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

April 25, 2005

Mr. M. R. Blevins, Senior Vice President
and Chief Nuclear Officer
TXU Power
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 05000445/2005002 AND 05000446/2005002

Dear Mr. Blevins:

On March 24, 2005, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at your Comanche Peak Steam Electric Station, Units 1 and 2, facility. The enclosed integrated inspection report documents the inspection findings which were discussed on March 31, 2005, with Mr. R. Flores 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.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosure 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 05000445/2005002 and 05000446/2005002
w/attachment: Supplemental Information

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ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION

REGION IV

Dockets:	50-445, 50-446
Licenses:	NPF-87, NPF-89
Report:	05000445/2005002 and 05000446/2005002
Licensee:	TXU Generation Company LP
Facility:	Comanche Peak Steam Electric Station, Units 1 and 2
Location:	FM-56, Glen Rose, Texas
Dates:	January 1 through March 24, 2005
Inspectors:	D. Allen, Senior Resident Inspector A. Sanchez, Resident Inspector W. McNeill, Reactor Inspector E. Owen, Reactor Inspector D. Overland, Reactor Inspector G. Replogle, Senior Reactor Inspector T. Brown, Project Engineer
Approved by:	W. D. Johnson, Chief, Project Branch A Division of Reactor Projects
Attachment:	Supplemental Information

SUMMARY OF FINDINGS

Comanche Peak Steam Electric Station, Units 1 and 2
NRC Inspection Report 05000445/2005002, 05000446/2005002

IR 05000445/2005002, 05000446/2005002; 01/01/2005-03/24/2005; Comanche Peak Steam Electric Station, Units 1 & 2; integrated inspection report.

This report covered a three-month period of inspection by two resident inspectors, three regional reactor inspectors, one senior reactor inspector, and one regional project engineer. 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

None.

B. Licensee Identified Violations

None.

REPORT DETAILS

Summary of Plant Status

Comanche Peak Steam Electric Station (CPSES) Unit 1 began the period at essentially 100 percent power. On February 3, 2005, Unit 1 commenced a reactor shutdown to Mode 3 to repair a secondary system leak from Steam Generator 3 Tubesheet Drain Valve 1-MS-0664. The reactor was returned to 100 percent power on February 5, 2005, and remained at essentially 100 percent power for the rest of the inspection period.

CPSES Unit 2 began the period operating at essentially 100 percent power. On February 23, 2005, at 1:53 am, a ground fault occurred on the Stephenville power line to the 138 kV switchyard. Breaker 7050, Stephenville line to the 138 kV switchyard, opened to isolate the fault as expected. Breaker 7020, DeCordova line to the 138 kV switchyard, also opened and failed to reclose. As a result, the 138 kV switchyard was completely de-energized. The turbine driven auxiliary feedwater pump started and turbine power was reduced to 98 percent power to ensure that reactor power would not exceed 100 percent power. On February 24, 2005, reactor power was further reduced to approximately 52 percent power to remove Main Feedwater Pump B from service for turbine control valve repair. On February 25, 2005, the reactor was returned to 100 percent power, and remained at essentially 100 percent power until March 20, 2005. On March 20, 2005, the reactor began a coastdown to refueling outage 2RF08 and ended the inspection period at 95 percent power.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

a. Inspection Scope

The inspectors reviewed Station Administrative Procedure (STA) STA-634, “Extreme Temperature Equipment Protection Program,” Revision 3, and Abnormal Conditions Procedure (ABN) ABN-912, “Cold Weather Preparations/Heat Tracing and Freeze Protection System Malfunction,” Revision 7, to determine if these procedures were adequate to ensure that safety-related equipment would remain operable during freezing weather. On January 31 and February 3, 2005, the inspectors reviewed the control room log of activities associated with the ABN-912 preparations. The inspectors performed partial walkdowns of the following areas, in each unit, to verify that the freeze protection measures in ABN-912 had been implemented prior to the expected onset of freezing conditions.

