UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION IV
612 EAST LAMAR BLVD, SUITE 400
ARLINGTON, TEXAS 76011-4125

August 4, 2008

Mike Blevins, Executive Vice President
and Chief Nuclear Officer
Luminant Generation Company, LLC
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 05000445/2008003 AND 05000446/2008003

Dear Mr. Blevins:

On June 22, 2008, the U.S. Nuclear Regulatory Commission (NRC) completed an integrated inspection at your Comanche Peak Steam Electric Station, Units 1 and 2, facility. The enclosed report documents the inspection results, which were discussed on June 19, 2008, with Mr. R. Flores and other members of your staff.

The inspection examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

Based on the results of this inspection five findings of very low safety significance were identified. Four of these findings involved violations of NRC requirements and were NRC-identified; one of the findings did not involve a violation of NRC requirements and was self-revealing. Additionally, licensee-identified violations which were determined to be of very low safety significance are listed in this report. However, because of the very low safety significance, and because they are entered into your corrective action program, the NRC is treating the issues as noncited violations in accordance with Section VI. A. 1 of the NRC Enforcement Policy.

If you contest the noncited violations in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the U.S. Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, with copies to the Regional Administrator, U.S. Nuclear Regulatory Commission - Region IV, 612 East Lamar Blvd, Suite 400, Arlington, TX 76011-4125; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the Comanche Peak Steam Electric Station.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be made available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records component of NRC's document system (ADAMS), accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

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

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

NRC Inspection Report 05000445/2008003 and 05000446/2008003
w/Attachment: Supplemental Information

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U. S. NUCLEAR REGULATORY COMMISSION
REGION IV

Dockets:	50-445, 50-446
Licenses:	NPF-87, NPF-89
Report:	05000445/2008003 and 05000446/2008003
Licensee:	Luminant Generation Company LLC
Facility:	Comanche Peak Steam Electric Station, Units 1 and 2
Location:	FM-56, Glen Rose, Texas
Dates:	March 24 though June 22, 2008
Inspectors:	D. Allen, Senior Resident Inspector B. Tindell, Resident Inspector P. Elkmann, Senior Emergency Preparedness Inspector, Plant Support Branch 1 L. Ricketson, P.E., Senior Health Physicist, Plant Support Branch 2 S. Makor, Reactor Inspector, Engineering Branch 1 M. Young, Reactor Inspector, Engineering Branch 1 P. Goldberg, Reactor Inspector, Plant support Branch 2
Approved By:	C. Johnson, Chief, Project Branch A Division of Reactor Projects

SUMMARY OF FINDINGS

IR 05000445/2008003, 05000446/2008003; 03/24/2008-06/22/2008; Comanche Peak Steam Electric Station, Units 1 and 2: Integrated Resident and Regional Report; Fire Protection, Maintenance Rule Implementation, Access Control to Radiologically Significant Areas, Identification and Resolutions of Problems, Other Activities

This report covers a 3-month period of inspection by resident inspectors, an emergency preparedness inspector, a senior health physicist and three engineering inspectors. Five Green findings were identified during the inspection period. Four of the findings were identified by the inspectors and were considered noncited violations of NRC regulations, and one self-revealing finding was not a violation of NRC regulations. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using the Inspection Manual Chapter 0609, "Significance Determination Process." Findings for which the Significant Determination Process does not apply may be Green or 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 4, dated December 2006.

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Initiating Events

- Green. The inspectors reviewed a self-revealing finding for the licensee's failure to follow a tubing installation specification when installing condenser vacuum instrument tubing. Specifically, the installation did not follow Tubing Specification CPSES-I-1018 for general flexibility or thermal growth considerations, ultimately resulting in tubing failure. The tubing failure caused turbine trip instrumentation to fail low, causing a Unit 2 turbine and reactor trip. The licensee entered the finding into their corrective action program and modified the instrument tubing in both Units 1 and 2 to prevent another failure.

  The finding is greater than minor because it is associated with the Initiating Events Cornerstone attribute of design control and affected the cornerstone objective, in that it caused a turbine and reactor trip that challenged critical safety functions. The finding is of very low safety significance because, although the likelihood of a reactor trip increased, all mitigating systems were available. The cause of this finding is related to the human performance cross-cutting component of Work Practices, in that, the licensee failed to provide proper oversight of contractors such that nuclear safety is supported [H4.c] (Section 1R12).

Cornerstone: Mitigating Systems

- Green. The inspectors identified a noncited violation for failure to establish adequate compensatory measures for inoperable containment fire hose stations as required by the fire protection program as defined in Unit 2 License Condition 2.G. This resulted in a period of eighteen days during a refueling outage where inadequate compensatory measures were established to fight a fire in containment with hoses. Specifically, fire protection water to hose stations inside containment was isolated and the established compensatory measure was for the fire brigade to connect hoses from an operable outside containment hose station in order to reach the postulated fire in containment or to pressurize another hose station inside of containment. This compensatory measure would have required that fire hose be run through the personnel airlock and then pressurized. The fire preplan for a fire in containment on the 905' elevation, states "keep airlock access closed to prevent release," This guidance conflicts with the compensatory measure provided. In addition, other procedures such as a loss of inventory or loss of shutdown cooling may require the personnel airlock to be closed, preventing the fire brigade from running fire hose through the personnel airlock. Therefore, the inspectors determined that the licensee failed to provide adequate compensatory actions during the time that fire protection water to containment was isolated. The licensee entered the finding into their corrective action program for resolution.

This finding is more than minor because it is associated with the Protection Against External Factors attribute of the Mitigating Systems Cornerstone and affected the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Using NRC Inspection Manual Chapter 0609, Attachment 4, "Phase 1 - Initial Characterization and Screening of Findings," the inspectors determined that this finding should be evaluated using NRC Inspection Manual Chapter 0609, Appendix F, "Fire Protection Significance Determination Process," because it affects fire protection defense-in-depth strategies involving manual suppression equipment. However, Appendix F, Assumptions and Limitations states that the fire protection significance determination process does not address the potential risk significance of fire protection inspection findings for shut down reactors. Therefore, the significance of this finding was assessed using Manual Chapter 0609 Appendix M, "Significance Determination Process Using Qualitative Criteria". The finding is of very low safety significance because there were a limited number of postulated fires that could affect shutdown cooling, a single fire could not credibly affect both residual heat removal system loops, and a postulated fire could not have formed a hot-gas layer affecting the equipment (Section 1R05).

- Green. The inspectors identified a noncited violation for failure to expeditiously return to service a manual isolation valve for fire protection water to containment as required by the fire protection program as defined in Unit 2 License Condition 2.G. This resulted in the Unit 2 containment fire hose stations to be out-of-service for thirteen additional days during a refueling outage following maintenance. The valve was closed in order to perform leak rate testing of the containment penetration, however, after the test was complete, the valve was left closed. The licensee entered the finding into their corrective action program for resolution.

  This finding is greater than minor because it was similar to Example 4.g in NRC Inspection Manual Chapter 0612, Appendix E, "Examples of Minor Issues and met the "not minor if" criteria because certain postulated fires would have restricted operator access to the valve for environmental reasons. Using NRC Inspection Manual Chapter 0609, Attachment 4, "Phase 1 - Initial Characterization and Screening of Findings," the inspectors determined that this finding should be evaluated using NRC Inspection Manual Chapter 0609,

Appendix F, “Fire Protection Significance Determination Process,” because it affects fire protection defense-in-depth strategies involving manual suppression equipment. However, Appendix F, Assumptions and Limitations states that the fire protection significance determination process does not address the potential risk significance of fire protection inspection findings for shut down reactors. Therefore, the significance of this finding was assessed using Manual Chapter 0609, Appendix M, “Significance Determination Process Using Qualitative Criteria”. The finding is of very low safety significance because there were a limited number of postulated fires that could affect shutdown cooling, a single fire could not credibly affect both residual heat removal system loops, and a postulated fire could not have formed a hot-gas layer affecting the equipment. The cause of the finding is related to the human performance cross-cutting component of work control, in that, the licensee did not appropriately coordinate work activities both because of lack of communication and a failure to plan work activities to limit fire protection system unavailability [H3.b] (Section 1R05).

Cornerstone: Barrier Integrity

- Green. The inspectors identified a non-cited violation of Technical Specification 5.4.1.a for failure to implement Procedure OPT-435B. This resulted in the Unit 2 Train B containment spray pumps recirculation valves being closed when they were required to be open during pump operations to support testing. The licensee entered this violation into their corrective action program.

  The finding is greater than minor because it could be viewed as a precursor to a significant event, in that, not implementing the prerequistes prior to performing test on other safety-related pumps could lead to significant damage. Unique features of the containment spray system design prevented damage to the pumps. The same failure to ensure a flow path for other safety-related pumps would have resulted in significant damage. The violation is associated with the Barrier Integrity cornerstone attribute of structure, system, and component reliability. Since Unit 2 was in Mode 6 on residual heat removal cooling, Appendix G of Manual Chapter 0609 applied and Checklist 4 determined this to be of very low safety significance. The cause of this violation is related to the human performance crosscutting component of Work Practices in that operations management failed to effectively communicate expectations regarding procedural requirements and operations personnel failed to follow procedures [H4.b] (Section 4OA2).

Cornerstone: Occupational Radiation Safety

- Green. The inspector identified a noncited violation of Technical Specification 5.7.1 because a high radiation area was not barricaded and conspicuously posted. The inspector identified dose rates as high as 109 millirems per hour at 30 centimeters in the compactor area on the 810-foot elevation of the fuel building. The area was controlled and posted as a radiation area. As immediate corrective action, the licensee barricaded the area with rope and posted it as a high radiation area and documented the finding in the corrective action program.

The finding is greater than minor because, if left uncorrected, the finding could become a more significant safety concern. Using the Occupational Radiation Safety Significance Determination Process, the inspector determined the finding to have very low safety significance because (1) it was not associated with ALARA planning or work controls, (2) there was no overexposure, (3) there was no substantial potential for an overexposure, and (4) the ability to assess dose was not compromised. Additionally, the finding had a cross-cutting aspect in the area of human performance, work control component, because the licensee did not coordinate work activities by incorporating actions to address the need for work groups to communicate, coordinate, and cooperate with each other during activities in which interdepartmental coordination is necessary to assure human performance [H3.b] (Section 2OS1).

B. Licensee-Identified Violations

Violations of very low safety significance that were identified by the licensee have been reviewed by inspectors. Corrective actions planned or taken by the licensee have been entered into the licensee's corrective action program. These violations and corrective action tracking numbers are listed in Section 4OA7 of this report.

REPORT DETAILS

Summary of Plant Status

Comanche Peak Steam Electric Station (CPSES) Unit 1 began the reporting period at full power and operated at essentially full power for the entire reporting period.

CPSES Unit 2 began the reporting period at full power and on March 27, 2008, began a reactor power coastdown. On March 29, at noon, Unit 2 entered Mode 3 to begin Refueling Outage 2RF10. On April 19, at 4 p.m., the outage ended when the main generator breakers were closed. Unit 2 returned to full power on April 23 and remained at essentially full power for the remainder of the reporting period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, and Barrier Integrity

1R01 Adverse Weather Protection (71111.01

.1 Readiness For High Grid Loading Season

a. Inspection Scope

In May, a review of offsite and alternate AC power systems readiness for high grid loading season was conducted. The inspectors reviewed the licensee's procedures for operation and continued availability of offsite power, including communications protocols between operations and transmission grid controller (transmission system operator) to verify that the appropriate information is exchanged when issues arise that could impact the offsite power system. The inspectors ensured that (1) actions were specified for notification that the posttrip voltage of the switchyard would not be acceptable to assure continued operation of safety-related loads without transferring to the onsite power supply, (2) compensatory actions were required if it was not possible to predict the posttrip voltage in the switchyard, (3) actions were specified to re-assess plant risk based on maintenance activities which could impact grid reliability or the ability of the transmission system to provide offsite power, and (4) communications were required between the transmission grid controller and operations when changes at the site could impact the transmission system or when the capability of the transmission system to provide adequate voltage is challenged.

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

.2 Readiness For Impending Adverse Weather Condition – Severe Thunderstorm Watch

a. Inspection Scope

Since thunderstorms with potential tornados and high winds were forecast in the vicinity of the facility for April 17, 2008, the inspectors reviewed the licensee's overall preparations/protection for the expected weather conditions. On April 17, 2008, the inspectors walked down the licensee's emergency diesel generators, because their safety-related functions could be affected or required as a result of high winds or tornado-generated missiles or the loss of offsite power. The inspectors evaluated the licensee staff's preparations against the site's procedures and determined that the staff's actions were adequate. During the inspection, the inspectors focused on plant specific design features and the licensee's procedures used to respond to specified adverse weather conditions. The inspectors also toured the plant grounds to look for any loose debris that could become missiles during a tornado. The inspectors evaluated operator staffing and accessibility of controls and indications for those systems required to control the plant. Additionally, the inspectors reviewed the Updated Final Safety Analysis Report (UFSAR) and performance requirements for systems selected for inspection and verified that operator actions were appropriate as specified by plant specific procedures. The inspectors also reviewed a sample of corrective action program (CAP) items to verify that the licensee identified adverse weather issues at an appropriate threshold and dispositioned them through the CAP in accordance with station corrective action procedures. Specific documents reviewed during this inspection are listed in the attachment.

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignment (71111.04)

.1 Quarterly Partial System Walkdowns

a. Inspection Scope

The inspectors performed partial system walkdowns of the following risk-significant systems:

- Unit 2 turbine driven auxiliary feedwater subsystem in accordance with Operations Testing Procedure (OPT) OPT-206B, "AFW System," Revision 20, following return of system to operations after Refueling Outage 2RF10, on April 25, 2008

- Unit 1 Train B containment spray system in accordance with Procedure OPT-205A, "Containment Spray System," Revision 16, while the Train A system was out-of-service for scheduled maintenance and surveillance testing on April 29, 2008

- Unit 2 Train B emergency diesel generator in accordance with System Operating Procedures (SOPs) SOP-609B, "Diesel Generator System," Revision 9, and OPT 203B, "Diesel Generator Operability Test," Revision 13, while the Unit 2 Train A emergency diesel generator was inoperable for scheduled maintenance and surveillance on May 28, 2008

The inspectors selected these systems based on their risk significance relative to the reactor safety cornerstones at the time they were inspected. The inspectors attempted to identify any discrepancies that could impact the function of the system, and, therefore, potentially increase risk. The inspectors reviewed applicable operating procedures, system diagrams, UFSAR, Technical Specifications (TS) requirements, Administrative TS, outstanding work orders, condition reports, and the impact of ongoing work activities on redundant trains of equipment in order to identify conditions that could have rendered the systems incapable of performing their intended functions. The inspectors also walked down accessible portions of the systems to verify system components and support equipment were aligned correctly and operable. The inspectors examined the material condition of the components and observed operating parameters of equipment to verify that there were no obvious deficiencies. The inspectors also verified that the licensee had properly identified and resolved equipment alignment problems that could cause initiating events or impact the capability of mitigating systems or barriers and entered them into the CAP with the appropriate significance characterization.

