-29, the inspectors documented a finding where, under certain circumstances, the Unit 2 calculated reactor coolant system inventory would be nonconservative.

On February 6, the inspectors reviewed the licensee's standing orders and found that Standing Orders 96-001 and 96-002 were removed from the standing order book. However, when the inspectors reviewed Procedure OPT-303, "Reactor Coolant System Water Inventory," they found that it still directed operators to subtract the calculated reactor coolant system leakage through pressure isolation valves. The inspectors also reviewed the controlled computer calculation for Procedure OPT-303 (Form OPT-303-3) and found that the calculation still referred to the engineering calculated leakage through pressure isolation valves.

The inspectors questioned licensee management on their plans for the procedure, and they indicated that they would revise the reactor coolant system water inventory procedure at a later date and that their failure to revise the procedure was an oversight.

9 FOLLOWUP - ONSITE ENGINEERING (92903)

9.1 Closed - Inspection Followup Items 445/9602-02, "Diagnostic Testing of Inverters," and 50-445/9602-03, "Corrective Actions and Incorporation of Industry Information as it Related to Safety-Related Inverter Reliability and Equipment Material History"

9.1.1 Review of Inverter Operating History

In NRC Inspection Report 50-445/96-02, the inspectors performed a review of the safety-related inverter operating history data and found that the operating history of the Unit 1 10kVA inverters since January 1993 appeared to have a higher failure rate than the other inverters.

The inspectors noted that several recurring 10kVA inverter component failures were evident. These recurring failures included (1) ARD 440 relays, (2) DC-DC converters, (3) relay drive boards, and (4) static switch sensing boards. The inspectors review focused on whether or not the licensee implemented adequate corrective actions to prevent recurrence of inverter failures.

Additionally, the inspectors noted that on a number of occasions, the system engineer was involved in resetting the bypass out-of-limits alarm by adjusting a potentiometer in the circuitry. The inspectors were concerned that it appeared little or no control was placed on that adjustment.

9.1.2 Evaluation of Repetitive Failures

The inspectors reviewed the degree of licensee involvement in preventing repetitive failures. Based on the type of failures which occurred, the inspectors focused their review on capacitor and relay degradation.

9.1.2.1 Capacitor Degradation

Technical Evaluations 91-307 and 94-1657, which addressed an adverse industry trend on capacitor degradation and recommended replacements of older capacitors to improve 10kVA inverter reliability, were reviewed by the inspectors. In addition, the inspectors reviewed inverter work history to independently verify that capacitor replacements had been performed as recommended in the technical evaluations. The inspectors noted that all the 10kVA inverter large power capacitors were periodically replaced and were thermally monitored for degradation during the interim periods.

The inspectors also noted that the licensee replaced a number of smaller circuit card capacitors during the Unit 1 inverter diagnostic outage. The licensee indicated that, although no small capacitor failures were found, some degradation of inverter signals was noted. The licensee indicated that the replacement of the smaller capacitors was a precautionary measure to ensure that the inverters were reliable to the end of the Unit 1 operating cycle.

The inspectors concluded that the licensee took appropriate actions in response to industry information to minimize inverter capacitor failures.

9.1.2.2 Relay Degradation

As discussed above, the inspectors noted a fairly high failure rate on inverter relays. The inspectors also noted that safety-related circuit card failures were frequently coincident with relay failures. The primary concern the inspectors had was the potential for the nonsafety relays to cause failures of the safety-related circuits in the inverters. A review of the circuit configuration and discussions with the licensee revealed that the relays were adequately separate from the safety-related portions of the inverters. The licensee indicated that the relay failures were identified because other components had failed and that they did not cause the safety-related components to fail.

The inspector reviewed the licensee's reliability improvement efforts associated with inverter relays and found that they had replaced all the affected relays in the Unit 1 10kVA inverters in 1993. The licensee replaced the affected relays because the existing Westinghouse Model ARD440SR relays were not rated for the existing operating voltages in the 10kVA inverters due to a design error as documented in Technical Evaluation 93-814. The inspector verified that the licensee procured new Westinghouse Model ARD440UR relays which were rated for the inverter operating voltages in September 1993.