- Units 1 and 2 Emergency Diesel Generator (EDG) rooms
- Units 1 and 2 turbine buildings and adjacent exterior areas

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment

.1 Partial System Walkdown (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 14, and Operations Testing Procedure (OPT) OPT-205A, "Containment Spray System," Revision 13, while the Train A containment spray system was inoperable for scheduled maintenance on February 8, 2005

- Unit 1 Train B safety injection system in accordance with SOP-201A, "Safety Injection System," Revision 14, while Train A safety injection was out of service for planned maintenance on March 7, 2005

- Unit 1 Train A motor driven auxiliary feedwater pump and Unit 1 turbine driven auxiliary feedwater pump in accordance with OPT-206A, "AFW System," Revision 24, and Drawing M1-206, Revision 19; Drawing M1-206 sheet 1, Revision 13; and Drawing M1-206 Sheet 2, Revision 17, on March 24, 2005.

b. Findings

No findings of significance were identified.

.2 Detailed Semiannual Walkdown (71111.04S)

a. Inspection Scope

The inspectors conducted a detailed semiannual inspection of the 6.9 kV safety related electrical systems for both Units 1 and 2, using SOP-603A, "6900 V Switchgear" Revision 13, SOP-603B, "6900 V Switchgear" Revision 13, OPT-215, "Class 1E Electrical Systems Operability," Revision 12, and system drawings to ascertain if the system and its operating procedures were in accordance with the design and licensing bases of the system. Outstanding maintenance work requests and design issues were reviewed to determine if any impacted the system's ability to operate as designed. The system engineer was interviewed concerning the system's maintenance history and current and long range plans to modify and update system components. A walkdown of the system was performed on March 1 through 3, 2005.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

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 1-SD009 - Unit 1 safeguards building 810 foot elevation, Room 83, on January 12, 2005
- Fire Area 2-SA - Unit 2 safeguards building 790 foot to 810 foot elevations, Train B Emergency Core Cooling System (ECCS) equipment rooms on February 7, 2005
- Fire Area 1-SA - Unit 1 safeguards building 790 foot to 810 foot elevations, Train B ECCS equipment rooms on February 8, 2005
- Fire Zone 1-SG010 - Train A EDG Room 1-084 and Fuel Oil Day Tank Room 1-99B on March 23, 2005
- Fire Zone AA 153/154 - Unit 1 and Unit 2 Train A and B Safety Chiller Rooms 115A and 115B on March 23, 2005
- Fire Zone 2-SE016 - Unit 2 Safeguards Electrical Equipment Room 96 on March 23, 2005

b. Findings

No findings of significance were identified.

1R06 Flood Protection (71111.06)

a. Inspection Scope

The inspectors conducted an inspection of flood protection measures at Comanche Peak. 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 probabilistic risk assessment, a walkdown of the Unit 1 and Unit 2 safeguards buildings, 852'-6", 860', 873'-6", and 880'-6" elevations, was performed on March 9, 2005, to assess the adequacy of the flood protection measures regarding the postulated break of the 4-inch fire piping and inadvertent fire sprinkler actuation. The walkdown included determining whether mitigating systems defined in the flood analysis were in place and functional. Interviews were conducted with the responsible engineer for the flooding calculation and a probabilistic risk analyst concerning the area in question.

b. Findings

No findings of significance were identified.

1R07 Biennial Heat Sink Performance (71111.07B)

a. Inspection Scope

Inspection procedure 71111.07 requires inspecting 2 to 3 heat exchangers for the biennial effort. The inspectors selected 3 safety-related heat exchangers for this inspection, including the: 1) Train A control room air conditioning; 2) Unit 1, Train B, emergency diesel generator jacket water cooler; and 3) Unit 1 Component Cooling Water Heat Exchanger 1-02. For the selected heat exchangers and the ultimate heat sink the inspectors reviewed the surveillance/inspection results, design calculations, chemical controls, Updated Safety Analysis Report specifications, Technical Requirements Manual and Technical Specifications. The inspectors verified that heat exchangers could adequately perform their safety functions under design basis conditions. The inspectors also verified that the licensee took appropriate actions to identify and correct heat exchanger related conditions adverse to quality.

b. Findings

Introduction. The inspectors identified an unresolved item concerning the licensee's control room air conditioning system surveillance test. Specifically, the acceptance criteria did not appear to properly account for differences between test conditions and accident conditions. The licensee performed a bounding operability analysis to demonstrate current operability.