The inspectors completed three samples.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05)

Routine Resident Inspector Tours (71111.05Q)

a. Inspection Scope

The inspectors conducted fire protection walkdowns which were focused on availability, accessibility, and the condition of firefighting equipment in the following risk-significant plant areas:

- Fire Zone EQ-149, Units 1 and 2, Train B uninterruptible power supply air conditioner Room 115D on March 26, 2008

- Fire Zone ER-150, Units 1 and 2, Train A uninterruptible power supply air conditioner Room 115C on March 26, 2008

- Unit 2 pressurizer cubicle during hot work activities on April 4, 2008

- Fire Area 2CA - Unit 2 containment building, all elevations on April 7-8, 2008

The inspectors reviewed areas to assess if the licensee had implemented a fire protection program that adequately controlled combustibles and ignition sources within the plant; effectively maintained fire detection and suppression capability; maintained passive fire protection features in good material condition; and had implemented adequate compensatory measures for out-of-service, degraded, or inoperable fire protection equipment, systems, or features in accordance with the licensee's fire plan. The inspectors selected fire areas based on their overall contribution to internal fire risk as documented in the plant's Individual Plant Examination of External Events with later additional insights, their potential to impact equipment which could initiate or mitigate a plant transient, or their impact on the plant's ability to respond to a security event. Using the documents listed in the attachment, the inspectors verified that fire hoses and extinguishers were in their designated locations and available for immediate use; that fire detectors and sprinklers were unobstructed; that transient material loading was within the analyzed limits; and fire doors, dampers, and penetration seals appeared to be in satisfactory condition. The inspectors also verified that minor issues identified during the inspection were entered into the licensee's CAP.

The inspectors completed four samples.

b. Findings

.1 Introduction: The inspectors identified a Green noncited violation (NCV) for a failure to comply with the License Condition 2.G requirement to maintain in effect all provisions of the approved fire protection program. Specifically, fire protection water to the hose stations inside containment was isolated without adequate compensatory measures being established during the Unit 2 refueling outage.

Description: From March 30 until April 16, 2008, during Refueling Outage 2RF10, the Unit 2 outside containment fire protection isolation valve was intentionally closed, isolating fire protection water to all of the hose stations inside of containment. Outage activities during the period, when the hose stations inside containment were out-of-service, included the risk significant midloop configuration and reactor coolant pump maintenance activities with the potential for an oil fire which portable extinguishers may not have been able to extinguish.

The inspectors noted during the inspection that the practice of manually isolating containment fire protection water using the outside containment isolation valve during refueling outages originated in approximately 1999 in order to avoid inadvertent flooding of dry fire protection pipe which must be drained and flushed due to the chemical treatment in the fire protection system.

Fire Protection Impairment 9598 was in place for those 18 days during Refueling Outage 2RF10 to track the containment hose stations being unavailable due to this isolation. The established compensatory measure was for the fire brigade to connect hoses from an operable outside containment hose station in order to reach the postulated fire in containment or to pressurize another hose station inside of containment. This compensatory measure would have required that the fire hose be run through the personnel airlock and then pressurized. However, the fire preplan for a fire in containment on the 905-foot elevation, Instruction FPI-204B, "Unit 2 Containment Building Elevation 905'-0"," in the special precautions section, states "Keep airlock access closed to prevent release." This guidance conflicts with the compensatory measure provided. In addition, other procedures such as a loss of inventory or loss of shutdown cooling may require the personnel airlock to be closed, preventing the fire brigade from running the fire hose through the personnel airlock. Therefore, the CPSES Fire Protect Program states, "Standpipes and hose stations are located on each elevation in the Containment Buildings such that an effective hose stream can reach any location," and "Operation of the fire protection systems should not compromise integrity of the containment or the other safety-related systems. Fire protection activities in the containment areas should function in conjunction with total containment requirements such as control of contaminated liquid and gaseous release and ventilation." The inspectors determined that the licensee failed to provide adequate compensatory actions during the time that fire protection water to containment was isolated.

The compensatory measures were established in 1999, when the practice of manually isolating containment fire protection water began and have been perpetuated each refueling outage. Therefore, the inspectors did not consider the performance deficiency to be representative of current licensee performance.

Analysis: The inspectors determined that the failure to provide adequate compensatory actions during the time that fire protection water to containment was isolated is a performance deficiency. This finding is more than minor because it is associated with the Protection Against External Factors attribute of the Mitigating Systems Cornerstone and affected the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. Using NRC Inspection Manual Chapter 0609, Attachment 4, “Phase 1 - Initial Characterization and Screening of Findings,” the inspectors determined that this finding should be evaluated using NRC Inspection Manual Chapter 0609, Appendix F, “Fire Protection Significance Determination Process,” because it affects fire protection defense-in-depth strategies involving manual suppression equipment. However, Appendix F, Assumptions and Limitations states, “The Fire Protection SDP focuses on risks due to degraded conditions of the fire protection program during full power operation of a nuclear power plant. This tool does not address the potential risk significance of fire protection inspection findings in the context of other modes of plant operation (i.e., low power or shutdown).” Therefore, this issue was referred to a Region IV senior reactor analyst to further evaluate the risk.

The analyst assessed the risk of this condition using appropriate portions of the quantitative methods from Appendix F and Manual Chapter 0609, Appendix G, “Shutdown Operations Significance Determination Process,” as well as hand calculations. Additionally, a qualitative assessment of the conditions that existed throughout the refueling outage was used.

The analyst evaluated the impacts that a fire in containment could have on the risk of a shutdown reactor at Comanche Peak site. During the Individual Plant Examination of External Events, the licensee excluded the risk of containment fires because of the low ignition frequency and the small number of active components affecting the risk of an at power reactor. However, during shutdown operations, the fire ignition frequency increases and those components deenergized for risk purposes are reenergized and made active. The primary concern during a refueling outage is availability and reliability of residual heat removal. The dominant equipment inside containment for shutdown cooling at Comanche Peak are the four motor-operated shutdown cooling suction isolation valves, two of which are in each steam generator cubicle. To assess the risk, three factors are important: the likelihood of a fire during the time of interest, the probability of the fire causing an initiating event, and the availability of mitigation equipment.

Initiating Event Likelihood

The analyst noted that the shutdown cooling suction valves are located approximately 6 feet off the floor in the steam generator cubicles. This location essentially eliminates the likelihood of damage from a hot-gas layer produced by a fire elsewhere. There are several cable trays in the vicinity of the valves and two reactor coolant pumps in each cubicle. Additionally, hot work can be significant during an outage. To estimate the ignition frequency the analyst used the following data from Appendix F, Attachment 4:

Cables (Assume Non-Qualified):	1.4×10^{-3}/year
Reactor Coolant Pumps:	3.1×10^{-4}/year/pump
Transient Loads (Assume High):	1.7×10^{-3}/year
Hot Work (Assume High):	6.9×10^{-4}/outage

Using these values, the analyst estimated an initiating event likelihood (IEL) of 1.86×10^{-6}/hour for each steam generator cubicle.

Probability of the Fire Causing an Initiator

The analyst assessed the four primary initiators discussed in Appendix G, Attachment 2, "Phase 2 Significance Determination Process Template for PWR during Shutdown." The analyst determined that it would be extremely difficult for a fire inside the reactor containment to result in a loss of offsite power, a loss of inventory, or a loss of level control. Additionally, most of the risk of fires causing such an event would be baseline risk. Therefore, the analyst quantitatively assessed only the risk associated with losses of residual heat removal.

To bound the risk associated with this finding, the analyst assumed that, as a result of the performance deficiencies, one half of all fires initiating in the steam generator cubicles would lead to a loss of the operating train of residual heat removal (P_{RHR}).

Availability of Mitigating Equipment

Using Appendix G, Attachment 2, the analyst evaluated the mitigation credit to be used for each of the three major plant operating states. First, Worksheet 9 was used to assess the affect of the finding on the risk during reduced inventory conditions. The exposure time (EXP) used for both reduced inventory conditions was 21 hours, representing the actual time that the early midloop conditions existed. For the early reduced inventory conditions (ΔCDF_{RI-1}), the analyst gave no credit for recovery of the other train of RHR ($P_{RECOVER-1}$) and limited the mitigation credit for injection (P_{INJ-1}) to 2 because of the short time to core damage. For the back-end mid loop (ΔCDF_{RI-2}), the analyst gave a credit of 1 for recovery of residual heat removal and 4 for injection before core damage. For both scenarios, the credit for recovery of the other train before refueling water storage tank depletion (P_{RWST}) was 2 and the credit for borated water makeup (P_{BORON}) was 2. The change in risk was then bounded using the following calculations:

$$\Delta CDF_{RI-1} = IEL * EXP * P_{RHR} * \{P_{RECOVER-1} * [(P_{INJ-1}) + (P_{RWST} * P_{BORON})]\}$$

$$= 1.86 \times 10^{-6}/hr * 21\ hrs * 0.5 * \{1.0 * [(1 \times 10^{-2}) + (1 \times 10^{-2} * 1 \times 10^{-2})]\}$$

$$= 1.86 \times 10^{-6}/hr * 21 * 0.5 * 0.0101$$

$$= 1.98 \times 10^{-7}$$

and

$$\Delta CDF_{RI\text{-}2} = IEL * EXP * P_{RHR} * \{P_{RECOVER\text{-}2} * [(P_{INJ\text{-}2}) + (P_{RWST} * P_{BORON})]\}$$

$$= 1.86 \times 10^{-6}/hr * 21\ hrs * 0.5 * \{0.1 * [(1 \times 10^{-4}) + (1 \times 10^{-2} * 1 \times 10^{-2})]\}$$

$$= 1.86 \times 10^{-6}/hr * 21 * 0.5 * 2 \times 10^{-5}$$

$$= 9.90 \times 10^{-8}$$

The analyst determined that the calculation of $\Delta CDF_{RI\text{-}2}$ contained all the appropriate parameters for assessing the affect of the finding on the risk during vented operations with reactor vessel level above reduced inventory (ΔCDF_{FULL}). Because it is more limiting than the risk with the refueling pool full, the analyst used this calculation to assess the risk for the remainder of the 18-day exposure period. This resulted in the following:

$$\Delta CDF_{FULL} = IEL * EXP * P_{RHR} * \text{Mitigating System Credit}$$

$$= 1.86 \times 10^{-6}/hr * [(16\ days * 24\ hrs/day) + 10\ hrs] * 0.5 * 2 \times 10^{-5}$$

$$= 7.35 \times 10^{-9}$$

The total risk was then calculated as the sum of these three operating states. The resulting ΔCDF was 3.0E-7.

Given the above bounding assessment of the quantitative change in risk caused by the finding, associated with postulated fires that result in a loss of shutdown cooling, and the qualitative assessment of those scenarios that would have a negligible impact on risk, the analyst recommended that this finding be considered to be of very low risk significance (Green), in accordance with NRC Inspection Manual Chapter 0609, Appendix M, “Significance Determination Process Using Qualitative Criteria (Section 1R05).

Enforcement: CPSES, Unit 2 Facility Operating License Condition 2.G. states, “Luminant Generation Company LLC shall implement and maintain in effect all provisions of the approved fire protection program as described in the UFSAR through Amendment 87.” Comanche Peak UFSAR Section 13.3B, CPSES Fire Protection Program, Amendment 101, states “CPSES is committed to meeting the requirements of the Fire Protection Report.” Comanche Peak Fire Protection Report, Revision 25, Section IV - 3.0, Compensatory Measures states, “compensatory measures are implemented to assure that an alternate source of fire protection is maintained.” Contrary to the above, during the period of March 30 through April 16, 2008, the licensee failed to assure that an alternate source of fire protection is maintained per Fire Protection Report, Section IV. This violation is in the licensee’s CAP as SMF-2008-001831-00. Because this violation was determined to be of very low safety significance, it is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement

Policy and is identified as NCV 05000446/2008003-01, Inadequate Fire Protection Compensatory Actions During Refueling Outage.

.2 Introduction: The inspectors identified a Green NCV for failure to comply with the License Condition 2.G requirement to maintain in effect all provisions of the approved fire protection program. Specifically, fire protection water to the hose stations inside containment was left isolated for 13 additional days after maintenance was completed during a refueling outage.

Description: As discussed in the other finding in this section, the licensee has isolated fire protection water to the hose stations inside of containment using the outside containment isolation valve during refueling outages since approximately 1999. Since that time, the licensee has designated an operator on watch to open the outside containment isolation valve in case of a fire inside of containment. However, this was not proceduralized, and was not the credited compensatory action for having the system isolated as discussed above. The inspectors determined that opening the isolation valve would probably be successful because fire protection personnel informed the operators of this responsibility, and it was a relatively simple task. However, during the Spring 2008 refueling outage, the licensee also isolated the inside containment isolation valve for maintenance but failed to return this valve to service in a timely manner.

On March 30, 2008, during Refueling Outage 2RF10, the Unit 2 inside containment fire protection isolation valve was closed in order to perform leak rate testing of the penetration, isolating fire protection water to all of the hose stations inside of containment. The work that required the isolation was completed on April 4, 2008. However, the inside containment isolation valve was left isolated until April 16, 2008, for a total of 13 additional days. Outage activities during the period when the hose stations inside containment were out-of-service included the risk significant midloop configuration and reactor coolant pump maintenance activities with the potential for an oil fire which portable extinguisher's may not have been able to extinguish. Compensatory actions were put in place to run hoses through the personnel airlock, however, they were inadequate as documented above. Nonproceduralized compensatory actions were also in place for operations to open the outside containment isolation valve, however, this would not have provided water to the inside containment fire hose stations because the inside containment isolation valve was shut. The inspectors determined that the licensee failed to expeditiously return the inside containment fire protection isolation valve to service.

