UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
611 RYAN PLAZA DRIVE, SUITE 400
ARLINGTON, TEXAS 76011-4005

July 23, 2003

Mr. C. L. Terry, Senior Vice President
and Principal Nuclear Officer
TXU Energy
ATTN: Regulatory Affairs
Comanche Peak Steam Electric Station
P.O. Box 1002
Glen Rose, Texas 76043

SUBJECT: COMANCHE PEAK STEAM ELECTRIC STATION - NRC INTEGRATED INSPECTION REPORT 05000445/2003002 AND 05000446/2003002

Dear Mr. Terry:

On July 5, 2003, the US Nuclear Regulatory Commission (NRC) completed an inspection at your Comanche Peak Steam Electric Station, Units 1 and 2. The enclosed integrated inspection report documents the inspection findings which were discussed on July 9, 2003, with you and other members of your staff.

This inspection examined activities conducted under your licenses as they related to safety and compliance with the Commission's rules and regulations and with the conditions of your licenses. Within these areas, the inspection consisted of selected examination of procedures and representative records, observations of activities, and interviews with personnel. Based on the results of this inspection no findings of significance were identified.

Since the terrorist attacks on September 11, 2001, NRC has issued five Orders and several threat advisories to licensees of commercial power reactors to strengthen licensee capabilities, improve security force readiness, and enhance controls over access authorization. In addition to applicable baseline inspections, the NRC issued Temporary Instruction 2515/148, "Inspection of Nuclear Reactor Safeguards Interim Compensatory Measures," and its subsequent revision, to audit and inspect licensee implementation of the interim compensatory measures required by order. Phase 1 of TI 2515/148 was completed at all commercial power nuclear power plants during Calender Year 2002 and the remaining inspection activities for Comanche Peak Steam Electric Station were completed in May 2003. The NRC will continue to monitor overall safeguards and security controls at Comanche Peak Steam Electric Station.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response will be made available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Should you have any questions concerning this inspection, we will be pleased to discuss them with you.

Sincerely,

/RA/

William D. Johnson, Chief
Project Branch A
Division of Reactor Projects

Dockets: 50-445
50-446
Licenses: NPF-87
NPF-89

Enclosure:
NRC Inspection Report 05000445/2003002 and 05000446/2003002
w/Attachment: Supplemental Information

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ADAMS: √ Yes ☐ No Initials: __WDJ__
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ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION

REGION IV

Dockets:	50-445, 50-446
Licenses:	NPF-87, NPF-89
Report:	05000445/2003002 and 05000446/2003002
Licensee:	TXU Generation Company LP
Facility:	Comanche Peak Steam Electric Station, Units 1 and 2
Location:	FM-56, Glen Rose, Texas
Dates:	April 6 through July 5, 2003
Inspectors:	D. B. Allen, Senior Resident Inspector A. A. Sanchez, Resident Inspector T. R. Farnholtz, Senior Project Engineer J. M. Keeton, Project Engineer
Approved by:	W. D. Johnson, Chief, Project Branch A Division of Reactor Projects

SUMMARY OF FINDINGS

IR 05000445/2003-02, 05000446/2003-02; 04/06/2003-07/05/2003; Comanche Peak Steam Electric Station, Units 1 & 2; Integrated Resident Report.

This report covered a 3-month period of inspection by resident inspectors and project engineers. No findings were identified. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

A. NRC-Identified and Self - Revealing Findings

No findings of significance were identified.

B. Licensee-Identified Violations

None

REPORT DETAILS

Summary of Plant Status

Unit 1 began the report period at essentially 100 percent power. On May 15, 2003, at 2:52 a.m., Units 1 and 2 tripped on main generator load rejection following an electrical fault on the 345 kV Parker line and failure of the protective relays associated with circuit Breaker 8040 to isolate the fault. On May 18, the Unit 1 reactor startup commenced and the unit was synchronized to the grid at 12:38 p.m. On May 19, the unit achieved full power and operated at essentially 100 percent power for the remainder of the report period.

