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

May 4, 2007

Mike Blevins, Senior Vice President
and Chief Nuclear Officer
TXU Power
ATTN: Regulatory Affairs
Comanche Peak Steam Electric Station
P.O. Box 1002
Glen Rose, TX 76043

SUBJECT: COMANCHE PEAK STEAM ELECTRIC STATION - NRC INTEGRATED INSPECTION REPORT 05000445/2007002 AND 05000446/2007002

Dear Mr. Blevins:

On March 23, 2007, 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 29, 2007, with Mr. M. Lucas 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. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

The report documents one NRC identified finding of very low safety significance (Green). The finding was determined to involve a violation of NRC requirements. However, because of the very low safety significance and because it was entered into your corrective action program, the NRC is treating the finding as a noncited violation (NCV) consistent with Section VI.A.1 of the Enforcement Policy. If you contest any NCV in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN.: Document Control Desk, Washington DC 200555-0001; with copies to the Regional Administrator, Region IV, 611 Ryan Plaza Drive, Suite 400, Arlington, Texas 76011-4005; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the Comanche Peak Steam Electric Station.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response (if any) 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/

Claude E. Johnson, Chief
Project Branch A
Division of Reactor Projects

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

Enclosure:
NRC Inspection Report 05000445/2007002
and 05000446/2007002 w/attachment:
Supplemental Information

cc w/Enclosure:
Fred W. Madden, Director
Regulatory Affairs
TXU Power
P.O. Box 1002
Glen Rose, TX 76043

George L. Edgar, Esq.
Morgan Lewis
1111 Pennsylvania Avenue, NW
Washington, DC 20004

Terry Parks, Chief Inspector
Texas Department of Licensing
and Regulation
Boiler Program
P.O. Box 12157
Austin, TX 78711

The Honorable Walter Maynard
Somervell County Judge
P.O. Box 851
Glen Rose, TX 76043

Richard A. Ratliff, Chief
Bureau of Radiation Control
Texas Department of Health
1100 West 49th Street
Austin, TX 78756-3189

Environmental and Natural
Resources Policy Director
Office of the Governor
P.O. Box 12428
Austin, TX 78711-3189

Brian Almon
Public Utility Commission
William B. Travis Building
P.O. Box 13326
Austin, TX 78711-3326

Susan M. Jablonski
Office of Permitting, Remediation
and Registration
Texas Commission on
Environmental Quality
MC-122
P.O. Box 13087
Austin, TX 78711-3087

Electronic distribution by RIV:
Regional Administrator **(BSM1)**
DRP Director **(ATH)**
DRS Director **(DDC)**
DRS Deputy Director **(RJC1)**
Senior Resident Inspector **(DBA)**
Branch Chief, DRP/A **(CEJ1)**
Senior Project Engineer, DRP/A **(TRF)**
Team Leader, DRP/TSS **(FLB2)**
RITS Coordinator **(MSH3)**
DRS STA **(DAP)**
D. Cullison, OEDO RIV Coordinator **(DGC)**
ROPreports
CP Site Secretary **(ESS)**

SUNSI Review Completed: _CEJ__ ADAMS: √ Yes ☐ No Initials: ___CEJ____
√ Publicly Available ☐ Non-Publicly Available ☐ Sensitive √ Non-Sensitive

R:_REACTORS_CPSES\2007\CP2007-02 DBA.wpd

RIV:RI:DRP/A	SPE:DRP/A	SRI:DRP/A	C:DRS/EB1	C:DRS/OB
AASanchez;mjs	TRFarnholtz	DBAllen	WBJones	ATGody
T-TRF	***/RA/***	***T-TRF***	***CPaulk For***	***TOM for***
4/30/07	4/25/07	4/30/07	4/24/07	4/25/07
C:DRS/PSB	C:DRS/EB2	C:DRP/A		
MPShannon	LJSmith	CEJohnson		
/RA/	***/RA/***	***/RA/***		
4/27/07	4/22/07	5/4/07		

OFFICIAL RECORD COPY T=Telephone E=E-mail F=Fax

U.S. NUCLEAR REGULATORY COMMISSION

REGION IV

Dockets:	50-445, 50-446
Licenses:	NPF-87, NPF-89
Report:	05000445/2007002 and 05000446/2007002
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 23, 2007
Inspectors:	D. Allen, Senior Resident Inspector A. Sanchez, Resident Inspector T. McKernon, Senior Operations Engineer J. Drake, Operations Engineer K. Clayton, Operations Engineer P. Elkmann, Emergency Preparedness Inspector R. Kopriva, Senior Reactor Inspector, Engineering Branch 1 W. Sifre, Senior Reactor Inspector, Engineering Branch 1 R. Azua, Reactor Inspector, Engineering Branch 1 G. George, Reactor Inspector, Engineering Branch
Approved by:	Claude Johnson, Chief, Project Branch A Division of Reactor Projects

SUMMARY OF FINDINGS

IR 05000445/2007002, 05000446/2007002; 01/01/2007-03/23/2007; Comanche Peak Steam Electric Station, Units 1 and 2; Surveillance Testing.

This report covered a 3-month period of inspection by two resident inspectors, three Operations Engineers, four Engineering Branch Inspectors, and an Emergency Preparedness Inspector. One Green noncited violation was identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter 0609, "Significance Determination Process." Findings for which the significance determination process does not apply may be Green or may be assigned a severity level after NRC management review. 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

Cornerstone: Mitigating Systems

Green. An NRC identified noncited violation of Technical Specification 5.4.1.e was identified for the failure to establish, implement and maintain written procedures for the inservice testing program. STA-711, "Inservice Testing Program for Pumps and Valves" required a new set of reference values be determined following pump replacement and all subsequent test results be compared to the new reference values. Station Service Water Pump 2-02 was declared operable on October 19, 2006, following pump replacement and, although the new pump's performance was fully acceptable, the inservice testing requirements to establish new reference values were not performed and subsequent test results were not compared to the new reference values. On March 13, 2007, the licensee provided technical justification for the operability of Station Service Water Pump 2-02, based, in part, on comparison of the new pump performance with the design flow requirements.

This violation is more than minor because it resulted in a condition where there was a reasonable doubt of the operability of the pump, and programmatic deficiencies were identified in the Inservice Testing Program that could lead to significant errors if not corrected. The violation affected the mitigation system cornerstone objective to ensure the capability of the station service water system and the attribute of human performance. The finding has very low safety significance because the pump was always fully capable of performing its safety function. The cause of the finding has a crosscutting aspect in the area of human performance with a resources component, in that, the licensee failed to ensure complete, accurate and up-to-date procedures were available and adequate to implement the inservice testing program (Section 1R22).

B. Licensee Identified Violations

None.

