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

April 7, 2006

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: ERRATA FOR COMANCHE PEAK STEAM ELECTRIC STATION - NRC INTEGRATED INSPECTION REPORT 05000445/2005005 AND 05000446/2005005

Dear Mr. Blevins:

Please replace page 4 of the Summary of Findings, pages 33, 34 and 35 of the Report Details, and Page A-2 of Supplemental Information in NRC Inspection Report 05000445/2005005 and 05000446/2005005, dated February 13, 2006, with the enclosed revised pages. These changes are necessary to revise the characterization of the Non-Cited Violation of Section 40A5.2 from a Technical Specification 3.8.1 violation to a 10 CFR Part 50, Appendix B, Criterion XVI violation.

During and subsequent to the inspection process, we discussed this Technical Specification 3.8.1 violation with your staff and did not come to full agreement regarding the technical basis for the violation. Your staff provided a position paper, which is enclosed. They continue to believe that the failure of Relay 27BX1/ST1 was not aging related. However, we were not able to identify a mechanism that was not aging related that would also cause the described manufacturing defect to manifest itself 16 years after placing Relay 27BX1/ST1 in service. The differing view points make it not clear exactly when the relay became inoperable, calling into question the validity of the Technical Specification 3.8.1 violation. In cases like this, Section 8.1.2 of the NRC Enforcement Manual directs us to cite against the root cause of the initial Technical Specification violation. In this case, the root cause was inadequate corrective action, a violation of 10 CFR Part 50, Appendix B, Criterion XVI.

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 update, we will be pleased to discuss them with you.

Sincerely,

/RA/

Linda Smith, Chief
Engineering Branch 2
Division of Reactor Safety

Docket Nos.: 50-445, 50-446
License Nos.: NPF-87, NPF-89

Enclosures:
1. Errata pages for NRC Inspection Report 05000445/2005005 and 05000446/2005005
2. Position Paper Related to NCV 050000446/2005-05

cc w/enclosures:
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J. Dixon-Herrity, OEDO RIV Coordinator **(JLD)**
ROPreports
CP Site Secretary **(ESS)**

SUNSI Review Completed: __LJS ADAMS: / Yes ☐ No Initials: LJS___
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DOCUMENT: R:_REACTORS_CPSES\2005\CP2005-05 errata2.wpd

RIV:DRS\EB2	C:EB2	RIV:C:DRP/A			
DLLivermore:nlh	LJSmith	CEJohnson			
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04/06/06	04/06/06	04/07/06			

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ENCLOSURE

Revised Pages for NRC Integrated Inspection

Report 05000445/2005005 AND 05000446/2005005

- Green. A Green self-revealing noncited violation of Appendix B, Criterion XVI was identified for failure to implement effective corrective actions for a significant condition adverse to quality. Specifically, station service water Pump 1-01 was returned to service on October 20, 2005, and after two hours of operation tripped on an electrical fault on Phase C of the motor leads. The degraded electrical condition of the motor lead had been identified during restoration from the pump maintenance, but the actions taken to ensure the pump was reliable failed. Phase C of the motor leads was replaced prior to returning the pump to service.

  The failure to take effective corrective actions was the performance deficiency. The violation was more than minor because the pump was returned to service with a degraded motor lead. At the time of the event, Unit 1 was defueled and did not require an operable station service water pump. However, Unit 2 was required by Technical Specifications 3.7.8 to have at least one operable station service water pump from the opposite unit. With Unit 2 at 100 percent power, a significance determination was performed using Appendix A of Manual Chapter 0609. The finding was determined to be of very low safety significance (Green) because it did not represent a loss of system safety function, was not an actual loss of safety function for a single Unit 2 train, did not involve equipment or function specifically designed to mitigate a seismic, flooding, or severe weather initiating event, and did not involve the total loss of any safety function that contributed to external event initiated sequences. The cause of this finding is related to the crosscutting aspects of problem identification and resolution. The event was entered into the corrective action program as Smart Form 2005-004220 (Section 4OA3.2).

- Green. A Green self-revealing non-cited violation of 10 CFR 50, Appendix B, Criterion XVI was identified for failure to take prompt and adequate corrective action for a condition adverse to quality. Specifically, on October 19, 2004, an unplanned loss of the preferred offsite power caused the Unit 2, Train B, 6.9 kV safeguards bus to de-energize. A degraded Agastat relay delayed the normal power supply breaker from opening for 30 seconds, which delayed powering the bus from the alternate offsite AC power supply or the emergency diesel generator. This issue had crosscutting aspects in the area of problem identification and resolution because the licensee previously identified that aged Agastat relays were unreliable and should be replaced if they were in service greater than 12 years. The failed relay had been in service for 16 years.

  The licensee's failure to identify the cause and implement corrective actions to prevent repetitive failures of safety related Agastat relays was a performance deficiency. The violation was more than minor because it impacted the Mitigating Systems Cornerstone objective of availability, reliability, and capability of systems that respond to initiating events. Using Inspection Manual Chapter 0609, Appendix A, "Determining the Significance of Reactor Inspection Findings for At-Power Situations," the finding was determined to be of very low safety significance because the likelihood of a medium or large break loss of coolant accident coincident with a loss of offsite power, which are the only conditions where the deficiency would cause a non-negligible change in the baseline risk

The inspectors determined that the direct visual inspections, coupled with mirror assisted visual inspections were capable of detecting, identifying and characterizing small boric acid deposits, if present, as described in NRC Bulletin 2004-01. This fact was determined via direct inspection during the licensee inspection of the pressurizer and associated steam space piping connections.

6. Identified deficiencies that required repair

   No deficiencies were identified.

7. Impediments to effective examinations

   There were no impediments that adversely affected effective bare metal visual examinations. In all examination cases, mirror insulation was required to be removed. The examination of the pressurizer safety and power operated relief valve line welds was supplemented by a mirror to allow examination of the downhill side of the welds. The dose rates were acceptable, and the inspectors received approximately 50 mRem to complete the in-plant portion of the temporary instruction.

8. Techniques used for augmented inspections

   Augmented inspections were not required.

9. Appropriateness of follow-on examinations

   Follow-on examinations were not required.

.2 (Closed) URI 05000446/2005009-01: Inoperability of Emergency Power to a Safety Bus

Introduction. A Green self-revealing noncited violation of 10 CFR 50, Appendix B, Criterion XVI was identified for failure to take prompt and adequate corrective action for a condition adverse to quality.

Description. On October 19, 2004, an unplanned loss of the preferred offsite power caused the Unit 2, Train B, 6.9 kV safeguards bus to deenergize. A degraded Agastat relay exceeded its 0.5 second time delay setpoint and prevented the normal power supply breaker from opening for 30 seconds. Both the EDG and the alternate power supply were delayed from powering the bus due to a breaker interlock with the normal supply. This delay rendered both the EDG and alternate offsite AC power supplies inoperable. The 30 second delay in providing power to the safeguards bus would have resulted in the station not meeting the 10 CFR Part 50, Appendix K, “Emergency Core Cooling System Evaluation Models Acceptance Criteria,” for that equipment train.

The licensee had a previous opportunity to correct the degraded Agastat relay issues. On October 7, 2002, EDG 1-02 unexpectedly started due to a degraded Agastat relay. The licensee concluded that the failure could have been caused by aging and formed a corrective action plan to replace all safety related Agastat relays that had been in service for greater than the licensee established 12 year lifetime. EVAL-2003-001440-01-01 stated that the main effect of aging on these relays was an increase in setpoint drift. The licensee issued SMF-2004-003528 to track the root cause and corrective actions associated with the faulty Agastat relays. Also, the NRC previously identified that Agastat relays used in the 6.9 kV bus transfer circuitry were exhibiting setpoint drift (SMF-2002-001504 and Inspection Report 05000445/2003006; 05000446/2003006). The relay that failed in October 2004 was 16 years old.

Analysis. The licensee's failure to identify the cause and implement corrective actions to prevent repetitive failures of safety related Agastat relays was a performance deficiency. The violation was more than minor because it impacted the Mitigating Systems Cornerstone objective of availability, reliability, and capability of systems that respond to initiating events. Using Inspection Manual Chapter 0609, Appendix A, "Determining the Significance of Reactor Inspection Findings for At-Power Situations," the finding was determined to be of very low safety significance because the likelihood of a medium or large break loss of coolant accident coincident with a loss of offsite power, which are the only conditions wherein the deficiency would cause a non-negligible change in the baseline risk profile, is less than or equal to 1E-6 per year. Therefore, the change in core damage frequency will be less than 1E-6 per year. The violation has a problem identification and resolution crosscutting aspect because the licensee had previously identified that aged Agastat relays can cause these types of problems but had failed to take effective corrective actions in a timely manner. The licensee captured the issue in their corrective action program as SMF-2004-003528.

Enforcement. 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," requires, in part, that measures shall be established to assure that conditions adverse to quality, such as failures, deficiencies, and deviations, are promptly identified and corrected. Contrary to the above, the licensee failed to take prompt and adequate corrective action for a condition adverse to quality. Specifically, on August 13, 2003, the licensee identified that Agastat relay 27BX-1/ST exceeded its 12-year expected service life, and scheduled an interim calibration check to be performed during refueling outage 2RF07. Due to 2RF07 outage duration reduction in October, 2003, the interim calibration check was deferred to 2RF08, in the Spring of 2005. On October 19, 2004, the Agastat relay exceeded its time delay setpoint and delayed the normal power supply breaker from opening when the Unit 2, Train B, 6.9 kV safeguards bus deenergized during an unplanned loss of preferred offsite power. Because this issue is of very low safety significance and has been entered into the corrective action program as SMF-2004-003528, this violation is being treated as a Non-Cited Violation, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000446/2005005-05, Inoperability of Emergency Power to a Safety Bus Due to Degraded Relay.

4OA6 Meetings, Including Exit

Exit Meeting Summary

The inspectors presented the results of the inservice inspection to Mr. M. Lucas, Vice President of Nuclear Engineering, and other members of licensee management on

October 21, 2005. Licensee management acknowledged the inspection findings. The licensee confirmed that any proprietary information reviewed by the inspectors was not retained by the inspectors.

On December 15, 2005, the inspector debriefed the preliminary results of the emergency preparedness inspection to Mr. M. Blevins, Senior Vice President and Chief Nuclear Officer, and other members of his staff who acknowledged the findings. The inspector confirmed that proprietary information was not provided or examined during the inspection. After additional information was provided by the licensee on January 11, 2006, the inspector presented the inspection results to Mr.R. Flores, Vice President, Nuclear Operations, and other members of his staff who acknowledged the findings.

On January 31, 2006, Mr. N. O'Keefe presented the inspection results of the URI in regards to Agastat relays to Mr. T. Hope and D. Snow of your staff, who acknowledged the finding, by teleconference.

The inspector presented the resident inspection results to Mr. R. Flores, Vice President, Operations, and other members of licensee management on January 12, 2006. The inspectors confirmed that proprietary information was not provided or examined during the inspection.