Discussion. Technical Specification Surveillance Requirement 3.7.11.1 required the licensee to test the control room air conditioning system every 18 months to verify that the system can remove the required heat load. The licensee used Procedure OPT-116, "CR AC System Surveillance Test," Revision 3, to satisfy this requirement. The test method determined the amount of excess cooling capacity observed during the surveillance and compares that amount to a chart which was intended to take into account the differences between test and design basis conditions.

The inspector identified two potential concerns with the licensee's practices. First, the licensee's surveillance acceptance criteria were based on a maximum component cooling water temperature of 108° F. However, the worst case component cooling water temperature was 135° F. Second, the surveillance method accounted for only one variable (outside air temperature) when at least two variables exist (outside air temperature and component cooling water temperature). Low component cooling water temperatures would increase the apparent capacity of the chiller when compared to higher temperature water.

Analysis. The licensee performed an initial operability assessment and concluded that the system was capable of performing its design basis function. The inspectors need additional time to review information to determine whether the test methodology adequately demonstrates the equipment heat removal capability under design basis conditions. This issue is unresolved pending further NRC evaluation of the pertinent issues (Unresolved Item 050000445;446/2005002-01). The significance of any issues identified during the additional review will be assessed when closing the unresolved item.

Enforcement. No violation of NRC requirements was identified at this time.

1R11 Licensed Operator Requalification (71111.11Q)

a. Inspection Scope

The inspector observed a licensed operating requalification exam in the control room simulator on March 1, 2005. The simulator examination consisted of two scenarios. The first scenario consisted of: a steam generator tube leak of greater than 75 gallons per day, steam impulse pressure channel failure, a main steam line low pressure safety injection, two stuck rods, and a faulted steam generator. The second scenario consisted of: a failure of a steam generator level transmitter, a letdown leak inside containment, a component cooling water pump trip, a reactor coolant pump sheared shaft, a large break loss of coolant accident, and a residual heat removal system pump trip. 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. The inspector also observed administration of the exam and the implementation of exam security measures.

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 four equipment performance problems:

- The Units 1 and 2 steam dump valves that had unsatisfactory performance testing and timing results between October 2004 and February 2005. This issue was entered into the corrective action program as Smart Form (SMF) SMF-2005-0867-00.

- The Unit 2 personnel airlock outer door functional failures on December 5 and 11, 2004. The expert panel classified this as a repetitive maintenance functional failure and placed this system into a(1) status until December 15, 2006. This issue was entered into the corrective action program as SMF-2004-3921-00, SMF-2004-4007, SMF-2004-4012, and SMF-2005-0164-00.

- The Unit 2 Train B 6.9 kV Switchgear experienced a functional failure on October 19, 2004, when an Agastat relay delayed the fast transfer to the alternate power source, Transformer XST2, when the primary power source, XST1, was lost. This caused the system to exceed the reliability component of the performance criteria and enter a(1) status until October 19, 2006. This issue was entered into the corrective action program as SMF-2004-3528-00.

- The extended, planned outage of the 345 kV West Bus, for reliability enhancing upgrades during the upcoming 2RF08 refueling outage, in excess of the existing performance criteria. The maintenance rule expert panel decided to allow a one time change of the performance criteria for unavailability, and allow a longer outage time for 345 kV West Bus to increase future reliability. This was documented in the Maintenance Rule Review Panel Meeting Minutes 05-0322.

The inspectors reviewed whether the structures, systems, or components (SSCs) that experienced problems were properly characterized in the scope of the Maintenance Rule Program and whether the SSC failure or performance problem was properly characterized. The inspectors assessed the appropriateness of the performance criteria established for the SSCs where applicable. The inspectors also independently verified that the corrective actions and responses were appropriate and adequate.

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:

- Emergent work to repair a pressure regulator air leak on Steam Admission Valve 1-HV-2452-02 in conjunction with scheduled maintenance and testing of the Unit 1 turbine driven auxiliary feedwater pump on January 13, 2005

- Emergent work to replace the oil sight glass/oil bubbler for the Unit 2 turbine driven auxiliary feedwater pump concurrent with scheduled maintenance on safety related Inverter IV2PC2 and Steam Dump Valve 2-TV-2370E on January 25, 2005

- Shutdown of Unit 1 to Mode 3 to repair leaking Steam Generator 1-03 tube sheet drain Valve 1-MS-0664 and the subsequent startup on February 3 and 4, 2005

- Unit 2 downpower to 55 percent power to troubleshoot and repair Main Feedwater Pump 2B on February 24, 2005

- Emergent work to repair damaged insulator on 138 kV line from Stephenville concurrent with scheduled Unit 1 turbine driven auxiliary feedwater pump maintenance and surveillance testing on February 24, 2005

b. Findings

No findings of significance were identified.

