ENCLOSURE 2

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Inspection Report: 50-445/95-29
50-446/95-29

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: November 26, 1995, through January 6, 1996

Inspectors: A. T. Gody, Jr., Senior Resident Inspector
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Approved: W D Johnson 2/5/96
William D. Johnson, Chief, Project Branch B Date

Inspection Summary

Areas Inspected (Units 1 and 2): Routine, unannounced inspection, including plant operations; maintenance; on-site engineering; surveillance observations; plant support; engineering followup; and review of Licensee Event Reports.

Results (Units 1 and 2):

Plant Operations

- An automatic trip of Unit 2 occurred when erratic steam dump operation resulted in excessive shrink of all steam generators and low-low steam generator levels following an automatic runback. Circuit card and other equipment failures both caused and complicated the event. The frequency of circuit card failures causing or complicating transients and unit trips increased (Section 2.1).

- Tours of the plant revealed that the observable plant material condition and housekeeping had improved (Section 3.1).

- A tour of the Unit 1 containment revealed that containment housekeeping was very good and that the licensee's efforts to find and correct minor leaks were appropriate (Section 3.1).

- Standing orders and procedures for determining identified reactor coolant system leakage did not reflect the licensee's conservative operating philosophy demonstrated in the past. The operating procedure allowed use of nonconservative leakage values obtained during refueling outage local leak rate testing which did not reflect actual Unit 2 leakage noted from the past year's operating experience. Although the licensee indicated that they would take the appropriate actions in the event reactor coolant system leakage increased, the procedure, if implemented as written, may not have required a plant shutdown (Section 3.3).

- The inspectors concluded that operations control of main feedwater pump troubleshooting and implementation of compensatory measures prior to the plant trip was appropriate (Section 3.4).

- The NRC granted the licensee enforcement discretion for a failure of the Unit 2 remote shutdown panel wide range reactor coolant system Loop 1 hot leg temperature which was identified by the licensee during surveillance testing (Section 3.5).

Maintenance

- The inspectors noted during a surveillance on the Unit 2 Train A emergency diesel generator that the local level indication for jacket water read in pounds-per-square-inch and the alarm response procedure limits were described in inches. Although a conversion was provided in the surveillance package, the inspectors concluded that the conversion provided an unnecessary opportunity for error (Section 4.1).

- The inspectors observed maintenance troubleshooting of Main Feedwater Pump 2A after the plant trip and found that it was not well planned. In addition, the inspectors noted that licensee knowledge of circuit operation appeared limited, even though the vendor was present. This concern became apparent through direct observation after the licensee aborted the pump startup when operators found that speed control had not been repaired. Further troubleshooting utilizing an oscilloscope revealed that speed probe signals were abnormal (Section 5.1).

Engineering

- The inspectors reviewed the licensee's engineering self-assessment and found it to be thorough and self-critical (Section 6.1).

- A switchyard design modification was implemented in January 1995, by TU Electric Transmission Engineering, which resulted in a reduction in the

reliability of the 345kV switchyard. The inspectors found that the licensee procedures did not provide formal review requirements for switchyard design changes. The licensee performed a review of the design change prior to its implementation, but did not identify the error (Section 8.2).

Plant Support

- The licensee's investigation of the Unit 1 steam generator chemistry transient was thorough (Section 7.1).

- A planned evolution to change the spent resin sluice filter was not conducted properly. The potential for an unplanned exposure was present because radiation protection personnel did not adequately survey radiological conditions prior to the evolution and did not provide continuous radiological monitoring during the evolution. The failure to perform the proper surveys was a violation of Technical Specification 6.11.1 (Section 7.2).

Summary of Inspection Findings:

- Licensee Event Report 446/94-010-00 was closed (Section 9.1).
- Licensee Event Report 446/94-022-00 was closed (Section 9.2).
- Violation 445/9529-01; 446/9529-01 was opened (Section 7.2).

Attachment:

- Persons Contacted and Exit Meeting

DETAILS

1 PLANT STATUS

Unit 1 began the reporting period at approximately 30 percent power due to steam generator chemistry being out of specification. Steam generator chemistry was restored on November 28, and the unit was returned to 100 percent power. On December 1, the licensee reduced Unit 1 to 53 percent power to repair Main Feedwater Pump (MFP) 1A. Unit 1 was returned to 100 percent power on December 5, and remained at approximately 100 percent power until the end of the reporting period on January 6.

Unit 2 began the reporting period at 100 percent power. On December 5, Unit 2 automatically tripped from approximately 60 percent power following an automatic runback which was manually initiated by operators tripping MFP 2A. Unit 2 remained in operating Mode 3 to perform repairs until December 8. Unit 2 power was returned to 100 percent on December 13, and remained at approximately 100 percent until the end of the reporting period on January 6.

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

2.1 Automatic Trip of Unit 2

On December 5, with Unit 2 at 100 percent power, the inspectors were observing the licensee set up equipment to troubleshoot an apparent failure of the MFP 2A speed control circuit when the MFP 2A turbine control valve began to open and close repeatedly (Section 3.4). Operators immediately tripped MFP 2A in accordance with pre-established contingency plans. A plant runback from 100 percent to 60 percent power occurred as designed. The inspectors immediately responded to the control room.

About 1 minute after the runback, steam dumps operated erratically. The erratic steam dump operation resulted in excessive shrink of all steam generator levels and a unit trip from low-low Steam Generator 2-02 level. The inspectors verified that all rods fully inserted and that the reactor exhibited normal shutdown characteristics. The inspectors also verified the operation of all auxiliary feedwater pumps which automatically started as designed. The licensee placed the steam dumps in the steam pressure mode of operation and they appeared to work properly. Steam generator levels were restored using auxiliary feedwater.