On April 7, 2006, Ms. Linda Smith and Mr. Dan Livermore presented a change in the characterization of the Agastat relay green NCV from a Technical Specification 3.8.1 violation to a 10 CFR 50, Appendix B, Criterion XVI violation to Mr. Tim Hope, who acknowledged the change, by teleconference.

ATTACHMENT: SUPPLEMENTAL INFORMATION

05000445/2005005-03	NCV	Trip of Emergency Diesel Generator Due to Lube Oil Check Valve Installed Backwards (Section 4OA3.1)
05000445/2005005-04	NCV	Trip of Station Service Water Pump Due to Degraded Motor Lead (Section 4OA3.2)
05000446/2005005-05	NCV	Inadequate Corrective Action Impacts Operability of Emergency Power to a Safety Bus Due to Degraded Relay (Section 4OA5.2)

Closed

05000446/2005009-01	URI	Inoperability of Emergency Power to a Safety Bus (Section 4OA5.2)

Discussed

None

LIST OF DOCUMENTS REVIEWED

Section 1R08 Inservice Inspection Activities (71111.08)

Boric Acid Evaluation

Unit 1 Containment Boron Leaks 1RF11, draft report

Procedures

Number	Title	Revision
STA-737	Boric Acid Corrosion Detection and Evaluation	3
TX-ISI-8	VT-1 and VT-3 Visual Examination	56
TX-ISI-11	Liquid Penetrant Examination for Comanche Peak Steam Electric Station	11
TX-ISI-302	Ultrasonic Examination of Austenitic Piping Welds	2
WLD-106	ASME/ANSI General Welding Requirements	2 with Procedure Change Notice 4

Position Paper Related to NCV 05000446/2005005-05

NCV Description
The Analysis section (page 34) states that "The licensee's failure to identify the cause and implement corrective actions to prevent repetitive failures of safety related Agastat relays was a performance deficiency." The Enforcement section (page 34) states "Technical Specification 3.8.1 required the licensee to restore either the alternate offsite transmission source or the EDG to the onsite Class 1E AC electrical distribution system within 12 hours. Contrary to the above, neither the alternate offsite transmission source nor the EDG was capable of supplying the Class 1E AC electrical distribution within the response time assumed in the accident analysis. This condition existed for an extended duration, in excess of the 12-hour TS limiting condition for operation."

Discussion
As documented in SMF 2004-003528 and also in a failure analysis report prepared by Southwest Research Institute (SWRI) in January 2005, the failure of this relay (27BX1/ST1) was determined to be caused by particles that entered either the variable-length orifice groove or the port between the "clean" cavity and the orifice groove. This was likely a vendor defect as SWRI noted in their report that ". . . there is significant probability that at least some of the particles in the clean areas were introduced during relay fabrication." The particles restricted air flow through the timing structure and lengthened the time delay. Therefore, TXU Power believes that this was a random equipment failure and that aging was not a factor in the failure of relay 27BX1/ST1.

Although aging was determined to have been a factor in the failure of safety related Agastat relays at Grand Gulf, aging was not a factor in the failure of relay 27BX1/ST1. Comanche Peak's E7000 model Agastat relays are different from the GP model Agastat relays at Grand Gulf because the GP model relay, which is not a time delay relay, is constructed differently from the E7000 model relay. Another difference between the Grand Gulf application and CPSES is that the Grand Gulf GP model relays are in a continuously energized state. At the time relay 27BX1/ST1 failed, a schedule had been implemented to replace the E7000 Agastat relays which perform a safety function and had been in service beyond 12 years (including relay 27BX1/ST1). Currently all E7000 Agastat relays that perform a safety related function have been replaced.

Because this was considered to be a random equipment failure and not age related, TXU Power believes that the Class 1E AC electrical distribution system can be assumed to be operable per the TS 3.8.1 until the relay failed on October 19, 2004. Based on discussions with NRC Region IV personnel, TXU Power believes that the NRC used the time from the last successful surveillance until the relay failed and then applied the SDP "t/2" criteria for this condition to determine that the safety bus had been inoperable for greater than 12 hours. However, TXU Power believes that use of this criteria is limited to the SDP process and it is not an appropriate criteria to determine whether or not a performance deficiency existed.

As described above, TXU Power believes that the failure of relay 27BX1/ST1 was due to a random equipment failure and was not age related. For this reason, TXU Power believes that the Class 1E AC electrical distribution system should not be considered inoperable for greater than 12 hours.

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March 14, 2006

Mike Blevins, Senior Vice President
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Comanche Peak Steam Electric Station
P.O. Box 1002
Glen Rose, TX 76043

SUBJECT: ERRATA FOR COMANCHE PEAK STEAM ELECTRIC STATION - NRC INTEGRATED INSPECTION REPORT 05000445/2005005 AND 05000446/2005005

Dear Mr. Blevins:

Please replace the Summary of Findings and page 11 of the Report Details in NRC Inspection Report 05000445/2005005 and 05000446/2005005, dated February 13, 2006, with the attached revised pages. The following changes are necessary to (1) delete the sentence in the Summary of Findings for the first finding "This finding has a problem identification and resolution crosscutting aspect because it was caused by lack of effective corrective actions"; (2) delete several phrases and words located in the Summary of Findings (fourth finding, both paragraphs) and (3) delete several phrases and words in Section 1R08.1, (Description and Enforcement paragraphs) to clarify the issues.

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/

Claude Johnson, Chief
Project Branch A
Division of Reactor Projects

Docket Nos.: 50-445, 50-446
License Nos.: NPF-87, NPF-89

Enclosure:
Errata pages for NRC Inspection Report 05000445/2005005 and 05000446/2005005

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Senior Project Engineer, DRP/A **(TRF)**
Team Leader, DRP/TSS **(RLN1)**
RITS Coordinator **(KEG)**
Regional State Liaison Officer **(WAM)**
NSIR/DIPM/EPHP **(REK)**

Only inspection reports to the following:
DRS STA **(DAP)**
J. Dixon-Herrity, OEDO RIV Coordinator **(JLD)**
ROPreports
CP Site Secretary **(ESS)**

SUNSI Review Completed: __CEJ ADAMS: / Yes ☐ No Initials: CEJ___
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Revised Pages for NRC Integrated Inspection
Report 05000445/2005005 AND 05000446/2005005

SUMMARY OF FINDINGS

IR 05000445/2005005, 05000446/2005005; 09/24/2005-12/31/2005; Comanche Peak Steam Electric Station, Units 1 and 2; Inservice Inspection Activities, Event Follow-up, and Other Activities

This report covered a 3-month period of inspection by two resident inspectors, two reactor inspectors, one operations engineer, one emergency preparedness inspector, one regional project engineer, and one consultant. Four Green noncited violations were identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter 0609, "Significance Determination Process" (SDP). Findings for which the SDP 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. <u>NRC-Identified and Self-Revealing Findings</u>

Cornerstone: Mitigating Systems

C <u>Green</u>. A Green self-revealing noncited violation of Technical Specification 5.4.1.a was identified for failure to implement the maintenance procedure to properly install a check valve in the Emergency Diesel Generator 1-01 lubrication system. On October 20, 2005, the diesel generator shutdown for lack of lube oil to the turbo-chargers after 60 seconds during a post maintenance test. The lube oil strainer check valve had been installed backwards during the previous refueling outage but the opposite strainer had been in service for the ensuing 18 months. The check valve was reinstalled properly, the flow direction of similar check valves verified, and the damaged turbo-chargers replaced.

The violation was more than minor because one of two lube oil strainers for the turbo-chargers was incapable of flow, thus affecting the reliability of the diesel generator. The finding has a human performance crosscutting aspect because the failure to follow the procedure caused the diesel generator failure. However, the error was committed in April 2004. The violation is of very low safety significance because CPSES operating experience indicated that the lube oil strainers had never been swapped outside of an outage, and then only to balance run time on the equipment. The significance determination process screened this out as Green because it only affected the mitigating systems cornerstone and it did not cause an actual loss of safety function of a single train nor a loss of safety function that contributed to external event initiated core damage sequences. This event was entered into the corrective action program as Smart Form 2005-004233 (Section 4OA3.1).

C Green. A Green self-revealing noncited violation of Appendix B, Criterion XVI was identified for failure to implement effective corrective actions for a significant condition adverse to quality. Specifically, station service water Pump 1-01 was returned to service on October 20, 2005, and after two hours of operation tripped on an electrical fault on Phase C of the motor leads. The degraded electrical condition of the motor lead had been identified during restoration from the pump maintenance, but the actions taken to ensure the pump was reliable failed. Phase C of the motor leads was replaced prior to returning the pump to service.

The failure to take effective corrective actions was the performance deficiency. The violation was more than minor because the pump was returned to service with a degraded motor lead. At the time of the event, Unit 1 was defueled and did not require an operable station service water pump. However, Unit 2 was required by Technical Specifications 3.7.8 to have at least one operable station service water pump from the opposite unit. With Unit 2 at 100 percent power, a significance determination was performed using Appendix A of Manual Chapter 0609. The finding was determined to be of very low safety significance (Green) because it did not represent a loss of system safety function, was not an actual loss of safety function for a single Unit 2 train, did not involve equipment or function specifically designed to mitigate a seismic, flooding, or severe weather initiating event, and did not involve the total loss of any safety function that contributed to external event initiated sequences. The cause of this finding is related to the crosscutting aspects of problem identification and resolution. The event was entered into the corrective action program as Smart Form 2005-004220 (Section 4OA3.2).

• Green. A Green self-revealing noncited violation of Technical Specification 3.8.1 was identified, after both the alternate and emergency power supplies to a 6.9 kV safeguards bus failed to provide power to the bus within the time assumed in the accident analysis. On October 19, 2004, an unplanned loss of the preferred offsite power caused the Unit 2, Train B, 6.9 kV safeguards bus to de-energize. A degraded Agastat relay delayed the normal power supply breaker from opening for 30 seconds, which delayed powering the bus from the alternate offsite AC power supply or the emergency diesel generator. This issue had crosscutting aspects in the area of problem identification and resolution because the licensee previously identified that aged Agastat relays were unreliable and should be replaced if they were in service greater than 12 years. The failed relay had been in service for 16 years.

The violation was more than minor because it impacted the Mitigating Systems Cornerstone objective of availability, reliability, and capability of systems that respond to initiating events. Using Inspection Manual Chapter 0609, Appendix A, "Determining the Significance of Reactor Inspection Findings for At-Power Situations," the finding was determined to be of very low safety significance because the likelihood of a medium or large break loss of coolant accident coincident with a loss of offsite power, which are the only conditions where the deficiency would cause a non-negligible change in the baseline risk profile, is less than or equal to 1E-6 per year. Therefore the change in core damage frequency will be less than 1E-6 per year. The licensee captured the issue in their corrective action program as Smart Form SMF-2004-003528 (Section 4OA5.2).