1R14 Personnel Performance During Nonroutine Plant Evolutions (71111.14)

a. Inspection Scope

For the nonroutine events described below, the inspectors observed the simulator just-in-time training and reviewed the applicable procedures prior to the evolution. The inspectors attended pre-job briefings and observed portions of the evolution from the control room. Procedural use, communications, coordination between organizations and safe operation of the plant during the evolution were evaluated to ensure risk was minimized and safety was maintained.

- On February 3, 2005, Unit 1 commenced a reactor shutdown in order to repair Steam Generator 3 Tubesheet Drain Valve 1-MS-0664. The inspectors interviewed reactor engineering staff concerning the midcycle shutdown and startup. The inspectors also observed the just in time training for the operations staff responsible for the shutdown and startup of the unit. The licensee repair plan and pre-job briefs were also reviewed and attended.

- On February 3, 2005, the reactor operators performed a Unit 1 startup following the shutdown to repair Valve 1-MS-0664, which was leaking to the floor drain inside containment. The inspector observed the control room activities during the reactor startup, with special attention to reactivity management due to the challenge of decreasing Xenon concentration from decay following the post-shutdown peak and burnup from increasing reactor power. The inspector observed the communication and coordination between the operators and the core performance engineers.

- On February 23, 2005, offsite power was lost to Startup Transformer XST1 due to a ground fault on the Stephenville line and a failure of the DeCordova line to the 138 kV switchyard. The DeCordova line failure was caused by failures of the protective relaying system designed to isolate a line fault from the switchyard. The effect on the plant was a slow transfer of Unit 2 safety related buses to the alternate power supply and automatic actuation of the auxiliary feedwater system, as expected. During the transient, operators reduced turbine load to prevent an overpower excursion. Main Feedwater Pump 2B did not properly respond to the demand for reduced speed. The inspector observed the control room operators stabilize plant conditions and return systems to their normal alignment.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors selected six operability evaluations conducted by CPSES personnel 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:

- Evaluation (EVAL) EVAL-2005-0408-01-00, to determine the operability of Unit 1 Source Range Channel N31 when its indication was below the acceptable channel check value when compared to Channel N32 following the shutdown on February 3, 2005

- Quick Technical Evaluation (QTE) QTE-2005-0406-01-01, to confirm the operability of the Unit 1 reactor coolant pump under frequency reactor trip function with unexpected alarms received during OPT-222A, “RCP UV Relay Test,” Revision 3, reviewed on February 22, 2005

- QTE-2005-0780–01-00, to determine whether Unit 2 was operating above the maximum licensed power of 3458 Mwth following repair of the Main Feedwater Pump 2B on February 25, 2005

- EVAL-2002-0270-02-00, evaluate if Station Service Water Pump 2-02 and Discharge Check Valve 2SW-0373 were operable during the period from November 7, 2001, to January 29, 2002, when the pump was observed to rotate backwards following shutdown, reviewed on March 11, 2005

- EVAL-2004-4007-01-01, to determine the operability of the Unit 2 personnel air lock inner door due to improper installation of the door seal during the period from November 17, 2004, to December 14, 2004, reviewed on March 17, 2005

- EVAL-2005-0395-01-00, to determine the operability of the Unit 2 source range detectors upon the discovery of a missed channel calibration during 2RF07 outage of the High Flux at Shutdown bistable NC-103, reviewed on March 17, 2005

b. Findings

No findings of significance were identified.

1R16 Operator Workarounds (71111.16)

a. Inspection Scope

On January 19, 2005, the inspector reviewed the course of action for the Unit 1 containment sump pump system, as documented in the Plan of the Day, to determine if the functional capability of the containment sump level and flow monitoring system or other reactor coolant system (RCS) leak detection instrumentation were affected. Specifically, the course of action was evaluated to determine the effect on the operator’s ability to identify an RCS leak and implement abnormal or emergency operating procedures. The course of action was also evaluated for the operator’s ability to comply with the specified actions. Operations personnel and control room operators were interviewed to determine the recent history and current condition of the leakage, and the referenced SMF-2004-2680-00 and Course of Action (COA) COA-2004-2680-01-00 were reviewed.