Immediately following the trip, the 345kV switchyard East bus experienced a lockout similar to the lockout which occurred during the Unit 1 trip on November 19, 1995. Both the November 19 Unit 1 and December 5 Unit 2 trips were complicated by a loss of one-half of the 345kV switchyard. The licensee found that the cause of the loss of one bus in each trip was switchyard breaker pole disagreement. Switchyard breaker pole disagreement protective relaying was designed to initiate when one pole of a breaker fails to open as expected. Following a seven cycle delay (approximately 116 milliseconds), the

pole disagreement protective relaying de-energized the switchyard bus by opening all of its supply breakers to isolate the sensed fault. The protective relay scheme caused the opposite unit breaker supplying the switchyard bus to open as it did in both trips (refer to Section 8.1).

Reactor Coolant Pump 2-01 tripped from Phases B and C instantaneous overcurrent when the nonsafeguards loads fast transferred from the unit auxiliary transformer to the startup transformer. The fast transfer occurred as designed following the main turbine trip. Initial troubleshooting indicated that no apparent motor or control failure occurred. The licensee experienced a similar trip of a reactor coolant pump during a fast bus transfer in August 1994, and believed that the trip was a result of a poorly-timed fast bus transfer or improperly set overcurrent trip (refer to Section 8.2).

3 PLANT OPERATIONS (71707)

The inspectors conducted daily examinations of plant operations. The inspectors reviewed control room staffing and access, adherence to procedures, compliance with Technical Specifications, and operator behavior and attentiveness 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 Plant Tours

The inspectors performed periodic plant tours to ascertain if licensed activities were being conducted safely and to note the general material condition of the plant. The inspectors noted that several significant plant design modification installation efforts continued and that the work was being conducted properly. In general, the observable plant material condition and housekeeping improved over previous observations. However, a number of equipment reliability and transient induced problems were noted during the report period. Equipment reliability problems were self-revealing as failures prior to and during unplanned plant transients. Other transient induced problems included minor steam leaks from bolted connections, valve packing leaks, and pipe hanger damage in the heater drain system following the November 19 Unit 1 trip and the December 5 Unit 2 trip. The inspectors observed aggressive problem resolution by the licensee following the plant transients to correct these deficiencies.

The inspectors performed a detailed tour of the Unit 1 containment on December 18. Several minor leaks were noted, all of which had been previously identified by the licensee. Maintenance personnel involved in the containment entry were involved in the repair of a number of those leaks and were observed to follow appropriate radiological practices. The inspectors found a large amount of boric acid residue on the floor and on one wall in the excess letdown heat exchanger room and informed the licensee. The licensee found that the boric acid residue was a result of a small (approximately one drop

per minute) body-to-bonnet leak from the Reactor Coolant Loop 1 charging isolation valve (Valve 1-8147) which was located in the letdown orifice room above the excess letdown heat exchanger room. This leak had been identified by the licensee previously. The licensee cleaned the boric acid from the wall, floor, and other components (including carbon steel supports) and began evaluating the applicability of a catch containment to direct any further leakage from carbon steel components. The licensee decided to schedule Valve 1-8147 repairs for the next outage because of the high dose rate in the letdown orifice room (approximately 170 mRem/Hr). The inspectors concluded that the licensee's actions to prevent boric acid corrosion of carbon steel components was appropriate and agreed that the licensee's decision to defer Valve 1-8147 repair was consistent with as-low-as-reasonably-achievable dose philosophy (Section 3.3.2).

3.2 Review of Operating Procedures

The inspectors reviewed Integrated Plant Operating Procedure 003B, "Power Operations," Revision 10, dated December 7, 1995. The focus of the inspector's review was to ascertain the effectiveness of plant operating procedure changes which allowed limited and controlled use of steam dumps during low power operation. The inspectors previously observed the operator workaround associated with avoiding the use of steam dumps (NRC Inspection Report 445/95-28; 446/95-28) and found the workaround to be burdensome and potentially detracting to operators. The new procedure directed operators to monitor main turbine low pressure turbine casing differential temperature when using steam dumps during low power operations and specified operating limits to prevent damage. The inspectors questioned the operators and unit supervisors for both units on where the low pressure turbine casing temperature could be monitored and found that they were not familiar with the location of the temperature monitoring points. After several minutes of discussion, one unit supervisor not directly involved in the operation of the two units, indicated that the temperature monitoring points were located on the plant computer for Unit 2 and only locally for Unit 1. The inspectors found that the Unit 2 procedure provided the appropriate guidance on where to monitor turbine casing temperature. Operators were not familiar with the new procedure but ultimately found the proper method for monitoring the turbine casing temperature. The inspectors concluded that the new procedure provided sufficient information to assist operators in its use.

3.3 Review of Operations Standing Orders

On December 29, 1995, and January 3, 1996, the inspectors reviewed operations standing orders associated with reactor coolant system leakage and containment entry equipment problem identification logs to ascertain if they were properly maintained and appropriate for operations use.