Cornerstone: Barrier Integrity

- Green. A Green noncited violation of 10 CFR Part 50, Appendix B, Criterion XVI (Corrective Action) was identified, in that licensee personnel failed to take effective corrective action for a condition adverse to quality. Specifically, licensee welders repaired a body-to-bonnet leak on Valve 1-8702B, Residual Heat Removal Pump 1-02 hot-leg recirculation isolation valve, in April 2004 by installing a seal weld. The valve required additional repair in October 2005 for a body-to-bonnet leak.

  The failure to take effective corrective action for a body-to-bonnet leak on Valve 1-8702 B was a performance deficiency. This finding is greater than minor because it is similar to Example 3.g. of Appendix E of Manual Chapter 0612 because the leakage reoccurred. The inspectors found this finding screened out of the Phase 1 process as Green. The inspectors considered this finding to be of very low safety significance because the event was leakage and not a line break. The cause of this finding is related to the crosscutting aspects of problem identification and resolution. (Section 1R08.1)

B. Licensee Identified Violations

None.

because of evidence of boron leakage since 1995. The valves were 2-8378B, Reactor Coolant System Loop 2-04 charging upstream check valve; 2-8379A, and 2-8379B, Reactor Coolant System Loop 2-01 charging system downstream check valves. Licensee personnel found all of these welds to subsequently leak within a year in 1996. In 2005, licensee welders also repaired two valve body-to-bonnet flanged connections because of evidence of leakage. These valves were numbered 2-8818B and 2-8818C, residual heat removal loop check valves. In summary, this repair has been done six times and failed four times. Two of the six times this repair has been done are unknown at this time in respect to leakage because a refueling outage has not occurred. The inspectors considered the evidence of boron leakage in these body-to-bonnet flanged connections to be a condition adverse to quality.

Analysis. The inspectors found this finding to be greater than minor because it is similar to Example 3.g. of Appendix E of Manual Chapter 0612 because the leakage reccurred. The inspectors considered this finding as of very low safety significance because the event was leakage and not a line break. The inspectors found this finding screened out of the Phase 1 process as Green. The licensee issued a Smart Form (SMF) SMF-2005-004209 regarding this finding.

Enforcement. Criterion XVI, *Corrective Actions*, of Appendix B to 10 CFR Part 50 states, in part, that measures shall be established to assure that conditions adverse to quality are promptly identified and corrected. Contrary to the above, corrective actions were inadequate in that leakage of the body-to-bonnet flanged connections on Valve 1-8702B after previous repair in 2004, and on Valves 2-8378B, 2-8379A/B in 1995, were recurrent. The inspectors identified this finding as an NCV because of its very low safety significance and because the licensee has entered this finding in its corrective action program. This is consistent with Section VI.A. of the NRC Enforcement Policy: NCV 05000445/2005005-01, Inadequate Corrective Actions for a Leaking Valve with a Seal Weld which Subsequently Leaked.

.2 Pressurizer Water Reactor Vessel Upper Head Penetration Inspection Activities (Section 02.02)

a. Inspection Scope

The inspection procedure requires observation or review of upper head inspections after the completion of Temporary Instruction 2515/150. The procedure requires samples similar in number to the preceding section.

The licensee plans to replace this head, and thus close the Temporary Instruction 2515/150. The licensee did not perform upper head inspections other than visual during this outage. The visual inspection activities are documented in Section 1R20 of this report.

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

February 13, 2006

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 05000445/2005005 AND 05000446/2005005

Dear Mr. Blevins:

On December 31, 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 January 12, 2006, 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. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

The report documents four self-revealing findings of very low safety significance (Green). All four of these findings were determined to involve violations of NRC requirements. However, because of the very low safety significance and because they are entered into your corrective action program, the NRC is treating these four findings as noncited violations (NCVs) 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 Nuclear Regulatory Commission, ATTN.: Document Control Desk, Washington DC 200555-0001; with copies to the Regional Administrator Region VI; the Director, Office of Enforcement, United States 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 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/

Claude Johnson, Chief
Project Branch A
Division of Reactor Projects

Docket Nos.: 50-445, 50-446
License Nos.: NPF-87, NPF-89

Enclosure: NRC Inspection Report 05000445/2005005 and 05000446/2005005
w/Attachment: Supplemental Information

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ROPreports
CP Site Secretary **(ESS)**

SUNSI Review Completed: __CEJ_ ADAMS: / Yes ☐ No Initials: __CEJ_
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RIV:RI:DRP/A	PE:DRP/A	SRI:DRP/A	C:DRS/EB	C:DRS/OB	C:DRS/PEB
AASanchez	MABrown	DBAllen	JAClark	ATGody	LJSmith
E-CEJ	***/RA/***	***E-CEJ***	***/RA/***	***/RA/***	***DLProulx for***
2/3/06	1/27/06	2/3/06	1/27/06	1/31/06	1/27/06
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U.S. NUCLEAR REGULATORY COMMISSION

REGION IV

Dockets:	50-445, 50-446
Licenses:	NPF-87, NPF-89
Report:	05000445/2005005 and 05000446/2005005
Licensee:	TXU Generation Company LP
Facility:	Comanche Peak Steam Electric Station, Units 1 and 2
Location:	FM-56 Glen Rose, Texas
Dates:	September 24 through December 31, 2005
Inspectors:	D. Allen, Senior Resident Inspector A. Sanchez, Resident Inspector T. Brown, Project Engineer W. McNeill, Reactor Inspector, Engineering Branch 1 P. Elkmann, Emergency Preparedness Inspector S. Garchow, Operations Engineer D. Livermore, Reactor Inspector J. Keeton, Consultant
Approved by:	Claude Johnson, Chief, Project Branch A Division of Reactor Projects
Attachment:	Supplemental Information

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SUMMARY OF FINDINGS

IR 05000445/2005005, 05000446/2005005; 09/24/2005-12/31/2005; Comanche Peak Steam Electric Station, Units 1 and 2; Inservice Inspection Activities, Event Follow-up, and Other Activities

This report covered a 3-month period of inspection by two resident inspectors, two reactor inspectors, one operations engineer, one emergency preparedness inspector, one regional project engineer, and one consultant. Four Green non-cited violations were identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter 0609, "Significance Determination Process" (SDP). Findings for which the SDP 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

C Green. A Green self-revealing noncited violation of Technical Specification 5.4.1.a was identified for failure to implement the maintenance procedure to properly install a check valve in the Emergency Diesel Generator 1-01 lubrication system. On October 20, 2005, the diesel generator shutdown for lack of lube oil to the turbo-chargers after 60 seconds during a post maintenance test. The lube oil strainer check valve had been installed backwards during the previous refueling outage but the opposite strainer had been in service for the ensuing 18 months. The check valve was reinstalled properly, the flow direction of similar check valves verified, and the damaged turbo-chargers replaced.

The violation was more than minor because one of two lube oil strainers for the turbo-chargers was incapable of flow, thus affecting the reliability of the diesel generator. The finding has a human performance crosscutting aspect because the failure to follow the procedure caused the diesel generator failure. However, the error was committed in April 2004. The violation is of very low safety significance because CPSES operating experience indicated that the lube oil strainers had never been swapped outside of an outage, and then only to balance run time on the equipment. The significance determination process screened this out as Green because it only affected the mitigating systems cornerstone and it did not cause an actual loss of safety function of a single train nor a loss of safety function that contributed to external event initiated core damage sequences. This finding has a problem identification and resolution crosscutting aspect because it was caused by lack of effective corrective actions. This event was entered into the corrective action program as Smart Form 2005-004233 (Section 4OA3.1).

C Green. A Green self-revealing noncited violation of Appendix B, Criterion XVI was identified for failure to implement effective corrective actions for a significant condition adverse to quality. Specifically, station service water Pump 1-01 was returned to service on October 20, 2005, and after two hours of operation tripped on an electrical fault on Phase C of the motor leads. The degraded electrical condition of the motor lead had been identified during restoration from the pump maintenance, but the actions taken to ensure the pump was reliable failed. Phase C of the motor leads was replaced prior to returning the pump to service.

The failure to take effective corrective actions was the performance deficiency. The violation was more than minor because the pump was returned to service with a degraded motor lead. At the time of the event, Unit 1 was defueled and did not require an operable station service water pump. However, Unit 2 was required by Technical Specifications 3.7.8 to have at least one operable station service water pump from the opposite unit. With Unit 2 at 100 percent power, a significance determination was performed using Appendix A of Manual Chapter 0609. The finding was determined to be of very low safety significance (Green) because it did not represent a loss of system safety function, was not an actual loss of safety function for a single Unit 2 train, did not involve equipment or function specifically designed to mitigate a seismic, flooding, or severe weather initiating event, and did not involve the total loss of any safety function that contributed to external event initiated sequences. The cause of this finding is related to the crosscutting aspects of problem identification and resolution. The event was entered into the corrective action program as Smart Form 2005-004220 (Section 4OA3.2).

- Green. A Green self-revealing noncited violation of Technical Specification 3.8.1 was identified, after both the alternate and emergency power supplies to a 6.9 kV safeguards bus failed to provide power to the bus within the time assumed in the accident analysis. On October 19, 2004, an unplanned loss of the preferred offsite power caused the Unit 2, Train B, 6.9 kV safeguards bus to de-energize. A degraded Agastat relay delayed the normal power supply breaker from opening for 30 seconds, which delayed powering the bus from the alternate offsite AC power supply or the emergency diesel generator. This issue had crosscutting aspects in the area of problem identification and resolution because the licensee previously identified that aged Agastat relays were unreliable and should be replaced if they were in service greater than 12 years. The failed relay had been in service for 16 years.

  The violation was more than minor because it impacted the Mitigating Systems Cornerstone objective of availability, reliability, and capability of systems that respond to initiating events. Using Inspection Manual Chapter 0609, Appendix A, “Determining the Significance of Reactor Inspection Findings for At-Power Situations,” the finding was determined to be of very low safety significance because the likelihood of a medium or large break loss of coolant accident coincident with a loss of offsite power, which are the only conditions where the deficiency would cause a non-negligible change in the baseline risk profile, is less than or equal to 1E-6 per year. Therefore the change in core damage frequency will be less than 1E-6 per year. The licensee captured the issue in their corrective action program as Smart Form SMF-2004-003528 (Section 4OA5.2).

Cornerstone: Barrier Integrity

- Green. A Green noncited violation of 10 CFR Part 50, Appendix B, Criterion XVI (Corrective Action) was identified, in that licensee personnel failed to identify the cause for a body-to-bonnet leak, a significant condition adverse to quality and take corrective action to prevent recurrence. Specifically, licensee welders repaired a body-to-bonnet leak on Valve 1-8702B, Residual Heat Removal Pump 1-02 hot-leg recirculation isolation valve, in April 2004 by installing a seal weld. The valve required additional repair in October 2005 for a body-to-bonnet leak.