On March 18, 2005, the inspector reviewed the course of action plan for reliability issues associated with the Unit 2 Train B main feedwater pump to determine if human reliability in responding to an initiating event was affected. Specifically, the course of action was evaluated to determine the effect on the operator’s ability to implement abnormal or emergency operating procedures. The Train B main feedwater pump issues included: low steam pressure isolated from the pump, apparent binding during a downpower on

January 8, 2005, and turbine speed divergence from the Train A feedwater pump during power changes. The inspector reviewed recent operational history, referenced SMF-2005-0069-00 and the COA-2005-0069-01.

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 equipment problems were identified in the corrective action program.

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications

.1 Annual Review (71111.17A)

a. Inspection Scope

For the permanent plant modification described below, the inspectors reviewed Final Design Authorizations (FDA) FDA-2003-004038-02-01 and -02, 10 CFR 50.59 screening, implementing work orders, installation and post-installation testing procedures, and observed installation and testing of portions of the modification to verify that design bases, license bases, and performance capability had not been degraded through these modifications.

- The removal of the source range flux doubling actuation of the valves which close to isolate the volume control tank from the charging pump suction line and the valves which open to align the refueling water storage tank to the charging pump suction line. This modification eliminated unexpected actuations during reactor startups. This modification affected both Units 1 and 2 and did require a license amendment.

b. Findings

No findings of significance were identified.

.2 Biennial Review (71111.17B)

a. Inspection Scope

The inspection procedure requires a minimum sample size of five to ten plant modifications. The inspectors reviewed seven permanent plant modification packages and associated documentation, such as 10 CFR 50.59 safety evaluations, applicability determinations and screenings, to verify that they were performed in accordance with regulatory requirements and plant procedures. The inspectors reviewed procedures governing plant modifications to evaluate the effectiveness of the programs for implementing modifications to risk-significant systems, structures, and components, such that these changes do not adversely affect the design and licensing basis of the facility. Procedures and permanent plant modifications reviewed are listed in the attachment to this report. The inspectors interviewed the cognizant design and system engineers for the identified modifications to gain their understanding of the modification packages.

The inspectors evaluated the effectiveness of the licensee's corrective action process to identify and correct problems concerning the performance of permanent plant modifications. In this effort, the inspectors reviewed 12 corrective action documents (Smart Forms listed in the attachment to this report) and the subsequent corrective actions pertaining to licensee-identified problems and errors in the performance of permanent plant modifications.

b. <u>Findings</u>

No findings of significance were identified.

1R19 <u>Postmaintenance Testing (71111.19)</u>

a. <u>Inspection Scope</u>

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

- Replace pressure regulator and diaphragm on Steam Admission Valve 1-HV-2452-2 and calibrate pump speed loop for Unit 1 turbine driven auxiliary feedwater pump in accordance with Work Orders (WO) WO-3-02-335198-01, WO-3-03-326217-01 and OPT-206A, "AFW System," Revision 24, on January 13, 2005 and OPT-603A, "TDAFW Accumulator Check Valve Leak Test," Revision 4, on January 14, 2005

- Unit 1 Train A Containment Spray Pumps 1-01 and 1-03 motor circuit analysis and pump cooler cleaning in accordance with WO-3-03-340011-01, WO-3-03-340013-01, WO-3-04-343848-01 and WO-3-04-343850-01 and OPT-205A, "Containment Spray System," Revision 13, on February 8, 2005

- Unit 1 Safety Injection Pump 1-01 lube oil cooler cleaning in accordance with WO-3-04-343862-01 and OPT-204A, "SI System," Revision 12, on March 7, 2005

- Unit 1 Centrifugal Charging Pump 1-02 lube oil cooler cleaning in accordance with WO-3-04-343859-01 and OPT-201A, "Charging System," Revision 13, on March 21, 2005