3.3.1 Identified Reactor Coolant System Leakage Standing Orders

Standing Orders 95-001R and 95-002R utilized engineering surveillances of reactor coolant system boundary leakage to quantify identified reactor coolant

system leakage. The inspectors noted that the purpose of the standing order and its attached engineering calculation was to provide operators with some identified leakage numbers which could be subtracted from the measured actual leakage. This calculation was described in the operations testing manual, Procedure OPT-303, "Reactor Coolant System Water Inventory." The Unit 1 calculated, identified leakage was 0.003 gallons per minute and the Unit 2 calculated, identified leakage was 3.681 gallons per minute. The inspectors were concerned that the Unit 2 identified leakage calculated by engineering could be potentially nonconservative in its strict procedural application in the event Unit 2 reactor coolant system leakage increased to greater than 1 gallon per minute. The inspectors specific concern was that the Unit 2 calculated leakage value, being significantly greater than the typical total reactor coolant system leakage of approximately 0.10 gallons per minute, could be used by operators to prevent a plant shutdown required by Technical Specifications in the event unidentified leakage exceeded the 1 gallon per minute limit.

The inspectors questioned licensee management on the proposed use of the identified reactor coolant system leakage standing order and they indicated that any increased reactor coolant system leakage would be immediately evaluated and that efforts to identify and repair the excess leakage would take precedence. The inspectors noted that this operating philosophy had been demonstrated by the licensee on several occasions in the past. When a small increase in reactor coolant system leakage was calculated, operators found the leaking component, and the small leaks were repaired prior to the leakage increasing any significant amount. Nevertheless, the inspectors concluded that the standing order and the operations test procedure were the formal operating requirements for shift crews and that they did not reflect the conservative operating philosophy discussed. The licensee also indicated that they would review the reactor coolant system leakage standing orders and evaluate potential changes to more accurately reflect the conservative operating philosophy discussed.

On January 3, 1996, the inspectors reviewed the new 1996, reactor coolant system leakage Standing Orders 96-001 and 96-002, and found that they had not changed from the 1995 standing orders. The inspectors questioned the unit supervisor on the use of the standing order and posed a hypothetical 4 gallon per minute reactor coolant system leakage increase on Unit 2. The unit supervisor reviewed the standing order and the operations test procedure and, after some thought, concluded that following the procedure would not be conservative. The inspectors agreed with this conclusion.

Further discussions with licensee management on the reactor coolant system leakage requirements revealed that the licensee still intended to revise the new 1996, standing orders and/or operations test procedure following the inspectors first observations and that the new procedures would reflect licensee management operating philosophy. The inspectors concluded that the licensee was considering appropriate changes to the operating procedures.

3.3.2 Containment Entry Equipment Problem Identification

The inspectors reviewed Standing Order 95-003R1, "Containment Entry Equipment Problem Identification," on December 29, 1995, and found it to be generally complete with one exception. The exception involved the licensee's failure to update the standing order following a containment entry on December 18, 1995, (Section 3.1). Specifically, the inspectors noted that the new information on Valve 1-8147 leakage had not been recorded as of December 29. The inspectors informed the licensee of the administrative record discrepancy. The inspectors concluded that the record discrepancy was actually conservative because not quantifying leakage from Valve 1-8147 would result in that leakage amount being considered unidentified.

3.4 Operations Control of Unit 2 MFP 2A Troubleshooting

The inspectors observed the conduct of MFP 2A troubleshooting activities on December 5. The inspectors were initially concerned that 100 percent power was not the appropriate plant condition to troubleshoot a defective MFP speed control circuit and discussed this concern with licensee management. The licensee indicated that they had decided that reducing power to perform the troubleshooting would not be conservative. The licensee's main concern was that since MFP 2A speed control was lost, reducing power would result in the working MFP 2B speed control to reduce its flow to the steam generators and if MFP 2A was later lost in that condition, the subsequent transient would be worse than a runback from 100 percent power with the 2B MFP operating near 100 percent capacity. Furthermore, the licensee indicated that valuable, as-found failure data could be lost if troubleshooting did not occur with MFP 2A in its as-found condition and that MFP 2A could be tripped manually at any time during the troubleshooting process. The inspectors agreed with the licensee's logic and was satisfied that the compensatory measures were appropriate. During the pre-evolutionary brief, the licensee appropriately emphasized the pre-established compensatory measures and discussed the other troubleshooting options.

During the troubleshooting activity, the MFP 2A turbine control valve began to open and close repeatedly. Operators appropriately implemented the pre-established compensatory measures and tripped MFP 2A.

3.5 Enforcement Discretion for Reactor Coolant System Hot Leg Temperature

On December 31, at 2:10 a.m. (CST), the licensee discovered that the Unit 2 reactor coolant system Loop 1 wide range hot leg temperature (T_H) on the remote shutdown panel indication was inoperable. The inoperable T_H channel was discovered during a channel calibration. Licensee troubleshooting efforts indicated a ground. The location of the ground was isolated to an area inside containment that is normally only accessible during periods of a reactor shutdown. Due to radiation levels, temperature, and personnel safety considerations, the licensee decided that corrective actions would not be possible without performing a plant shutdown and a possible cooldown.

Technical Specification 3.3.3.2.1 for remote shutdown indication requires that one channel of reactor coolant system wide range hot leg temperature be operable in Modes 1, 2, and 3. Action Statement A requires that an inoperable channel be restored to operable status within 7 days or be in at least Mode 4, hot shutdown, within the next 12 hours.

On January 5, the licensee submitted a request for enforcement discretion of Technical Specification 3.3.3.2.1.a for Unit 2 based on an engineering evaluation which concluded that there was sufficient diverse instrumentation for monitoring subcooling margin and decreasing temperature during a potential cooldown from outside the control room. In addition, the licensee submitted an application for an exigent Technical Specification amendment to allow operation with one of the four available instruments for reactor coolant system wide range hot leg temperature out of service until Unit 2 enters Mode 4 at the beginning of the second refueling outage, which is expected to commence on February 22.