  The failure to identify the root cause and to take effective corrective action to prevent recurrence was a performance deficiency. This finding is greater than minor because it is similar to Example 3.g. of Appendix E of Manual Chapter 0612 because the leakage reoccurred. The inspectors found this finding screened out of the Phase 1 process as Green. The inspectors considered this finding to be of very low safety significance because the event was leakage and not a line break. The cause of this finding is related to the crosscutting aspects of problem identification and resolution. (Section 1R08.1)

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 October 5, 2005 and commenced a reactor shutdown on October 8, 2005 at 8:56 a.m. to begin refueling outage 1RF11. The reactor was manually tripped and entered Mode 3 at 11:39 a.m. that same day. On November 8, 2005 Unit 1 ended refueling outage 1RF11 when the main generator output breakers were closed at 1:51 a.m. The reactor achieved 100 percent reactor power on November 15, 2005 at 3:51 p.m., and operated at essentially 100 percent power for the remainder of the 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 Conditions Procedure Manual (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 at the onset of colder weather conditions during the week of November 28, 2005. The inspectors reviewed the 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.

The inspectors completed one sample.

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 system and reviewed plant procedures and documents to verify that critical portions of the selected system 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 2 Train B safety injection system in accordance with System Operating Procedure (SOP) SOP-201B, "Safety Injection System," Revision 6, while the Train A emergency diesel generator (EDG) system was inoperable for scheduled surveillance, on December 14, 2005

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

.2 Detailed Semiannual System Walkdown (71111.04S)

a. Inspection Scope

The inspectors conducted a detailed semiannual inspection of the Unit 1 and Unit 2 atmospheric relief valves (ARVs), and supporting systems, to verify the functional capability of the system. The inspectors referenced and used the following documents to verify proper system alignment, electrical power supply and setpoints :

- Integrated Plant Operating Procedure (IPO) IPO-002A, "Plant Startup From Hot Standby," Revision 18

- Technical Data Manual TDM-501A, "SG - Feedwater Controller Data," Revision 4

- SOP-301A, "Main Steam System," Revision 14

- CPSES Drawings M1-202 and M2-202, "Flow Diagram Main Steam Reheat and Steam Dump," multiple sheets and revisions

The inspectors also reviewed recent corrective action documents, system health reports, outstanding work requests, and design issues to determine if any of these items impacted the system's ability to operate as designed or indicated a degradation in capability. In addition, the inspectors interviewed the system engineer and site valve experts and discussed the system's maintenance history, and current and long range plans to monitor, modify, or update the system and its components. A complete field walkdown was completed by the inspectors during the week of December 26, 2005.

The inspector 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 Area CA - Unit 1 containment building, all elevations on November 4, 2005
- Fire Zone SE016 - Unit 1 safeguards building 832 foot elevation electrical equipment Room 96 on November 10, 2005
- Fire Zone EA057 - Unit 1 inverter battery room corridor Room 125 on November 26, 2005
- Fire Zone EA054 - Unit 2 inverter battery room corridor Room 122 on November 26, 2005
- Fire Zone 1-SB008 - Unit 1 safeguards corridor 810 foot elevation Rooms 78, 79, and 82 on December 13, 2005
- Fire Zone 2-SB008 - Unit 2 safeguards corridor 810 foot elevation Rooms 78, 79, and 82 on December 13, 2005
- Fire Zone AA21F - Units 1 and 2 auxiliary building 852 foot elevation Rooms 234-235, 238-242 on December 13, 2005

The inspectors completed seven 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, testing, and surveillance of the Unit 1 Trains A and B Component Cooling Water (CCW) heat exchangers to ensure that these risk-important heat exchangers are capable of performing their required safety function during the design basis accident. Specifically, the Unit 1 Train A CCW heat exchanger interior was physically inspected for foreign material following the Unit 1 Train A station service water (SSW) pump ingestion of a vacuum hose in August 2005. The inspectors also viewed the contents from a containment spray seal oil cooler that was supplied from Train A CCW heat exchanger. The inspectors also observed actual heat exchanger testing for the Train A CCW heat exchanger, and reviewed the test data for the Train B CCW heat exchanger. The inspectors verified that the frequency of monitoring and inspection was sufficient to detect degradation prior to loss of heat removal capability. Corrective action documents and system drawings were reviewed by the inspectors. The system engineer was also interviewed by the inspectors.

The inspectors completed two samples.

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection Activities (71111.08)

This inspection procedure requires a minimum sample size of four samples consisting of Sections 02.01, 02.02, 02.03, and 02.04. All sections were completed except for 02.02 because the associated TI 2515/150 is not completed.

.1 Inspection Activities Other Than Steam Generator Tube Inspection, Pressurizer Water Reactor Vessel Upper Head Penetration Inspections, and Boric Acid Corrosion Control (Section 02.01)

a. Inspection Scope

The inspection procedure requires review of two or three types of nondestructive examination activities and one to three welds performed on the reactor coolant pressure boundary.

The inspectors observed 20 nondestructive examination activities including volumetric, surface and visual examinations as follows:

System	Component/Weld Identification	Examination Method
Safety Injection	17 components, 11 struts, 5 snubbers and 1 spring can: Summary Numbers 672400-800, 673200, 673400-600, 673800, 673900, 674200, 674400, 674500, and 674600.	VT-3 (visual)
Safety Injection	2 welded lugs: Summary Numbers 784300 and 784550.	Liquid Penetrant
Residual Heat Removal	Pipe to valve TBX-1-4101-3: Augmented Examination.	Ultrasonic

During the observation of each examination, the inspectors verified that activities were performed in accordance with the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code requirements and applicable procedures. The inspectors verified that the licensee compared the indications revealed by the examinations against the previous outage examination reports as applicable. No defects or reportable flaws were detected during the inservice examinations. The inspectors verified that the licensee used calibrated and qualified instruments and personnel.

Of the five ASME Class 1 and 2 welding activities performed by licensee personnel, the inspectors reviewed Work Order (WO) WO-04-05-163997-00, a canopy seal weld on Valve 1-CS8411. The inspectors verified that the welding activities met ASME Code requirements.

The inspector completed all required samples.

b. Findings

Introduction. The inspectors identified a Green self-revealing noncited violation (NCV) of 10 CFR Part 50, Appendix B, Criterion XVI. The licensee took inadequate corrective actions in that the licensee repaired a leaking valve with a seal weld which subsequently leaked.

Description. The inspectors found that licensee personnel planned to reweld a seal weld because of evidence of boron leakage on Valve 1-8702B found during this outage. Licensee welders repaired this valve in April 2004 because of boric acid leakage at that time. Valve 1-8702B is a Residual Heat Removal Pump 1-02 hot-leg recirculation isolation valve.

A review of the history of this type of repair found three additional examples where licensee welders had seal welded the valve body-to-bonnet flanged connections because of evidence of boron leakage since 1995. The valves were 2-8378B, Reactor Coolant System Loop 2-04 charging upstream check valve; 2-8379A, and 2-8379B, Reactor Coolant System Loop 2-01 charging system downstream check valves. Licensee personnel found all of these welds to subsequently leak within a year in 1996. In 2005, licensee welders also repaired two valve body-to-bonnet flanged connections because of evidence of leakage. These valves were numbered 2-8818B and 2-8818C, residual heat removal loop check valves. In summary, this repair has been done six times and failed four times. Two of the six times this repair has been done are unknown at this time in respect to leakage because a refueling outage has not occurred. The inspectors considered the evidence of boron leakage in these body-to-bonnet flanged connections to be a significant condition adverse to quality.

Analysis. The inspectors found this finding to be greater than minor because it is similar to Example 3.g. of Appendix E of Manual Chapter 0612 because the leakage reccurred. The inspectors considered this finding as of very low safety significance because the event was leakage and not a line break. The inspectors found this finding screened out of the Phase 1 process as Green. The licensee issued a Smart Form (SMF) SMF-2005-004209 regarding this finding.

Enforcement. Criterion XVI, *Corrective Actions*, of Appendix B to 10 CFR Part 50 states, in part, that measures shall be established to assure that conditions adverse to quality are promptly identified and corrected. In the case of significant conditions adverse to quality, the measures shall assure that the cause of the condition is determined and corrective action taken to preclude repetition. Contrary to the above, the measures established to identity the root cause and take corrective actions to prevent recurrence were inadequate in that leakage of the body-to-bonnet flanged connections on Valve 1-8702B after previous repair in 2004, and on Valves 2-8378B, 2-8379A/B in 1995, were recurrent. The inspectors identified this finding as an NCV because of its very low safety significance and because the licensee has entered this finding in its corrective action program. This is consistent with Section VI.A. of the NRC Enforcement Policy: NCV 05000445/2005005-01, Inadequate Corrective Actions for a Leaking Valve with a Seal Weld which Subsequently Leaked.

.2 Pressurizer Water Reactor Vessel Upper Head Penetration Inspection Activities (Section 02.02)

a. Inspection Scope

The inspection procedure requires observation or review of upper head inspections after the completion of Temporary Instruction 2515/150. The procedure requires samples similar in number to the preceding section.

The licensee plans to replace this head, and thus close the Temporary Instruction 2515/150. The licensee did not perform upper head inspections other than visual during this outage. The visual inspection activities are documented in Section 1R20 of this report.

b. Findings

No findings of significance were identified.

.3 Boric Acid Corrosion Control Inspection Activities (Section 02.03)

a. Inspection Scope

The procedure requires observation or review of boric acid corrosion control activities. Specifically, the procedure requires review of one to three engineering evaluations performed for boric acid residue found on reactor coolant system piping and components. This procedure also required review of one to three corrective actions taken because of evidence of boric acid leaks.

The inspectors reviewed records of a visual examination of the reactor coolant system pressure boundary integrity walkdown. The inspectors reviewed the 58 areas with light boric acid residue identified by the licensee as of the time of this review (the licensee had not completed all the inspections) to assure identification and correction of leakage. The inspectors reviewed the SMF written to evaluate and clean the areas identified during the last inspection. The inspectors verified that licensee personnel adequately evaluated 30 minor leaks including one active leak to assure correction of leakage problems. The inspectors reviewed the corrective actions taken at that time.

The inspector completed all required samples.

b. Findings

No findings of significance were identified.

.4 Steam Generator Tube Inspection Activities (Section 02.04)

a. Inspection Scope

The inspectors reviewed the leakage history for the steam generators to verify that the licensee had no leakage during operations before the shutdown. The inspectors verified that licensee personnel and contractors used properly qualified eddy current probes and equipment for the expected types of tube degradation to assure proper identification and evaluation of indications. The inspectors observed the collection and analysis and resolution of nine calibration groups of eddy current data performed by contractor personnel to evaluate tubes and possible loose parts in the steam generators to assure proper implementation of the procedures and program requirements. The inspectors verified that the licensee analysts reviewed the areas of potential degradation, based on site-specific and industry experience, to assure proper use of this information. The inspectors verified that the licensee compared flaws detected during the current outage against the previous outages' data. The inspectors reviewed the repair criteria used to assure compliance with technical requirements. The inspectors also verified the licensee's eddy current examination scope and expansion criteria met the Technical Specifications, industry guidelines, and commitments to the NRC.