- Unit 1 Control Rod Drive Motor Generator Set 1-01 inboard and outboard bearing replacement in accordance with WO-4-05-160404-00, Maintenance Section-Mechanical (MSM) procedure MSM-G0-0201, "Shaft Alignment," Revision 4, Maintenance Section-Electrical (MSE) procedure MSE-G0-4001, “Generic Motor Disconnection and Connection,” Revision 5, and MSE-C0-4321, “Control Rod Motor-Generator Set Rework,” Revision 0, on March 23, 2005

In each case, the associated work orders and test procedures were reviewed in accordance with the inspection procedure to determine the scope of the maintenance activity and to 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; and the effectiveness of the licensee’s problem identification and correction program. The following six surveillance test activities were observed and/or reviewed by the inspectors:

- Unit 2 Containment Spray Pump 2-01 and 2-03, via slave relay K644 and K645 actuation, in accordance with OPT-205B, “Containment Spray System,” Revision 11, OPT-453B, “Train A Safeguards Slave Relay K644 Test,” Revision 3, and OPT-454A, “Train A Safeguards Slave Relay K645 Actuation Test,” Revision 2, on February 1, 2005

- Unit 1 Train A Slave Relay K644 actuation in accordance with OPT-453A, “Train A Safeguards Slave Relay K644 Actuation Test,” Revision 5, on February 8, 2005

- Unit 2 Train A EDG operability test in accordance with OPT-214B, “Diesel Generator Operability Test,” Revision 12 in conjunction with Slave Relay K603 actuation test in accordance with OPT-465B, “Train A Safeguards Slave Relay K603 Actuation Test,” Revision 6, on February 9, 2005

- Unit 1 Residual Heat Removal Pump 1-02, in accordance with procedure OPT-203A, “Residual Heat Removal System,” Revision 14, on February 24, 2005

- Unit 1 turbine driven auxiliary feedwater pump, in accordance with procedure OPT-206A, “AFW System,” Revision 24, on February 24, 2005

- Unit 1 local leak rate tests for electrical penetrations E-0075 and E-48 through E-74 according to procedures OPT-861A, “Appendix J Leak Rate Test of Penetration E-0075,” Revision 1, and OPT-858A, “Appendix J Leak Rate Test of penetration 810' EPA,” Revision 1, on March 1, 2005

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope

The inspectors reviewed the following temporary modification and associated documentation. The temporary modification was verified to be installed and administratively controlled in accordance with plant documentation and procedures.

- The inspectors observed temporary repair of the Unit 1 secondary leak inside containment, via crimping and filling the line downstream of 1-MS-0664, Steam Generator 3 downstream tubesheet drain valve, with sealant on February 3, 2005. The inspectors also reviewed FDA-2004-0692-01-01, WO-4-04-154614-00, and SMF-2004-2680-00.

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 performed on January 26, 2005. Observations in the control room simulator and the emergency operations facility included opportunities for emergency classifications and offsite notifications and were to be included in the licensees’ Drill/Exercise Performance (DEP) performance indicator. The inspectors also reviewed the scenario and drill objectives, observed the licensee’s critique, and discussed observations with the drill evaluators. The inspection verified that the licensee was adequately conducting drills and critiquing drill performance. The inspection also verified the proper accounting of the DEP opportunities.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA2 Problem Identification and Resolution (71152)

a. Inspection Scope

The inspector selected SMF 2001-2793 for detailed review, because it documented a concern that Receiving Unsatisfactory Condition Reports (RUCs) were not described in STA-421, “Initiation of SmartForms,” and there was no guidance in NQA-3.09-11.3, “Receiving Inspection,” to determine when a RUC should be turned into a Smart Form (SMF). It further stated that there were no requirements to trend, determine root cause, or take appropriate corrective actions to prevent reoccurrence. The RUC was considered a lower-tier reporting and tracking system specifically for the identification and resolution of deficiencies of received parts. The inspector reviewed the applicable administrative procedures, including NPS 2.03, “Resolving Discrepancies At Receiving,” interviewed personnel that supervised and implemented the receiving inspections, and reviewed a selection of closed RUCs. SMF-2001-2793-00, EVAL-2001-2793-01-00, SMF-2001-2058-00, EVAL-2001-2058-07-00, ACTN-MAN-2058-16-00, EVAL-2002-2356-02, and Revision 11 of STA-421 were reviewed to determine the corrective actions taken to address the concerns. The inspector identified no RUCs that should have caused the initiation of a SMF. The issues identified in SMF 2001-2793 and further developed during the inspection were evaluated for their potential impact on plant safety. The corrective actions were evaluated for effectiveness, timeliness, and completeness.

b. Findings and Observations

No findings of significance were identified.