The licensee documented this issue in their CAP, identifying that adequate communication between the Outage Control Center and fire protection personnel did not occur due to the work processes in place.

Analysis: The inspectors determined that the licensee failed to comply with License Condition 2G, in that, fire protection water to the fire hose station inside containment was isolated, is a performance deficiency. This finding is greater than minor because it was similar to Example 4.g in NRC Inspection Manual Chapter 0612, Appendix E, "Examples of Minor Issues and met the "not minor if" criteria because certain postulated fires would have restricted operator access to the valve for environmental reasons. Using NRC Inspection Manual Chapter 0609, Attachment 4, "Phase 1 - Initial Characterization and Screening of Findings," the inspectors determined that this finding should be evaluated using NRC Inspection Manual Chapter 0609, Appendix F, "Fire Protection Significance

Determination Process," because it affects fire protection defense-in-depth strategies involving manual suppression equipment. However, Appendix F, Assumptions and Limitations states, "The Fire Protection SDP focuses on risks due to degraded conditions of the fire protection program during full power operation of a nuclear power plant. This tool does not address the potential risk significance of fire protection inspection findings in the context of other modes of plant operation (i.e., low power or shutdown)." Therefore, this issue was referred to a Region IV senior reactor analyst to further evaluate the risk.

The analyst determined that the change in risk related to this finding was completely bounded by the analysis performed for NCV 05000446/2008003-01, Inadequate Fire Protection Compensatory Actions During Refueling Outage (Section 1R05.1). Therefore, in accordance with Manual Chapter 0609, Appendix M, this finding is considered to be of very low risk significance.

The cause of this finding was related to the Human Performance crosscutting component of Work Control in that the licensee did not appropriately coordinate work activities both because of lack of communication and a failure to plan work activities to limit fire protection system unavailability [H.3.(b)].

Enforcement: CPSES, Unit 2 Facility Operating License Condition 2.G. states, "Luminant Generation Company LLC shall implement and maintain in effect all provisions of the approved fire protection program as described in the Final Safety Analysis Report (FSAR) through Amendment 87." Comanche Peak UFSAR Section 13.3B, CPSES Fire Protection Program, Amendment 101, states "CPSES is committed to meeting the requirements of the Fire Protection Report." Comanche Peak Fire Protection Report, Revision 25, Section IV - 3.0, "Compensatory Measures," states "Efforts and work activities conducted by individuals associated with an inoperable condition are conducted in an expeditious manner so that the fire protection equipment/systems are promptly restored to service." Contrary to the above, during the period of April 4 through April 16, 2008, the licensee failed to conduct work activities in an expeditiously manner in order to restore the inoperable fire protection water service to the Unit 2 containment. This violation is in the licensee's CAP as Smart Form SMF 2008-001686-00. Because this violation was determined to be of very low safety significance, it is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy and is identified as NCV 05000446/2008003-02, Failure to Expeditiously Restore Fire Hose Stations in Containment to Service.

1R07 Annual Heat Sink Performance (71111.07)

a. Inspection Scope

The inspectors reviewed the licensee's testing of CCW heat exchangers to verify that potential deficiencies did not mask the licensee's ability to detect degraded performance, to identify any common cause issues that had the potential to increase risk, and to ensure that the licensee was adequately addressing problems that could result in initiating events that would cause an increase in risk. The inspectors also observed Station Service Water Pump Bay 2-01 cleaning and observed CCW Heat Exchanger 2-01 cleaning on April 8, 2008.

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection Activities (71111.08)

.1 Inspection Activities Other Than Steam Generator (SG) Tube Inspection, PWR Vessel Upper Head Penetration Inspections, Boric Acid Corrosion Control (BACC) (Section 02.01)

a. Inspection Scope

The inspection procedure requires review of two or three types of NDEs activities and, if performed, one to three welds on the reactor coolant system (RCS) pressure boundary. Inspectors are also guided to review one or two examinations with recordable indications that have been accepted by the licensee for continued service.

The inspectors directly observed the following NDEs:

System	Component/Weld ID	Exam Type
SI	H1: SI-2-051-415-C42K (snubber)	PT / VT-3
SI	H2: SI-2-051-414-C42R (hanger)	PT / VT-3
SI	H3: SI-2-051-408-C42R (hanger)	PT / VT-3
SI	H4: SI-2-051-421-C42R (hanger)	PT / VT-3
RCS	12" Reactor Coolant line, TCX-1-4401	UT
PWOL	6" Safety (1) line (A), TCX-1-4501	PT / UT
PWOL	6" Safety (2) line (B), TCX-1-4502	PT / UT
PWOL	6" PORV, TCX-1-4504	PT / UT

The inspectors reviewed the following nondestructive examinations through record review:

System	Component/Weld ID	Exam Type
FW	H3: FW-2-017-446-C72R	MT

There was an indication identified during the magnetic particle testing. The flaw length was 0.25 inches and the interpolated acceptable length for inservice examinations is 0.30 inches. Since the actual flaw length was less than the acceptable length, the flaw length is code allowable. Inspectors reviewed the code and verified that the variables used to calculate the acceptable length.

Additionally, the inspectors reviewed the NDE personnel qualification records for those contractor personnel performing ASME Code Section XI inservice inspections.

The inspection procedure further required verification of one to three welds on Class 1 or 2 pressure boundary piping to ensure that the welding process and welding examinations were performed in accordance with the ASME Code. The inspectors observed portions of the pre-emptive structural weld overlay on the ASME Code Class 1 pressurizer spray line nozzle-to-safe end dissimilar metal weld and pipe-to-safe end stainless steel weld identified as follows:

System	Component/Weld Identification
Pressurizer Spray Line Nozzle-to-Safe End	Weld DMW TCX-1-4506-22 Gas Tungsten Arc Welding (machine)

Welding procedures and NDE of the welding repair conformed to ASME Code requirements and licensee commitments.

Welder qualification documentation packages and welder maintenance logs were reviewed for contract welders performing welding activities on the pressurizer spray nozzle. The documentation packages and logs were in accordance with Article III, QW-300 "Welding Performance Qualification" in Section IX of the ASME Code.

The inspectors verified, by review, that the welding procedure specification and the welders had been properly qualified in accordance with ASME Code, Section IX, requirements. The inspectors also verified, through observation and record review, that essential variables for the gas tungsten arc welding process (machine and manual) and the shielded metal arc welding process were identified, recorded in the qualification record, and formed the bases for qualification of the welding procedure specification.

The inspectors completed one sample under Section 02.01.

b. Findings

No findings of significance were identified.

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

a. Inspection Scope

The licensee performed NDEs of 100 percent of reactor vessel upper head penetrations. The inspectors directly observed a sample of the examinations performed as listed below:

System	Component/Weld Identification	Examination Method
RCS	Penetration 10	VT-2
RCS	Penetration 22	VT-2
RCS	Penetration 30	VT-2
RCS	Penetration 14	VT-2
RCS	Penetration 50	VT-2
RCS	Penetration 37	VT-2
RCS	Penetration 61	VT-2

The NDEs were performed in accordance with the requirements of NRC Order EA-03-009. Qualifications of NDE personnel were reviewed and verified to be current.

The inspectors completed one sample under Section 02.02.

b. Findings

No findings of significance were identified.

.3 BACC Activities

a. Inspection Scope

The inspectors evaluated the implementation of the licensee's BACC program for monitoring degradation of those systems that could be deleteriously affected by boric acid corrosion.

The inspection procedure required review of a sample of BACC walkdown visual examination activities through either direct observation or record review. The inspectors reviewed the documentation associated with the licensee's BACC walkdown as specified in Procedure STA-737, "Boric Acid Corrosion Detection and Evaluation," Revision 4. Visual records of the components and equipment were also reviewed by the inspectors.

The inspection procedure required verification that visual inspections emphasize locations where boric acid leaks can cause degradation of safety significant components. The inspectors verified through program/record review that the licensee's BACC inspection efforts are directed towards locations where boric acid leaks can cause degradation of safety-related components. On those components where boric acid was identified, the engineering evaluations gave assurance that the ASME Code wall thickness limits were properly maintained. The evaluations also confirmed that the corrective actions performed for evidence of boric acid leaks were consistent with requirements of the ASME Code.

The inspection procedure required both a review of one to three engineering evaluations performed for boric acid leaks found on RCS piping and components and one to three corrective actions performed for identified boric acid leaks. The inspectors reviewed one engineering evaluation associated with Smart Form SMF-2008-000608 which addressed a boric acid leak identified on flange of the excess letdown heat exchanger. The leak was identified as an active leak. The evaluation appropriately addressed the causes and corrective actions and was generally consistent with industry standards. The inspectors reviewed five smart forms associated with boric acid leaks and confirmed they were consistent with requirements of ASME Code and 10 CFR Part 50, Appendix B, Criterion XVI.

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

.4 SG Tube Inspection Activities (Section 02.04)

a. Inspection Scope

The inspection procedure specified performance of an assessment of in situ screening criteria to assure consistency between assumed NDE flaw sizing accuracy and data from the Electric Power Research Institute (EPRI) examination technique specification sheets. It further specified assessment of the appropriateness of tubes selected for in situ pressure testing, observation of in situ pressure testing, and review of in situ pressure test results. At the time of this inspection, no conditions had been identified that warranted in situ pressure testing.

In addition, the inspectors reviewed both the licensee site-validated and qualified acquisition and analysis technique sheets used during this refueling outage and the qualifying EPRI examination technique specification sheets to verify that the essential variables regarding flaw sizing accuracy, tubing, equipment, technique, and analysis had been identified and qualified through demonstration. The inspectors reviewed acquisition technique and analysis technique sheets which are identified in the attachment.

The inspection procedure specified comparing the estimated size and number of tube flaws detected during the current outage against the previous outage operational assessment predictions to assess the licensee's prediction capability. Compared to the projected damage mechanisms identified by the licensee, the number of identified indications fell within the range of prediction and was quite consistent with predictions. No new damage mechanisms had been identified during this inspection.

The inspection procedure specified confirmation that the SG tube eddy current test scope and expansion criteria met TS requirements, EPRI guidelines, and commitments made to the NRC. The inspectors evaluated the recommended SG tube eddy current test scope established by TS requirements and the licensee’s degradation assessment report. The inspectors compared the recommended test scope to the actual test scope and found that the licensee had accounted for all known flaws and had, as a minimum, established a test scope that met TS requirements, EPRI guidelines, and commitments made to the NRC.

The base scope inspection plan recommended for the Refueling Outage 2RF10 in April 2008 include primary side inspection of all four SGs so as to allow skipping primary side inspection during Refueling Outage 2RF11. The recommended inspection scope (all SGs) for Refueling Outage 2RF10 was:

- 55 percent full length bobbin inspection including tubes with prior indications
- 50 percent hot leg top tube sheet (TTS) plus point from 3 inch above to 3 inch below TTS
- 50 percent hot leg plus point from tube end to 2 inch above tube end (same tubes as Item 2)
- Plus point test of at least 50 percent of the BLGs and OXPs in hot leg tubesheet (subset of tubes from Item 2)
- 50 percent U-bend mag-biased mid-range plus point of Rows 1 and 2 (select from tubes included in Item 1)
- 50 percent plus point at expanded preheater baffle Plate1
- 100 percent plus point of > 2 volt dents at H3 TSP
- 50 percent plus point of > 5 volt dings and dents in the hot leg
- Special interest RPC (freespan signals without historical resolution, Bobbin I-code indications)
- 100 percent tube plug video inspection
- Top of tubesheet and typical (periphery and T-slot) Plate B secondary side video inspection including FOSAR
- Upper bundle video inspection (through Access Ports 1 and 2 only) in one SG-3
- Tubes which were identified as possibly having elevated residual stress Table A-1) will be included in the full length bobbin program (Item 1 above) and top of tubesheet plus point program (Items 2 above).

The final resulting scope of the licensee's eddy current examinations of tubes for all SGs included:

Item	Area Examined	Probe	Scope	Expansion Criteria
1	Full Length	Bobbin	55 percent	For wear indication expansion shall be per the TS
2	Row 1 and 2 U-bends	plus point RPC	50 percent	Expand to 100 percent of the affected area in the affected SG
3	TTS +/-3"	plus point RPC	50 percent	Expand to 100 percent of the affected area in the affected SG
4	THE +2	plus point RPC	50 percent	Expand to 100 percent of the affected area in the affected SG
5	OXP/BLG in TS	plus point RPC	50 percent	Expand to 100 percent of the affected area in the affected SG
6	Expanded tubes in preheater baffle plate B and D	plus point RPC	50 percent	Expand to 100 percent of the affected area in the affected SG
7	Dents >= 2 volts at H3 TSP	plus point RPC	100 percent	N/A
8	Dents/Dings >= 5 volts HL and U-bends	plus point RPC	50 percent	Expand to 100 percent of the affected area in the affected SG

The inspection procedure specified, if new degradation mechanisms were identified, to verify that the licensee fully enveloped the problem in its analysis of extended conditions including operating concerns and had taken appropriate corrective actions before plant startup. To date, the eddy current test results had not identified any new degradation mechanisms.

The inspection procedure requires confirmation that the licensee inspected all areas of potential degradation, especially areas that were known to represent potential eddy current test challenges (e.g., top-of-tubesheet, tube support plates, and U-bends). The inspectors confirmed that all known areas of potential degradation were included in the scope of inspection and were being inspected.

The inspection procedure further requires verification that repair processes being used were approved in the TS. The total number of tubes plugged was 13 tubes out of 18,215 in all 4 SGs. The inspectors verified that the mechanical expansion plugging process to be used was an NRC-approved repair process.

The inspection procedure also requires confirmation of adherence to the TS plugging limit, unless alternate repair criteria have been approved. The inspection procedure further requires determination whether depth sizing repair criteria were being applied for indications other than wear or axial primary water stress corrosion cracking in dented tube support plate intersections. The inspectors determined that the TS plugging limits were being adhered to (i.e., 40 percent maximum through-wall indication).