Regarding plugging and in-situ pressure testing, at the time of this inspection the licensee had not established the full scope of plugging and in-situ pressure testing to be performed. The inspectors verified that the predictions of tube plugging appeared to be the same as experienced in the past.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11)

Resident Inspector Quarterly Review (71111.11Q)

a. Inspection Scope

The inspector observed two licensed operator requalification training scenarios in the control room simulator on December 14, 2005. The first training session began with a short lesson on immediate operator actions for a pressurizer channel failure response. This was followed by a scenario that consisted of a feedwater heater tube leak, a main feedwater trip followed by a reactor trip, and loss of heat sink. The second training scenario consisted of a slow degradation of grid voltage and frequency, eventual loss of the 345kV buses, reactor trip, loss of the 138 kV switchyard, loss of all AC power and Train B DC power.

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 the operators were identifying crew performance problems as applicable.

The inspectors also observed a requalification classroom training session regarding the main feedwater system.

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R12 Maintenance Rule Implementation (71111.12)

a. Inspection Scope

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

- During the week of November 28, the inspectors reviewed the corrective actions and performance history of the Units 1 and 2 charging pump suction high point vent problems identified in SMF-2002-002396 and SMF-2002-004242 that had resulted in both systems being placed in Maintenance Rule (a)(1). Both Units systems have been returned to (a)(2) status based on successfully meeting the performance criteria.

- The common control room Heating Ventilation and Air Conditioning (HVAC) System, Train B was placed into (a)(1) status due to exceeding the functional performance criterion of two functional failures within two years. Both failures were from misaligned motor control center electrical bucket stabs. New performance criterion for the system has been established. This issue was entered and is being tracked in the corrective action program as SMF-2005-003830.

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.

The inspectors completed two samples.

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:

- Delay of completion of maintenance on switchyard Breaker 7980 resulted in increased risk for scheduled troubleshooting and maintenance of SSW Pump 1-02 flow indication on September 30, 2005

- Reschedule of crane operations near Transformer XST1 during scheduled surveillance testing of EDG 2-02 and ATWS Mitigation System Actuation Circuit on October 5 - 6, 2005

- Outage Risk Assessment for Refueling Outage 1RF11 (scheduled for October 8 - November 7, 2005) on October 6, 2005

- Delayed completion of maintenance on switchyard Breaker 8090 with concurrent scheduled maintenance on EDG 2-02 and Unit 1 reactor coolant system reduced inventory on October 27 - 28, 2005

- Switchyard Breaker 8050 restored but air switch left open, making the Venus line inoperable, discovered October 30 after opening Breaker 7970 on October 29-30, 2005

- Unit 1 reduced inventory evolution reschedule conflicted with the scheduled EDG 2-02 surveillance on November 2, 2005

The inspectors completed six samples.

b. Findings

No findings of significance were identified.

1R14 Personnel Performance During Nonroutine Plant Evolutions (71111.14)

a. Inspection Scope

For the two 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 October 8, 2005, the control room operators commenced the Unit 1 reactor shutdown to begin refueling outage 1RF11 via boration as per IPO-003A, “Power Operations,” Revision 24. At 11:39 a.m., reactor operators manually tripped the reactor and entered EOP-0.0A, “Reactor Trip or Safety Injection,” Revision 7. Operators transitioned to EOS-0.1A, “Reactor Trip Response,” Revision 7 and IPO-005A, “Plant Cooldown From Hot Standby to Cold Shutdown,” Revision 21. The inspectors observed control room activities and operator actions during the evolution to ensure formal and clear communications, proper procedure usage, command and control activities, proper use of emergency procedures, and the controlled and safe shutdown of the Unit 1 reactor.

- On October 11, 2005, the control room operators lowered Unit 1 reactor coolant system water level to approximately 56 inches above the reactor core (Midloop) in preparation to remove steam generator primary manways and install steam generator nozzle dams. The inspectors reviewed Generic Letter Number 88-17, "Loss of Decay Heat Removal" and TXU's responses. Integrated Plant Operating Procedure IPO-010A, "Reactor Coolant System Reduced Inventory Operations," Revision 16, was reviewed to ensure adequate controls were in place. The control room activities and operator's actions were observed during the evolution to ensure the procedure was followed, plant instruments were responding correctly, conservative decisions were made, and that the evolution was completed safely. Control room activities were periodically observed for distractions to the operators while the reactor vessel water level remained in reduced inventory.

The inspectors completed two 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 any Technical Specifications; (5) used the SDP to evaluate the risk significance of degraded or inoperable equipment; and (6) verified that the licensee has 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:

C Quick Technical Evaluation (QTE) QTE-2005-002098-01-00, distance between Unit 1 Train C Cable NK130951 and Handswitch 1/1-8823 does not meet separation criteria of ES-100 Appendix F, Attachment 1, Table 1, reviewed the week of November 21, 2005

- Evaluation (EVAL) EVAL-2005-004233-05-00, review past operability of EDG 1-01 with Check Valve 1DO-0152 installed backwards, reviewed on November 22, 2005

- QTE-2005-003945-01-00, determine operability of the common uninterruptible power supply (UPS) and distribution room HVAC system Train B following an observation of the compressor failing to start when the UPS air conditioning system was manually requested to start, reviewed on December 29-30, 2005

The inspectors completed three samples.

b. Findings

No findings of significance were identified.

1R16 Operator Workarounds (71111.16)

Cumulative Review of the Effects of Operator Workarounds

a. Inspection Scope

On November 29, 2005, the inspectors reviewed cumulative effects of identified operator workarounds on reliability, availability, and potential for system misoperation on both Units. The inspectors reviewed the cumulative effects of the operator workarounds on multiple mitigating systems and the ability of operators to respond in a correct and timely manner to plant transients and accidents.

The inspectors completed one sample.

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 1 SSW Pump 1-01 motor following failure of the Phase C cable to the motor on October 20, 2005, in accordance with Maintenance Section - Electrical procedure MSE-G0-4201, "Megger Testing of Power Cables, Motors and Generators," Revision 6, and MSE-G0-4003, "DC High Potential Testing With Baker Advanced Winding Analyzer," Revision 0, on October 24, 2005

- Unit 1 EDG 1-02 following digital upgrade of the voltage regulation system, in accordance with Maintenance Section-Mechanical Manual Procedure MSM-P0-3375, "Emergency Diesel Engine Break-in Run and Post Maintenance Run," Revision 7, on November 3, 2005

- Unit 1 Turbine Driven Auxiliary Feedwater (TDAFW) Pump following outage related maintenance including replacement of the governor, in accordance with Equipment Test Procedure ETP-304A, "Turbine Driven Auxiliary Feedwater Pump Overspeed Test," Revision 3, System Operation Procedure SOP-304A, "Auxiliary Feedwater System," Revision 16, Testing Procedure PPT-S1-9103A, "TDAFW Pump Actuation and Response Time Test, Train A," Revision 2 and OPT-206A, "AFW System," Revision 25, on November 6, 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.

The inspectors completed three samples.

b. Findings

No findings of significance were identified.

1R20 Refueling and Outage Activities (71111.20)

a. Inspection Scope

The inspectors evaluated licensee's 1RF11 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 Technical Specification 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

- Reduced inventory and midloop activities to perform steam generator manway removal, nozzle dam installation and removal
- Reactor coolant system 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, fuel transfer, and core reloading
- Electrical power source arrangement
- Containment cleanup and inspection
- Containment recirculation sump inspection
- Unit heatup and startup
- Reactor vessel upper head penetration review and inspection
- Reactor vessel lower head penetration review and inspection
- Licensee identification and resolution of problems related to refueling activities

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 containment close out inspection in accordance with procedure OPT-305, "Containment Close Out Inspection," Revision 10 and WO-5-04-504191-AA, reviewed on November 4, 2005

- Unit 1 low power physics testing following refueling, in accordance with Nuclear Engineering Procedure NUC-301, "Low Power Physics Testing," Revision 12, reviewed on November 10, 2005

- Unit 1, reactor coolant system leak rate surveillance, in accordance with OPT-303, "Reactor Coolant System Water Inventory," Revision 10, reviewed on November 21, 2005

- Unit 1 Train A slave relay and containment isolation valve actuation test, in accordance with OPT-459A, "Train A Safeguards Slave Relay K623 Actuation Test," Revision 5, reviewed on December 13, 2005

The inspectors completed four samples.

b. Findings

No findings of significance were identified.

1R23 Temporary Plant Modifications (71111.23)

a. Inspection Scope

The inspectors reviewed the Updated Final Safety Analysis Report, plant drawings, procedure requirements, Technical Specification and Technical Requirements Manual to ensure that the below listed temporary modification was properly implemented. The inspectors: (1) verified that the modification did not have an affect on system operability/availability; (2) verified that the installation was consistent with the modification documents; (3) ensured that the post-installation test results were satisfactory and that the impact of the temporary modification on permanently installed SSC's were supported by the test; (4) verified that the modification was identified on control room drawings and that appropriate identification tags were placed on the affected equipment; and (5) verified that appropriate safety evaluations were completed. The inspectors verified that licensee identified and implemented any needed corrective actions associated with temporary modifications.

- Unit 1 Construction Access Facility installed at tornado missile Door S1-27 at the south end of the Unit 1 safeguards building, reviewed on December 4, 2005

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

1EP1 Exercise Evaluation (71114.01)

a. Inspection Scope

The inspectors reviewed the objectives and scenario for the 2005 biennial emergency plan exercise to determine if the exercise would acceptably test major elements of the emergency plan. The scenario simulated a failure to automatically isolate a liquid release, plant fire lasting greater than 15 minutes, a reactor coolant pump failure, mechanical core damage, fission product barrier failures, and a radiological release to the environment via a steam generator tube rupture and stuck-open steam generator atmospheric safety valve, to demonstrate the licensee's capabilities to implement the emergency plan.

The inspectors evaluated exercise performance by focusing on the risk-significant activities of classification, notification, protective action recommendations, and offsite dose consequences in the following emergency response facilities:

- Simulator Control Room
- Technical Support Center
- Operations Support Center
- Emergency Operations Facility

The inspectors also assessed personnel recognition of abnormal plant conditions, the transfer of emergency responsibilities between facilities, communications, protection of emergency workers, emergency repair capabilities, and the overall implementation of the emergency plan.

The inspectors attended the post-exercise critiques in each of the above facilities to evaluate the initial licensee self-assessment of exercise performance. The inspectors also attended a subsequent formal presentation of critique items to plant management.

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1EP6 Drill Evaluation (71114.06)

a. Inspection Scope

On November 28, 2005, the inspectors evaluated the adequacy of emergency drills that contributed to performance indicator statistics performed on that day. Observations of two operations crews in the control room simulator included opportunities for emergency classifications and offsite notifications. The inspectors reviewed the drill scenario, drill objectives, activity log sheets, evaluations, and critique notes. The inspectors also observed the shift manager critique for both crews and discussed observations with the drill controllers and evaluators from the control room simulator. The inspectors verified that the licensee adequately conducted the drills and critiqued the drill performance in accordance with the facility guidelines.