REPORT DETAILS

Summary of Plant Status

Comanche Peak Steam Electric Station (CPSES), Unit 1 began the reporting period at 100 percent power. The unit began power coastdown on February 17, 2007, and commenced a reactor shutdown on February 24, 2007, at 10:00 a.m. to begin refueling outage 1RF12. The reactor was manually tripped and the unit entered Mode 3 at 12:00 noon that same day. The unit remained in the outage through the remainder of the reporting period.

CPSES Unit 2 operated at essentially 100 percent power for the entire reporting period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01)

a. Inspection Scope

The inspectors reviewed Abnormal Condition Procedure (ABN) ABN-912, “Cold Weather Preparations/Heat Tracing and Freeze Protection System Malfunction,” Revision 7, Section 2, “Cold Weather Preparations,” in the Unit 1 control room in anticipation of colder weather conditions. The inspectors reviewed the Procedure ABN-912 attachments and control room log to verify that plant cooling units and dampers had been aligned for cold weather and that temperatures were being monitored in accordance with the attachments. On March 2, 2007, the inspectors walked down Units 1 and 2 emergency diesel generators (EDGs) and the common control room heating, ventilation, and air conditioning system for overall readiness for expected cold weather.

The inspectors completed two samples.

b. Findings

No findings of significance were identified.

1R02 Evaluations of Changes, Tests, or Experiments (71111.02)

a. Inspection Scope

The inspectors reviewed the effectiveness of the licensee’s implementation of changes to the facility structures, systems, and components (SSC); risk-significant normal and emergency operating procedures; test programs; and the updated final safety analysis report in accordance with 10 CFR 50.59, "Changes, Tests, and Experiments." The inspectors utilized Inspection Procedure 71111.02, "Evaluation of Changes, Tests, or Experiments," for this inspection.

The inspectors reviewed six safety evaluations performed by the licensee since the last NRC inspection of this area at CPSES. The evaluations were reviewed to verify that licensee personnel had appropriately considered the conditions under which the licensee may make changes to the facility or procedures or conduct tests or experiments without prior NRC approval. The inspectors reviewed three licensee-performed applicability determinations and 15 screenings, in which licensee personnel determined that evaluations were not required, to ensure that the exclusion of a full evaluation was consistent with the requirements of 10 CFR 50.59. Evaluations, screenings, and applicability determinations reviewed are listed in the attachment to this report.

The inspectors reviewed and evaluated a sample of recent licensee condition reports to determine whether the licensee had identified problems related to 50.59 evaluations, entered them into the corrective action program, and resolved technical concerns and regulatory requirements. The reviewed condition reports (SMART FORMS) are identified in the Attachment.

The inspection procedure specifies that the inspectors review a minimum sample of six licensee safety evaluations and 12 applicability determinations and screenings (combined). The inspectors completed a review of six licensee safety evaluations and a combination of 18 applicability determinations and screenings.

Additional samples of Inspection Procedure 71111.02 “Evaluations of Changes, Tests, or Experiments” will be located in NRC Inspection Report 05000445/2007006 covering the 10 CFR 50.59 reviews performed for the Steam Generator and Reactor Vessel Head Replacement Project.

b. Findings

No findings of significance were identified

1R04 Equipment Alignment (71111.04)

.1 Partial System Walkdown (71111.04)

a. Inspection Scope

The inspectors: (1) walked down portions of the below listed risk important systems and reviewed plant procedures and documents to verify that critical portions of the selected systems were correctly aligned; and (2) compared deficiencies identified during the walkdown to the licensee's corrective action program to ensure problems were being identified and corrected.

- 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 16, while the Train A containment spray system was inoperable for scheduled surveillance, on January 29, 2007

- Unit 2 Train B centrifugal charging system while Train A was out-of-service for maintenance, in accordance with SOP-103B, "Chemical and Volume Control System," Revision 11, on January 30, 2007

- Unit 2 Train A safety injection system while Train B was out-of-service for maintenance, in accordance with SOP-201B, "Safety Injection System," Revision 6, on February 13, 2007

- Unit 1 Train A station service water (SSW) system in accordance with SOP-501A, "Station Service Water System," Revision 16, and OPT-207A, "Service Water System," Revision 13, after realignment from the Train A outage during 1RF12, on March 20, 2007

The inspectors completed four samples.

b. Findings

No findings of significance were identified.

.2 Detailed Semiannual System Walkdown (71111.04S)

a. Inspection Scope

The inspectors conducted a detailed inspection of the spent fuel pool cooling system to verify the functional capability of the system as described in the design basis documents. During the walkdowns, inspectors examined system components for correct alignment, for electrical power availability, and for material conditions of structural components that could degrade system performance. In addition, the inspectors referenced and used the following documents to verify proper system alignment and setpoints:

- Design Basis Document (DBD) DBD-ME-235, "Spent Fuel Pool Cooling and Cleanup System," Revision 15

- SOP-506, "Spent Fuel Pool Cooling and Cleanup System," Revision 17

- CPSES Drawing M1-0235, "Flow Diagram Spent Fuel Pool Cooling and Cleanup System," Revision CP-19 and 21

The inspectors also reviewed recent corrective action documents, system health reports, outstanding work requests, and design issues to determine if any of these items could effect the system's ability to perform as designed. The inspectors interviewed appropriate plant staff regarding the system's maintenance history. A field walkdown was completed during the weeks of March 5 and 19, 2007.

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05Q)

Fire Area Tours

a. Inspection Scope

The inspectors walked down the listed plant areas to assess the material condition of active and passive fire protection features and their operational lineup and readiness. The inspectors: (1) verified that transient combustibles and hot work activities were controlled in accordance with plant procedures; (2) observed the condition of fire detection devices to verify they remained functional; (3) observed fire suppression systems to verify they remained functional; (4) verified that fire extinguishers and hose stations were provided at their designated locations and that they were in a satisfactory condition; (5) verified that passive fire protection features (electrical raceway barriers, fire doors, fire dampers, steel fire proofing, penetration seals, and oil collection systems) were in a satisfactory material condition; (6) verified that adequate compensatory measures were established for degraded or inoperable fire protection features; and (7) reviewed the corrective action program to determine if the licensee identified and corrected fire protection problems.

- Fire Zone AA21D - Units 1 and 2 Auxiliary Building Elevation 831' on February 10, 2007

- Fire Zone 1SA - Unit 1 Train B emergency core cooling systems (ECCS) equipment rooms Elevations 773', 790', 810', and 831' on February 10, 2007

- Fire Zone AA 153/154 - Units 1 and 2 Train A and B safety chiller rooms, Elevation 778' on February 16, 2007

- Fire Zone 2SB2A - Unit 2 Train A ECCS pump rooms, Elevation 773' on February 16, 2007

- Fire Zone 1CA - Unit 1 containment, all elevations on March 2, 2007

- Fire Zone 2SA- Unit 2 Train B ECCS equipment rooms Elevations 773', 790', 810', and 831' on March 5, 2007

The inspectors completed six samples.

b. Findings

No findings of significance were identified.