Unit 2 began the report period at essentially 100 percent power. On May 15, 2003, at 2:52 a.m., both Units 1 and 2 tripped as described above. On May 28, the Unit 2 reactor startup commenced and the unit was synchronized to the grid at 12:38 p.m. on May 29. The unit achieved full power on May 30 and operated at essentially 100 percent power for the remainder of the report period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

a. Inspection Scope

On April 23, 2003, the inspectors reviewed Abnormal Operating Procedure ABN-907, “Acts of Nature,” Revision 9, in preparation for severe thunderstorms and possible tornados. The inspectors evaluated whether the licensee adequately addressed actions that should be taken to protect safety-related equipment during severe weather, such as thunderstorms, high winds, and tornados. The inspectors conducted a walkdown of the protected area to assess the threat to risk significant systems from wind-generated missile hazards, due to material stored in the open.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04)

a. Inspection Scope

The inspectors conducted partial walkdowns of the following three risk-significant systems to verify that they were in their proper standby alignment as defined by system operating procedures and system drawings. During the walkdowns, inspectors examined system components for materiel conditions that could degrade system performance. In addition, the inspectors evaluated the effectiveness of the licensee’s problem identification and resolution program in resolving issues which could increase event initiation frequency or impact mitigating system availability.

- Unit 1 Train B containment spray system in accordance with System Operating Procedure (SOP) SOP-204A, "Containment Spray System," Revision 13, while the Train A component cooling water system was inoperable due to scheduled cleaning and inspection of the heat exchanger on May 6, 2003

- Unit 1 emergency diesel Generator 1-02 in accordance with SOP-609A, "Diesel Generator System," Revision 15, and appropriate attachments on May 28, 2003, while emergency diesel Generator 1-01 was removed from service for planned maintenance

- Unit 2 Train A residual heat removal system in accordance with SOP-102A, "Residual Heat Removal System," Revision 13, during outage on Train B residual heat removal system for routine planned maintenance on June 19, 2003

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

.1 Fire Area Tours

a. Inspection Scope

The inspectors assessed the licensee's control of transient combustible materials, the materiel condition and lineup of fire detection and suppression systems, and the materiel condition of manual fire equipment and passive fire barriers during tours of the following six risk-significant areas. The licensee's fire preplans and Fire Hazards Analysis Report were used to identify important plant equipment, fire loading, detection and suppression equipment locations, and planned actions to respond to a fire in each of the plant areas selected. Compensatory measures for degraded equipment were evaluated for effectiveness.

- Fire Zone TB210 - Unit 2 non-safety related switchgear Room 2-267 on May 12, 2003

- Fire Zone ER150 - Units 1 & 2 Train A uninterruptible power supply heating and ventilation room

- Fire Zone EQ149 - Units 1 & 2 Train B uninterruptible power supply heating and ventilation room

- Fire Zone 2SG010 - Unit 2 Train A emergency diesel generator Rooms 84 and 99B on May 29, 2003

- Fire Zone 2SI012 - Unit 2 Train B emergency diesel generator Rooms 85 and 99A on May 29, 2003

- Fire Zone 2SK017A, B, C - Unit 2 feedwater and main steam penetration rooms on June 10, 2003

b. Findings

No findings of significance were identified.

.2 Annual Fire Drill

a. Inspection Scope

The inspectors observed the plant fire brigade during a fire drill on June 4, 2003, to assess its ability to fight fires. The fire drill consisted of a fire in a radiological trash storage container in the Unit 2 side of the fuel building truck bay. The drill also incorporated a contaminated, injured man in close proximity to the fire. Observations focused on the following aspects of the drill:

- Protective clothing/turnout gear is properly donned

- Self-contained breather apparatus (SCBA) equipment is properly worn and used

- Fire hose lines are capable of reaching all necessary fire hazard locations, that the lines are laid out without flow constrictions, the hose is simulated being charged with water, and the nozzle is pattern (flow stream) tested prior to entering the fire area of concern

- The fire area of concern is entered in a controlled manner (e.g., fire brigade members stay low to the floor and feel the door for heat prior to entry into the fire area of concern)

- Sufficient fire fighting equipment is brought to the scene by the fire brigade to properly perform their firefighting duties