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

a. Inspection Scope

The inspector sampled licensee submittals for the performance indicators listed below for the period July 2004 through September 2005. The definitions and guidance of NEI 99-02, “Regulatory Assessment Indicator Guideline,” Revisions 2 and 3, were used to verify the licensee’s basis for reporting each data element in order to verify the accuracy of performance indicator data reported during the assessment period. Licensee performance indicator data was reviewed against the requirements of Staff Guideline 20, “NRC Performance Indicators,” Revisions 6 and 7.

Emergency Preparedness Cornerstone:

- Drill and Exercise Performance
- Emergency Response Organization Participation
- Alert and Notification System Reliability

The inspector reviewed a 100 percent sample of drill and exercise scenarios and licensed operator simulator training sessions, notification forms, and attendance and critique records associated with training sessions, drills, and exercises conducted during the verification period. The inspector reviewed selected emergency responder drill participation records. The inspector reviewed alert and notification system testing procedures, maintenance records, and a 100 percent sample of siren test records. The inspector also interviewed licensee personnel responsible for collecting and evaluating performance indicator data.

The inspector completed three samples during this inspection.

b. Findings

The inspector identified 11 instances in which the licensee evaluated offsite notification forms as accurate when a site-wide emergency condition was marked as applying only to Unit 1. NEI 99-02, "Regulatory Assessment Performance Indicators," Revisions 2 and 3, identifies the unit applicability of an emergency condition as a component of offsite notification form accuracy. The inspector determined that the licensee had not provided guidance regarding the correct marking of unit applicability when emergency conditions impact more than one unit, resulting in inconsistent performance in marking the offsite notification form. The reevaluation of these 11 opportunities has the potential to cause the licensee's Drill and Exercise Performance Indicator to drop below the established 90% threshold.

This finding is similar to the Reactor Oversight Program (ROP) Frequently Asked Question (FAQ) 338, dated March 2003, which addressed evaluation of "Drill" or "Actual Event" as marked on offsite notification forms. FAQ 338 instructed licensees to submit similar issues to the ROP working group for guidance regarding post-submittal reevaluation. An Unresolved Item has been opened pending resolution of an FAQ submitted to the ROP working group on this issue; URI 05000445;05000446/2005005-02, Notification Form Accuracy Requires Additional Guidance.

4OA2 Problem Identification and Resolution (71152)

.1 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 help 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 (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.

.2 Semiannual Trend Review

a. Inspection Scope

On December 23, 2005, the inspectors completed a semiannual review of licensee internal documents, reports, and performance indicators to identify trends that might indicate the existence of more safety significant issues. The inspectors reviewed the following types of documents:

- Corrective Action Documents (Smart Forms)
- System Health Reports
- Planned Maintenance Work Week Critiques
- CPSES Nuclear Overview Department Evaluation Reports (Audits)
- Human Performance Program Health Indicators Package
- Corrective Action Program Health report
- Station Reliability Issues
- Degraded conditions evaluated in accordance with Generic Letter 91-18
- CPSES Self-Assessment Reports

b. Findings and Observations

No findings of significance were identified. However, during the review, the inspectors did note the following two items: (1) several issues related to foreign material exclusion, including fuel clad failure due to debris; and (2) issues related to the reliability of the main turbine generator digital control system and operator errors committed while operating the controls. The inspectors did not identify any additional trends.

The inspectors determined that the licensee had adequately identified adverse trends and entered them into the corrective action program using an appropriate threshold.

.3 Selected Issue for In-Depth Review: Review of Unit 2 TDAFW Pump

a. Inspection Scope

The inspectors performed a detail review of an issue involving the Unit 2 TDAFW pump failure to reduce speed during an operational surveillance test run. This issue was placed into the licensee's corrective action program as SMF-2005-002054. The inspectors reviewed the apparent cause evaluation, vendor written communication

(VL-05-002561), and procedure MSM-C0-8721, “Governor Valve for Terry Turbine,” Revision 1. The inspectors also performed a detailed system walkdown, and discussed the issue with the system engineer.

b. Findings and Observations

No findings of significance were identified. On May 12, 2005 during an operational surveillance run on the Unit 2 TDAFW pump, the turbine failed to reduce speed below 2440 revolutions per minute (rpm) when directed, by the procedure, for verification of governor oil level. The licensee determined that there was proper oil level in the governor, and determined that the ability of the governor valve to close completely did not cause the TDAFW pump to become inoperable. The safety function of the TDAFW pump is to operate at a speed of at least 4075 rpm, which it was capable of doing at that time.

The apparent cause analysis was completed and approved on August 10, 2005 and was determined using the “Why Tree” technique. The cause for the TDAFW pump not being able to reduce speed below 2440 rpm was determined to be the improper setting of the governor valve linkage. The governor valve linkage was not set correctly due to the difficulty of measuring the gap between the governor valve stem and the cam plate, which was specified as 0.075 inch, with a dial indicator in a physically cramped space. Two corrective actions were generated from the apparent cause analysis. The procedure controlling the TDAFW maintenance was modified to measure the gap between the governor valve stem and the cam plate in terms of 1/16 inch. This allows the mechanics to measure the gap with a ruler instead of a dial indicator. The licensee plans to purchase a spare Terry Turbine to allow the just-in-time training of the mechanics.

The licensee took the immediate action of readjusting the governor valve linkage and completed the necessary corrective action in a reasonable amount of time commensurate with the safety significance of the issue. SMF-2005-004986-00 was initiated to complete an effectiveness review of the completed corrective actions.

The inspectors completed one sample.

.4 Selected Issue for In-Depth Review: Review of Unit 2, Steam Generator 2-04 Atmospheric Relief Valve Repeatedly Exceeding Operational Alert Limits

a. Inspection Scope

The inspectors performed a detail review of an issue involving the Unit 2 ARV, 2-PV-2328, repeatedly exceeding its operational alert limit stroke time (open direction) test. The inspectors identified at least five occurrences since February 2004. The stroke time surveillance is performed on a 92 day frequency. The inspectors reviewed OPT-504B, “MS Section XI Valves,” Revision 10, recent system and component health reports, and Smart Forms. The Smart Forms reviewed are: SMF-2004-000566,

SMF-2004-003610, SMF-2005-000228, SMF-2005-002654, and SMF-2005-003804. Interviews were conducted with the system engineer, in-service testing engineer, and licensee valve experts. The inspectors also performed a system walkdown.

b. Findings and Observations

No findings of significance were identified; however the inspectors identified that the licensee had not identified nor had any action in place for Unit 2 ARV, 2-PV-2328, repeatedly exceeding the alert threshold for stroke time (open direction) during operational surveillance testing.

Between February 15, 2004 and October 10, 2005, the Unit 2 ARV, 2-PV-2328, had exceeded its operational alert limit stroke time test five times. In each instance the ARV had exceeded its surveillance alert stroke time limit of 9.0 seconds (open direction), but had not exceeded the acceptance criterion of 10 seconds. The design basis document states that the ARVs are required to be capable of a full stroke within 20 seconds, therefore, the valve was declared operable. Each of these instances of the valve exceeding its stroke time alert limit, the issue was placed into the corrective action program and evaluated. In each instance, the inservice testing engineer had evaluated the results, recommended no action, and determined that there was no significant degradation of valve performance.

In general, there has been a step increase in all Unit 2 ARV stroke times in the October 2003 time frame. The step change and the trend are especially obvious for the ARV 2-PV-2328. This trend was not identified and was not being addressed by the licensee. ASME Section XI sets alert limits and acceptance criteria for valve stroke times based on reference stroke time valves. This program is in place to detect degrading components to protect from unexpect failures. The licensee was not trending any of the surveillance testing results or the number of times this valve had exceeded the alert setpoint. The result of this review is that the licensee was not trending or aware of the change in ARV performance. This was a missed opportunity to identify a change in component function. The licensee has entered the issue into the corrective action program as SMF-2006-00125 and is currently reviewing the issue to determine a cause and to determine what corrective actions should be taken.

The inspectors complete one sample.

.5 Emergency Preparedness Annual Sample Review

a. Inspection Scope

The inspectors reviewed summaries of corrective actions assigned to emergency preparedness during calendar years 2004 and 2005, reviewed 6 drill reports, and observed licensee performance during a full-scale exercise, to determine the effectiveness of previous corrective actions.

b. Findings and Observations

No findings of significance were identified.

.6 Inservice Inspection Review of Problem Identification and Resolution

a. Inspection Scope

The inspection procedure requires review of a sample of problems associated with inservice inspections and steam generator inspections documented by licensee personnel in the corrective action program for appropriateness of the corrective actions.

The inspectors reviewed 9 of the 56 SMFs written since the last outage which dealt with inservice inspection and steam generator eddy current inspection activities and found the corrective actions were appropriate. The inspectors performed this review to assure that the licensee had an appropriate threshold for entering issues into the corrective action program and had procedures that direct root cause evaluations when necessary.

b. Findings

No findings of significance were identified.

4OA3 Event Follow-up (71153)

.1 Unit 1 EDG 1-01 trip due to Check Valve 1DO-0152 installed backwards in lubrication oil system

a. Inspection Scope

The inspectors reviewed the trip of the EDG 1-01 which occurred on October 20, 2005 during the initial post maintenance run. The inspectors interviewed personnel involved, attended the PERC meeting, reviewed SMFs and procedures.

b. Findings

Introduction. A Green, self-revealing, NCV was identified for failure to properly perform the installation procedure for Check Valve 1DO-0152 in the EDG 1-01 lube oil system, as prescribed in Technical Specification 5.4.1.a.

Description. On October 20, 2005, EDG 1-01 was started for a post maintenance run following the 1RF11 outage work on the EDG. The EDG tripped 60 seconds after starting on low lube oil pressure to the turbo-chargers. Troubleshooting by the licensee found that the right bank lube oil strainer outlet Check Valve 1DO-0152 was installed backwards, preventing lube oil flow to the turbo-chargers and rocker arm assemblies. The turbo-chargers were replaced and found to have been damaged by this event. Check Valve 1DO-0152 had last been replaced the previous refueling outage on

April 11, 2004. The installation had been performed in accordance with maintenance procedure MSM-P0-332, "Emergency Diesel Generator Lube Oil Check Valve Maintenance," Revision 2, Step 8.16.2, which required a verification of the check valve to ensure it was installed with the flow (arrow) pointing away from the strainer. Check Valve 1DO-0152 was found with the flow arrow pointing towards the strainer. The EDG 1-01 lube oil system had been aligned through the left bank lube oil strainer during the operating cycle, and the strainer alignment was shifted following the 1RF11 work window to balance run time on the equipment. Similar check valves in the other three EDGs were verified to be installed with the proper orientation, and Check Valve 1DO-0152 was reinstalled correctly. A review of the CPSES operating experience indicated the lube oil strainers had never been swapped outside of an outage for either units.