1R07 Heat Sink Performance (71111.07)

a. Inspection Scope

The inspectors reviewed the licensee's program for maintenance and testing for the eight risk-important heat exchangers listed below. The inspectors performed the review to ensure that these heat exchangers are capable of performing their required safety function during the design basis accident. Specifically, the inspectors observed the physical condition before and after cleaning activities and verified that the frequency of monitoring and inspection was sufficient to detect degradation prior to loss of heat removal capabilities below design requirements. Corrective action documents and design basis documents were also reviewed by the inspectors. The service water system and fouling monitoring program manager was also interviewed. The following heat exchangers were reviewed for this inspection:

- On February 13, 2007, the inspectors observed the as found, cleaning, and as left condition of the Unit 2 Safety Injection Pump 2-02 lube oil cooler.

- On February 20, 2007, the inspectors interviewed the system engineer and observed the cleaning and as left condition of the Unit 2 Centrifugal Charging Pump 2-02 lube oil cooler.

- On March 4, 2007, the inspectors observed the as found condition of the Unit 1 Train B EDG jacket water cooler.

- On March 20, 2007, the inspector interviewed the system engineer and discussed the performance and condition of all four component cooling water heat exchangers.

- On March 20, 2007, the inspectors interviewed the system engineer and reviewed the as found, cleaning, and as left condition of the Unit1 Train B EDG jacket water cooler.

The inspectors completed eight samples.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11)

.1 Biennial Inspection (71111.11B)

a. Inspection Scope

The inspectors: (1) evaluated examination security measures and procedures for compliance with 10 CFR 55.49; (2) evaluated the licensee's sample plan for the written examinations for compliance with 10 CFR 55.59 and NUREG-1021, as referenced in the facility requalification program procedures; and (3) evaluated maintenance of license conditions for compliance with 10 CFR 55.53 by review of facility records (medical and administrative), procedures, and tracking systems for licensed operator training, qualification, and watchstanding. In addition, the inspectors reviewed remedial training and examinations for examination failures for compliance with facility procedures and responsiveness to address areas failed. The inspectors also verified that on-shift operators requiring prescription lenses for self-containment breathing apparatus (SCBA) maintained their lenses secured in the control room.

Furthermore, the inspectors (1) interviewed seven personnel (four operators, two instructors/evaluators, and a training supervisor) regarding the policies and practices for administering examinations; (2) observed the administration of two dynamic simulator scenarios to two requalification crews by facility evaluators, including an engineering department manager, who participated in the crew and individual evaluations; and (3) observed four facility evaluators administer five job performance measures (JPM), including two in the control room simulator in a dynamic mode, and three in the plant under simulated conditions. Each JPM was observed being performed by at least two requalification candidates.

The inspectors also reviewed the biennial written examinations including two remediation written examinations for a reactor operator and a senior reactor operator. The inspectors verified question level of difficulty, knowledge level, and overlap between successive exams and remediation exams. Additionally, quality audits and training self-assessments, and training management meeting minutes were reviewed to ascertain the health of their training feedback processes.

Of the 77 licensed operators taking the biennial examinations, 1 staff license failed a JPM and 1 reactor operator and 1 senior reactor operator failed the written examination. The inspectors also reviewed the remediation process for one individual, a JPM failure. The inspectors also reviewed the results of the annual licensed operator requalification operating examinations for 2006 and 2007. The results of the examinations were also reviewed to assess the licensee's appraisal of operator performance and the feedback of that performance analysis to the requalification training program. Inspectors also observed the examination security maintenance during the examination week.

b. Findings

No significant findings were identified.

.2 Resident Inspector Quarterly Review (71111.11Q)

a. Inspection Scope

The inspectors observed a licensed operator requalification training scenario in the control room simulator on February 16, 2007. The scenario began with a discussion of the Integrated Plant Operations (IPO) procedure concerning reduced inventory, changes involving the temporary reactor vessel head, and possible loss of reactor coolant system (RCS) heat removal. The operations crew briefed the action of reducing RCS inventory to 56 inches in accordance with IPO-010A. A loss of the Train B residual heat removal (RHR) pump event occurred during the inventory reduction. Then the Train A RHR pump began to experience erratic current and flow readings. The Train A pump was manually secured. Abnormal condition procedure ABN-104 was entered due the loss of the RHR system at reduced inventory. Inventory continued to decline, due to an RCS leak, as operators began to reestablish heat removal. The scenario was terminated after operators established RCS hot leg injection via the safety injection pumps prior to RCS temperature reaching 212 degrees.

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 inspectors also verified that evaluators and operators were identifying crew performance problems as applicable.

On February 14, 2007, the inspectors also observed a requalification classroom training session regarding the switchyard system changes, system operation, as well as industry events. On February 16, 2007, the inspectors observed classroom training regarding the upcoming Unit 1, Cycle 13 reactor core characteristics following steam generator replacement.

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R12 Maintenance Rule Implementation (71111.12)

a. Inspection Scope

The inspectors reviewed the sample listed below for items such as: (1) appropriate work practices; (2) identifying and addressing common cause failures; (3) scoping in accordance with 10 CFR 50.65(b) of the maintenance rule; (4) characterizing reliability issues for performance; (5) trending key parameters for condition monitoring; (6) charging unavailability for performance; (7) classification and reclassification in accordance with 10 CFR 50.65(a)(1) or (a)(2); and (8) appropriateness of performance criteria for SSCs/ functions classified as (a)(2) and/or appropriateness and adequacy of goals and corrective actions for SSCs/ functions classified as (a)(1). In addition, the inspectors specifically reviewed events where ineffective equipment maintenance has resulted in invalid automatic actuations of Engineered Safeguards Systems affecting the operating units, when applicable. Items reviewed included the following:

- Spent fuel pool cooling system performance, reviewed on March 19, 2007

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

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

a. Inspection Scope

The inspectors reviewed 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:

- Replacement of Reactor Makeup Water Pump 2-01 to Makeup Water Header Isolation Valve XDD-0103 and related freeze seal, which isolated makeup water to the Unit 2 RCS for approximately 20 hours with the unit at 100 percent power on January 4, 2007

- Rescheduling of the Unit 1 Train B solid state safeguards sequencer undervoltage relay test due to an Energy Reliability Council of Texas (ERCOT) request to minimize maintenance that might result in a loss of generation because of severe winter weather and available spinning reserves on January 17, 2007

- Emergent troubleshooting and repair of Unit 1 Anticipated Transient Without Scram (ATWS) Mitigating System Actuation Circuitry (AMSAC) system with electric grid alerts and scheduled maintenance and testing of Unit 1 Train A EDG, safety-related inverters, and reactor protection system surveillances during the week of January 29, 2007

- Performance of the load test for the Outside Lift System, the crane and lift structure outside the Unit 1 containment built for the steam generator and reactor head replacement, coincident with an ERCOT advisory for reduced spinning electrical reserves on February 9, 2007