If SG leakage greater than 3 gallons per day was identified during operations or during post shutdown visual inspections of the tubesheet face, the inspection procedure requires verification that the licensee had identified a reasonable cause based on inspection results and that corrective actions were taken or planned to address the cause for the leakage. The inspectors did not conduct any assessment because this condition did not exist.

The inspection procedure requires confirmation that the eddy current test probes and equipment were qualified for the expected types of tube degradation and an assessment of the site-specific qualification of one or more techniques. The inspectors observed portions of eddy current tests performed on the tubes in all four SGs. During these examinations, the inspectors verified that: (1) the probes appropriate for identifying the expected types of indications were being used, (2) probe position location verification was performed, (3) calibration requirements were adhered, and (4) probe travel speed was in accordance with procedural requirements. The inspectors performed a review of site-specific qualifications of the techniques being used. These are identified in the attachment.

If loose parts or foreign material on the secondary side were identified, the inspection procedure required confirmation that the licensee had taken or planned appropriate repairs of affected SG tubes and that they inspected the secondary side to either remove the accessible foreign objects or perform an evaluation of the potential effects of inaccessible object migration and tube fretting damage. At this time of the inspection, no foreign material had been identified.

Finally, the inspection procedure specified review of one to five samples of eddy current test data if questions arose regarding the adequacy of eddy current test data analyses. The inspectors did not identify any results where eddy current test data analyses adequacy was questionable.

The inspectors completed one sample under Section 02.04.

b. Findings

No findings of significance were identified.

.5 Identification and Resolution of Problems

a. Inspection scope

The inspection procedure required review of a sample of problems associated with inservice inspections documented by the licensee in the CAP for appropriateness of the corrective actions.

The inspectors reviewed 15 smart forms, which dealt with inservice inspection activities, and found that the corrective actions were appropriate. From this review the inspectors concluded that the licensee had an appropriate threshold for entering issues into the

CAP and had procedures that direct a root cause evaluation when necessary. The licensee also had an effective program for applying industry operating experience.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification Program (71111.11)

Resident Inspector Quarterly Review (71111.11Q)

a. Inspection Scope

On May 28, 2008, the inspectors observed a crew of operators undergo training on circuit breaker operations. Specifically, the inspector observed training on correct use and implementation of procedures, as well as training on applicable operating experience.

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12)

a. Inspection Scope

The inspectors evaluated degraded performance issues involving the following risk significant condition:

- Unit 2 turbine and reactor trip on March 16, 2008, due to condenser instrument line failure, root cause, and corrective actions reviewed on June 2, 2008

The inspectors reviewed events such as where ineffective equipment maintenance had resulted in valid or invalid automatic actuations of engineered safeguards systems and independently verified the licensee's actions to address system performance or condition problems in terms of the following:

- Implementing appropriate work practices
- Identifying and addressing common cause failures
- Scoping of systems in accordance with 10 CFR 50.65(b) of the maintenance rule
- Characterizing system reliability issues for performance
- Charging unavailability for performance
- Trending key parameters for condition monitoring

- Ensuring 10 CFR 50.65(a)(1) or (a)(2) classification or re-classification

- Verifying appropriate performance criteria for structures, systems, and components (SSCs)/functions classified as (a)(2) or appropriate and adequate goals and corrective actions for systems classified as (a)(1)

The inspectors assessed performance issues with respect to the reliability, availability, and condition monitoring of the system. In addition, the inspectors verified maintenance effectiveness issues were entered into the CAP with the appropriate significance characterization. Documents reviewed are listed in the attachment.

The inspectors completed one sample.

b. Findings

Introduction: A Green self-revealing finding was identified for failure to install turbine instrumentation tubing in accordance with site specifications, which resulted in a turbine trip and reactor trip due to a tubing failure.

Description: On March 16, 2008, a self-revealing finding was identified when the Unit 2 main turbine tripped due to low sensed condenser vacuum, also causing a reactor trip. The operators quickly determined that the direct cause of the trip was a tubing failure that caused the condenser vacuum instruments for the turbine to sense low vacuum, and therefore trip the turbine. Actual condenser vacuum remained stable during the event as verified on multiple instruments. In addition, the rest of the trip recovery was uncomplicated.

The licensee's investigation determined that the root cause was a failure to install the tubing per Tubing Specification CPSES-I-1018. The specification states that tubing runs shall be routed to allow for general flexibility and thermal growth. However, the investigation revealed that with an installation that was too rigid, residual stress due to condenser movement combined with cyclic stress due to vibration ultimately resulted in failure of the tubing. Additionally, the investigation determined that a contractor installed the tubing using a field sketch prepared by an engineer.

The licensee's investigation also revealed that the vibration testing of the tubing was not performed properly because an evaluation should have been performed for the relatively high vibration at the tubing. However, the licensee was not able to determine the exact cause because of insufficient documentation.

The licensee's investigation determined that work practices caused this event in that the licensee failed to provide proper oversight of the contractor's work activities.

Analysis: The failure to install the tubing per specification which resulted in a turbine and reactor trip was a performance deficiency. The finding was more than minor because it was associated with the Initiating Events Cornerstone attribute of design control and affected the cornerstone objective, in that, it caused a turbine and reactor trip that challenged critical safety functions. The finding was determined to be of very low safety significance (Green) because, although the likelihood of a reactor trip increased, all mitigating systems were available.

The cause of this finding is related to the human performance crosscutting component of Work Practices in that the licensee failed to provide proper oversight of contractors such that nuclear safety is supported [H.4.(c)].

Enforcement: Enforcement action does not apply because the tubing that failed was nonquality related and nonsafety related and, therefore, this finding is not a violation of regulatory requirements. The licensee entered the performance deficiency into their CAP as SMF-2008-000795. FIN 05000446/2008003-03; Instrument Tubing Failure Causes Plant Trip.

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

a. Inspection Scope

The inspectors reviewed the licensee's evaluation and management of plant risk for the maintenance and emergent work activities affecting risk-significant and safety-related equipment listed below to verify that the appropriate risk assessments were performed prior to removing equipment for work:

- Scheduled routine maintenance for the week of March 24 through March 28 on Switchyard Breaker 7970, the East Bus feed to XST2, an offsite power source to safety-related buses for Units 1 and 2, including risk reduction activities to protect other sources of power

- Outage Risk Assessment for Refueling Outage 2RF10

- Scheduled and emergent maintenance, surveillance testing, and operational activities for the week of June 1 through June 7 on Unit 1 primary water system, station service water controls, motor-operated valves, and economic hands-off

These activities were selected based on their potential risk significance relative to the reactor safety cornerstones. As applicable for each activity, the inspectors verified that risk assessments were performed as required by 10 CFR 50.65(a)(4) and were accurate and complete. When emergent work was performed, the inspectors verified that the plant risk was promptly reassessed and managed. The inspectors reviewed the scope of maintenance work, discussed the results of the assessment with the licensee's probabilistic risk analyst or shift technical advisor, and verified plant conditions were consistent with the risk assessment. The inspectors also reviewed TS requirements and walked down portions of redundant safety systems, when applicable, to verify risk analysis assumptions were valid and applicable requirements were met.

The inspectors completed three samples.

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope

The inspectors reviewed the following issues:

- SMF-2008- 001055-00, ran containment spray Train B pumps deadheaded
- SMF-2008-001280-00, RHR Pump 2-01 exhibited signs of cavitation during surveillance run
- SMF-2008-000255-00, as found response time allowable range exceeded for Unit 1 SG 1-02 narrow range level Loop 1-L-059
- SMF-2008-001372-00, unidentified leakage from Unit 2 RCS via residual heat removal Train A to Train B sample valves
- SMF-2008-000009-00, Unit 1 reactor makeup water to spent fuel pool cooling system check Valve XSF-0160 failed closed test per Procedure OPT-223, Section 8.3

The inspectors selected these potential operability issues based on the risk-significance of the associated components and systems. The inspectors evaluated the technical adequacy of the evaluations to ensure that TS operability was properly justified and the subject component or system remained available such that no unrecognized increase in risk occurred. The inspectors compared the operability and design criteria in the appropriate sections of the TS and USAR to the licensee's evaluations to determine whether the components or systems were operable. Where compensatory measures were required to maintain operability, the inspectors determined whether the measures in place would function as intended and were properly controlled. The inspectors determined, where appropriate, compliance with bounding limitations associated with the evaluations. Additionally, the inspectors also reviewed a sampling of corrective action documents to verify that the licensee was identifying and correcting any deficiencies associated with operability evaluations. Documents reviewed are listed in the attachment.

The inspectors completed five samples.

b. Findings

No findings of significance were identified.

1R18 Plant Modifications (71111.18)

a. Inspection Scope

For the following plant modifications described below, the inspectors reviewed the final design authorization (FDA) documents, 10 CFR 50.59 screenings, the UFSAR, TSs, implementing work orders, associated drawings, installation and postinstallation testing procedures, and observed installation and testing of portions of the modifications to verify that design bases, license bases, and performance capability had not been degraded through these modifications.

- Final Design Document 2001-000461-02-01, relocate orifice plate to provide less turbulent flow conditions at valve in station service water system, observed during Unit 2 outage

- Temporary installation and phase rotational testing of the alternate power diesel generators in accordance with Maintenance Section – Electrical Procedure MSE-G2-0850, "Unit 2 Alternate Power Diesel Generators Installation and Removal," Revision 1, MSE-G0-0850, "Alternate Power Diesel Generators Synchronism Phase Check," Revision 1, and SOP-614B, "Alternate Power Generator Operation," Revision 8, on March 31, 2008

The inspectors completed one permanent modification sample and one temporary modification sample.

b. <u>Findings</u>

No findings of significance were identified.

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

a. <u>Inspection Scope</u>

The inspectors reviewed the following postmaintenance (PM) activities to verify that procedures and test activities were adequate to ensure system operability and functional capability:

- Unit 2 preservice test of Valve 2-HV-4526, CCW non-Safeguards loop upstream isolation valve, in accordance with PPT-S0-6005, "Motor Operated Quarter Turn Valve Risk-Informed IST Testing," Revision 1, following elastomer replacement, observed on April 11, 2008

- Unit 2 Reactor Coolant Pump Motor 2-01 uncoupled coastdown, following motor replacement, performed on April 12, 2008

- Unit 2 Main Steam Safety 2MS-0021, re-installation following jack and lap, observed on April 14, 2008

- Unit 2 Safety Injection Pump 2-02 in accordance with Procedure OPT-204B, "SI System," Revision 11, following replacement of the inboard pump mechanical seal and pump to motor coupling, performed on April 16, 2008

- Unit 1 Train B EDG in accordance with Procedure OPT-214A, "Diesel Generator Operability Test," Revision 19, following inspection and cleaning of the station service water side of the jacket water heat exchanger, performed on May 7, 2008

These activities were selected based upon the SSCs ability to impact risk. The inspectors evaluated the following activities (as applicable):

- The effect of testing on the plant had been adequately addressed

- Testing was adequate for the maintenance performed

- Acceptance criteria were clear and demonstrated operational readiness

- Test instrumentation was appropriate

- Tests were performed as written in accordance with properly reviewed and approved procedures

- Equipment was returned to its operational status following testing (temporary modifications or jumpers required for test performance were properly removed after test completion)

- Test documentation was properly evaluated.

The inspectors evaluated the activities against TS, the UFSAR, 10 CFR Part 50 requirements, licensee procedures, and various NRC generic communications to ensure that the test results adequately ensured that the equipment met the licensing basis and design requirements. In addition, the inspectors reviewed corrective action documents associated with postmaintenance tests to determine whether the licensee was identifying problems and entering them in the CAP and that the problems were being corrected commensurate with their importance to safety. Documents reviewed are listed in the attachment.

The inspectors completed five samples.

b. Findings

No findings of significance were identified.

1R20 Outage Activities (71111.20)

Refueling Outage Activities

a. Inspection Scope

The inspectors reviewed the outage risk assessment and management and contingency plans for Refueling Outage 2RF10, conducted March 29 through April 19, 2008, to confirm that the licensee had appropriately considered risk, industry experience, and previous site-specific problems in developing and implementing a plan that assured maintenance of defense-in-depth. During the refueling outage, the inspectors observed portions of the shutdown and cooldown processes and monitored licensee controls over the outage activities listed below:

- Licensee configuration management, including maintenance of defense-in-depth commensurate with the outage risk assessment and management for key safety functions and compliance with the applicable TS when taking equipment out-of-service

- Implementation of clearance activities and confirmation that tags were properly hung and equipment appropriately configured to safely support the work or testing

- Installation and configuration of reactor coolant pressure, level, and temperature instruments to provide accurate indication, accounting for instrument error

- Controls over the status and configuration of electrical systems to ensure that TS and outage safety plan requirements were met, and controls over switchyard activities

- Monitoring of decay heat removal processes, systems, and components

- Controls to ensure that outage work was not impacting the ability of the operators to operate the spent fuel pool cooling system

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

- Controls over activities that could affect reactivity

- Refueling activities, including fuel handling and mast sipping to detect fuel assembly leakage

- Startup and ascension to full power operation, tracking of startup prerequisites, walkdown of the containment to verify that debris had not been left which could block emergency core cooling system recirculation sump screens, and reactor physics testing

- Licensee identification and resolution of problems related to refueling outage activities

Documents reviewed during the inspection are listed in the attachment.