Analysis. The inspectors determined that the licensee's failure to install check valve 1DO-0152 in the EDG 1-01 lube oil system correctly was a performance deficiency. This finding is more than minor because the improper installation of the check valve prevented flow through the right bank lube oil strainer, which affected the mitigating systems cornerstone objective to ensure the availability, reliability and capability of systems that respond to initiating events to prevent undesirable consequences. This finding has a human performance cross-cutting aspect because the failure to follow the maintenance procedure was the cause of the degraded condition. Phase 1 of the significance determination process screened this finding as very low safety significance (Green) because it only affected the mitigating systems cornerstone, was not a design or qualification deficiency, did not cause a loss of system safety function or an actual loss of safety function of a single train, did not involve equipment or functions specifically designed to mitigate a seismic, flooding, or severe weather initiating event, and did not involve the total loss of a safety function that contributes to external event initiated core damage sequences.

Enforcement. Technical Specification 5.4.1.a requires written procedures to be established, implemented, and maintained covering activities recommended in Regulatory Guide 1.33, Revision 2, Appendix A, which includes maintenance procedures that could affect performance of safety-related equipment. Contrary to the above, maintenance procedure MSM-P0-332, "Emergency Diesel Generator Lube Oil Check Valve Maintenance," Revision 2 was not properly implemented on April 11, 2004. Because this violation was of very low safety significance and was entered into the corrective action program as SMF-2005-004233, it is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy:
NCV 05000445/2005005-03, Trip of Emergency Diesel Generator Due to Lube Oil Check Valve Installed Backwards.

.2 Unit 1 Station Service Water Pump 1-01 Trip Due to Overcurrent Condition on Phase C

a. Inspection Scope

The inspectors reviewed the trip of the SSW Pump 1-01 which occurred on October 20, 2005. The inspectors interviewed personnel involved, attended the PERC meeting, reviewed Smart Forms, and procedures.

b. Findings

Introduction. A Green, self-revealing, NCV was identified for failure to implement effective corrective actions for a condition adverse to quality prior to returning a safety related SSW pump to service.

Description. On October 19, 2005, a degraded condition had been noted on the Phase C cable of the SSW Pump 1-01 during preparations to reland the motor leads following pump overhaul. The licensee made repairs to correct the degraded conditions by replacing part of the Phase C cable closest to the motor. Following surveillance testing, the licensee declared the SSW Pump 1-01 operable. On October 20, 2005 at 5:00 a.m., SSW Pump 1-01 was placed in service and SSW Pump 1-02 was tagged out in preparations for a scheduled Train B SSW outage. At 6:55 a.m., SSW Pump 1-01 tripped on an overcurrent condition sensed on the Phase C motor lead. At the time of the trip, Unit 1 was in "no mode" (reactor fuel was in the spent fuel pool for 1RF11) and Unit 2 was at 100 percent power with both SSW trains in service. In response to the trip of SSW Pump 1-01, the licensee restored SSW Pump 1-02 to service at 10:35 a.m. The degraded condition on Phase C motor lead was corrected by replacing the entire cable.

Analysis. The failure to take effective corrective actions for the degraded motor lead was the performance deficiency. The inspectors consider this finding to be more than minor because there are several examples in Appendix E of Manual Chapter 0612 where an issue is more than minor because the system is returned to service with a degraded condition. Although Unit 1 was in an outage, Appendix G of Manual Chapter 0609 was not applicable, as there was no requirement for Unit 1 to have an operable SSW system. However, Unit 2 was required to have an operable Unit 1 SSW pump for Mode 1 by Technical Specification 3.7.8. A Phase 1 significance determination in accordance with Appendix A was performed. Since this finding did not affect the initiating events cornerstone for Unit 2, it only affected one cornerstone, the mitigating systems cornerstone. The finding was determined to have a very low safety significance (Green) because it did not represent a loss of system safety function, was not an actual loss of safety function for a single Unit 2 train, did not involve equipment or function specifically designed to mitigate a seismic, flooding, or severe weather initiating event, and did not involve the total loss of any safety function that contributed to external event initiated sequences. This finding has a problem identification and resolution crosscutting aspect because it was caused by lack of effective corrective actions.

Enforcement. Criterion XVI of Appendix B to 10 CFR Part 50 requires that measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment and nonconformances are promptly identified and corrected. Contrary to the above, on October 20, 2005, SSW Pump 1-01 was returned to service after identification of a deficiency in the Phase C motor lead without implementing effective corrective actions. Because this violation was of very low safety significance and was entered into the corrective action program as SMF-2005-004220, it is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy:
NCV 05000445/2005005-04, Trip of Station Service Water Pump Due to Degraded Motor Lead.

4OA5 Other Activities

.1 Pressurizer Penetration Nozzles and Steam Space Piping Connections in U.S. Pressurized Water Reactors (NRC Bulletin 2004-01) (Temporary Instruction 2515/160)

This Temporary Instruction provided the guidelines to verify compliance with licensee commitments to NRC Bulletin 2004-01, "Inspection of Alloy 82/182/600 Materials Used in the Fabrication of Pressurizer Penetrations and Steam Space Piping Connections at Pressurized-Water Reactors." The inspector used the inspection requirements for the bare metal visual examination to conduct this inspection on the CPSES Unit 1 pressurizer and steam space penetrations during the 1RF11 refueling outage, Fall 2005.

a. Inspection Scope

The inspector performed this performance-based evaluation and assessment to ensure that the NRC had an independent review of the condition of the pressurizer and steam space piping alloy 82/182 dissimilar metal welds. The inspector assessed the effectiveness of the licensee examinations of the pressurizer vessel and penetrations. Specifically, the inspector:

- met with licensee representatives to review and discuss inspection plans and contingencies

- attended pre-job briefs

- directly inspected and assessed the condition of the pressurizer and the associated piping weld penetrations

- assessed the physical difficulties in performing the inspection, which included any debris, dirt, boron, and other viewing impediments

- interviewed the licensee inspectors

- assessed the licensee's ability to distinguish small boron deposits located at the weld locations

- verified that the licensee documented deficiencies in their corrective action program

- assessed the overall effectiveness of the process used to perform the bare metal visual inspection

The inspector also reviewed the following documents during this inspection:

- NRC Bulletin 2004-01, "Inspection of Alloy 82/182/600 Materials Used in the Fabrication of Pressurizer Penetrations and Steam Space Piping Connections at Pressurized-Water Reactors," dated May 28, 2004

- NRC Information Notice 2004-11, "Cracking in Pressurizer Safety and Relief Nozzles and in Surge Line Nozzle," dated May 6, 2004

- Comanche Peak Steam Electric Station 60-Day Response to NRC Bulletin 2004-01, "Inspection of Alloy 82/182/600 Materials Used in the Fabrication of Pressurizer Penetrations and Steam Space Piping Connections at Pressurized Water Reactors," TXX-04140, dated July 27, 2004

- Comanche Peak Steam Electric Station Response to NRC's Request for Additional Information Request regarding the response to NRC Bulletin 2004-01, "Inspection of Alloy 82/182/600 Materials Used in the Fabrication of Pressurizer Penetrations and Steam Space Piping Connections at Pressurized Water Reactors," TXX-05056 , dated March 7, 2005

- CPSES Station Administration Manual Procedure STA-737, "Boric Acid Corrosion Detection and Evaluation," Revision 3

- NRC Inspection Manual, Inspection Procedure 57050, "Visual Testing Examination," issued March 9, 1999

b. Findings

No findings of significance were identified. The inspector concluded that the licensee met the applicable commitments in that they performed a 100 percent bare metal visual inspection of the circumference over the axial length of the Alloy 82/182 identified welds for the Unit 1 pressurizer. These inspections were performed by a VT-2 Level II certified examiner. The inspector has provided the following details of the inspection as required by Temporary Instruction 2515/160, "Pressurizer Penetration Nozzles and Steam Space Piping Connections in U.S. Pressurized Water Reactors (NRC Bulletin 2004-01)," issued October 6, 2004.

1. Examination

   The licensee's examiner was certified in accordance with CPSES procedures to meet the ASME Section XI for VT-2 Level II.

   The examination was conducted in accordance with a CPSES examination plan, "RCS Pressure Boundary DM Weld Supplemental Visual Examination Plan," Revision 1, approved on March 28, 2005. The examination plan provided: (1) responsibilities for the examination process; (2) examiner qualification; (3) scope of welds to be examined, a description of the basic bare metal inspection technique and the expectation of 100 percent inspection coverage; (4) acceptance criteria for the inspection; (5) types of indications that shall be further investigated; (6) criteria for cleaning the examined area; and (7) sufficient guidance to satisfy licensee commitments for the inspection. The inspectors concluded that the inspection plan, combined with training, have provided adequate guidance for the licensee examiner to identify, disposition, and resolve deficiencies.

   Due to the proximity of the bare metal visual examination, VT-2 Level II qualified personnel, and the accessability of the specified Alloy 82/182 welds, the inspectors determined that RCS leakage described in NRC Bulletin 2004-01 would be identified, if present.

2. Physical condition penetration nozzles and steam space piping

   In general, the condition of the weld areas examined were in excellent condition. Access to the welds only required the removal of a relatively small amount of mirror insulation, radiation levels were acceptable, and the welds themselves were very new looking with no residue of previous spills or in-service inspections. Only on the downhill side of the safety and pressurizer power operated relief valve welds was it necessary to use a mirror (due to limited space below the piping). All other examinations were performed with the naked eye.

3. Visual inspection protocol

   Direct visual inspection and the use of a mirror were the inspection techniques used by qualified examination personnel.

4. Inspection coverage

   The inspectors observed that the licensee completed a 100 percent, 360 degree bare metal inspection of the pressurizer penetration nozzles and steam space piping connections.

5. Capability to identify and characterize small boric acid deposits

The inspectors determined that the direct visual inspections, coupled with mirror assisted visual inspections were capable of detecting, identifying and characterizing small boric acid deposits, if present, as described in NRC Bulletin 2004-01. This fact was determined via direct inspection during the licensee inspection of the pressurizer and associated steam space piping connections.

6. Identified deficiencies that required repair

   No deficiencies were identified.

7. Impediments to effective examinations

   There were no impediments that adversely affected effective bare metal visual examinations. In all examination cases, mirror insulation was required to be removed. The examination of the pressurizer safety and power operated relief valve line welds was supplemented by a mirror to allow examination of the downhill side of the welds. The dose rates were acceptable, and the inspectors received approximately 50 mRem to complete the in-plant portion of the temporary instruction.

8. Techniques used for augmented inspections

   Augmented inspections were not required.

9. Appropriateness of follow-on examinations

   Follow-on examinations were not required.

.2 <u>(Closed) URI 05000446/2005009-01</u>: Inoperability of Emergency Power to a Safety Bus

<u>Introduction</u>. A Green self-revealing noncited violation of Technical Specification 3.8.1 was identified because both the alternate offsite AC power source and the EDG did not supply power to a 6.9 kV safeguards bus within the time assumed in the accident analysis.