A review of industry operating experience was performed by the inspectors. NRC Information Notice 91-45, and its supplement, "Possible Malfunction of Westinghouse ARD, BFD, and NBFD Relays, and A200 DC and DPC 250 Magnetic Contactors," were issued in July 1991 and July 1994, respectively. Both NRC information notices informed licensees that certain Westinghouse relays exhibited potential failures under continuously energized and high heat applications. The inspectors found that the licensee's review of the Information Notice (ONE Form FX-91-779) concluded that "...none of the ARD relays installed in the plant present a problem due to epoxy flow because the relays are either not installed in a 1E application, do not serve a safety-related function, or have been energized sufficiently to have resulted in epoxy flow and have been through at least two surveillance test periods and had no epoxy related failures."

The inspectors concluded that the nonsafety-related 10kVA inverter relays, although installed in safety-related components, did not have a safety-related function. The inspectors also concluded that the failures of the 10kVA inverter relays did not appear to have any impact on the operability of the 10kVA inverters. Also, the inspectors found that the licensee was well aware of the inverter relay failure problems and took the appropriate actions to replace failed components when they were discovered.

9.1.3 Setpoint Control and Inverter Calibration Weaknesses

The inspectors' review of Unit 1 inverter material history revealed that occasionally, when an inverter bypass out of limits alarm was received, the system engineer, with the assistance of an electrician, adjusted the circuitry setpoint to get the alarm to clear. When an inverter bypass out of limits alarm is received, the inverter reverse transfer function is locked out, disabling transfer to the bypass AC source. The inspectors interviewed licensee personnel involved in the periodic alarm clearing process. The inspectors found that the work was typically performed on a work request (green tag) and that the conduct of work did not include a reverification of the proper inverter setpoint.

The inspectors reviewed the CPSES Updated Final Safety Analyses Report (UFSAR), Chapter 8, Section 8.3.1.1.13, which stated that the external, alternate AC input source voltage was 120 Vac plus or minus 10 percent nominal. The inspectors were concerned that the setpoint changes above could have resulted in the inverter bypass out of limits setpoint being incorrect. The licensee indicated that when they actually adjust the circuitry to reset the bypass out of limits alarm, they would ensure that the potentiometer was returned to the exact spot it was in prior to the adjustment. The inspectors questioned the licensee on how coarse the potentiometer was and the accuracy which could be placed on visual potentiometer placement. It was not clear that the potentiometer adjustment was sufficiently fine to be able to rely on visual placement. The licensee did not have any empirical data to show that this type of adjustment was repeatable. The inspector concluded that the lack of setpoint control during the periodic circuit adjustments was a potential weakness.

In an effort to evaluate the licensee's assertion that the uncontrolled bypass out of limit setpoint adjustments were repeatable, the inspectors requested the as-found bypass out of limits setpoint data from the Unit 1 inverter diagnostic testing. The licensee provided the inspectors with a list of as-found and as-left data. Licensee Procedure MSE-CO-5810, "10KVA Elgar Inverter Calibration and Adjustment," Revision 0, dated October 6, 1995, indicated that the reverse transfer lockout setpoint range was 131.4 to 132.6 Vac. The inspectors noted that this setpoint range was partially outside the nominal voltage range given in UFSAR Section 8.3.1.1.13 for the alternate AC input source. The as-found setpoints ranged from 130 to 132 Vac. Based on the as-found data being outside the calibration values, the inspectors concluded that the licensee could not adequately control the bypass out of limits setpoint by visual verification of potentiometer position.

While reviewing the as-found and as-left data the licensee provided, the inspectors noted that the diagnostic testing of the Unit 1 10kVA inverters in January 1996 left the inverter bypass out of limits setpoint out of calibration on three of the inverters. The inspectors concluded that the licensee failed to develop adequate work documents to ensure that the safety-related 10kVA inverter bypass out of limit setpoints would be left in their calibrated condition as specified in Procedure MSE-CO-5810 which became effective on January 5, 1996. This was a violation of Technical Specification 6.8.1. The inspectors concluded that the significance of the licensee's failure to ensure the 10kVA inverters were left calibrated was low. This conclusion was based on the fact that normal bypass bus voltages were typically around 127 to 128 Vac. Since the lowest bypass out of limits setpoint was left at 130 Vac, the inspectors concluded that inverter availability would not be significantly affected by the lower setpoint. Therefore, this failure constitutes a violation of minor significance and is being treated as a noncited violation, consistent with Section IV of the NRC Enforcement Policy.