- The fire brigade leader's fire fighting directions are thorough, clear, and effective

- Radio communications with the plant operators and between fire brigade members are efficient and effective

- Members of the fire brigade check for fire victims and propagation into other plant areas

- Effective smoke removal operations were simulated
- The fire fighting pre-plan strategies were utilized
- The licensee pre-planned the drill scenario was followed, and that the drill objectives acceptance criteria were met

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures (71111.06)

a. Inspection Scope

The inspectors conducted an inspection of flood protection measures at Comanche Peak Steam Electric Station (CPSES). This included a review of flood analysis documentation and calculations to determine areas in the plant susceptible to flooding from internal sources. Based on that review and a review of the CPSES probabilistic risk assessment summary document, a walkdown was performed on June 17, 2003, which included the Units 1 and 2 safeguards elevation 831' pipe penetration Rooms 1-088 and 2-088 to assess the adequacy of flood protection measures regarding a postulated flood. The walkdown included determining whether mitigating systems defined in the flood analysis were in place and functional.

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance (71111.07)

a. Inspection Scope

The inspectors observed the inspection and cleaning of two risk-significant heat exchangers cooled by the station service water system, the Unit 1 Train A component cooling water heat exchanger on May 7, 2003, and the Unit 1 Train B component cooling water heat exchanger on June 17, 2003. The inspectors reviewed the station service water system fouling monitoring program test data and results for the equipment and dates listed below. The test results were reviewed for inclusion of instrument uncertainties and comparison to appropriate criteria used to determine when these heat exchangers should be cleaned. The frequency of testing was compared to the program requirements.

- Units 1 and 2, both trains of centrifugal charging pump lube oil coolers from January 2002 to May 2003

- Units 1 and 2, both trains of component cooling water heat exchangers from January 2002 to May 2003

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11)

a. Inspection Scope

The inspectors observed a licensed operator training session in the control room simulator and attended the critique on June 12, 2003. The crew was comprised of shift and staff operators. The scenario included: a reactivity manipulation, reactor makeup auto stop relay failure, accidental release of radioactive liquid, steam generator tube leak, steam generator flow and level instrument line leak, and a steam generator tube rupture. Simulator observations included formality and clarity of communications, group dynamics, the conduct of operations, procedure usage, command and control, and activities associated with the emergency plan.

b. Findings

No findings of significance were identified.

1R12 Maintenance Rule Implementation (71111.12)

a. Inspection Scope

The inspectors independently verified that CPSES personnel properly implemented 10 CFR 50.65, “Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants,” for the following equipment performance problems:

- A Forced Loss Rate for Unit 1 of 4.1%, which exceed the action level of 3.5% . This was largely due to the failure of condensate pump Motor 1-01. This was entered into the corrective action program as SMF-2003-001118-00

- Unit 1, Train B residual heat removal Pump 1-02 exceed maintenance rule reliability performance criteria. This train has been placed into the a(1) category of 10 CFR 50.65. This was entered into the corrective action program as SMF 2003-001091-00

The inspectors also independently verified that the corrective actions and responses were appropriate and adequate.

The inspectors reviewed whether the structures, systems, or components (SSCs) were properly characterized in the scope of the Maintenance Rule Program and whether the

SSCs failure or performance problem was properly characterized. The inspectors assessed the appropriateness of the performance criteria established for the SSCs (if applicable).

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessments and Emergent Work Evaluation (71111.13)

a. Inspection Scope

The inspectors reviewed five selected activities regarding risk evaluations and overall plant configuration control. The inspectors discussed emergent work issues with work control personnel and reviewed the potential risk impact of these activities to verify that the work was adequately planned, controlled, and executed. The activities reviewed were associated with:

- Emergency diesel Generator 1-01 out of service while draining component cooling water heat Exchanger 1-01 concurrent with emergent switchyard maintenance on May 5-6, 2003

- Cleaning and inspecting jacket water heat exchanger for emergency diesel Generator 2-01, scheduled maintenance on the motor driven auxiliary feedwater Pump 2-01 and emergent switchyard maintenance on May 6-8, 2003