The licensee's compensatory actions included: (1) that procedures were in place to address the control room evacuation scenarios on which operators were trained, (2) that shift licensed personnel were briefed on the loss of reactor coolant system Loop 1 T_H remote shutdown indication, the alternate indications that existed, and the impact on the procedures, (3) verification of satisfactory surveillance tests on the remaining instrumentation, and 4) verification that no external causes of the T_H failure existed.

The inspector reviewed the compensatory actions committed to by the licensee for the enforcement discretion. The inspector attended shift turnover meetings, questioned several operators, and verified that the appropriate procedures were in place. In addition, the inspector reviewed the results of the surveillance tests performed on the alternate indications. The inspector concluded that all compensatory actions were in place, and that operators were generally knowledgeable of the inoperable T_H channel and the alternate indications that existed.

On January 5, the NRC granted the enforcement discretion of Technical Specification 3.3.3.2.1.a.

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 was being conducted in accordance with Technical Specifications and other regulatory requirements.

4.1 Diesel Generator Surveillance

On December 28, the inspectors observed the licensee perform a slave relay start of the Train A diesel generator from the diesel generator room. The inspectors observed the auxiliary operator perform the prerequisite steps prior to starting the diesel and observed the operator and two system

engineers inspect the diesel for proper operation following the start. The inspectors concluded that the surveillance test was properly controlled from the diesel generator room and that the presence of the engineers demonstrated a good level ownership by system engineering.

During the surveillance test, the inspectors reviewed the alarm response manual for Alarm Window 4.3, "Low Jacket Water," and noted that the procedure required the operator to verify whether the level was less than or equal to the alarm level of 35 inches. The inspectors noted that the only indication available to the local operator, Level Indicator 2-LI-3415-1, was calibrated in pounds per square inch and not in inches. The inspectors concluded that the conversion factor included in the procedure, 0.43352 psig = 1 foot H_2O, required a calculation and that the procedure would be more "user friendly" if the alarm setpoint were in the same units as those available to the operators (psig).

The inspectors went to the Unit 2 control room to determine whether the reactor operators had any indication for low jacket water level which was calibrated in inches. The reactor operator indicated that they did not have a remote indication which read in inches. The operator and inspectors reviewed the control room alarm response manual and compared the procedure against the Unit 1 procedure and noted that the Unit 1 procedure listed the alarm level in both inches and in pounds. The operator initiated a procedure change to list the Unit 2 alarm level in pounds. The inspectors concluded that this was appropriate.

5 MAINTENANCE OBSERVATIONS (62703)

To ensure safe operation of the plant and plant equipment, the inspectors conducted a review of 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.

5.1 MFP 2A Troubleshooting and Repairs (WR 4-95-095548-00)

On December 7, the inspectors observed the licensee troubleshoot and repair the MFP 2A speed control circuitry in accordance with instrumentation and control Procedure ICI-4217B, "Calibration of Feedwater Pump Turbine FWPT 2A Speed Control," Revision 1, dated June 6, 1992. Initial licensee troubleshooting efforts revealed several circuit card failures. The inspectors observed that adequate controls were placed on both the troubleshooting and replacement activities. The inspectors verified that the measurement and test equipment was calibrated.

The inspectors noted that the maintenance troubleshooting of MFP 2A was not well planned in that licensee knowledge of circuit operation was limited, even though a vendor representative was present. This concern became apparent through direct observation after the licensee aborted the pump startup when operators found that speed control had not been repaired. Further

troubleshooting utilizing an oscilloscope revealed that speed probe signals were abnormal. The licensee replaced the defective speed probes and restarted MFP 2A.

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 Review of Engineering Self-Assessment

The inspectors reviewed the licensee's 1995 engineering self-assessment and found it to be thorough and appropriately self-critical. Some of the licensee's findings included: (1) management expectations in several areas needed improvement and reemphasis, (2) workload and resource management improvements were recommended, (3) many system engineers questioned the value of certain management expectations during system walkdowns such as maintaining a notebook of observations, (4) engineers indicated that data provided for Nuclear Plant Reliability Data System reports in most work orders was inconsistent and incomplete, and (5) state of the system meetings had not been effective in prioritizing engineering effort. The engineering self-assessment did not identify any unresolved safety or hardware issues.

7 PLANT SUPPORT ACTIVITIES (71750)

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

7.1 Unit 1 Steam Generator Chemistry Transient

On November 25, an apparent resin intrusion occurred into the Unit 1 steam generators. The resin intrusion resulted in cation conductivity and sulfate values reaching chemistry Action Level 2 as defined in Procedure STA-610, "Secondary Water Chemistry Control." In accordance with this procedure, the licensee appropriately reduced power to 30 percent and maximized steam generator blowdown to the unit condenser. Sulfate values reached a maximum of 280 parts per billion (which fell between the 100 and 500 parts per billion Action Level 2 limits) and cation conductivity increased to a maximum of 2.7 micromhos (which fell between the 2 and 7 micromho Action Level 2 limits). The various action levels of Procedure STA-610 were designed to minimize corrosion of the steam generators and other balance-of-plant components. By reducing power and maximizing blowdown, the licensee minimized the amount of concentration which took place in the steam generators. The cation conductivity values were primarily caused by the high sulfate concentration. If left uncorrected, the high sulfate concentration could have resulted in steam generator tube wastage and intergranular attack. A high sulfate

concentration has also been implicated in the denting and pitting of steam generator tubes. Action Level 1 was active for approximately 15 hours prior to entering Action Level 2, during which the licensee appropriately began investigating the cause for the increased sulfate and cation conductivity values as required by Procedure STA-610. Steam generator chemistry was in Action Level 2 for approximately 22 hours.