- The Unit 1RF12 Outage Risk Assessment and defense-in-depth contingency plans (DIDCP) on February 23-26, 2007

- Outage of Unit 1 non-safeguards component cooling water train, concurrent with full core offload to Spent Fuel Pool X-01, resulting in a configuration of only one train of heat removal available for the spent fuel pool cooling system (Unit 2 non-safeguards component cooling water train, which would be tripped on a Unit 2 loss of offsite power or safety injection), as evaluated in DIDCP 1RF-03, reviewed on March 7, 2007

The inspectors completed six samples.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors: (1) reviewed plant status documents such as operator shift logs, emergent work documentation, deferred modifications, and standing orders to determine if an operability evaluation was warranted for degraded components; (2) referred to the Updated Safety Analysis Report and design basis documents to review the technical adequacy of licensee operability evaluations; (3) evaluated compensatory measures associated with operability evaluations; (4) determined degraded component impact on Technical Specifications (TSs); (5) used the significance determination process to evaluate the risk significance of degraded or inoperable equipment; and (6) verified that the licensee had identified and implemented appropriate corrective actions associated with degraded components. The inspectors interviewed appropriate licensee personnel to provide clarity to operability evaluations, as necessary. Specific operability evaluations reviewed are listed below:

- Smart Form (SMF) SMF-2006-003263-00, to determine the operability of the Unit 2 EDG with Ultra Low Sulfur Diesel fuel, reviewed January 29, 2007

- DIDCP for Maintaining Unit 1 Containment Pressure DIDCP 1RF-22 and Evaluation (EVAL) EVAL-2005-000658-03-00, to determine the operability of Unit 1 containment with the proposal to cut the containment liner during Modes 5 and 6, reviewed on March 5, 2007

- DIDCP for Temporary Power of Unit 1 SSWP 1RF-21, provided implementation steps and evaluation of the operability of Unit 1 SSWP to support Unit 2 operation during the refueling outage, including the potential for a dropped load to damage the safety-related power source to the Unit 1 SSWP, reviewed on March 9, 2007

- EVAL-2007-005556-01-02, to determine SSWP 2-02 operability following pump replacement and failed surveillance test on February 21, 2007, reviewed the week of March 12, 2007

- EVAL-2006-004030-02-00 for ECCS train operability following personnel entries into

Units 1 and 2 containment recirculation sumps at full reactor power, reviewed March 21, 2007

- EVAL-2006-004064-04-00 for Unit 2 RCS due to a leak in the hydraulic line to Steam Generator 2-04 upper lateral hydraulic snubber, reviewed March 23, 2007

The inspectors completed six samples.

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications (71111.17B)

a. Inspection Scope

The inspectors reviewed permanent plant modification documentation related to the steam generator and reactor vessel head replacement project for Unit 1. The results of Inspection Procedure 71111.17B "Permanent Plant Modifications," covering the biennial permanent plant modifications will be documented separately in NRC Inspection Report 05000445/2007006, developed specifically for the Steam Generator and Reactor Vessel Head Replacement Project. No permanent plant modifications unrelated to the steam generator replacement project were reviewed.

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 maintenance activities:

- Unit 2, Train B EDG following replacement of the right bank number 3 fuel injector pump in accordance with Procedure OPT- 214B, "Diesel Generator Operability Test," Revision 13, observed on January 24, 2007

- Unit 1 Motor Driven Auxiliary Feedwater Pump SSW Suction Valve 1-HV-2481, following a major inspection of the motor operator, in accordance with OPT-502A, "AFW/SSW Crosstie Valves," Revision 8, reviewed on January 24, 2007

- Unit 2 Centrifugal Charging Pump 2-01, following lube oil cooler cleaning, and motor oil change, in accordance with OPT-201B, "Charging System," Revision 7 and SOP-103B, "Chemical and Volume Control System," Revision 11, observed on January 30, 2007

- Unit 1 Train B Safety Chilled Water Recirculation Pump 1-06, following an oil change, lube oil cooler cleaning, and replacement of the motor cooling fan, in accordance with OPT-209A, "Safety Chilled Water System," Revision 13, reviewed on March 11, 2007

- Unit 1 RHR System to Cold Leg Containment Isolation Valve 1-8890A, following elastomer and subcomponent replacement, in accordance with OPT-512A, "RHR and SI Subsystem Valve Test," Revision 9, reviewed on March 17, 2007

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.

The inspectors completed five samples.

b. Findings

No findings of significance were identified.

1R20 Refueling and Outage Activities (71111.20)

a. Inspection Scope

The inspectors evaluated licensee's 1RF12 activities to ensure that risk was considered when developing and when deviating from the outage schedule, the plant configuration was controlled in consideration of facility risk, mitigation strategies were properly implemented, and TS requirements were implemented to maintain the appropriate defense-in-depth. Specific outage inspections performed and outage activities reviewed and/or observed by the inspectors included:

- Discussions and review of the outage schedule concerning risk with the Outage Manager

- Unit shutdown and cooldown

- Containment walkdowns to identify indications of reactor coolant leakage, evaluate material condition of equipment not normally available for inspection, inspect fire protection equipment and fire hazards, observe radiation protection postings and barriers, and evaluate coatings and debris for potential impact on the recirculation containment sumps

- RCS instrumentation including Mansell level instrumentation

- Defense in depth and mitigation strategy implementation

- Containment closure capability

- Verification of decay heat removal system capability

- Spent fuel pool cooling capability

- Reactor water inventory control including flow paths, configurations, alternate means for inventory addition, and controls to prevent inventory loss

- Controls over activities that could affect reactivity

- Refueling activities that included fuel offloading, and fuel transfer

- Implementation of procedures for foreign material exclusion

- Electrical power source arrangement

- Containment recirculation sump inspection after modification of sump filters

- Licensee identification and resolution of problems related to refueling activities

Additional inspections were performed in accordance with Inspection Procedure 71007, “Reactor Vessel Head Replacement Inspection,” Inspection Procedure 50001, “Steam Generator Replacement Inspection,” and will be documented in Inspection Report 05000445/2007006.