- Maintenance on electrical Bus 2A2 and motor current collection for heater drain pump and circulating water pump concurrent with scheduled maintenance on Unit 2 Train A safety chilled water to electrical room cooler and emergent maintenance on fault detector relay for switchyard Breaker 8040 on May 30, 2003

- Relay maintenance for 138 kV Breaker 7020 (feeder from DeCordova), failure of Breaker 9812 (supply to 12 kV loop) and subsequent troubleshooting and repair activities in the 138 kV switchyard, request for unscheduled line work on the 345 kV Parker line concurrent with scheduled risk significant maintenance and testing activities on the Unit 1 turbine driven auxiliary feedwater pump and emergency diesel Generators 1-02 and 2-02 during the week of June 16-20, 2003

- A “Red” risk assessment category, moderate to high instantaneous core damage frequency, was entered due to the emergency diesel Generator 1-02 being inoperable (jacket water cooler leak) and the entry into Abnormal Operating Procedure ABN-907, “Acts of Nature,” Revision 9 on June 11, 2003. This was entered into the corrective action program as SMF-2003-001679-00

b. Findings

No findings of significance were identified.

1R14 Personnel Performance During Nonroutine Evolutions and Events (71111.14)

a. Inspection Scope

For the two nonroutine events described below, the inspectors reviewed operator logs, procedure use, plant computer data, and applicable SMFs and interviewed ROs to determine what occurred and to determine if the operator response was in accordance with plant procedures. When applicable the inspectors also attended Plant Event Review Committee meetings.

- On May 9, 2003, indication was lost for breaker position for Breaker 2A4-1, normal supply from Transformer 2UT to non-safety related Bus 2A4. The licensee determined that the breaker could not be electrically tripped, defeating the breaker protective features. Technical Requirements Manual 13.8.32 required the containment penetration overcurrent protection provided by this breaker to be restored within 72 hours. On May 10, 2003, Bus 2A4 was fast transferred to the alternate supply by manually opening Breaker 2A4-1. Breaker 2A4-1 was repaired and returned to normal electrically lineup. The inspectors attended the pre-evolution briefings and monitored the transfer from the control room. SMF-2003-1305-00 was initiated to enter the event into the corrective action program.

- On May 15, 2003, at 2:52 a.m., a dual unit trip occurred due to an electrical fault on the 345 kV Parker line. The inspectors responded to the control room and observed control room activities to establish stable plant conditions and assess the equipment response to the dual unit generator load rejection, plant trip and loss of non-safety related power. The inspectors attended a debriefing of the off-going operation crew following shift turnover. SMF-2003-1365-00 was initiated to enter the event into the corrective action program. See Section 4OA3 for additional details.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors selected five operability evaluations conducted by CPSES personnel during the report period involving risk-significant systems or components. The inspectors evaluated the technical adequacy of the licensee's operability determination, determined whether appropriate compensatory measures were implemented, and determined whether or not other pre-existing conditions were considered, as applicable. Additionally, the inspectors evaluated the adequacy of the CPSES problem identification and resolution program as it applied to operability evaluations. Specific operability evaluations reviewed are listed below:

- Quick Turnaround Evaluation QTE-2003-001365-01-01, Operability evaluation of offsite power sources in regard to loss of the 138 kV DeCordova substation feeder as a result of the 345 kV bus trips on May 15, 2003

- Quick Turnaround Evaluation QTE-2003-001421-01-00, Operability evaluation of Train B Aux / Safeguards / Fuel Building Negative Pressure following identification of missed surveillance on May 20, 2003

- Quick Turnaround Evaluation QTE-2003-001521-01-00, Operability of Unit 2 Main Steam Isolation Valve 2-02 following a higher than normal hydraulic actuator pressure, reviewed June 6, 2003

- SMF-2003-1212-00, Potential insufficient NPSH to the centrifugal charging pumps during gravity feed from the boric acid storage tanks due to nitrogen addition per FDA-2001-960, reviewed on June 17, 2003

- Quick Turnaround Evaluation QTE- 2003-584-00, Operations Guideline 18 Attachment A regarding pressure boundary leakage from ASME class 2 and 3 components, based on Operability guidance from NRC Inspection Manual Part 9900, reviewed on June 18, 2003

b. Findings

No findings of significance were identified.