The licensee established a task team to review the sequence of events, chemistry data, and interview involved personnel. The task team found that no definitive conclusion could be drawn from the facts because several evolutions took place that could have caused the problem. Nevertheless, the licensee found that the resin intrusion probably occurred when new lateral filters were installed in the mixed bed Demineralizer 1-01. Apparently, the licensee determined through interviews that when maintenance personnel vacuumed the excess resin beads from mixed bed Demineralizer 1-01 they did not ensure that all resin beads had been completely removed. The licensee postulated that when the old lateral filters were removed, some leftover resin beads could have entered the demineralizer discharge plenum during the maintenance activity. The inspectors questioned the licensee on how they planned to prevent this type of maintenance error in the future, and they indicated that maintenance personnel would ensure that resin beads would be thoroughly vacuumed from the demineralizers prior to performing any maintenance on lateral filters. The inspectors concluded that the licensee's investigation was thorough and the corrective actions were appropriate.

7.2 Potential Excess Radiation Exposure During Spent Resin Sluice Filter Change Evolution

On December 11, a radiation protection technician surveyed the incorrect discharge filter which ultimately led to the removal of a highly radioactive discharge filter without using a shielded transfer system. In addition, the radiation protection technician did not perform surveys during filter removal. While the technicians involved with the maintenance activity received minimal dose, the problems identified poor health physics practices.

7.2.1 Sequence of Events

The lead radiation protection technician instructed a technician (Technician A) to survey the spent resin sluice filter which he believed was located in Cubicle 59 in preparation for a filter changeout. The lead technician required the survey to determine whether the filter could be changed out manually or whether a shielded assembly would be required. If the radiation level were greater than 100 millirem per hour, then the filter would have to be changed using a shielded transfer system. Technician A heard the lead technician say "spent resin sluice pump filter" rather than "spent resin sluice filter." Technician A looked on a list of filter locations and saw that the only one listed as a sluice pump filter was "steam generator blowdown spent resin sluice Pump Filter 01," located in Cubicle 7.

Technician A measured the dose rate on the filter in Cubicle 7 and reported to the lead technician that the dose rate on the "steam generator spent resin sluice pump filter" was less than 0.1 millirem per hour. The lead technician acknowledged the dose rate and concluded that the shielded transfer system would not be necessary.

Because Technician A was not qualified to cover the filter changeout, the lead technician assigned another technician (Technician B) to support the filter changeout. Both the lead technician and Technician B thought that the dose rate was abnormally low but assumed that the report from Technician A was correct. Mechanics were informed that the dose was minimal and that the filter would be changed by hand. The mechanics signed the work order that the prejob survey had been completed.

Because the assumed dose rate was negligible, the technician assisted in the filter changeout rather than providing direct radiological protection coverage. The mechanics and Technician B reviewed the tag number of the component and noted that it matched the work order and then prepared to change the filter. Technician B did not survey the area as part of the preparation but instead held the plastic bag into which the mechanics would place the filter.

One of the mechanics (Mechanic A) lifted the filter out of the housing and cubicle using a long pole. When the filter cleared the edge of the cubicle, the dosimeters of Technician B and the other mechanic (Mechanic B) began to alarm (set at 50 mr/hr). Technician B instructed Mechanic A to place the filter in the bag and instructed Mechanic B to back away. After they placed the filter in the bag, all three backed away to assess the situation. At this point, Technician B had received 8 mR, Mechanic A had received 1 mR and Mechanic B had received 4 mR. Because of the low exposure received, Technician B decided that they would place the filter in a shielded cart, and then contact the lead technician.

7.2.2 Requirement

The maintenance activity was performed using Work Order 4-95-095428-00. The work order included applicable pages of the Maintenance Procedure MSM-CO-9206, "NSSS [Nuclear Steam Supply System] Filter Removal/Transfer/Installation." The inspectors noted that the mechanical maintenance supervisor authorized the filter removal evolution without the transfer cask, in accordance with Step 6.2.3 of the prerequisites section.

Radiation Protection Instruction 206, "Liquid Process Filter Control," Revision 7, described three different methods for transferring filters; one using a roll-around or concrete shielded drum, one using a Teledyne transfer cask, and one using an unshielded (manual) filter transfer method. The procedure states that if the total effective dose equivalent for a filter change was greater than 50 millirem, then the Teledyne transfer cask was the preferred method. Additionally, the procedure limited the use of the manual method to filters with contact dose rates which were less than 100 mR/hr.

Radiation Work Permit 95000500 "Waste Processing," Item 4, June 6, 1995, stated that the "RP Technician providing coverage shall perform and document necessary surveys in accordance with RPI-602."

Radiation Protection Instruction 602, "Radiological Surveillance and Posting," Section 6.1.2, required that nonroutine surveys should be performed as required to ensure adequate knowledge of radiological conditions prior to, during, and/or after any evolution involving exposure or potential exposure to radiological hazards.

10 CFR 20.1501(a)(2)(i), (ii), and (iii) states that each licensee shall make, or cause to be made, surveys that are reasonable under the circumstances to evaluate the extent of radiation levels, concentrations or quantities of radioactive material, and the potential radiological hazards that could be present.