9.2 Conclusions

The inspectors review of CPSES Unit 1 10kVA inverter operating history and industry operating experience revealed that a number of repetitive circuit card failures had occurred at CPSES and that a number of generic industry issues applied to the 10kVA inverters. The inspectors concluded that the licensee implemented corrective actions to preclude certain ARD relay and capacitor failures from affecting inverter reliability and implemented periodic monitoring or replacement of short lived components. Notwithstanding these actions, the inspectors found that inverter failures continued to occur at an increasing rate, particularly since January 1993. The licensee found that several small electrolytic capacitors had not been replaced but their contribution to the inverter failure rates was not certain.

In NRC Inspection Report 50-445/96-02, the inspectors found that the licensee's troubleshooting and diagnostic plan was good because it directed the technicians to review specific inverter operating characteristics, including specific waveforms in the inverter controls. The inspectors found that setpoint control of inverter bypass out of limit alarms and the reverse transfer lockout was a weakness. The inspectors also found that the troubleshooting and diagnostic plan did not leave the bypass out of limit alarm and reverse transfer lockout within calibration tolerances which were effective on January 5, 1996, but that this failure was not significant.

ATTACHMENT 1

1 PERSONS CONTACTED

1.1 Licensee Personnel

Barker, J. L., Mechanical Engineering Manager
Beerck, C. L., Senior Maintenance Analyst
Blevins, M. R., Plant Manager
Curtis, J. R., Radiation Protection Manager
Davis, D. L., Nuclear Overview Manager
Ellis, S. L., Instrumentation and Control Manager
Finneran, Jr., J. C., Civil Engineering Manager
Flores, R., System Engineering Manager
Grace, W. F., Safety Services Manager
Hope, T. A., Regulatory Compliance Manager
Jenkins, T., Electrical Maintenance Manager
Kelley, J. J., Vice President, Nuclear Engineering and Support
Lucas, M. L., Maintenance Manager
Madden, F. W., Engineering Overview Manager
Marsh, T. L., Prompt Team Manager
Moore, D. R., Operations Manager
Prince, R. J., Mechanical Maintenance Manager
Smith, S. L., Work Control Manager
Snow, D. W., Senior Regulatory Compliance Specialist
Theimer, R. L., Chemistry Supervisor
Walker, R. D., Regulatory Affairs Manager

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

1.2 NRC Personnel

A. T. Gody, Jr., Senior Resident Inspector
H. A. Freeman, Resident Inspector
V. L. Ordaz-Purkey, Resident Inspector

2 REVIEW OF UFSAR COMMITMENTS

A recent discovery of a licensee operating their facility in a manner contrary to the UFSAR description highlighted the need for a special focused review that compares plant practices, procedures and/or parameters to the UFSAR description.

While performing the inspections discussed in this report, the inspectors reviewed the applicable portions of the UFSAR that related to the areas inspected. The following inconsistency was noted between the wording of the UFSAR and the plant practices, procedures and/or parameters observed by the inspectors.

- The inspectors found that the CPSES UFSAR, Chapter 8, Section 8.3.1.1.13, stated that the external alternate AC input source voltage was 120 Vac plus or minus 10 percent nominal (107 to 132 Vac). Procedure MSE-CO-5810, "10kVA Elgar Inverter Calibration and Adjustment," Revision 0, dated October 6, 1995, indicated that the reverse transfer lockout setpoint range was 131.4 to 132.6 Vac. This possible minor inconsistency was identified for their evaluation and correction, as appropriate (Section 9.1.3).

3 EXIT MEETING

An exit meeting was conducted on February 20, 1996. During this meeting, the inspectors reviewed the scope and findings of the report. The licensee provided clarifying information that supported the inspectors conclusions during the exit. The licensee did not identify as "proprietary" any information provided to, or reviewed by, the inspectors.