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope

The inspectors reviewed the test results for the following activities to determine whether risk-significant systems and equipment were capable of performing their intended safety function and to verify testing was conducted in accordance with applicable procedural and TS requirements:

Routine Surveillance Testing

- Unit 2 emergency core cooling system operability test in accordance with Procedure OPT 521B, “ECCS Operability,” Revision 3, performed on April 13, 2008

- Unit 2 containment sump inspection in accordance with Procedure OPT-306, “Containment Sump Inspection,” Revision 6, performed on April 14, 2008

- Unit 2 emergency core cooling system fill and vent in accordance with Procedures OPT 201B, “Charging System,” Revision 7, and OPT-204B, “SI System”, Revision 11, observed on April 17, 2008

- Unit 2 RCS flow measurement in accordance with Instrumentation and Control Procedure INC-7018B, “Reactor Coolant System Flow Measurement,” Revision 2, performed on April 21, 2008

Inservice Testing Surveillance

- Unit 2 Station Service Water Pump 2-01 baseline test in accordance with Procedure ETP 215B, “Service Water Pump Test”, Revision 3, performed on April 11, 2008

The inspectors observed in-plant activities and reviewed procedures and associated records to determine whether: (1) any preconditioning occurred; (2) effects of the testing were adequately addressed by control room personnel or engineers prior to the commencement of the testing; (3) acceptance criteria were clearly stated, demonstrated operational readiness, and were consistent with the system design basis; (4) plant equipment calibration was correct, (5) accurate, and properly documented; (6) as left setpoints were within required ranges; (7) the calibration frequency were in accordance with TSs, the USAR, procedures, and applicable commitments; (8) measuring and test equipment calibration was current; (9) test equipment was used within the required range and accuracy; (10) applicable prerequisites described in the test procedures were satisfied; (11) test frequencies met TS requirements to demonstrate operability and reliability; (12) tests were performed in accordance with the test procedures and other applicable procedures; (13) jumpers and lifted leads were controlled and restored where used; (14) test data and results were accurate, complete, within limits, and valid; test equipment was removed after testing; (15) where applicable for inservice testing activities, testing was performed in accordance with the applicable version of Section XI, American Society of Mechanical Engineers Code, and reference values were consistent with the system design basis; (16) where applicable, test results not meeting acceptance criteria were addressed with an adequate operability evaluation or the system or component was declared inoperable; (17) where applicable for safety-related instrument control surveillance tests, reference setting data were accurately incorporated in the test procedure; (18) where applicable, actual conditions encountering high resistance electrical contacts were such that the intended safety function could still be accomplished; (19) prior procedure changes had not provided an opportunity to identify problems encountered during the performance of the surveillance or calibration test; (20) equipment was returned to a position or status required to support the performance of its safety functions; and (21) all problems identified during the testing were appropriately documented and dispositioned in the CAP.

Documents reviewed are listed in the attachment.

The inspectors completed four routine surveillances and one inservice testing surveillance sample.

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness (EP)

1EP2 Alert Notification System Testing (71114.02)

a. Inspection Scope

The inspector discussed with licensee staff the status of offsite siren systems to determine the adequacy of licensee methods for testing the alert and notification system in accordance with 10 CFR Part 50, Appendix E. The licensee's alert and notification system testing program was compared with criteria in NUREG 0654, A Criteria for Preparation and Evaluation of Radiological Emergency Response Plans and Preparedness in Support of Nuclear Power Plants, Revision 1, Federal Emergency Management Agency (FEMA) Report REP 10, A Guide for the Evaluation of Alert and Notification Systems for Nuclear Power Plants," and the licensee's current, Federal Emergency Management Agency approved alert and notification system design report, "Alert and Notification System for Comanche Peak Steam Electric Station, Final Report," revised September 28, 2004. The inspector also reviewed EP Staff Guideline 12, "Alert and Notification System Surveillance," Revision 12, and EP Staff Guideline 17, "Conducting Monthly Communications Equipment Checks," Revision 2.

The inspector completed one sample during the inspection.

b. Findings

No findings of significance were identified.

1EP3 Emergency Response Organization Augmentation Testing (71114.03)

a. Inspection Scope

The inspector discussed with licensee staff the status of primary and backup systems for augmenting the on-shift emergency response staff to determine the adequacy of licensee methods for staffing emergency response facilities in accordance with their emergency plan. The inspector reviewed EP Staff Guideline 5, "Quarterly Augmentation Verification of the Emergency Response Organization," Revision 11, and the references listed in the attachment to this report, to evaluate the licensee's ability to staff the emergency response facilities in accordance with the licensee's emergency plan and the requirements of 10 CFR Part 50, Appendix E.

The inspector completed one sample during the inspection.

b. Findings

No findings of significance were identified.

1EP4 Emergency Action Level and Emergency Plan Changes (71114.04)

a. Inspection Scope

The inspector reviewed EP Procedures (EPP)-100, “Maintaining Emergency Preparedness,” Revision 3, Attachment 9, “10 CFR 50.54(Q) Evaluation Guidance,” 10 CFR 50.54Q Evaluation: “EPP-201, Revision 11, PCN 2, November 14, 2006”; and 10 CFR 50.54Q Evaluation: “EPP-201, Revision 11, PCN 3, March 21, 2007” to determine if the licensee was adequately implementing the requirements of 10 CFR 50.54(q) and whether revisions were conducted in accordance with 10 CFR 50.54(q). This review was not documented in a safety evaluation report and did not constitute approval of the licensee’s changes, therefore, these revisions are subject to future inspection.

The inspector completed two samples during the inspection.

b. Findings

No findings of significance were identified.

1EP5 Correction of Emergency Preparedness Weaknesses and Deficiencies (71114.05)

a. Inspection Scope

The inspector reviewed the licensee’s CAP requirements in Procedure STA-421, “Initiation of Smart Forms,” Revision 13. The inspector reviewed summaries of 182 smart forms (CAP entries) assigned to the EP department and emergency response organization between August 2006 and April 2008, and selected 15 for detailed review against the program requirements. The inspector evaluated the response to the corrective action requests to determine the licensee’s ability to identify, evaluate, and correct problems in accordance with the licensee program requirements, planning standard 10 CFR 50.47(b)(14), and 10 CFR Part 50, Appendix E. The inspector also reviewed other documents as listed in the attachment to this report.

The inspector completed one sample during the inspection.

b. Findings

No findings of significance were identified.

1EP6 Drill Evaluation (71114.06)

EP Drill Observation

a. Inspection Scope

The inspectors evaluated the conduct of a routine licensee emergency drill on May 14, 2008, to identify any weaknesses and deficiencies in classification, notification, and protective action recommendation development activities. The inspectors observed emergency response operations in the control room simulator and the technical support center to determine whether the event classification, notifications, and protective action recommendations were performed in accordance with procedures. The inspectors also attended the licensee drill critique to compare any inspector-observed weakness with those identified by the licensee staff in order to evaluate the critique and to verify whether the licensee staff was properly identifying weaknesses and entering them into the CAP. As part of the inspection, the inspectors reviewed the drill package and other documents listed in the attachment.

The inspectors completed one sample.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2OS1 Access Control To Radiologically Significant Areas (71121.01)

a. Inspection Scope

This area was inspected to assess the licensee's performance in implementing physical and administrative controls for airborne radioactivity areas, radiation areas, high radiation areas, and worker adherence to these controls. The inspector used the requirements in 10 CFR Part 20, the TSs, and the licensee's procedures required by TSs as criteria for determining compliance. During the inspection, the inspector interviewed the radiation protection manager, radiation protection supervisors, and radiation workers. The inspector performed independent radiation dose rate measurements and reviewed the following items:

- Performance indicator (PI) events and associated documentation packages reported by the licensee in the Occupational Radiation Safety Cornerstone

- Controls (surveys, posting, and barricades) of radiation, high radiation, or airborne radioactivity areas

- Radiation work permits, procedures, engineering controls, and air sampler locations

- Conformity of electronic personal dosimeter alarm set points with survey indications and plant policy; workers' knowledge of required actions when their electronic personnel dosimeter noticeably malfunctions or alarms

- Barrier integrity and performance of engineering controls in airborne radioactivity areas

- Physical and programmatic controls for highly activated or contaminated materials (nonfuel) stored within spent fuel and other storage pools

- Self-assessments, audits, licensee event reports, and special reports related to the access control program since the last inspection

- Corrective action documents related to access controls

- Licensee actions in cases of repetitive deficiencies or significant individual deficiencies

- Radiation work permit briefings and worker instructions

- Adequacy of radiological controls, such as required surveys, radiation protection job coverage, and contamination control during job performance

- Dosimetry placement in high radiation work areas with significant dose rate gradients

- Changes in licensee procedural controls of high dose rate - high radiation areas and very high radiation areas

- Controls for special areas that have the potential to become very high radiation areas during certain plant operations

- Posting and locking of entrances to all accessible high dose rate - high radiation areas and very high radiation areas

- Radiation worker and radiation protection technician performance with respect to radiation protection work requirements

The inspector completed 20 of the required 21 samples.

b. Findings

Introduction: The inspector identified a NCV of TS 5.7.1 because a high radiation area was not barricaded and conspicuously posted. The violation had very low safety significance.

Description: On April 8, 2008, the inspector toured the 810-foot elevation of the fuel building and observed bags of radioactive trash stored in the compactor area. The area was posted and controlled as a radiation area. The inspector made preliminary radiation measurements around the bags and then contacted radiation protection personnel for assistance. A radiation protection technician conducted additional radiation measurements and confirmed a maximum dose rate of 109 millirems per hour at 30 centimeters from the source of radiation. The radiation protection technician barricaded the area with rope and posted it as a high radiation area. The licensee placed the finding into the CAP and preliminarily concluded there was a lack of communication and coordination between personnel transporting trash bags and radiation protection technicians responsible for surveying radiation dose rates. Licensee representatives surveyed the bags individually and found no one bag exceeded 100 millirems per hour. Therefore, the high radiation area was caused by the accumulation of the bags of radioactive trash.

Analysis: The failure to barricade and post a high radiation area is a performance deficiency. The finding is more than minor because, if left uncorrected, the finding could become a more significant safety concern. Using the Occupational Radiation Safety Significance Determination Process, the inspector determined the finding to have very low safety significance because (1) it was not associated with as low as reasonably achievable (ALARA) planning or work controls, (2) there was no overexposure, (3) there was no substantial potential for an overexposure, and (4) the ability to assess dose was not compromised.

Additionally, the finding had a crosscutting aspect in the area of human performance, work control component, because the licensee did not coordinate work activities by incorporating actions to address the need for work groups to communicate, coordinate, and cooperate with each other during activities in which interdepartmental coordination is necessary to assure human performance [H.3(b)].

Enforcement: TS 5.7.1 requires each entryway to a high radiation area be barricaded and conspicuously posted as a high radiation area. The licensee violated this requirement when it failed to barricade and conspicuously post the compactor area on the 810-foot elevation of the fuel building. Because this failure to barricade and post a high radiation area is of very low safety significance and has been entered into the licensee's CAP as Smart Form 2008-001195, this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy:
NCV 05000445;05000446/2008003-04, Failure to Barricade and Post a High Radiation Area.

2OS2 ALARA Planning and Controls (71121.02)

a. Inspection Scope

The inspector assessed licensee performance with respect to maintaining individual and collective radiation exposures ALARA. The inspector used the requirements in 10 CFR Part 20 and the licensee's procedures required by TSs as criteria for determining compliance. The inspector interviewed licensee personnel and reviewed:

- Integration of ALARA requirements into work procedure and radiation work permit documents
- Use of engineering controls to achieve dose reductions and dose reduction benefits afforded by shielding
- Workers' use of the low dose waiting areas

- Radiation worker and radiation protection technician performance during work activities in radiation areas, airborne radioactivity areas, or high radiation areas

The inspector completed 2 of the required 15 samples and 2 of the optional samples.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator Verification (71151)

.1 Data Submission Issue

a. Inspection Scope

The inspectors performed a review of the data submitted by the licensee for the First Quarter 2008 PIs for any obvious inconsistencies prior to its public release in accordance with Inspection Manual Chapter 0608, “Performance Indicator Program.”

This review was performed as part of the inspectors’ normal plant status activities and, as such, did not constitute a separate inspection sample.

b. Findings

No findings of significance were identified.

.2 RCS Specific Activity

a. Inspection Scope

The inspectors sampled licensee submittals for the reactor coolant system specific activity PI for Units 1 and 2 for the period from April 2007 through March 2008. To determine the accuracy of the PI data reported during those periods, PI definitions, and guidance contained in the Nuclear Energy Institute (NEI) Document 99-02, “Regulatory Assessment Performance Indicator Guideline,” Revision 5, were used. The inspectors reviewed the licensee’s dose equivalent Iodine 131 data from Form CHM-120-101-01, RCS Control, Technical Specification, and Fuel Performance, Mode 1-3,” Revisions 9-12, for the period April 2007 to March 2008 to validate the accuracy of the submittals. The inspectors also reviewed the licensee’s smart form database to determine if any problems had been identified with the PI data collected or transmitted for this indicator.

The inspectors completed two samples.

b. Findings

No findings of significance were identified.

.3 RCS Leakage

a. Inspection Scope

The inspectors sampled licensee submittals for the reactor coolant system leakage PI on Units 1 and 2 for the period from the second quarter 2007 to the first quarter 2008. To determine the accuracy of the PI data reported during those periods, PI definitions and guidance contained in NEI Document 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 5, were used. The inspectors reviewed the licensee's operator logs, RCS leakage tracking data, issue reports, event reports and NRC integrated inspection reports for the period of April 2007 to March 2008 to validate the accuracy of the submittals. The inspectors also reviewed the licensee's issue report database to determine if any problems had been identified with the PI data collected or transmitted for this indicator and none were identified. Specific documents reviewed are described in the attachment to this report.

The inspectors completed two samples.

b. Findings

No findings of significance were identified.

.4 Drill and Exercise Performance, Emergency Response Organization Drill Participation, Alert and Notification System Reliability

a. Inspection Scope

The inspector reviewed licensee evaluations for the three EP cornerstone PIs of Drill and Exercise Performance, Emergency Response Organization Participation, and Alert and Notification System Reliability for the period July 2007 through March 2008. The definitions and guidance of NEI Document 99-02, "Regulatory Assessment Indicator Guideline, Revisions 3 and 4, and the licensee PI Procedure EP Staff Guideline 20, "NRC Performance Indicators," Revision 11, were used to verify the accuracy of the licensee's evaluations for each PI reported during the assessment period.

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 27 selected emergency responder qualification, training, and drill participation records to determine the accuracy of the licensee's emergency response organization drill participation database. The inspector reviewed alert and notification system testing procedures, maintenance records, and a 100 percent sample of siren test records. The inspector also reviewed other documents pertaining to drill and exercise performance as listed in the attachment to this report.

The inspector completed three samples during the inspection.

b. Findings

No findings of significance were identified.