<u>Description</u>. Technical Specification 3.8.1 requires two operable qualified circuits between the offsite transmission network and the onsite Class 1E AC electrical power distribution system; and two operable diesel generators (DGs) capable of supplying the onsite Class 1E power distribution subsystem. On October 19, 2004, an unplanned loss of the preferred offsite power caused the Unit 2, Train B, 6.9 kV safeguards bus to deenergize. A degraded Agastat relay delayed the normal power supply breaker from opening for 30 seconds. Both the EDG and the alternate power supply were prevented from powering the bus due to a breaker interlock with the normal supply. This delay rendered both the EDG and alternate offsite AC power supplies inoperable. The 30 second delay in providing power to the safeguards bus would have resulted in the station not meeting the 10 CFR Part 50, Appendix K, “Emergency Core Cooling System Evaluation Models Acceptance Criteria,” for that equipment train.

The licensee had a previous opportunity to correct the degraded Agastat relay issues. On October 7, 2002, EDG 1-02 unexpectedly started due to a degraded Agastat relay. The licensee concluded that the failure could have been caused by aging and formed a corrective action plan to replace all safety-related Agastat relays that have been in service for greater than the licensee established 12 year lifetime. EVAL-2003-001440-01-01 stated that the main effect of aging on these relays was an increase in setpoint drift. The licensee issued SMF-2004-003528 to track the root cause and corrective actions associated with the faulty Agastat relays. Also, the NRC previously identified that Agastat relays used in the 6.9 kV bus transfer circuitry were exhibiting setpoint drift (SMF-2002-001504 and Inspection Report 05000445/2003006; 05000446/2003006). The relay that failed in October 2004 was 16 years old.

Analysis. The licensee's failure to identify the cause and implement corrective actions to prevent repetitive failures of safety-related Agastat relays was a performance deficiency. The violation was more than minor because it impacted the Mitigating Systems Cornerstone objective of availability, reliability, and capability of systems that respond to initiating events. Using Inspection Manual Chapter 0609, Appendix A, "Determining the Significance of Reactor Inspection Findings for At-Power Situations," the finding was determined to be of very low safety significance because the likelihood of a medium or large break loss of coolant accident coincident with a loss of offsite power, which are the only conditions wherein the deficiency would cause a non-negligible change in the baseline risk profile, is less than or equal to 1E-6 per year. Therefore the change in core damage frequency will be less than 1E-6 per year. The violation has a problem identification and resolution crosscutting aspect because the licensee had previously identified that aged Agastat relays can cause these types of problems but had failed to take effective corrective actions in a timely manner. The licensee captured the issue in their corrective action program as SMF-2004-003528.

Enforcement. Technical Specification 3.8.1 required the licensee to restore either the alternate offsite transmission source or the EDG to the onsite Class 1E AC electrical distribution system within 12 hours. Contrary to the above, neither the alternate offsite transmission source nor the EDG were capable of supplying the Class 1E AC electrical distribution within the response time assumed in the accident analysis. This condition existed for an extended duration, in excess of the 12 hour TS limiting condition for operation. Because this issue is of very low safety significance and has been entered into the corrective action program as SMF-2004-003528, this violation is being treated as a NCV, consistent with Section VI.A of the NRC Enforcement Policy: NCV 05000446/2005005-05, Inoperability of Emergency Power to a Safety Bus Due to Degraded Relay.

4OA6 Meetings, Including Exit

Exit Meeting Summary

The inspectors presented the results of the inservice inspection to Mr. M. Lucas, Vice President of Nuclear Engineering, and other members of licensee management on

October 21, 2005. Licensee management acknowledged the inspection findings. The licensee confirmed that any proprietary information reviewed by the inspectors was not retained by the inspectors.

On December 15, 2005, the inspector debriefed the preliminary results of the emergency preparedness inspection to Mr. M. Blevins, Senior Vice President and Chief Nuclear Officer, and other members of his staff who acknowledged the findings. The inspector confirmed that proprietary information was not provided or examined during the inspection. After additional information was provided by the licensee on January 11, 2006, the inspector presented the inspection results to Mr.R. Flores, Vice President, Nuclear Operations, and other members of his staff who acknowledged the findings.

On January 31, 2006, Mr. N. O'Keefe presented the inspection results of the URI in regards to Agastat relays to Mr. T. Hope and D. Snow of your staff, who acknowledged the finding, by teleconference.

The inspector presented the resident inspection results to Mr. R. Flores, Vice President, Operations, and other members of licensee management on January 12, 2006. The inspectors confirmed that proprietary information was not provided or examined during the inspection.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

O. Bhatty, Inservice Test Engineer
M. Blevins, Senior Vice President and Chief Nuclear Officer
D. Bozeman, Manager, Emergency Planning
S. Bradley, Supervisor, Health Physics, Radiation Protection & Safety Services
R. Calder, Executive Assistant
T. Clouser, Manager, Shift Operations
J. Curtis, Radiation Protection Manager, Radiation and Industrial Safety
D. Ellis, Level III Qualified Data Analyst
S. Ellis, Director, Nuclear Oversight
R. Flores, Vice President, Nuclear Operations
T. Hope, Manager, Regulatory Performance
R. Kidwell, Licensing Engineer
M. Lucas, Vice President Nuclear Engineering
F. Madden, Director, Regulatory Affairs
J. Meyer, Technical Support Manager
P. Passalugo, Inservice Inspection Program Coordinator
P. Polefrone, Plant Manger
V. Polizzi, Steam Generator Programs Engineer
S. Sewell, Nuclear Training Manager
J. Skelton, System Engineer
R. Smith, Director, Operations
S. Smith, Director, System Engineering
C. Tran, Engineering Programs Manager
D. Wilder, Radiation and Industrial Safety Manager
I. Witt, Boric Acid Program Coordinator

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000445;05000446/2005005-02,	URI	Notification Form Accuracy Requires Additional Guidance (Section 40A1)

Opened and Closed

05000445/2005005-01	NCV	Inadequate Corrective Actions for a Leaking Valve with a Seal Weld which Subsequently Leaked (Section 1R08.1)

05000445/2005005-03	NCV	Trip of Emergency Diesel Generator Due to Lube Oil Check Valve Installed Backwards (Section 4OA3.1)
05000445/2005005-04	NCV	Trip of Station Service Water Pump Due to Degraded Motor Lead (Section 4OA3.2)
05000446/2005005-05	NCV	Inoperability of Emergency Power to a Safety Bus Due to Degraded Relay (Section 4OA5.2)

Closed

05000446/2005009-01	URI	Inoperability of Emergency Power to a Safety Bus (Section 4OA5.2)

Discussed

None

LIST OF DOCUMENTS REVIEWED

Section 1R08 Inservice Inspection Activities (71111.08)

Boric Acid Evaluation

Unit 1 Containment Boron Leaks 1RF11, draft report

Procedures

Number	Title	Revision
STA-737	Boric Acid Corrosion Detection and Evaluation	3
TX-ISI-8	VT-1 and VT-3 Visual Examination	56
TX-ISI-11	Liquid Penetrant Examination for Comanche Peak Steam Electric Station	11
TX-ISI-302	Ultrasonic Examination of Austenitic Piping Welds	2
WLD-106	ASME/ANSI General Welding Requirements	2 with Procedure Change Notice 4

Nondestructive Examination Reports

Penetrant Report, 11PT06, dated October 14, 2005
Ultrasonic, Calibration Data Sheet, Weld TBX-1-4101, dated October 14, 2005
Visual Examination Data, Report No. 11VT14, dated October 11, 2005

Smart Forms

SMF-2004-000502	SMF-2004-002974	SMF-2005-004021
SMF-2004-001292	SMF-2005-000934	SMF-2005-004095
SMF-2004-001971	SMF-2005-001089	SMF-2005-004195
SMF-2004-002758	SMF-2005-001635	SMF-2005-004209
SMF-2004-002074	SMF-2005-002813	SMF-2005-004243

Work Orders

3-04-344421-01

Miscellaneous

Site specific training and testing results of various contracted eddy current testing personnel

Technical Specifications Sections 5.5.9, Amendment 112

TXU Power Comanche Peak Steam Electric Station Steam Generator Assessment for Unit #1 Cycle 11, September 2, 2004

Unit 1 - Second Interval ASME Section XI Inservice Inspection Program Plan, Revision 4

Unit 1 Steam Generator Eddy Current Analysis Guidelines 1RF11, Revision 0

Welding Procedure Specification CP-301, Revision 11

Westinghouse Letter MSR-TRC-1669, Use of Appendix H Qualified Techniques at Comanche Peak Unit 1 11th RFO, dated September 9, 2005

Various Certifications of education, training, experience and visual acuity of contracted ECT personnel

Section 1EP1 Exercise Evaluation (71114.01)

EP1

Procedures
1. EPP-109, "Duties and Responsibilities of the Emergency Coordinator/Recovery Manager," Revision 12

2. EPP-116, “Emergency Repair and Damage Control and Immediate Entries," Revision 6

3. EPP-204, “Activation and Operation of the Technical Support Center," Revision 14

4. EPP-205, “Activation and Operation of the Operations Support Center,” Revision 11

5. EPP-206, “Activation and Operation of the Emergency Operations Facility,” Revision 14

6. EPP-303, “Operation of the Computer Based Emergency Dose Assessment System,” Revision 12

7. EPP-305, “Emergency Exposure Guidelines and Personnel Dosimetry,” Revision 11

8. EPP-306, “Use of Thyroid Blocking Agents,” Revision 10

<u>4OA1</u>

Procedures

1. EPP-201, “Assessment of Emergency Action Levels, Emergency Classification, and Plan Activation,” Revision 11

2. EPP-203, “Notifications,” Revision 14

3. EPP-304, “Protective Action Recommendations,” Revisions 17 and 18

<u>Section 4OA5.2 , Inoperability of Emergency Power to a Safety Bus</u>

<u>Smart Forms</u>: SMF-2002-003391 , SMF-2004-003528

LIST OF ACRONYMS

ABN	abnormal conditions procedure
ARV	atmospheric relief valve
ASME	American Society of Mechanical Engineers
ATWS	anticipated transient without scram
CCW	component cooling water
CFR	*Code of Federal Regulations*
CPSES	Comanche Peak Steam Electric Station
EDG	emergency diesel generator
EVAL	evaluation
HVAC	heating, ventilation and air conditioning
IPO	integrated plant operating procedure
MSM	maintenance section-mechanical manual
NCV	noncited violation
NRC	Nuclear Regulatory Commission
OPT	operations testing
PERC	plant event review committee
QTE	quick technical evaluation
SMF	smart form
SOP	system operating procedure
SSC	structures, systems, or components
SSW	station service water
STA	station administrative procedure
TDAFW	turbine driven auxiliary feed water
UPS	uninterruptible power supply
WO	work order