CPSES Technical Specification 6.11.1 states, in part, that procedures for personnel radiation protection shall be prepared consistent with the requirements of 10 CFR Part 20 and shall be approved, maintained, and adhered to for all operations involving personnel radiation exposure.

The inspectors concluded that because the licensee did not survey the correct filter, Spent Resin Sluice Filter X-01, Tag Number TBX-SPFLRS-01, the licensee did not properly evaluate the potential radiological hazards as required by Radiation Protection Instruction 602 and, consequently, removed a highly radioactive filter without using a shielded method. In addition, the radiation protection technician did not perform surveys as required by Radiation Work Permit 95000500 during the filter removal. This is a violation of Technical Specification 6.11.1 (445/9529-01; 446/9529-01).

7.2.3 Assessment

The inspectors reviewed various documents which contained the noun names of the various NSSS filters. The inspectors noted that the lists were not consistent in the description of the filters. Tag number TBX-WPFLRS-01, for example, was listed in the work order as, "Liquid Waste Processing System Spent Resin Sluice Filter X-01," in the torque table contained in MCM-CO-9206 as, "Spent Resin Sluice," and in the drawing describing filter cubicle locations as, "Spent Resin Sluice Filter 01." Additionally, Tag Number CPX-SBFLSR-01 was listed in MSM-CO-9206 as, "S.G. Blowdown Resin Sluice," and in the locations drawing as, "SGBD Spent Resin Sluice PMP Filter 01." The inspectors concluded that the inconsistent use of filter noun names contributed to the confusion.

The actual dose rate of the filter was 20R on contact and 7R at 6 inches. The total measured exposure to personnel associated with the unsurveyed filter change out was 21 mR with a maximum exposure to a single individual of 12 mR. Radiation Work Permit 95000500 required both a thermolumenescent dosimeter and alarming electronic dosimeter for filter changeout with the electronic dosimeter set to alarm at 20 mR total dose and 50 mR/hr dose rate. The

inspectors concluded that the electronic dosimeters alerted the workers to the actual radiological conditions.

The inspectors concluded that the radiological protection technician failed to provide radiological protection coverage prior to and during the filter changeout. The inspectors also concluded that the technician appropriately directed the maintenance activity following discovery of the actual radiological conditions and minimized the absorbed dose for the situation. The inspectors also concluded that the inconsistent use of filter noun names and lack of documented surveys contributed to the problem.

8 FOLLOWUP - ENGINEERING (92903)

8.1 Unit 2 - Reactor Coolant Pump 2-01 Trip

Following the December 5, Unit 2 trip and subsequent normal fast transfer of 6.9kV Bus 2A1 to the alternate startup source feed on December 5, the Reactor Coolant Pump 2-01 breaker tripped. When investigated by the licensee, relay flags indicated that the breaker had tripped on instantaneous overcurrent on Phases B and C. The licensee's initial review prior to starting up Unit 2 found that the most probable cause of the reactor coolant pump breaker trip was an anomalous high inrush current caused, most likely, by an improper setting on the fast transfer circuit.

The inspectors were concerned that this trip and a previous trip on August 15, 1994, may have been indicative of a change in reactor coolant pump coastdown characteristics. In response to questions from the inspectors, the licensee reviewed reactor coolant pump operating parameter history and performance. The licensee's review found that Reactor Coolant Pump 2-01 had been operating properly. The inspectors reviewed the information provided by the licensee and agreed with the licensee's conclusion.

On December 29, the licensee found that the early B contact for the Unit 2 6.9kV nonsafety fast transfer permissive was set incorrectly and wrote ONE Form 96-0007. The licensee concluded that the current setting was within acceptance criteria tolerance and that operability was not affected. The licensee also found that the setpoint discrepancy could not be corrected until an outage.

8.2 Switchyard Design Modification Resulted in Increased Risk to Facility

The inspectors reviewed the circumstances surrounding the East 345kV bus lockout following the December 5 Unit 2 trip and the West 345kV bus lockout associated with the Unit 1 trip on November 19 and found that modifications had been made to the affected switchyard breakers early in 1995, which increased the risk to the facility during similar events.

8.2.1 Switchyard Description

Site power distribution from the 345kV and 138kV switchyards was directed to site loads through station service transformers (1ST and 2ST), unit auxiliary transformers (1UT and 2UT), and station start-up transformers (XST1 and XST2) during normal power operation. The 345kV portion of the switchyard consisted of an East and West bus interconnected and energized by 5 independent offsite power sources and both unit main generators. Each connection to the East and West buses was accomplished through SF_6 type, 345kV power circuit breakers. Of the twelve 345kV switchyard breakers, eight were ITE 345kV breakers. The ITE 345kV breakers consisted of three poles, each independently controlled by a distinct operating mechanism. This type of design required the breaker poles to be timed to prevent a pole mismatch from occurring during normal breaker operation.

The preferred source of power for the Unit 1 Class 1E 6.9kV buses is the 345kV switchyard via Transformer XST2. The preferred source of power for the Unit 2 Class 1E 6.9kV buses is the 138kV switchyard via Transformer XST1. Upon a loss of power on the preferred Class 1E source, the source of power will slow transfer to the alternate source, Transformer XST1 or XST2, dependent on which preferred source is lost. Additionally, the emergency diesel generators will start in the standby mode. The preferred sources of power to the Unit 1 and Unit 2 non-Class 1E 6.9kV busses are Transformer 1UT and Transformer 2UT, respectively. Upon a loss of Transformer 1UT or 2UT, the alternate source, Transformer 1ST or 2ST, respectively, is fast transferred to supply nonsafety 6.9kV loads such as reactor coolant pumps and main circulating water pumps.