1R16 Operator Workarounds (71111.16)

a. Inspection Scope

Following the dual unit trip on May 15, the inspectors noted that Valve 1-HV-2491B, motor driven auxiliary feedwater Pump 1-01 to steam Generator 1-01 isolation valve, was closed while the isolation valves for the other steam generators were open. SMF-2003-1379-00 documented that to prevent excessive auxiliary feedwater leakage into steam Generator 1-01, the isolation valve was closed. The inspectors reviewed this condition to determine if the functional capability of the system or human reliability in responding to an initiating event was affected. The inspectors also reviewed the corrective work order that will correct the valve seat leakage.

In addition, compensatory actions for equipment problems, shift orders, and caution tags were reviewed to determine that CPSES personnel were identifying operator workarounds at an appropriate threshold and that the equipment problems were identified in the corrective action program.

b. Findings

No findings of significance were identified.

1R19 Postmaintenance Testing (71111.19)

a. Inspection Scope

The inspectors witnessed or reviewed the results of the postmaintenance tests for the following five maintenance activities:

- Preventative maintenance on Unit 2 Train A safety injection pump and Operability Test OPT-204B, “Train A Safety Injection Pump 2-01 Operability Test,” on April 28, 2003

- Preventative maintenance on Unit 1 emergency diesel Generator 1-01 and Operability Test OPT-214A, “Diesel Generator Operability Test,” Revision 17, on May 29, 2003

- Major inspection of containment spray header isolation Valve 2-HV-4777 on May 13, 2003

- Removal of the magnetic pickup (MPU) signal selector switch and the direct connection of the magnetic pickup to the 701 governor on emergency diesel Generator 2-02 on May 22, 2003

- Repair of the leaking jacket water cooler on emergency diesel Generator 1-02 on June 12, 2003

In each case, the associated work orders and test procedures were reviewed against the attributes in Inspection Procedure 71111, Attachment 19, to determine the scope of the maintenance activity and determine if the testing was adequate to verify equipment operability.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors evaluated the adequacy of periodic testing of important nuclear plant equipment, including aspects such as preconditioning, the impact of testing during plant operations, and the adequacy of acceptance criteria. Other aspects evaluated included test frequency and test equipment accuracy, range, and calibration; procedure adherence; record keeping; the restoration of standby equipment; test failure evaluations; jumper control (if applicable); and the effectiveness of the licensee's problem identification and correction program. The following six surveillance test activities were observed or reviewed by the inspectors:

- Unit 2 Train A containment spray pump surveillance test run in accordance with OPT-205B, "Containment Spray System," Revision 9, performed on April 3, 2003

- Unit 2 turbine driven auxiliary feedwater (AFW) pump surveillance test run in accordance with OPT-206B, "AFW System," Revision 14, performed April 17, 2003

- Unit 2 turbine driven auxiliary feedwater pump discharge to steam Generator 2-04 check valve surveillance test in accordance with OPT-530B, "AFW Check Valve Reverse Flow Test," Revision 0, performed on April 17, 2003

- Unit 2 Train A residual heat removal pump in accordance with Operability Test OPT - 203B, "Train A RHR Pump 2-01," May 1, 2003

- Unit 1 Train A station service water pump in accordance with Operability Test OPT-207A, "Service Water System," Revision 11, May 27, 2003

- Unit 1 Train B safety chilled water recirculation pump in accordance with OPT-209A, " Safety Chilled Water System," Revision 10, performed on June 12, 2003

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

1EP6 Drill Evaluation (71114.06)

a. Inspection Scope

The inspectors observed the emergency exercise conducted on May 14, 2003, with the Blue team. Observations were conducted in the simulator control room and the technical support center and included the opportunities for emergency classification, offsite notification, and protective action recommendations during the scenario. This evaluation included reviewing the scenario and drill objectives, observing licensee performance in the emergency facilities, observing the licensee's critique, and discussing observations and the licensee's findings with the emergency preparedness manager.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