.5 Occupational Exposure Control Effectiveness

a. Inspection Scope

The inspector reviewed licensee documents from September 1, 2007, through March 31, 2008. The review included corrective action documentation that identified occurrences in locked high radiation areas (as defined in the licensee's TS), very high radiation areas (as defined in 10 CFR 20.1003), and unplanned personnel exposures (as defined in NEI Document 99-02, "Regulatory Assessment Indicator Guideline," Revision 5). Additional records reviewed included ALARA records and whole body counts of selected individual exposures. The inspector interviewed licensee personnel that were accountable for collecting and evaluating the PI data. In addition, the inspector toured plant areas to verify that high radiation, locked high radiation, and very high radiation areas were properly controlled. PI definitions and guidance contained in NEI 99-02, Revision 5, were used to verify the basis in reporting for each data element.

The inspector completed the required one sample in this cornerstone.

b. Findings

No findings of significance were identified.

.6 Radiological Effluent TS/Offsite Dose Calculation Manual Radiological Effluent Occurrences

a. Inspection Scope

The inspector reviewed licensee documents from September 1, 2007, through March 31, 2008. Licensee records reviewed included corrective action documentation that identified occurrences for liquid or gaseous effluent releases that exceeded PI thresholds and those reported to the NRC. The inspector interviewed licensee personnel that were accountable for collecting and evaluating the PI data. PI definitions and guidance contained in NEI 99-02, Revision 5, were used to verify the basis in reporting for each data element.

The inspector completed the required one sample in this cornerstone.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity, Emergency Preparedness, Public Radiation Safety, Occupational Radiation Safety, and Physical Protection

.1 Routine Review of Items Entered into the CAP

a. Inspection Scope

As part of the various baseline inspection procedures discussed in previous sections of this report, the inspectors routinely reviewed issues during baseline inspection activities and plant status reviews to verify that they were being entered into the licensee's CAP at an appropriate threshold, that adequate attention was being given to timely corrective actions, and that adverse trends were identified and addressed. Attributes reviewed included: the complete and accurate identification of the problem; that timeliness was commensurate with the safety significance; that evaluation and disposition of performance issues, generic implications, common causes, contributing factors, root causes, extent of condition reviews, and previous occurrences reviews were proper and adequate; and that the classification, prioritization, focus, and timeliness of corrective actions were commensurate with safety and sufficient to prevent recurrence of the issue. Minor issues entered into the licensee's CAP as a result of the inspectors' observations are included in the attached list of documents reviewed. These routine reviews for the identification and resolution of problems did not constitute any additional inspection samples. Instead, by procedure they were considered an integral part of the inspections performed during the quarter.

b. Findings

No findings of significance were identified.

.2 Daily CAP Reviews

a. Inspection Scope

In order to assist with the identification of repetitive equipment failures and specific human performance issues for follow-up, the inspectors performed a daily screening of items entered into the licensee's CAP. This review was accomplished through inspection of the station's daily condition report packages.

These daily reviews were performed by procedure as part of the inspectors' daily plant status monitoring activities and, as such, did not constitute any separate inspection samples.

b. Findings

No findings of significance were identified.

.3 Semi-Annual Trend Review

a. Inspection Scope

On June 5, 2008, the inspectors completed a review of the licensee's CAP and associated documents to identify trends that could indicate the existence of a more significant safety issue. The inspectors' review considered the results of daily inspector CAP item screening discussed in Section 4OA2.2 above, licensee trending efforts, and licensee human performance results.

The review also included issues documented outside the normal CAP in major equipment problem lists, repetitive and/or rework, maintenance lists, departmental problem/challenges lists, system health reports, quality assurance audit/surveillance reports, self assessment reports, and Maintenance Rule assessments. The inspectors compared and contrasted their results with the results contained in the licensee's CAP trending reports. Corrective actions associated with a sample of the issues identified in the licensee's trending reports were reviewed for adequacy.

This review constituted a single semi-annual trend inspection sample.

b. Findings

No findings of significance were identified. The inspectors did note that the licensee has measured a decrease in the rate of human performance errors over the last several years. Also, a quality assurance audit documented in Smart Form SMF-2008-001548 found that previous corrective actions regarding material control have not been effective. The inspector did not identify any additional trends.

.4 Selected Issue Follow-up Inspection: Review of Instrument Air Joints

a. Inspection Scope

During a plant tour, the inspectors identified two leaking instrument air joints on main headers. The inspectors then walked down all accessible main instrument air headers on April 29, 2008, reviewed the licensee's response to operating experience on instrument air joint failures, and reviewed the licensee's CAP for instrument air joint failures. This issue was selected due to operating experience at other nuclear plants where complicated plant transients have occurred due to instrument air header joint failures.

b. Findings

No findings of significance were identified.

.5 Selected Issue Follow-up Inspection: Review of Heat Exchanger Performance

a. Inspection Scope

The inspectors reviewed the licensee's smart forms to verify that the licensee had entered heat exchanger/heat sink performance problems into the CAP. The inspectors noted that Smart Form SMF-2007-002444-00 documented that the service water flow to

Component Cooling Water Heat Exchanger 2-02 was approximately 14,750 gallons per minute. This value was below the minimum required design flow of 14,900 gallons per minute. The licensee indicated that the system was degraded but operable based on conditions at that specific time. The inspectors reviewed Design Basis Document DBD-ME-229, "Component Cooling Water System," and DBD-ME-233, "Service Water System," both dated May 1, 2008.

b. Findings

No findings of significance were identified.

.6 Selected Issue Follow-up Inspection: Review of Corrective Actions for Smart Form SMF-2008-1055-00, Unit 2 Containment Spray Pumps Ran with Recirculation Valves Closed

a. Inspection Scope

The inspectors reviewed the events of April 3, 2008, when the Unit 2 Train B Containment Spray Pumps 2-02 and 2-04 ran during the performance of Procedure OPT-435B, "Train B Integrated Test Sequence," Revision 7, with the Recirculation Valves 2 FV 4773-1 and 2-FV-4773-2 closed. The evaluation to determine operability of the system was reviewed for adequacy and completeness. The basic cause analysis, PERC notes, error precursors, flawed defenses, latent organizational weaknesses, and corrective actions were reviewed to ensure the analyses were broad in scope and the corrective actions would address the causes of the event.

The inspectors completed two samples of selected issue followup.

b. Findings

Introduction: The inspectors identified a Green NCV of TS 5.4.1.a for failing to implement the prerequisites for the Train B integrated test sequence which resulted in the containment spray pumps running without an adequate minimum flow path.

Description: On April 3, 2008, Unit 2 was in Mode 6 with Train A residual heat removal system providing shutdown cooling to the nuclear fuel in the open reactor vessel. Operations Test Procedure OPT-435B, "Train B Integrated Test Sequence," was being performed. This test initiated a manual safety injection signal with a concurrent simulated loss of offsite power and demonstrated that the approximately 40 components actuate including the containment spray pumps. The prerequisites for this test included verifying the affected equipment was in the correct standby alignment. Step 6.2.7 was to verify the "Train B containment spray pumps are in standby per SOP-204B." Procedure SOP-204B, "Containment Spray System," Revision 5, step 5.1.1, Placing the System in a Standby Condition included verifying that the containment spray pump recirculation Valves 2 FV 4773-1 and –FV-4773-2 are open.

Approximately 2 hours and 46 minutes after the pumps started for this test, operators noted the recirculation valves were closed and opened the valves, which would not stay open. The operators then stopped the pumps. Subsequent review determined that Clearance CP-07-1490 on the system heat exchanger outlet valves had de-energized the inputs to the recirculation valves causing them to remain closed. The condition of the pumps was evaluated and determined there was no detected damage. Although the recirculation and test flow paths were closed, these pumps have a small flow path from the discharge through an eductor and return to the suction. In addition, review of the plant computer data indicated the discharge relief Valve 2CT-0005 was intermittently lifting during the event, providing addition of cooler water as well as pressure relief. These unique features contributed to the observed lack of damage to the pumps.

The licensee's basic cause analysis identified the clearance on the outlet valves as the cause of the event. Their corrective actions included: (1) enlist control room staff to assist in subsequent tests, (2) discuss the scheduling of the test with the surveillance manager, (3) training department to provide training concerning re-establishing flow through a pump that has been dead-headed could have negative consequences, and (4) outage scheduling to assess effectiveness of outage preparation and schedule review. The licensee failed to identify that prerequisite step 6.2.7 was not properly performed and would have revealed the inability to open the recirculation valves, thus preventing the event. There were no corrective actions addressing the failure to perform this prerequisite step.

Since the licensee did not identify the failure to follow the procedure and did not implement appropriate corrective actions, the NRC inspector significantly added value by identifying previously unknown weakness in the licensee's evaluation and corrective actions for this finding.

After the inspector informed the licensee that they had not documented nor addressed the failure to satisfy the prerequisite step 6.2.7, the licensee revised their apparent cause analysis. The revised apparent cause of the event was the decision by the test lead reactor operator to consider the containment spray system in standby without verifying it per Procedure SOP-204B. Operations management considered this practice (considering a system in standby without reviewing the applicable operating procedure) as acceptable for normal plant operations, but during outages, expect that prerequisites be verified.

Analysis: The licensee's failure to ensure that a minimum flow path was established as required by Procedure SOP-204 prior to starting the containment spray pumps, which resulted in the pumps operating for more than 2 hours without the required flow path, is a performance deficiency. The finding is more than minor because it could be viewed as a precursor to a significant event. Had operators made the same error on any other safety-related pump which was started by this test (e.g., Train B residual heat removal pump), the pump would have been significantly damaged. The licensee's failure mode analysis of running a pump without flow postulated that "excessive heating of the fluid would lead to an uneven thermal growth of the casing and rotating element resulting in severe damage of the pump. A degraded condition could occur due to increased wear related to the impeller or other internal sub-component wear parts." This finding affects the Containment Barrier Integrity Cornerstone attribute of SSC reliability. Since Unit 2 was in Mode 6 with residual heat removal pump providing cooling, Appendix G, "Shutdown Operations Significance Determination Process" of Manual Chapter 0609 applied to this analysis. Checklist 4 of Appendix G determined that the finding was of very low risk significance (Green).

The cause of this finding was related to the human performance crosscutting component of Work Practices in that operations management failed to effectively communicate expectations regarding procedural requirements and operations personnel failed to follow procedures [H.4.(b)].

Enforcement: TS 5.4.1.a requires written procedures shall be established, implemented, and maintained covering activities as recommended in Regulatory Guide 1.33, Revision 2, Appendix A. Procedure OPT-435B, step 6.2.7 required Train B containment spray pumps to be in standby per Procedure SOP-204B. Procedure SOP-204B required the pump recirculation Valves 2-FV-4773-1 and 2-FV-4773-2 to be open. Contrary to the above, Procedure OPT-435B, Section 8.1, was performed with the valves closed. This violation is in the licensee's CAP as Smart Form SMF-2008-001055-00. Because the violation was determined to be of very low safety significance, it is being treated as an NCV, consistent with Section VI.A.1 of the NRC Enforcement Policy and is identified as NCV 05000446/2008003-05, Failure to Ensure a Flow Path for Containment Spray Pumps.

.7 EP Annual Sample Review

a. Inspection Scope

The inspector reviewed summaries of 182 smart forms (CAP entries) assigned to the EP department and emergency response organization between August 2006 and April 2008, and selected 15 smart forms for detailed review, and reviewed 8 smart forms generated by the licensee between May 5 and May 8, 2008. The CAP entries were reviewed to ensure the full extent of the issues were identified, an appropriate evaluation was performed, a significance level appropriate to the issue was assigned, and appropriate corrective actions were specified, prioritized, and completed. The inspector evaluated the selected smart forms against the program requirements of Procedures STA-421, "Initiation of Smart Forms," Revision 13; STA-422, "Processing Smart Forms," Revision 21; and the CPNPP Cause Analysis Handbook.

b. Findings

No findings of significance were identified.

.8 Occupational Radiation Safety

The inspector evaluated the effectiveness of the licensee's problem identification and resolution process with respect to the following inspection areas:

- Access control to radiologically significant areas (Section 2OS1)
- ALARA planning and controls (Section 2OS2)

No findings of significance were identified.

4OA3 Followup of Events and Notices of Enforcement Discretion (71153)

(Closed) LER 05000446/2008001-00, Reactor Trip due to a Sheared Condenser Vacuum Instrument Sensing Line

On March 16, 2008, Unit 2 tripped from 100 percent power due to failed instrument tubing. This LER was reviewed by the inspectors for compliance and significance and one finding of more than minor significance was identified. See Section 1R12 for more details. This LER is closed.

4OA5 Other Activities

.1 Quarterly Resident Inspector Observations of Security Personnel and Activities

a. Inspection Scope

During the inspection period, the inspectors performed the following observations of security force personnel and activities to ensure that the activities were consistent with licensee's security procedures and regulatory requirements relating to nuclear plant security. These observations took place during both normal and off-normal plant working hours.

These quarterly resident inspector observations of security force personnel and activities did not constitute any additional inspection samples. Rather, they were considered an integral part of the inspector's normal plant status review and inspection activities.

b. Findings

No findings of significance were identified.

.2 Temporary Instruction 2515/166, "Pressurized Water Reactor Containment Sump Blockage," Comanche Peak Steam Electric Station, Units 1 and 2 (Closed)

Temporary Instruction 2515/166 was performed at CPSES Units 1 and 2. The results of the inspection phase of Temporary Instruction 2515/166 for Units 1 and 2 are subsequently documented in this report. The inspection phase of Temporary Instruction 2515/166 for both Units 1 and 2 is closed. The final modification commitments for both containment sumps will be reviewed by NRR.

CPSES requested an extension from the NRC for completion of actions with regards to Generic Letter 2004-02, "Potential Impact of Debris Blockage on Emergency Recirculatoin during Design Basis Accidents at Pressurized-Water Reactors," as a result of analyses, testing, and design evaluations not being fully complete. In June 2008, CPSES will provide an update at the completion of the final analyses.

The inspection team verified the implementation of the plant modifications and procedural changes and identified additionally commitments (or actions to be taken) that were not included in the list of commitments submitted to the NRC. The commitments referenced are in regards to the modeling and analysis of containment conditions with less aluminum content than actual conditions. This variation and actions to address this were not included in the commitments, but are tracked in smart forms which is essentially the CAP.

To complete their analysis, CPSES is waiting on the completion of the upstream and downstream effects analysis and the opportunity to complete their documentation. In summary, 9 of the 22 commitments have been completed, 4 are currently in review, and the remaining 9 are in process.