The ITE 345kV breakers had a history of pole disagreement which meant that the pole timing was off a small amount (e.g., one or more pole positions did not agree with the other positions). The historical problems with pole disagreement made it very difficult for operators to close the breakers during normal plant operations. If a pole disagreement occurred during an attempt to close the breaker, the breaker would immediately trip. The pole disagreement trip was designed, in part, to ensure that the breaker would continue its attempt to retrip the breaker open if, for whatever reason, one pole remained closed when the breaker received a trip signal.

In an effort to make it easier for operators to close the ITE 345kV breakers, the TU Electric Company transmission organization modified the protective relaying to install a 10 cycle delay on the retrip function following a pole disagreement. The protective relay modification was implemented on the ITE 345kV switchyard breakers during December 1994, and January 1995.

The switchyard protective relay scheme included West and East bus trip/isolation (bus lockout) in the event a bus fault did not clear following a seven-cycle delay (including a breaker pole disagreement). For example, if a pole disagreement occurred on a breaker that was opening to isolate a fault and the pole disagreement remained in place for longer than seven cycles, a bus lockout would occur. A bus lockout would result in the tripping open of all breakers connected to that bus.

8.2.2 Event Description

The Unit 1 main generator breakers opened after the November 19 trip; however, a pole disagreement occurred on the West bus generator Breaker 8010. Since the retrip function for 8010 was delayed by 10 cycles because of the design modification described above, a bus lockout occurred in 7 cycles. The bus lockout caused all West bus breakers to open, including the Unit 2 West bus generator breaker (8030). Transformer 2ST, being aligned to the West bus, lost power. Since 2ST was an alternate source, not supplying normal plant loads, no other equipment de-energized. Transformer 1UT, being normally powered from the Unit 1 main generator, de-energized. The nonsafety 6.9kV buses fast transferred as designed to Transformer 1ST with no problems. The licensee recognized the error made when the retrip delay design modification was implemented and jumpered out the West bus breakers retrip delay circuitry. In addition, to prevent an inadvertent trip of the Unit 2 and East bus breakers, the licensee turned the Unit 2 delay settings to as short as the adjustment would allow.

The Unit 2 main generator breakers opened after the December 5 trip and another pole disagreement occurred. This time, the pole disagreement was on the East bus generator Breaker 8020. Since the retrip delay settings were adjusted to the lowest value possible, the delay time was in a race with the East bus lockout relay. The East bus lockout relay energized first and, as a result, the East bus was isolated. Transformer 2UT, being normally powered from the main generator, de-energized. The nonsafety 6.9kV buses fast transferred as designed to Transformer 2ST. During the fast transfer, the reactor coolant Pump 2-01 breaker tripped (Section 8.1).

8.2.3 Potential Significance of Improper Breaker Protective Relay Design Modification

The inspectors reviewed the switchyard protective relay design and questioned the licensee on several postulated scenarios which could have occurred if other switchyard breakers experienced a pole mismatch during a unit trip or bus fault.

One scenario involved a postulated pole mismatch on the Unit 2 west bus generator Breaker 8030. If Breaker 8030 had tripped on December 5, rather than Breaker 8020, the west bus could have experienced a lockout and Unit 2 would have lost all circulating water pumps and reactor coolant pumps. Subsequently, the reactor coolant system would have been in the natural circulation mode and decay heat removal would have been through the steam generator atmospheric relief valves.

Another less probable scenario involved a postulated pole mismatch on both the Unit 2 main generator Breakers 8020 and 8030 following a Unit 2 trip. If both Breakers 8020 and 8030 had a pole mismatch, both the east and west buses could have experienced a lockout. This scenario would have resulted in a trip of Unit 1 and a loss of all circulating water and reactor coolant pumps. As a result, both units would have been in the natural circulation mode and decay

heat removal would have been through the steam generator atmospheric relief valves.

The inspectors questioned the licensee's risk and reliability experts on what risk impact the improper switchyard design modification had on the facility assuming a loss of both 345kV switchyard buses. In response to the inspectors questions, the licensee evaluated the following scenarios (1) loss of main feedwater, (2) loss of main feedwater with planned maintenance activities, (3) loss of the 345kV switchyard buses, and (4) loss of the 345kV buses with some major plant components assumed out-of-service. Scenarios 1, 2, and 3 resulted in a minimal increase in core damage frequency. One of the Scenario 4 sequences, a loss of the 345kV switchyard coincident with a loss of one service water pump, resulted in an instantaneous risk of 6.76E-04.

The inspectors noted that during the summer, when lake temperatures were high, the licensee frequently took component cooling water heat exchangers out of service for cleaning due to fouling. Since the switchyard design modification had been implemented throughout the summer of 1995, the inspectors noted that the risk associated with the Scenario 4 sequence described above when one component cooling water heat exchanger was out of service would have been slightly higher than the instantaneous risk of 6.76E-04.

The licensee concluded that the November 19 and December 5 events posed no significant risk to the facility. The licensee also concluded that the overall risk to the facility described in Scenario 4 was low because it involved multiple equipment failures, each with an actual low probability of occurrence. The inspectors agreed with the licensee's conclusions.