.2 Daily Condition Report Review

a. Inspection Scope

As required by Inspection Procedure 71152, "Identification and Resolution of Problems,” and in order to help identify repetitive equipment failures or specific human performance issues for followup, the inspectors performed a daily screening of items entered into the licensee’s corrective action program. This review was accomplished by reviewing the licensee’s computerized corrective action program database (SMFs), reviewing hard copies of selected SMFs and attending related meetings such as Plant Event Review Committee (PERC) meetings.

b. Findings

No findings of significance were identified.

4OA6 Meetings, Including Exit

Exit Meeting Summary

The inspectors presented the results of the permanent plant modification inspection to Mr. B. Hamilton, Project Engineering Manager, and other members of licensee management on February 18, 2005. The inspectors asked the licensee whether any materials retained by the inspectors should be considered proprietary. The licensee identified no proprietary information.

On March 10, 2005, the reactor inspector discussed the biennial heat exchanger inspection with Mr. P. Polefrone, Plant Manger, and other members of the licensee's staff. Some proprietary information was provided during the inspection but it was given back to the licensee before the exit meeting. None of the information was included in this report.

The inspectors presented the resident inspection results to Mr. R. Flores, Vice President of Nuclear Operations, and other members of licensee management on March 31, 2005. The inspectors confirmed that proprietary information was not provided or examined during the inspection.

ATTACHMENT: SUPPLEMENTAL INFORMATION

ATTACHMENT

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

M. Blevins, Senior Vice President & Chief Nuclear Officer
K. Broglie, Responsible Engineer
R. Flores, Vice President Nuclear Engineering
R. Kidwell, Licensing Engineer
B. Hamilton, Project Engineering Manager
B. Henley, Consulting Engineer
T. Hope, Manager, Regulatory Performance
R. Kidwell. Licensing Engineer
M. Killgore, Reactor Engineering Manager
M. Lucas, Director of Engineering
F. Madden, Director, Regulatory Affairs
G. Merka, Regulatory Affairs
P. Polefrone, Plant Manager
F. Powers, Project Engineer
D. Weyandt, System Engineer
D. Wilder, Radiation and Industrial Safety Manager, Radiation and Industrial Safety
J. Wren, Installation Supervisor

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000445;446/2005002-01	URI	Nonconservative control room heat exchanger testing (Section 1R07)

Opened and Closed

NONE

Closed

NONE

Discussed

NONE

DOCUMENTS REVIEWED

Design Basis Documents

Number	Title	Revision
DBD-ME-014-01	Turbine/Moisture Separator Reheater	14
DBD-ME-014-04	Turbine Control System	7
DBD-ME-028	Classification of Structures, Systems and Components	11
DBD-ME-218	Instrument Air System	15
DBD-ME-229	Component Cooling Water System	28
DBD-ME-233	Station Service Water System	13
DBD-ME-250	Reactor Coolant System	25

Final Modification Authorizations

Number	Title	Revision
FMA-00-3111-1	Unit 1 Thermal Uprate	1
FMA-00-3113-1	Unit 1 Replace High Pressure Turbine	1
FMA-01-0158-4	Instrument Air Compressor/Dryer	5
FMA-01-0158-5	Instrument Air Compressor/Dryer	2
FMA-01-0960-1	Add Unit 2 Nitrogen Sparger in Boric Acid Tank	2
FMA-02-1634-3	Component Cooling Water Thermal Relief Valves	3
FMA-02-1634-4	Component Cooling Water Thermal Relief Valves	5
FMA-02-2294-1	Remove Excessive Control Room Noise from Air Conditioner Compressors	10
FMA-02-3002-1	Re-rout Service Water Piping	2

Probabilistic Risk Analysis System Notebooks

Number	Title	Revision
R&R-PN-002	Component Cooling Water	2
R&R-PN-006	Station Service Water	2

Number	Title	Revision
R&R-PN-010	Reactor Coolant System	2
R&R-PN-018	Instrument Air	2
R&R-PN-023B	Turbine Plant Cooling Water	2