Per NRR guidance, this temporary instruction is closed for Units 1 and 2.

Listed below are the commitments and actions taken by the licensee and their current status:

	Corrective Action Description	Status
1	Containment condition assessment	Complete
2	Replacement of Radiation Protection Locked High Rad Doors to the SG Compartments	Complete
3	Redesign of the Drain Path to the Inactive Sump	Complete
4	Removal of Radiation Protection Barriers and a Tool Room enclosure	Complete
5	Implementation of Compensatory Actions	Complete
6	Reassessment of Containment Coatings to provide current assessment of unqualified coatings.	Complete
7	Evaluation of the Plant Labeling Program	Complete
8	Upstream Effects Evaluation	Complete
9	Event Characterization	In review, estimated completion date is April 15, 2008
10	Debris Evaluation	In review, estimated completion date is April 30, 2008
11	Debris transport evaluation	In review, estimated completion date is April 15, 2008
12	Summary of Debris Generation and Transport Evaluation	In review, estimated completion date is April 30, 2008
13	Downstream Effects Evaluation, Blockage	In process, estimated completion date is May 30, 2008
14	Downstream Effects Evaluation, Equipment Wear	In process, estimated completion date is May 30, 2008

	Corrective Action Description	Status
15	Downstream Effects Evaluation, Valve Wear	In process, estimated completion date is May 30, 2008
16	Downstream Effects Evaluation, Reactor Vessel	In process, estimated completion date is May 30, 2008
17	Downstream Effects Evaluation, Fuel	In process, estimated completion date is May 30, 2008
18	Downstream Effects Evaluation, Long Term Cooling	In process, estimated completion date is May 30, 2008
19	Calculation of Required and Available NPSH	In process, estimated completion date is May 30, 2008
20	Strainer Replacements (and interrelated modifications)	In process for pump suction pressure instrumentation that needs to be done on Unit 1, estimated completion date is June 30, 2008
21	Strainer Structural Analysis	Complete
22	Potential or Planned Design/Operational/Procedural Changes	In process, estimated completion date is June 30, 2008

.3 Temporary Instruction 2515/172, "Reactor Coolant System Dissimilar Metal Butt Welds," CPSES, Unit 2

Licensee's Implementation of the MRP-139 Baseline Inspections (Section O3.01)

a. MRP-139 baseline inspections:

The inspectors observed performance and reviewed records of structural weld overlays and NDE activities associated with the CPSES Unit 2 pressurizer structural weld overlay mitigation effort. The baseline inspections of the pressurizer dissimilar metal butt welds (DMBWs) were completed during the spring 2008 refueling outage.

To implement the inspections of MRP-139 at CPSES, Procedures STA-760 and "EPG-9.02" have been developed. Procedure STA-760, "RCS Materials Management Program," is a station administrative procedure detailing the administration of the CPSES program plan. Procedure EPG-9.02, "CPSES Alloy 600 Management Program," is an engineering program procedure further amplifying the aspects of the program.

To implement the program, a detailed spread sheet with the frequencies and basis of the required inspections has been prepared. Both procedures and the spread sheet have been included. At present time, the only reactor pressure vessel head inspections that are planned are visual. Should deterioration of the base metal or boric acid crystals be present, a contingency plan has been developed for further evaluation. At the time the plan would be implemented, standards used for evaluation would be established with the contractor.

b. At the present time, the licensee is not planning to take any deviations from the baseline inspection requirements of MRP-139, and all other applicable DMBWs are scheduled in accordance with MRP-139 guidelines.

Volumetric Examinations (Section 03.02)

a. There were no inspections of unmitigated pressurizer DMBWs performed during this outage.

b. Inspectors directly observed and/or reviewed records of NDE performed on pressurizer weld overlays. This effort is documented in Section 1R08 of this inspection report.

For each weld overlay inspected, the licensee submitted and received NRC approval by letter dated February 29, 2008, "Comanche Peak Steam Electric Station Docket NO. 50-446 Relief Request B-4 to the Unit 2 Inservice Inspection (ISI) Program Plan from the 1998 Edition of ASME Code, Section XI, Through 2000 Plan from the 1998 Edition of ASME Code, Section XI, through 2000 Addenda (Interval Start Date – August 033, 2004, Second Interval)."

Inspection coverage met requirements of MRP-139.

No relevant conditions were identified.

c. The certification records of ultrasonic examination personnel used in the examination of the unmitigated hot and cold legs DMBWs and the mitigated pressurizer DMBWs were reviewed. All personnel records showed that they were qualified under the EPRI Performance Demonstration Initiative.

d. No deficiencies were identified during the NDE.

Weld Overlays (Section 03.03)

a. The inspectors observed structural weld overlay welding and reviewed records pertaining to the pressurizer nozzles and determined that welding was performed in accordance with ASME Code Section IX requirements. Welding inspections are documented in Section 1R08 of this inspection report.

b. The licensee submitted and received NRC approval to install weld overlays by letter dated February 29, 2008, “Comanche Peak Steam Electric Station Docket NO. 50-446 Relief Request B-4 to the Unit 2 Inservice Inspection (ISI) Program Plan from the 1998 Edition of ASME Code, Section XI, Through 2000 Plan from the 1998 Edition of ASME Code, Section XI, through 2000 Addenda (Interval Start Date – August 3, 2004, Second Interval).”

c. The qualification records of welders were reviewed and all qualifications were current.

d. No relevant conditions were identified.

Mechanical Stress Improvement (SI) (Section 03.04)

This item is not applicable because the licensee did not employ a mechanical SI process.

During the upcoming CPSES refueling outage there are no SI activities planned. As part of the hot leg and cold leg bare metal visual inspection an assessment is planned to determine the feasibility of future SIs.

There have been no prior SI activities at CPSES, therefore, there are no prior qualification reports available for review

Inservice Inspection Program (Section 03.05)

The licensee MRP-139 inservice inspection program has basically been controlled through the designated procedures and the CAP using smart forms to assure that requirements identified in the MRP-139 guidelines are not inadvertently missed. As such, the MRP-139 inservice inspection program is in-process although it was recognized that this may not be the most appropriate way to control DMBW locations and scheduling requirements. This item will receive further in-office inspection at a later date.

The inspectors’ review determined that the pressurizer weld overlay on the DMBWs nozzles was appropriately categorized in accordance with MRP-139 requirements. The structural weld overlay mitigation effort positioned the pressurizer nozzles in Category A and the categorization of all other DMBWs will receive further in-office inspection at a later date. Additionally, the licensee's MRP-139 Inservice Inspection Program will receive additional in-office review at a later date.

4OA6 Management Meetings

Exit Meeting Summary

On April 11, 2008, the inspector presented the occupational radiation safety inspection results to Mr. R. Flores, Site Vice President, and other members of his staff who acknowledged the findings. The inspector confirmed that proprietary information was not provided or examined during the inspection.

On April 11, 2008, the inspectors presented the results of the inservice inspection to R. Flores, Site Vice President, and other members of licensee. Licensee management acknowledged the inspection findings. The inspectors returned proprietary material examined during the inspection.

On May 8, 2008, the inspector presented the results of the onsite EP program inspection to Mr. D. Kross, Plant Manager, and other members of his staff, who acknowledged the findings. The inspector confirmed that proprietary, sensitive, or personal information examined during the inspection had been returned to the identified custodian.

On June 19, 2008, the inspectors presented the inspection results to Mr. R. Flores, Site Vice President, and other members of the licensee staff. The licensee acknowledged the issues presented. The inspector asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

On July 24, 2008, the inspectors presented the results of the inspection associated with report Section 4OA2.5, review of heat exchanger performance to Mr. T. Hope, Manager, Regulatory Affairs, and other members of the licensee staff who acknowledged the issues presented. The inspectors asked the licensee whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

4OA7 Licensee-Identified Violations

.1 The following violations of very low safety significance (Green) were identified by the licensee and are violations of NRC requirements which meets the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as an NCV:

- Part 50.54(q) of Title 10 of the Code of Federal Regulations requires that licensees maintain and follow an emergency plan that meets the requirements of 10 CFR 50.47(b); 10 CFR 50.47(b)(6) and 50.47(b)(10) require in part that the licensee establish systems for prompt communication to emergency response personnel, and establish a range of protective actions for emergency workers and the public. Contrary to this, on April 14, 2008, the licensee discovered a Gai-tronics speaker in the Unit 2 high pressure turbine area was inoperable because the speaker cone was stuffed with material. The inspector determined this speaker was relied upon during operations to communicate with emergency response personnel and to warn licensee employees to take protective actions during an emergency. This issue was identified in the CAP as Smart Form 2008-001325. The inspector determined that a speaker could be degraded or inoperable for up to 2 years before being discovered through the licensee's routine surveillance and testing program, and that multiple Gai-tronics speakers have been routinely found stuffed with material following unit outages since at least 1999 (per Smart Form SMF-1999-000659), without effective corrective action to prevent the problem. This finding is of very low safety significance because it is a failure to comply with NRC requirements, the finding is associated with planning standards 10 CFR 50.47(b)(6) and 50.47(b)(10), the finding is not associated with the risk-significant aspects of 50.47(b)(10), and the finding is not a functional failure of the planning standards because many of the Gai-tronics speakers remained operable.

- TS 5.7.1 requires each entryway to a high radiation area be barricaded and conspicuously posted as a high radiation area. On April 8, 2008, the licensee identified a high radiation area sign was no longer on the barricade at the entrance to Loop Room 2-01, an area with dose rates greater than 100 millirems per hour. The licensee estimated the sign was down 10-30 minutes. The finding was no greater that low safety significance because: (1) it was not associated with ALARA planning or work controls, (2) there was no overexposure, (3) there was no substantial potential for an overexposure, and (4) the ability to assess dose was not compromised.

.2 The following Severity Level IV violation was identified by the licensee and is a violation of NRC requirements which meets the criteria of Section VI of the NRC Enforcement Policy, NUREG-1600, for being dispositioned as an NCV:

- Part 50.54Q of Title 10 of the Code of Federal Regulations states, in part, that a licensee shall maintain and follow emergency plan that meets the requirements of 10 CFR 50.47(b) and Appendix E to Part 50; 10 CFR Part 50, Appendix E, IV(E)(8) requires a licensee have a near-site emergency operations facility (EOF); the requirements for a licensee with a near-site EOF to have an Alternate EOF are found in NUREG-0696 and 0737. Contrary to this, in 2005 the licensee changed the location of its Alternate EOF from the Hood County Law Enforcement Center to the Daffin Industrial Park without making concurrent changes to its Emergency Plan to describe the Alternate EOF currently in service. The error was not identified for 3 years although the licensee had several opportunities to identify the discrepant condition. This issue was identified in the licensee's CAP as Smart Form 2008 000746. This finding is a Severity Level IV violation because a licensee's failure to maintain accurate information in its emergency plan affects the NRC's ability to perform its regulatory function, the finding is not similar to the Severity Level I, II, or III examples found in the Enforcement Policy, and the Daffin Industrial Park Alternate EOF meets the requirements of 10 CFR Part 50 Appendix E, IV (E)(8), NUREG 0696 and 0737.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION
KEY POINTS OF CONTACT

Licensee

M. Blevins, Executive Vice President and Chief Nuclear Officer
S. Bradley, Health Physics Supervisor, Radiation and Industrial Safety
M. Bozeman, Supervisor, Emergency Planning
A. Cares, Radiation Protection ALARA Coordinator
G. Casperson, Interim Manager, Training
E. Dalasta, Shaw Engineering
D. Davis, Director, Plant Improvement
E. Dyes, Senior Nuclear Auditor
R. Flores, Site Vice President
D. Goodwin, Director, Operations
R. Green, Alloy 600 Programs
S. Harvey, Manager, Shift Operations
A. Heap, System Engineer
N. Hood, Alliance Manager
T. Hope, Manager, Regulatory Performance
G. Johnson, Senior Nuclear Auditor
R. Kidwell, Senior Licensing Analyst, Regulatory Affairs
W. Knowles, Radiation Protection Supervisor, Radiation and Industrial Safety
G. Krishnan, Process Engineering & Programs Manager
D. Kross, Plant Manager
C. LaSoya, Wesdyne Inservice Inspection Project Manager
F. Madden, Director, Regulatory Affairs
B. Mays, Director, Engineering Support
E. Meaders, Manager, Outage
J. Mercer, Maintenance Rule Coordinator
J. Meyer, Manager, Nuclear Technical Support
C. Miller, Reliability Programs Supervisor
J. Mitchell, Utility Level III Eddy Current Testing
D. Moore, Shaw Engineering Director, Engineering
W. Morrison, Interim Director, Nuclear Maintenance
D. O'Connor, Radiation Protection Supervisor, Radiation and Industrial Safety
P. Passalugo, Inservice Inspection Programs Owner
B. Patrick, Radiation Protection Manager, Radiation and Industrial Safety
J. Patton, Supervisor, Quality Assurance
M. Pearson, Quality Assurance Manager
W. Reppa, Manager, System Engineering
A. Singh, Shaw Engineering Program Fire Protection
J. Skelton, System Engineer
D. Wilder, Manager, Security, Emergency Planning, and Environmental

Nuclear Regulatory Commission

D. Allen, Senior Resident Inspector
B. Tindell, Resident Inspector

LIST OF ITEMS OPENED, CLOSED AND DISCUSSED

Opened

None

Opened and Closed

05000446/2008003-01	NCV	Inadequate Fire Protection Compensatory Actions During Refueling Outage (Section 1R05)
05000446/2008003-02	NCV	Failure to Expeditiously Restore Fire Hose Stations in Containment to Service (Section 1R05)
05000446/2008003-03	FIN	Instrument Tubing Failure Causes Plant Trip (Section 1R12)
05000445/2008003-04 05000446/2008003-04	NCV	Failure to Barricade And Post A High Radiation Area (Section 2OS1)
05000446/2008003-05	NCV	Failure to Ensure a Flow Path for Containment Spray Pumps (Section 4OA2)

Closed

05000446/2008001-00	LER	Reactor Trip due to a Sheared Condenser Vacuum Instrument Sensing Line

Discussed

None

LIST OF DOCUMENTS REVIEWED

The following is a partial list of documents reviewed during the inspection. Inclusion on this list does not imply that the NRC inspector reviewed the documents in their entirety, but rather that selected sections or portions of the documents were evaluated as part of the overall inspection effort. Inclusion of a document on this list does not imply NRC acceptance of the document or any part of it, unless this is stated in the body of the inspection report.