8.2.4 Control of Switchyard Modifications

The inspectors reviewed the licensee's process for controlling the configuration of the switchyard and found it to lack formality. Engineering Procedure ECE 5.05, "Design Drawings," indicated that design drawings associated with the switchyard (Drawings E1-0200 through E1-0250 Sheet D) were not controlled by the licensee's engineering organization, rather they were controlled by TU Electric Transmission Engineering. As a result, no procedural controls were in place to require detailed engineering review of proposed changes to the switchyard and its drawings. The inspectors found that the licensee had performed an informal review of the switchyard design modification but did not sufficiently review the details to recognize the potential loss of switchyard reliability. The inspectors concluded that the lack of a formal process to review switchyard design modifications and design drawing changes was a weakness that may have contributed to the implementation of the switchyard design modification.

8.2.5 Licensee's Breaker Task Force

The licensee developed a task force to improve the reliability of switchyard breaker operation. The task force was comprised of Fort Worth and Glen Rose transmission personnel, licensee maintenance and engineering personnel, and

management. The licensee informed the inspectors that the task team planned to evaluate the conduct of maintenance, preventative maintenance, vendor recommendations, and the conduct of design changes in the switchyard and recommend program changes focused on improving switchyard breaker reliability.

8.2.6 Conclusions

The inspectors concluded that the design modification implemented by TU Electric Transmission Engineering which defeated the pole mismatch retrip of 345kV switchyard breakers, was not thoroughly reviewed by the licensee prior to its implementation. Additionally, the inspectors concluded that the design modification marginally increased the risk to the facility.

9 ONSITE FOLLOWUP OF WRITTEN REPORTS OF NONROUTINE EVENTS AT POWER REACTOR FACILITIES (92700)

9.1 (Closed) Licensee Event Report 446/94-010-00: Reactor Trip/Turbine Trip Due to a Short in the Current Transformer Cable

This licensee event report documented a turbine trip and subsequent reactor trip caused by a short circuit in current transformer cables which had occurred in Unit 2 on June 27, 1994. The event was documented in NRC Inspection Report 50-445/94-15; 50-446/94-15. Following the trip, the licensee had determined that the short was caused by temperature-induced insulation failure in the vicinity of the transformer. High temperatures had been caused by hysteresis losses in a ferro-magnetic conduit carrying the cables in magnetic fields surrounding the transformers. The licensee had implemented design modifications to replace the cables with higher temperature rated ones and to replace the conduit with one made from nonmagnetic material prior to the unit startup which had occurred on July 9, 1994.

The inspectors reviewed the licensee's investigation surrounding the causes of the event. The licensee had determined that potential problems had been previously identified by the turbine supplier in a letter dated August 24, 1981, and a design modification to replace the conduit had been implemented in Unit 1, but not in Unit 2. The licensee had noted that this modification had been flagged complete for Unit 2 in their data base. The licensee reviewed a sample of similarly flagged modifications and had determined that they had been implemented. The inspector concluded that these actions were appropriate.

9.2 (Closed) Licensee Event Report 446/94-022-00: Labeling Error Leading to Inoperability of the Power Range Instrumentation

On November 24, 1994, licensed operators observed that Channel N-41 axial flux difference indicated lower than and operated opposite from the other three channels. The licensee found that the upper and lower detector cables had been inadvertently swapped earlier that same day when the power range module in Channel N-41 was replaced to correct repeated fuse problems. Further investigation by the licensee found that the detector cables were

inadvertently swapped due to labeling differences on the newly installed power module. The licensee reinstalled the detector cables to their proper position, inspected all spare modules to ensure that they were labeled properly, and trained technicians to be more aware of this type of problem. The licensee concluded that this event was isolated. The inspectors reviewed the licensee's documentation of corrective actions and found them to be appropriate.

ATTACHMENT

1 PERSONS CONTACTED

1.1 Licensee Personnel

Bird, R. D., Jr., Nuclear Planning Manager
Blevins, M. R., Plant Manager
Bozeman, D. M., Chemistry Manager
Broughton, T., Work Control Shift Manager for Operations Support
Byrd, R. C., Construction Operations Support Group Manager
Curtis, J. R., Radiation Protection Manager
Davis, D. L., Nuclear Overview Manager
Finneran, J. C., Jr., Civil Engineering Manager
Flores, R., Shift Operations Manager
Grace, W. F., Safety Services Manager
Harvey, S. E., Day Shift Manager
Hope, T. A., Regulatory Compliance Manager
Jenkins, T., Electrical Maintenance Manager
Johnson, S. E., Emergency Plan Supervisor
Justis, T., Information Technology
Kesinger, C. F., Training Projects Manager
LaMarca, J. J., Unit 1 Outage Manager
Lucas, M. L., Maintenance Manager
Marvray, H. A., Maintenance Engineering Manager (Acting)
Meyer, J. W., NSSS and HVAC System Supervisor
Moore, D. R., Operations Manager
Muffett, J. W., Station Engineering Manager
Prince, R. J., Mechanical Maintenance Manager
Rickgauer, C. W., Maintenance Overview Manager
Sly, W. D., Material Coordinator Manager
Snow, D. W., Senior Regulatory Compliance Specialist
Sunseri, M. W., Training Manager
Taylor, J. A., Procurement Engineering Manager (Acting)
Terrel, N. L., Reactor Engineering Supervisor
Terry, C. L., Group Vice President, Nuclear Production

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

2 EXIT MEETING

An exit meeting was conducted on January 11, 1996. During this meeting, the inspectors reviewed the scope and findings of the report. Licensee representatives acknowledged the findings and provided additional clarifying information which was incorporated into this report where appropriate. The licensee did not identify any information provided to, or reviewed by, the inspectors as "proprietary."