Mitigating Systems

a. Inspection Scope

The inspectors reviewed a sample of performance indicator data submitted by the licensee regarding the mitigating systems cornerstone to verify that the licensee's data was reported in accordance with the requirements of NEI 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 2. The sample included data taken from control room reactor operator logs, the SMFs database, monthly plant performance reports and licensee event reports for April through June 2002 and March 2003, for both Units 1 and 2 for the following performance indicators:

- Safety system unavailability, emergency ac power system
- Safety system unavailability, high pressure injection system
- Safety system unavailability, AFW heat removal system
- Safety system unavailability, residual heat removal system

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

No Visible Oil Level in Residual Heat Removal Pump 1B Lower Bearing Sight Glass

a. Inspection Scope

The inspectors performed a detailed review of the licensee's identification and resolution of a condition where the oil level in the lower bearing sight glass of the 1B residual heat removal pump was lowering to the point that a level was no longer visible. The inspectors reviewed photographs of the sight glass and disassembled pump components, Smart Forms SMF-2001-001245-00 and SMF-2001-001980-00, residual heat removal Pump 1B operating history, Work Order 4-02-144627-00, and Westinghouse Nuclear Services report (TXU P.O. S0398021 6S2). The inspectors also discussed this issue with the system engineer.

b. Findings and Observations

On August 22, 2001, a plant equipment operator noted that the lower bearing sight glass on residual heat removal pump was dry and indicated no oil level. The pump was in service at the time in the shut down cooling mode to support a maintenance outage. The licensee conducted an investigation to determine the cause of the lowering oil level. The licensee's evaluation indicated that several theories were proposed to explain the lowering oil level including a siphoning or wicking effect at the location where the pump shaft passes through the lower bearing reservoir cover. The installation of "windback seals" was performed to minimize the escape of oil laden air through the shaft clearance fit.

Other sources of leakage from the lower bearing reservoir was investigated. The threaded connections at the lower reservoir were inspected for leakage and were disassembled and reassembled using a different type of thread sealant. These actions did not effectively correct the lowering oil level condition.

The licensee monitored and documented the lower bearing reservoir oil level and bearing temperatures during the maintenance outage in August 2001 and again during the period of September 28 through October 3, 2002. These trends indicated that the oil level decreased to a point below the level of the sight glass and then stopped decreasing and remained steady. This was established by a constant bearing temperature and the addition of a known amount of oil after the pump was stopped. The licensee's evaluation of this condition included a discussion of the risk significance. It was established that no oil would be required to be added to the pump during the first 24 hours after an accident initiating event which is the time analyzed in the Probabilistic Risk Assessment.

No definitive cause for this condition was identified as a result of these efforts. The motor was removed and replaced with a spare motor. The original motor was sent to Westinghouse for disassembly and further investigation into the cause of the lowering oil level. The inspectors reviewed the Westinghouse report dated June 20, 2003.

The cause of this condition was established as a mispositioned bead of sealant that was installed at the factory. Photographs indicated that the sealant bead was not properly positioned and did not effectively seal the gap between the lower bearing reservoir and the reservoir cover. This allowed oil to escape the lower reservoir and then be entrained in the motor cooling air flow. In addition, the sealant used to seal the bolt heads that fasten the cover in place may have contributed to the oil leakage.

Westinghouse proposed a modification to this area of the motor involving the installation of a rubber gasket in place of the sealant bead and the use of special washers under the bolt heads. The inspectors discussed this approach with the system engineer. The proposed modification was being evaluated for acceptability.

If approved, the system engineer indicated that the repaired and modified motor would be installed in place of another residual heat removal pump during 1RF10 and the motor modified to better seal this area. The same action would be taken to modify the remaining motors during 2RF08, 1RF11, and 2RF09. This would correct the identified condition on all in-service residual heat removal pump motors and the spare motor.