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; system alarm and annunciator functionality; and the effectiveness of the licensee’s problem identification and correction program. The following surveillance test activities were observed and/or reviewed by the inspectors:

- Unit 1 Motor Driven Auxiliary Feedwater Pump 1-02 in accordance with work order (WO) WO-5-06-505610-AD and OPT-206A, “AFW System,” Revision 25, reviewed on January 24, 2007

- Unit 2 Turbine Driven Auxiliary Feedwater Pump 2-01 inservice testing in accordance with OPT-206B, “AFW System,” Revision 18, reviewed on February 1, 2007

- Unit 1 RHR Pump 1-01 surveillance test in accordance with OPT-203A, “Residual Heat Removal System,” Revision 15, observed on February 1, 2007

- Unit 1 static load test of the steam generator and reactor vessel head outside (containment) lift system, in accordance with WO-2-06-167488-00, on February 9, 2007

- Unit 1 Main Steam Safety Valves 1MS-0023, 1MS-0059, 1MS-0060, 1MS-0095, 1MS-0129, and 1MS-0130 surveillance testing in accordance with Mechanical Section - Maintenance Manual Procedure (MSM)-S0-8702, "Main Steam Safety Valve Testing," Revision 3, reviewed on February 21, 2007

- Unit 1 Train B 6.9kV bus manual transfer, automatic transfer on undervoltage and EDG 1-02 output breaker trip on safety injection signal surveillance testing in accordance with Maintenance Section - Electrical Manual (MSE) procedure MSE-S1-0602B, "Electrical UV Relay Test, Response Time Test and Bus Transfer Test," Revision 0, performed on March 5, 2007 and reviewed on March 12 - 13, 2007

- Unit 2 SSWP 2-02 inservice test in accordance with OPT-207B, "Service Water System," Revision 12, reviewed week of March 12, 2007

The inspectors completed seven samples.

b. Findings

Introduction: A Green NRC identified noncited violation of TS 5.4.1.e was identified for the failure to establish, implement, and maintain written procedures for the inservice testing program. Station Administration Procedure (STA) STA-711, "Inservice Testing Program for Pumps and Valves" required a new set of reference values be determined following pump replacement and all subsequent test results be compared to the new reference values. Station Service Water Pump 2-02 was declared operable on October 19, 2006, following pump replacement and, although the new pump's performance was fully acceptable, the inservice testing requirements to establish new reference values were not performed. Subsequent surveillance tests were performed with the old reference value as the basis for the test acceptance criterion which was not in accordance with the ASME code.

Description: On February 21, 2007, surveillance testing of SSWP 2-02 was performed in accordance with OPT-207B, "Service Water System," Revision 12, Section 8.3, and Data Sheet OPT-207B-5, "SSWP 2-02 Data Sheet," Revision 13, to satisfy the quarterly pump performance surveillance. The measured pump flow of 12,996 gallons per minute (gpm) did not meet the acceptance criterion (new reference value of 16,761 gpm). The pump was declared inoperable and all appropriate actions were taken, including reviewing past pump performance. The licensee determined that the pump had met the surveillance test criterion (old reference value of 13,045 gpm) when last performed on November 27, 2006, and that the surveillance procedure Data Sheet OPT-207B-5 had been revised on December 1, 2006, changing to the new reference value. The licensee issued Revision 14 to the data sheet using the Revision 12 acceptance criterion (i.e., old reference values), evaluated the test results against this criterion and declared the pump operable.

During Unit 2 refueling outage 2RF09 the SSWP 2-02 had been replaced. On October 18, 2006, the pump was flow tested in accordance with Equipment Test Procedure (ETP) ETP-215B, "Service Water Pump Test," Revision 2, for the purpose of obtaining reference values for pump performance (flow, developed pump head, and vibrations). However, the test did not comply with the applicable ASME OMa Code-1999 Addenda to ASME OM Code - 1998, "Code for Operation and Maintenance of Nuclear Power Plants" which required at least 5 points to be measured after pump conditions are as stable as the system permits (pump shall be run at least 2 minutes at each point). Instead, ETP-215B had collected pump data with an automated data acquisition system as the discharge valve opened on pump start vice throttling to establish distinct, stable flow conditions. The ETP-215B also collected data at a flow rate of approximately 16,000 gpm with the intent of using this for the new reference value during subsequent surveillance testing.

On October 19, 2006, EVAL-2006-003466-02-00 was performed to determine the operational readiness of the pump based on the results of the ETP-215B. SSWP 2-02 was declared operable based on a comparison of the pump start data with the pump curve in the Design Basis Document DBD-ME-233, "Station Service Water System," Revision 16, and a comparison of the pump full flow data from ETP-215B to the DBD design flow of 15,556 gpm. EVAL-2006-003466-02-00 did not establish a new reference value nor verify whether the previous reference value in the surveillance procedure was still valid. The DBD design flow value of 15,556 gpm was subsequently determined to be in error, the actual value should have been 16,456 gpm.

On November 8, 2006, EVAL-2006-003466-01-00 was performed to rebaseline the SSWP 2-02 based on the ETP-215B results and establish a new reference value for surveillance procedure OPT-207B, "Service Water System." An action item was created to incorporate the new reference value into the procedure, with a due date of December 25, 2006. In this evaluation, the full flow value of 16,761 gpm was incorrectly provided as the reference value (for Section 8.3 of the OPT-207B) which was intended to be approximately 16,000 gpm. Furthermore, Section 8.3 established a system configuration with pump developed head of approximately 90 psid, which corresponds to the previous reference value for a flow of approximately 13,000 gpm. It was not communicated to the procedure writers that the new reference value for a flow of 16,000 gpm (or 16,761 gpm) required a different system configuration for Section 8.3.

On November 27, 2006, OPT-207B was performed to satisfy the routine quarterly surveillance requirement. OPT-207B had not yet been revised with the new reference value and the SSWP 2-02 was declared operable based on the previous reference value. On December 1, 2006, OPT-207B was revised to incorporate the new reference value from EVAL-2006-003466-01-00. Section 8.3 of the procedure still established system conditions of pump developed head of approximately 90 psid, but with a flow rate (16,761 gpm) that was more appropriate for a developed head of approximately 57 psid. On February 21, 2007, when the new reference values were used for the first time, SSWP 2-02 failed to satisfy the test acceptance criterion.

On February 22, 2007, a plant event review committee (PERC) meeting was held to determine the cause of SSWP 2-02 failing to meet the acceptance criterion of Data Sheet OPT-207B-5, Revision 13. Although the PERC came to the conclusion that the data sheet was incorrect, other related issues remained unresolved, including the inspector's concerns about the operability of SSWP 2-02 and the basis for determining that the pump was operable.

On February 28, 2007, another PERC was held to address these issues and to identify other contributing causes of the inadequate surveillance Procedure OPT-207B. On March 13, 2007, EVAL-2007-000556-01-02 provided the technical justification for the operability of SSWP 2-02, based on comparison of the new pump performance obtained from ETP-215B and both surveillance tests with the correct design flow requirement of 16,456 gpm at full flow, as well as the DBD pump curve and the previous pump performance. This evaluation also documented the failure to comply with the ASME Code following the pump replacement, in that an adequate baseline pump test had not been performed, nor was a new reference value determined. ETP-215B has been revised to incorporate the ASME requirements and will be performed at the next available work window. New reference values and limits will be determined and incorporated into OPT-207B.