Procedures

Number	Title	Revision
ECE-5.01	Design Control Program	8
ECE-5.01-08	Electronic Design Change Process	7
2CP-PT-58-02	“Residual Heat Removal at Hot Functional,”	3
OPT-116	“CR AC System Surveillance Test,”	3
STA-716	Modification Process	16
STA-734	“Service Water System Fouling Monitoring Program,”	3

Training Manuals

Number	Title	Revision
LO21.DCS.MT1	BASIC OPERATOR DIGITAL CONTROL	01/26/04
OP51.SYS.IA1	INSTRUMENT AIR	12/16/03
OP51.SYS.MG1	MAIN GENERATOR	01/08/04
OP51.SYS.MT1	MAIN TURBINE0	01/20/04
OP51.SYS.RC1	REACTOR COOLANT SYSTEM	08/16/02

Smart Forms

SMF-2000-2967-01	SMF-2004-003695-00	SMF-2004-004058-00
SMF-2002-1043-00	SMF-2004-003697-00	SMF-2004-004105-00
SMF-2002-2433-00	SMF-2004-0036724-00	SMF-2004-004115-00
SMF-2003-0009-00	SMF-2004-003739-00	SMF-2005-000024-00
SMF-2003-1266-00	SMF-2004-003757-00	SMF-2005-000032-00
SMF-2003-1503-00	SMF-2004-003831-00	SMF-2005-000082-02

Calculations

093 “Hydraulic Analysis of CCW system,” Revision 1

15454, “Service Water System Train A Fluid Transient Analysis for Pump Trip,” Revision 2

2-ME-0006, “Station Service Water System Steady State Hydraulic Calculations - Evaluation of Unit 1 Calculation and its Applicability to Unit 2,” Revision 0

2-ME-0171, “Hydraulic Analysis of the CCW System,” Revision 0

DBD-ME-229, “Component Cooling Water System,” dated March 9, 2005

F34 “SW Study of Vapor Collapse During Pump Trip Test,” Revision 0

IC(S)-0012, “Emergency Diesel Generator Package Jacket Water Heat Exchanger SSW Outlet Flow Loop Accuracy Calculation,” Revision 1

ME(B)-391, “Minimum Allowable Service Water Flow to Diesel Generators,” Revision 3

ME-CA-0011-3075, “Diesel Jacket Heat Exchanger Fouling Factor Analysis,” Revision 2

ME-CA-0304-3331, “Control Room HVAC TS Surveillance of A/C Units,” Revision 0

RXE-LA-CPX/0-018, “Ultimate Heat Sink and Maximum Sump Temperatures,” Revision 4

RXE-LA-CPX/0-019, “RHR Tube-side Temperatures, Flow Rates and Heat Exchanger Input for CONTEMPT-LT1028-TV MSLB Analysis and HX Input for LOCA,” Revision 1

X-EB-304-4, “Cooling Capacity of Control Room Air Conditioners,” Revision 4

Work Orders

3-01-314431-01
3-01-328363-01
3-02-342677-01
3-02-342680-01
3-02-342680-02
3-02-342680-03
3-02-328363-01
3-02-314431-01
3-03-314431-01
3-03-328363-01
3-03-342677-01
3-03-342677-02
3-03-342677-03
3-03-342680-01
4-01-134504-01
4-01-134503-01

Miscellaneous

Number	Title	Revision
WCAP-15142	Comanche Peak Steam Electric Station Units 1 And 2	2

Number	Title	Revision
ER-ME104	Evaluation of Comanche Peak Steam Electric Station Balance of Plant Systems, Structures, and Components for a Proposed Power Uprate	3

“Operation and Maintenance Instruction Manual for R-12 Condenser”

Inspection photographs of component cooling water, emergency diesel generator jacket cooling water and decay heat removal heat exchangers

LIST OF ACRONYMS

ABN	Abnormal Conditions Procedure
CFR	*Code of Federal Regulations*
COA	course of action
CPSES	Comanche Peak Steam Electric Station
EDG	emergency diesel generator
EVAL	evaluation
FDA	final design authorization
NRC	Nuclear Regulatory Commission
OPT	operability test
PERC	plant event review committee
QTE	quick technical evaluation
RCS	reactor coolant system
RUC	receiving unsatisfactory condition report
SMF	Smart Form
SOP	system operating procedure
STA	station administrative procedure
WO	work order