4OA3 Event Followup (71153)

Dual Unit Trip Due to Loss of 345 kV Switchyard

a. Inspection Scope

On May 15, 2003, at 2:52 a.m., both Units 1 and 2 tripped on main generator load rejection following an electrical fault on the Parker 345 kV line and subsequent failure of the switchyard Breaker 8040 to trip. Unit 2 maintained the normal power to the safety related equipment from the 138 kV offsite sources via Transformer XST1. Unit 1 experienced a successful fast transfer of safety related equipment from XST2 to XST1 upon loss of power to Transformer XST2 from the 345 kV switchyard. As a result, there was no loss of power to the safety related buses and the emergency diesel generators were not called upon to start. All safety related equipment operated as designed. Major control systems, such as atmospheric steam relief valves, operated as designed. The loss of non-safety related power caused a loss of condenser vacuum and the main steam isolation valves closed, as required. The operators stabilized both units and offsite electrical power was restored to the 345 kV switchyard shortly after 5 a.m.

The cause of the loss of the switchyard was a lightning storm and failure of various protective devices in the offsite transmission system. A phase to ground fault occurred on the 345 kV Parker line approximately 4 miles from the CPSES 345 kV switchyard. The fault was not isolated from the switchyard when Breaker 8040 failed to open. The CPSES Units 1 and 2 neutral ground overcurrent relaying tripped as a result of the initial ground fault to prevent the generator stator from exceeding its thermal limits. The operation of the neutral ground actuated the generator lockout relay, opening the generator output breakers and actuating the load rejection circuitry that tripped the turbine and the reactor of each unit.

The CPSES switchyard Breaker 8040 from the Parker line failed to open and isolate the phase to ground fault from the 345 kV switchyard. Both primary and backup fault detection circuitry for breaker 8040 failed to perform their design function. Upon inspection, four separate relay contacts in the protection circuits did not operate properly, either exhibiting high resistance on the contact surface or other failure mechanisms. In the backup trip circuit, the pickup value of the fault detector relay was approximately 30 percent above the desired value. The fault was cleared only after tripping the remote breakers from all offsite sources to the CPSES 345 kV switchyard and tripping of the Unit 1 and 2 generator breakers. The event also caused the loss of power to the 138 kV switchyard from the DeCordova station. The 138 kV and 345 kV transmission systems are interconnected through a transformer in the DeCordova switchyard, and the protective relaying did not prevent isolating the feeder to the CPSES 138 kV switchyard.

The inspectors responded to the site; reviewed operator logs, interviewed operators and the shift manager; and walked down the control boards. The licensee's posttrip review package was reviewed in accordance with procedure Operations Department Administration Manual ODA-108, "Post RPS/ESF Actuation Evaluation," Revision 8.

Unit 1 was restarted and returned to full power on May 19. Unit 2 experienced a turbine generator primary water leak and the leak was repaired prior to returning to full power on May 30, 2003.

b. Findings

No findings of any significance were identified.

4OA6 Meetings, Including Exit

Exit Meeting Summary

The inspectors presented the inspection results to Mr. C. L. Terry, Senior Vice President and Principal Nuclear Officer, and other members of licensee management at the conclusion of the inspection on July 9, 2003.

At the conclusion of this meeting, the inspectors asked the licensee's management whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

ATTACHMENT: SUPPLEMENTAL INFORMATION

ATTACHMENT

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee personnel

M. Blevins, Vice President and Deputy to the Senior Vice President
R. Flores, Vice President Operations
J. Kelley, Vice President, Nuclear Engineering and Support
D. Moore, Director of Nuclear Engineering
C. Terry, Senior Vice President & Principal Nuclear Officer
R. Walker, Manager, Regulatory Affairs

NRC personnel

NONE

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

NONE

LIST OF ACRONYMS

ABN	abnormal operating procedure
AFW	auxiliary feedwater
CFR	*Code of Federal Regulations*
CPSES	Comanche Peak Steam Electric Station
ESF	engineered safety feature
NEI	Nuclear Energy Institute
NPSH	net positive suction head
ODA	Operations Department administrative procedure
OPT	operability test
QTE	quick turnaround evaluation
RHR	residual heat removal
RO	reactor operator
SMF	smart form

SOP	system operating procedure
SSC	structures, systems, or components