Analysis: The performance deficiency was the failure to implement STA-711 "Inservice Testing Program for Pumps and Valves," which required (1) new reference values be determined by the test method in the ASME OM Code and (2) the new reference valves be used for all subsequent testing. The inspectors determined that the finding is more than minor because it affected the mitigation system cornerstone attribute of human performance (pre-event) and objective to ensure the capability of the SSW system to respond to initiating events with sufficient flow to prevent core damage. This finding does not affect the initiating event of "loss of service water" because the potential consequence is not a loss of flow but degraded flow. Degraded flow would not challenge the SSW system's ability to provide operational cooling to the component cooling water system. This finding is also similar to Examples 3.j and 3.k of Appendix E of IMC-0612, in that it is not minor because it resulted in a condition where there was now a reasonable doubt on the operability of the SSWP 2-02, and programmatic deficiencies were identified in the implementation of the Inservice Testing Program that could lead to worse errors if not corrected. The significance of the finding is very low (Green) because the SSWP 2-02 was always fully capable of performing its safety function. The finding was screened as Green in Phase 1 of the significance determination process because it did not involve an actual loss of any safety function, nor contributed to external event initiated core damage accident sequences (i.e., initiated by seismic, flooding, or severe weather event).

The finding had a crosscutting aspect in the area of human performance with a resources component, in that, the licensee failed to ensure complete, accurate and up-to-date procedures were available and adequate to ensure nuclear safety. Specifically, ETP-215B, "Service Water Pump Test," Revision 2 did not comply with the ASME Code requirements for testing following pump repair, OPT-207B, "Service Water System," Revision 12 with Data Sheet OPT-207B-5 R-13 was not adequate for the quarterly surveillance test, and no procedure ensured the new reference values were incorporated into surveillance procedures prior to their use.

Enforcement: Technical Specification 5.4.1.e requires written procedures be established and implemented for the Inservice Testing Program. Station Administrative

Procedure STA-711, “Inservice Testing Program for Pumps and Valves,” Revision 6, Section 6.3.3 required that when a reference value or set of reference values may have been affected by repair, replacement, or routine maintenance of a pump, the requirements of ASME OM Code - 1998, “Code for Operation and Maintenance of Nuclear Power Plants,” Section ISTB-3310 shall be met. ASME OMa Code - 1999 Addenda to ASME OM Code, Section ISTB-3310 required a new reference value or set of values shall be determined in accordance with ISTB-3300, or the previous value reconfirmed by a comprehensive or Group A test run before declaring the pump operable. Deviations between the previous and new set of reference values shall be evaluated, and verification that the new values represent acceptable pump operation shall be placed in the record of tests. The ASME OM Code also required all subsequent test results shall be compared to new reference values. Contrary to the above, SSWP 2-02 was declared operable on October 19, 2006, without determining the required new reference values in accordance with the required test method. Subsequent surveillance test results were compared to the previous reference values without first reconfirming their validity. This violation was entered into the licensee’s corrective action program as SMF-2007-000556-00. Since this violation is of very low safety significance and has been entered into the corrective action program, it is being treated as a noncited violation, consistent with Section VI.A.1 of the NRC Enforcement Policy (NCV 05000446/2007002-01, Failure to Perform Required Inservice Testing Following Pump Replacement).

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

Initiating Events

a. Inspection Scope

The inspectors reviewed a sample of performance indicator data submitted by the licensee regarding the initiating events cornerstone to verify that the licensee’s data was reported in accordance with the requirements of Nuclear Energy Institute NEI 99-02, “Regulatory Assessment Performance Indicator Guideline,” Revision 4. The sample included data taken from control room operator logs, the SMF database, and licensee event reports for January 2005 through December 2006 for the following performance indicators:

- Units 1 and 2, unplanned scrams per 7,000 critical hours
- Units 1 and 2, unplanned scrams with loss of normal heat removal
- Units 1 and 2, unplanned power changes per 7,000 critical hours

During plant tours, inspectors periodically determined if access to high radiation areas was properly controlled and if potentially unmonitored release pathways were present.

The inspectors completed six samples.

b. Findings

No findings of significance were identified.

4OA2 Problem Identification and Resolution (71152)

Review of Items Entered into the Corrective Action Program

a. Inspection Scope

As required by Inspection Procedure 71152, "Identification and Resolution of Problems," and in order to identify repetitive equipment failures or specific human performance issues for follow-up, the inspectors performed a routine screening of all items entered into the licensee's corrective action program. This review was accomplished by reviewing the licensee's computerized corrective action program database, reviewing hard copies of selected SMFs, and attending related meetings such as PERC meetings.

b. Findings

No findings of significance were identified.

4OA3 Event Follow-up (71153)

.1 (Closed) LER 05000446/2006-002 Reactor Trip Due to a Secondary Transient Initiated During Load Rejection Testing

On October 27, 2006, Unit 2 was in Mode 1 at 28 percent power performing planned 25 MWe load reject tests following digital modifications to the protection circuitry of the turbine generator. The third 25 MWe swing resulted in a divergent oscillation in the secondary system. Operators identified the oscillations and took manual control of the feedwater system, but the level in Steam Generator 2-02 reached the HI-HI setpoint. The HI-HI level caused a trip of the main turbine and the isolation of main feedwater. The operators manually tripped the Unit 2 reactor. The licensee determined that there was enough information gathered to declare testing of the turbine generator digital upgrade was complete. The licensee's corrective actions included: (1) modifying the procedure for sequencing secondary system pumps, (2) changing gain settings for the main feedwater pump speed controller back to the previous settings, which had been changed at 100 percent power to help maintain a tighter feedwater flow rate band and thus operate closer and more consistently at 100 percent power, and (3) implementing lessons learned training. More specific event details can be found in Section 4OA3, Event Followup, of Inspection Report 2006-005. The LER was reviewed by the inspectors and no findings of significance were identified and no violations of NRC requirements occurred. The licensee documented the event in their corrective action program in SMF-2006-003632-00. This LER is closed.

.2 <u>(Closed) LER 05000446/2006-003</u> Unit 2 Reactor Trip Due to Feedwater Regulating Valve Malfunction

On October 29, 2006, Unit 2 was in Mode 1 at 80 percent power and holding for Xenon stabilization, when a manual reactor trip was initiated due to Steam Generator 2-03 level lowering uncontrollably. The licensee investigated and determined that Solenoid Valve SV-2 associated with Feedwater Regulating Control Valve 2-FCV-530, had a loose wire. The loss of continuity resulted in the loss of air between the valve positioner and the valve operator diaphragm, causing the flow control valve to fail closed. The licensee was able to duplicated the failure in the valve workshop. Corrective actions included: (1) reviewing and checking the other Unit 2 feedwater regulating control valves on Unit 2 prior to restart, (2) inspecting Unit 1 feedwater regulating control valves, and (3) modifying the maintenance procedure to ensure that the wires in the terminal blocks are tight. More specific details can be found in Section 4OA3.2, Event Followup, of Inspection Report 2006-005. The LER was reviewed by the inspectors and no findings of significance were identified and no violations of NRC requirements occurred. The licensee documented the event in the corrective action program as SMF-2006-003660-00. This LER is closed.