Section 1R05: Fire Protection

Smart Forms

SMF-2008-001686-00   SMF-2008-001831-00

Procedures

NUMBER	TITLE	REVISION
Fire Preplan FPI-204B	Unit 2 Containment Building Elev. 905’-0	1
Fire Preplan Instruction Procedure (FPI), FPI-501	Electrical and Control Building Elevation 778’-0” Fire Zones 149 and 150	4

Work Order

395320

Drawings

NUMBER	TITLE	REVISION
M2-0225	Flow Diagram Containment Building Unit 2 Fire Protection	CP-6

Other

Clearance 08-0326, U2 CNTMT FP HDR IRC ISOL VLV
Impairment 9598
FDA-1999-002438-01-00
CPSES Fire Protection Report

Section 1R08: Inservice Inspection Activities

Procedures

NUMBER	TITLE	REVISION
STA-422	Processing SmartForms	21
STA-421	Initiation of SmartForms	13
STA-737	Boric Acid Corrosion Detection and Evaluation	4
WCI-607	Fluid Leak Management Process	1
GQP 9.7	Liquid Penetrant Examination and Acceptance Standards for Welds, Base Materials and Cladding	11
TX-ISI-11	Liquid Penetrant Examination for Comanche Peak Steam Electric Station	11
TX-ISI-302	Ultrasonic Examination of Austenetic Piping Welds	3
WLD-105	Welding Material Storage and Control	6

WLD-103	Welder Performance Qualifications	6
WLD-101	Welding Program Requirements	6
WLD-106	ASME/ANSI General Welding Requirements	2
EPG-9.02	CPSES Alloy 600 Management Program	0
WPT-17126	2RF10 Steam Generator Final Degradation Assessment	February 2 9,2008
WPT-17125	2RF10 Steam Generator Video Inspection Plan	February 29, 2008
WPT-16670	Steam Generator Operational Assessment for Cycles 9 and 10	June 13, 2005
STA-760	RCS Materials Management Program	February 9, 2006

Smart Forms (Corrective Action)

SMF-2006-003535-00	SMF-2007-000799-00	SMF-2006-003943-00
SMF-2006-003669-00	SMF-2007-000075-00	SMF-2007-000387-00
SMF-2008-000477-00	SMF-2007-001737-00	SMF-2007-001814-00
SMF-2007-001831-00	SMF-2007-001861-00	SMF-2007-002955-00
SMF-2007-002296-00	SMF-2007-002414-00	SMF-2006-002789-00
SMF-2007-002743-00		

Drawings

NUMBER	TITLE	REVISION
10034D44	Comanche Peak Unit 2 Pressurizer Safety Nozzle SWOL Field Implementation (Safety A)	0
10034D42	Comanche Peak Unit 2 Pressurizer Spray Nozzle SWOL Field Implementation	0
10034D41	Comanche Peak Unit 2 Pressurizer Surge Nozzle SWOL Field Implementation	0

Miscellaneous

NUMBER	TITLE	REVISION
TXX-07008	Submittal of Unit 2 2RF09 Summary Report	January 24 , 2007
	Luminant CPNPP Unit 2 Analysis Guidelines	1
	Reactor Vessel Closure Head Visual Examination Plan	3
	RCS Pressure Boundary Dissimilar Metal Weld Visual Examination Plan	2
	Reactor Vessel Closure Head Visual Examination Plan	3
	Reactor Vessel Lower Head Visual Examination Plan	2
CPSES-200701172	Technical Justification for Deviation from EPRI MRP-139 Inspection Requirements for Alloy 82/182 Pressurizer Butt Welds for Comanche Peak Steam Electric Station Unit 2	July 12, 2007
WPS 3-8/52-TB MC-GTAW-N638	Welding Procedure Supplement (Project No. 900813)	7
TCX-A-108	CPNPP Unit 2 Analysis Guidelines (Steam Generator Eddy Current Inspection Multi-Frequency Eddy Current Parameters)	1
TCX-B-108	CPNPP Unit 2 Analysis Guidelines (Steam Generator Eddy Current Inspection Multi-Frequency Eddy Current Parameters)	1
TCX-C-108	CPNPP Unit 2 Analysis Guidelines (Steam Generator Eddy Current Inspection Multi-Frequency Eddy Current Parameters)	
TCX-D-108	CPNPP Unit 2 Analysis Guidelines (Steam Generator Eddy Current Inspection Multi-Frequency Eddy Current Parameters)	1
TCX-01-108	610 Bobbin	0
TCX-02-108	590 Bobbin	1
TCX-03-108	610 3 Coil plus point	0
TCX-04-108	580 MB UB plus point	0

NUMBER	TITLE	REVISION
TCX-05-108	580 UB plus point	0
GQP 9.7	Procedure Supplement PS-03	11

Section 1R12: Maintenance Effectiveness

Smart Forms

SMF-2008-000583-00	SMF-2008-000795-00	EVAL-2008-000795-04-00

Other

NUMBER	TITLE	REVISION
CPSES-I-1018	Specification Installation of Piping/Tubing and Instrumentation	18

Section 1R13: Maintenance Risk Assessments and Emergent Work Control

Procedures

NUMBER	TITLE	REVISION
CP7970-036	Routine Protective Relay Maintenance	4
STA-629	Switchyard Control	6

Section 1R15: Operability Evaluations

Smart Forms/Evaluations

SMF-2008-001055-00 SMF-2008-001280-00	SMF-2008-001372-00	EVAL-2008-001372-01-00

Procedures

NUMBER	TITLE	REVISION
STA-706	Transient and Fatigue Cycle Monitoring	1
SOP-102B	Residual Heat Removal System	11
OPT-203B	Residual Heat Removal System	11

INC-7326A	Analog Channel Operational Test and Channel Calibration Steam Generator Narrow Range Level, Loop 2, Protection Set 1, Channel 0529	6
DBD-ME-260	Residual Heat Removal System	20
DBD-ME-235	Spent Fuel Pool Cooling and Cleanup System,"	17

Other

NUMBER	TITLE	REVISION
Vendor Technical Manual CP-0012-001	Containment Spray Pumps	25

Section 1R18: Plant Modifications

Other

FDA-2001-000461-02-01

Section 1R19: Postmaintenance Testing

Smart Form

SMF-2006-003470-00

Work Orders

3443005	408068	408083

Section 1R20: Outage Activities

Work Order

408442

Section 1R22: Surveillance Testing

Smart Forms

SMF-2008-001287-00	SMF-2008-001728-00

Procedures

NUMBER	TITLE	REVISION
ETP-215B	Service Water Pump Test	3

Work Orders

396714	407658

Other

NUMBER	TITLE	REVISION
Clearance 08-0447-A	SIP 2-02 REWORK IN 2RF10	

Section 1EP3: Emergency Response Organization Augmentation Testing

NUMBER	TITLE	REVISION
EPP-202	Emergency Communications Systems and Equipment	7
EP Staff Guideline 8	Emergency Response Organization Roster Updates	10

Evaluation Reports for Quarterly Surveillances Conducted

2006 - September 27, December 18
2007 - February 18, February 24, June 21, June 23, September 21, and December 4
2008 - March 24

Section 1EP5: Correction of Emergency Preparedness Weaknesses and Deficiencies

NUMBER	TITLE	REVISION
EPP-100	Maintaining Emergency Preparedness	6
EPP-121	Reentry, Recovery, and Closeout	9
STA-421	Initiation of Smart Forms	13
STA-422	Processing Smart Forms	21
STA-424	Self Assessment and Benchmarking Programs	4
STA-430	Emergency Planning Review Boards	0
STA-662	Administrative Control of the Siren System	0
NQA-3.02	Audit and Surveillance Programs	3
EP Staff Guideline 6	Resolving Player Comments	3
EP Staff Guideline 18	EP Self Assessment Program	1
EP Staff Guideline 22	Emergency Preparedness Staff Training	0

MSE-PO-9328	Emergency Alerting System Inspection	4 June 30, 2003
LPEP	Assessment Plans, Core Process: Loss Prevention, Sub-Process: Emergency Preparedness	3 August 1, 2006
Nuclear Policy Statement 124	Self Assessment Guiding Principles	2
	CPNPP Cause Analysis Handbook	
ETP-908	Sounded Powered Phones and Evacuation Alarm System Periodic Testing	7
EVAL-2008-001	CPSES Nuclear Overview Department Evaluation Report: Emergency Preparedness	March 30, 2008
EVAL-2008-003	Worksheet 10, Emergency Preparedness	April 9, 2008
Self Assessment SA-2006-001	2006 Self-Assessment of CPSES Emergency Response Organization	October 2, 2007
Self Assessment SA-2006-038	Self Assessment of the 2006 Operations Control Room Mini-Drills for NRC Drill and Exercise Performance Indicator Credit	February 7, 2007
Self Assessment SA-2007-026	2007 Self Assessment of CPSES Emergency Response Organization	
Self Assessment SA-2008-004, Worksheet 1	Drill Results for the January 23, 2008, Blue Team Exercise	May 1, 2008
Self Assessment SA-2008-014	Emergency Planning Training	
Shift Operations Desktop Instruction 22	CareFlite/LifeStar 5 Request from CPNPP	3
Position Assistance Document	EOF Dose Assessor	June 6, 2000
CPSES Nuclear Overview Department Evaluation Worksheet, EVAL-2006-002	Emergency Preparedness	June 14, 2006

CPSES Nuclear Overview Department Evaluation Worksheet, EVAL-2006-012	Emergency Preparedness	December 18, 2006
CPSES Nuclear Overview Department Evaluation Worksheet, EVAL-2007-001	Emergency Preparedness	July 19, 2007
CPSES Nuclear Overview Department Evaluation Worksheet, EVAL-2007-006	Emergency Preparedness	January 10, 2008
CPSES Nuclear Overview Department Evaluation Worksheet, EVAL-2008-003	Emergency Preparedness	April 9, 2008
Preventive Maintenance Work Order PM318350	Site Evacuation Alarm Testing	
EP Bulletin 2008-008		May 7, 2008

Quarterly CPSES Program Status Reports:
First Quarter 2007, Second Quarter 2007, Third Quarter 2007, Fourth Quarter 2007

Emergency Planning Bulletin (Observations from the 2006 Control Room Mini-Drills)

Emergency Planning Issue, EPI-INT-2004-003891-01-00

Evaluation Reports for Drills and Exercises Conducted:

2006 - August 9, August 28, September 13, September 26, October 26, November 16, November 29, and December 20

2007 - January 29, February 27, March 29, April 25, May 25, June 14, June 28, July 25, July 30, August 29, September 24, September 25, September 26, October 31, November 6, November 8, November 29, and December 5

2008 - January 23, January 30, February 27, March 25, and April 30

Smart Forms

2006 - 003188	2007 - 002374	2008 - 000987
2006 - 003286	2007 - 002682	2008 - 001325
2007 - 000432	2007 - 002971	2008 - 001611
2007 - 000583	2008 - 000039	2008 - 001617
2007 - 001132	2008 - 000574	2008 - 001626
2007 - 001459	2008 - 000637	2008 - 001634
2007 - 001542	2008 - 000746	
2007 - 001919	2008 - 000772	

Section 1EP6: Drill Evaluation

Other:

Staff Guideline 020, Attachment 1

Section 2OS1: Access Controls to Radiologically Significant Areas

Corrective Action Documents (Smart Forms)

2008-000420	2008-000987	2008-001042, 2008-001148
2008-000949	2008-001021	
2008-000959		

Audits and Self-Assessments

Nuclear Overview Department Evaluation EVAL-2007- 008, “Radiation Protection Audit”

Radiation Work Permits

NUMBER	TITLE	REVISION
2008-2212	System Breach Maintenance Activities in 2-154A & 2-154D	
2008-2400	Nozzle Dam Installation and Removal Activities	
2008-2407	Pressurizer 905’ Weld Overlay Work Activities	

Procedures

NUMBER	TITLE	REVISION
RPI-507	Internal Dose Calculation	4
RPI-602	Radiological Surveillance and Posting	33

STA-650	General Health Physics Plan	6
STA-660	Control of High Radiation Areas	12

Section 2OS2: ALARA Planning and Controls

Procedures

NUMBER	TITLE	REVISION
STA-656	Radiation Work Control	13

Section 4OA1: Performance Indicator Verification

NUMBER	TITLE	REVISION
EPP-109	Duties and Responsibilities of the Emergency Coordinator/Recovery Manager	12
EPP-201	Assessment of Emergency Action Levels, Emergency Classification, and Plan Activation	11
EPP-203	Notifications	14
EPP-304	Protective Action Recommendations	18
	Offsite Notification Form	10

Other

Comanche Peak Steam Electric Station Emergency Plan, Revision 33

Shift Operations Desktop Instruction NO. 012, Revision 7, 11-4-04, “Operations Department - NRC ROP Performance Indicator: RCS Identified Leakage”

CPSES Operations Testing Manual, Procedure OPT-303, Revision 12, 2-21-07, “Reactor Coolant System Water Inventory”

Section 4OA2: Problem Identification and Resolution

Smart Forms

SMF-2005-004423-00	SMF-2008-001060-00	SMF-2008-001548-00

Other

San Onofre Nuclear Generating Station – NRC Special Inspection Report 2007013

Section 4OA3: Followup of Events and Notices of Enforcement Discretion

Other

LER 05000446/2008001-00, Reactor Trip due to a Sheared Condenser Vacuum Instrument Sensing Line

LIST OF ACRONYMS

ALARA	as low as reasonably achievable
BACC	boric acid corrosion control
CAP	corrective action program
CPSES	Comanche Peak Steam Electric Station
DMBW	dissimilar metal butt welds
EOF	emergency operations facility
EPRI	Electric Power Research Institute
FDA	final design authorization
NCV	noncited violation
NDE	nondestructive examination
OPT	operations test procedure
RCS	reactor coolant system
SG	steam generator
SI	stress improvement
SMF	smart form
SOP	system operating procedure
SSCs	structures, systems, and components
TS	Technical Specification
TTS	top tube sheet
UFSAR	Updated Final Safety Analysis