4OA6 <u>Meetings, Including Exit</u>

<u>Exit Meeting Summary</u>

On January 24, 2007, the inspectors presented the inspection results of the licensed operator requalification inspection to Mr. T. Hope, Manager, Regulatory Affairs, and other members of the licensee's management staff at an exit interview. The licensee acknowledged the findings presented. The inspectors also asked the licensee whether any materials examined during the inspections should be considered proprietary. No proprietary information was identified.

On February 9, 2007, the inspectors presented the safety evaluation and permanent plant modifications inspection results to Mr. S. Smith, Site Engineering Director, and other members of the staff who acknowledged those results. No proprietary information was included in this report.

On March 29, 2007, the inspectors presented the resident inspection results to Mr. M. Lucas, Vice President Nuclear Engineering and Support, and other members of licensee management. The inspectors confirmed that proprietary information was not provided or examined during the inspection.

On April 20, 2007, the inspectors held a re-exit meeting with Mr. T. Hope, Manager of Regulatory Performance, to present changes in the characterization of violations identified during the inspection period and presented in the March 29 exit meeting.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

D. Bersi, Steam Generator Replacement Project, Component Design/Fabrication Lead
O. Bhatty, Inservice Test Engineer
M. Blevins, Senior Vice President and Chief Nuclear Officer
J. Brabec, Steam Generator Replacement Project, Installation Manager/Asst. Project Manager
G. Casperson, Supervisor, Simulator
J. Finneran, Steam Generator Replacement Project, Project Engineering Manager
R. Flores, Site Vice President, Nuclear Operations
D. Haggerty, Project Engineer, Bechtel
N. Hood, Project Engineering Manager
T. Hope, Manager, Regulatory Affairs
M. Killgore, Engineering Support Director
D. Kissinger, Design Engineering Analysis Engineer
B. Lichtenstein, Engineer, Risk and Reliability, Westinghouse
M. Lucas, Vice President Nuclear Engineering and Support
F. Madden, Director, Regulatory Affairs
S. Maier, Design Engineering Analysis Manager
B. Mays, Steam Generator Project Manager
E. Meaders, Outage Manager
J. Meyer, Technical Support Manager
K. Pitilli, Design Engineering Analysis Engineer
W. Reppa, JET Manager
S. Sewell, Nuclear Training Manager
J. Skelton, System Engineer
R. Smith, Director, Operations
S. Smith, Director, System Engineering
G. Struble, Operations Training Supervisor
D. Tirsun, Engineer, Risk and Reliability, Westinghouse

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

None

Opened and Closed

05000446/2007002-01	NCV	Failure to perform required inservice testing following pump replacement (Section 1R22)

Closed

05000446/2006-002	LER	Reactor Trip Due to a Secondary Transient Initiated During Load Rejection Testing (Section 4OA3.1)
05000446/2006-003	LER	Unit 2 Reactor Trip Due to Loss of Feedwater Regulating Valve Malfunction (Section 4OA3.2)

Discussed

None

LIST OF DOCUMENTS REVIEWED

Section 1R02: Evaluations of Changes, Tests, or Experiments

Evaluations

Document Number	Title/Description	Revision
59EV-2003-002426-03-00	Multiflex 3.0 Computer Code	0
59EV-2004-002661-01-00	Temporary Bypass or reset of containment polar crane protection devices	0
59EV-2004-001255-02-00	Upgrade the Unit 2A and B Train DG Exciter/Voltage Regulator	0
59EV-2006-003867-01-00	Procedural changes to control bypassing of Containment Crane Anti-Collision Control System	0
59EV-2004-000773-02-00	Final phase replacement of the Unit 2 Turbine-Generator Protection Systems Analog to Digital	0
59EV-2001-001672-02-01	Design Modification to replace Unit 1 Turbine Generator analog controls to digital controls	1

10 CFR 50.59 Screenings

Document Number	Title/Description	Revision
59SC-2005-000658-02-01	Rigging and Transport of OSGs, RSGs, ORVH, and RRVH	1
59SC-2004-002831-01-01	Add stops to new fuel elevator for reconstitution of fuel	1

59SC-2005-001537-01-00	Accept manufactures minimum wall thickness violation of ASME Section III piping	0
59SC-2000-000526-05-01	Extend LAN in plant.	1
59SC-2000-002072-01-00	Revise Plant Flow Diagrams M1-0222 and M2-0222 to show valve operations.	0
59SC-2004-003549-03-00	Change to allow Unit 1 & 2 Seal Steam Controllers to transfer from automatic to manual control	0
59SC-2005-004516-01-00	Abandon inoperable incore thermocouple 1-TE-0024	0
59SC-2006-003564-01-00	Delete the stroke time acceptance criteria for AFW Steam Supply Valves 1/2-HV-2452-1, 2	0
59SC-2006-003609-01-00	Comp Actions for 2-HV-2417A stuck open	0
59SC-2002-001361-01-00	Add jack-bolts to CCW Motors	0
59SC-2005-001630-01-00	Penetration Seal Design	0
59SC-2005-003364-09-01	RWST Level Alarm Setpoint & Logic Changes	1
59SC-2005-004280-01-00	Revise DBD-ME-233 to change low pressure alarm setpoint	0
59SC-2005-001785-01-00	Add valve to isolate leakage past valve 2CO-0300	0
59SC-2004-001702-00-00	Installed Components for New Grated Barriers	0

Applicability Determinations

2004-003549-03-00 - Change in Seal Steam controller operating system. Automatic to Manual Function.

2004-002831-01-01 - New Fuel elevator for reconstitution.

2005-004516-01-00 - Abandon inoperable incore thermocouple

Condition Reports (SMART Forms)

2005-000702-00	2005-002931-00	2006-002181-00	2006-002830-00
2005-001955-00	2005-003271-00	2006-002548-00	2006-002963-00
2005-002136-00	2005-003748-00	2006-002575-00	2006-003234-00
2005-002224-00	2006-000032-01	2006-002606-00	2006-003337-00

Section 1R05: Fire Protection (71111.05Q)

Comanche Peak Steam Electric Station Fire Protection Report, Unit 1 and Unit 2, Revision 25

STA-729, Control of Transient Combustibles, Ignition Sources and Fire Watches, Revision 7

FPI-101A, Unit 1 Safeguards Building Elevation 773'-0" Train “A” & “B” - RHR, SI & CS Pump Rooms, Revision 3

FPI-101B, Unit 2 Safeguards Building Elevation 773'-0" “A” & “B” RHR, SI & Containment Spray Pump Rooms, Revision 1

FPI-102A, Unit 1 Safeguards Building Elevation 790'-0", Revision 3

FPI-102B, Unit 2 Safeguards Building Elevation 790'-0", Revision 2

FPI-103A, Unit 1 Safeguards Building Elevation 810"-6" Rad, Pen. Area & Elec. Equip. Rm, Revision 3

FPI-103B, Unit 2 Safeguards Building Elevation 810"-6" Rad, Pen. Area & Elec. Equip. Rm, Revision 3

FPI-106A, Unit 1 Safeguards Building Elevation 831'-6" Main Corridor, RB Assess, & Electrical Equi-pment Area, Revision 4

FPI-107A, U1 Safeguards Building, Elevation 852'-6" Electrical Equipment Area & FW Penetration Area, Revision 3

FPI-107B, U2 Safeguards Elevation. 852' Electrical Equipment Area & Feedwater Penetration Area, Revision 2

FPI-201A, Unit 1 Containment Building Elev. 808'-0", Revision 3

FPI-202A, Unit 1 Containment Building Elev. 832'-6", Revision 3

FPI-203A, Unit 1 Containment Bldg. Elevation 860'-0", Revision 3

FPI-204A, Unit 1 Containment Building, Elev. 905'-0", Revision 3

FPI-406, Auxiliary Building Elevation 831'-6", Revision 4

Section 1R11: Licensed Operator Requalification - Biennial Inspection (71111.11B)

Procedures

TRA-204, "Licensed Operator Requalification Training" Revision 14

TRA-204, Attachment 8.A "Licensed Operator Annual Requalification Examination Development and Security Guidelines" Revision 14

TRA-204, Attachment 8.B "Requalification Training Commitments" Revision 14

NTP-103 "Design" Revision 12

NTP-105, "Implementation" Revision 18

ODA-315, "Licensed Operator Maintenance Tracking" Revision 5

ABN-302,"Feedwater, Condensate, Heater Drain System malfunction," Revision 13

ABN-107,"Emergency Boration," Revision 7

ABN-705, "Pressurizer Pressure Malfunction," Revision 11

ABN-707, "Steam Flow Instrument Malfunction," Revision 6

ABN-712, "Rod Control Malfunction," Revision 10

EOP-0.0A, "Reactor Trip or safety Injection," Revision 8

EOP-1.0A, "Loss of Reactor or Secondary Coolant," Revision 8

EOP-2.0A, "Faulted Steam Generator Isolation," Revision 8

EOS-1.1A, "Safety Injection Termination," Revision 8

EOS-1.3A, "Transfer to Cold Leg Recirculation," Revision 8

FRP-0.1A, "Response To Imminent Pressurized Thermal Shock Condition," Revision 8

FRZ-0.1A, "Response To High Containment Pressure," Revision 8

Other Documents Reviewed

STA-419, "Training and Program Review Boards," Revision 8

EPP-201, "Assessment of Emergency Action Levels Emergency Classification and Plan Activation," Revision 11

2005/2006 Requalification Sample Plan

Licensed Operator Requalification (LORT) JPM, Annual Examination

LORT Simulator Annual Examination

LORT Annual SRO Written Exam Material

LORT Annual RO Written Exam Material

Training Program Curriculum Licensed Operator and STA Requalification

Licensed Operator/STA Requalification Curriculum

Dynamic Simulator Scenario Index

Licensed Operator Job Performance Measures (JPMs) Index

<u>LORT Dynamic Exam Scenarios</u>:

Simulator Exercise Guide, LBLOCA (D0067B) Dated 10/03/06 Revision 0

Simulator Exercise Guide, MSLB ORC (D0061) Dated 10/03/06 Revision 10

<u>Job Performance Measures</u>:

RO*7037A, "Response to Excessive RCS Leakage"
RO1336A, "RMUW Malfunction"
AO*4217A, "Bypass Inverter"
AO*5421, "Response to Safety Chilled Water Recirc Pump Discharge Pressure Low"
AO*5403, "Local Dilution Path isolation"

Medical Records and a 100% sampling of corrective lenses in Control Room

<u>Operations Curriculum Review Committee Meeting minutes from</u>:

February 2, 2006
April 6, 2006
May 18, 2006
June 29, 2006
August 10, 2006

<u>Operations Training Program Review Board Meeting minutes from</u>:

January 18, 2006
February 16, 2006
May 3, 2006
May 9, 2006
June 12, 2006
July 11, 2006
August 1, 2006
August 14, 2006
September 14, 2006
September 25, 2006
November 13, 2006
December 12, 2006

Lesson Plans (18 Classroom and 6 Simulator) sampled

Written Biennial Requalification Exams (7 weeks of RO & SRO plus 1 RO and 1 SRO Remedial exam)

Accreditation Self-Evaluation Report, March 21, 2006

Evaluation 2005-003, Training and Qualification of Nuclear Power Plant Personnel

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

EVAL-2005-000658-02-00

Section 1R15: Operability Evaluations (71111.15)

SMF-2006-003263-00

ECE-2.15 Evaluation Log 138, February 2007, Revision 0, PRA Considerations Related to Proposed Containment Alternate Access (CAA) Liner Breach Prior to Offload

Section 1R22: Surveillance Testing (71111.22)

SMF-2007-000921-00
WO-5-06-505398-AE
WO-5-05-502693-AA
WO-5-05-502688-AA
WO-5-05-502692-AA
WO-5-05-502702-AA
WO-5-05-502698-AA
WO-5-07-505614-AA
EVAL-2006-003466-01-00
LCOAR A2-07-0108

Section 4OA1: Performance Indicator Verification (71151)

Procedures

Desktop Initiating Events: Unplanned Scrams per 7000 Critical Hours and Unplanned Power Changes Per 7000 Critical Hours, Revision 2, NRC Performance Indicators, Initiating Events:

LIST OF ACRONYMS

1RF12	Unit 1 twelfth refueling outage
ABN	Abnormal Condition Procedure
AMSAC	ATWS Mitigation System Actuating Circuit
ASME	American Society of Mechanical Engineers
ATWS	Anticipated Transient Without Scram
CFR	*Code of Federal Regulations*
CPSES	Comanche Peak Steam Electric Station
DBD	design basis document
DIDCP	Defense in Depth Contingency Plan
ECCS	emergency core cooling systems
EDG	emergency diesel generator
ERCOT	Energy Reliability Council of Texas
ETP	equipment test procedure
EVAL	evaluation
IPO	integrated plant operations
JPM	job performance measures
LER	licensee event report
LORT	Licensed Operator Requalification
MSE	maintenance section - electrical
MSM	mechanical section - maintenance
NCV	noncited violation
NRC	Nuclear Regulatory Commission
OPT	operations testing procedure
PERC	plant event review committee
RCS	reactor coolant system
RHR	residual heat removal

SDP	significance determination process
SMF	Smart Form
SOP	system operating procedure
SSC	structures, systems, or components
SSW	station service water
SSWP	station service water pump
STA	station administration procedure
TS	Technical Specifications
WO	work order