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

September 12, 2005

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

SUBJECT: TXU GENERATION COMPANY LP COMANCHE PEAK STEAM ELECTRIC STATION UNITS 1 AND 2 -- NRC PROBLEM IDENTIFICATION AND RESOLUTION INSPECTION REPORT 05000445/2005009 and 05000446/2005009

Dear Mr. Blevins:

On July 29, 2005, the Nuclear Regulatory Commission (NRC) completed a team inspection at your Comanche Peak Steam Electric Station. The enclosed report presents the results of this inspection. On July 29, 2005, we discussed the inspection results with you and other members of your staff.

This inspection examined activities conducted under your license as they relate to the identification and resolution of problems, compliance with the Commission's rules and regulations and with the conditions of your license. The team reviewed approximately 150 risk important issues, apparent and root cause analyses, and other related documents. In addition, the team reviewed cross-cutting aspects of NRC and licensee-identified findings and interviewed personnel regarding the safety-conscious work environment.

On the basis of the sample selected for review, the team concluded that your processes to identify, prioritize, evaluate, and correct problems were generally effective; thresholds for identifying issues remained appropriately low and, in most cases, corrective actions were adequate to address conditions adverse to quality. The team concluded that a positive safety-conscious work environment existed at Comanche Peak Steam Electric Station.

The report documents one finding concerning inadequate corrective actions to address longstanding Agastat relay issues which resulted in the inoperability of a 6.9 kV safeguards bus. This finding has potential safety significance greater than very low significance. This finding did not present an immediate safety concern because the licensee has replaced, at the time of the exit meeting, 192 of 210 safety related relays in the plant. The team reviewed the function and compensatory measures in place for those relays that had not been replaced and deemed them to be adequate until long-term corrective measures have been implemented. In addition, the report also documents two findings that were evaluated under the risk significance determination process as having very low safety significance (Green). The NRC determined that a violation was associated with one of these findings. The violation is being treated as a noncited violation because it was of very low safety significance and because it has been entered into your corrective action program consistent with Section VI.A of the Enforcement Policy. If you contest the violation or the significance of the noncited violation, you should provide a response within 30 days of the date of the inspection report, with the basis for your denial, to the U.S. Nuclear Regulator Commission, ATTN: Document Control Desk, Washington, DC 20555-0001, with copies to the Regional Administrator, U.S. Nuclear Regulatory Commission, Region IV, 611 Ryan Plaza Drive, Suite 400, Arlington, Texas 76011; the Director, Office of Enforcement, U.S. Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the Comanche Peak Steam Electric Station.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response 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). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

//RA//

Linda Joy Smith, Chief
Engineering Branch 2
Division of Reactor Safety

Dockets: 50-445
50-446

Licenses: NPF-87
NPF-89

Enclosure:
Inspection Report 05000445/2005009; 05000446/2005009
w/Attachment: Supplemental Information

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

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

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

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

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

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

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

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

Electronic distribution by RIV:
Regional Administrator **(BSM1)**
DRP Director **(ATH)**
DRS Director **(DDC)**
DRS Deputy Director **(KMK)**
Senior Resident Inspector **(DBA)**
Branch Chief, DRP/A **(CEJ)**
Senior Project Engineer, DRP/A **(TRF)**
Team Leader, DRP/TSS **(RLN1)**
RITS Coordinator **(KEG)**

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

SISP Review Completed: Yes ADAMS: ■ Yes ☐ No Initials: Ljs
■ Publicly Available ☐ Non-Publicly Available ☐ Sensitive ■ Non-Sensitive

R:\REACTORS_CP\2005\CP2005009RP-MSP.wpd

DRP/B:SRI	DRP/A:SRI	DRS/EB2:RI	DRS/TSS:RI	DRP/A:RI
MSPeck	DAllen	BTindell	JGroom	ABarrett
	/RA/ E	/RA/ E	/RA/ E	/RA/ E
9/ /05	9/ 7 /05	9/ 7 /05	9/ 7 /05	9/ 7 /05

DRS/EB2:RI	C:EB2	DRP/A	C:EB2	
DLivermore	LJSmith	CEJohnson	LJSmith	
/RA/ E	/RA/	/RA/	/RA/	
9/ 7 /05	9/ 9 /05	9/ 12 /05	9/ 12 /05	

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

ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Docket:	50-445, 50-446
License:	NPF-87, NPF-89
Report:	05000445/2005009 and 05000446/2005009
Licensee:	TXU Power
Facility:	Comanche Peak Steam Electric Station, Units 1 and 2
Location:	FM-56, Glen Rose, Texas
Dates:	July 5 through July 29, 2005
Inspectors:	M. Peck, Senior Resident Inspector D. Allen, Senior Resident Inspector B. Tindell, Reactor Inspector J. Groom, Reactor Inspector A. Barrett, Resident Inspector D. Livermore, Reactor Inspector
Approved By:	L. Smith, Chief Engineering Branch 2 Division of Reactor Safety

SUMMARY OF FINDINGS

IR 05000445/2005009 and 05000446/2005009; 7/05/05 - 7/29/05; Comanche Peak Steam Electric Station, Units 1 & 2; Biennial baseline inspection of the identification and resolution of problems, prioritization and evaluation of issues, and effectiveness of corrective actions.

This report documents the biennial assessment of identification and resolution of problems conducted by two senior resident inspectors, one resident inspector, and three reactor inspectors. Three findings were identified during the inspection: two Green findings of very low safety significance, one of which was classified as a noncited violation, and one finding, which was unresolved for pending completion of inspection necessary to determine the significance. The findings were evaluated using the significance determination process. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609, “Significance Determination Process.” Findings for which the significance 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 3, dated July 2000.

A. Identification and Resolution of Problems

- The team reviewed 151 risk significant issues, apparent and root cause analyses, and other related documents, to assess the effectiveness of the licensee's problem identification and resolution processes and systems. The team concluded that the licensee's management systems were generally effective. However, the team identified poor evaluation, prioritization, and corrective actions associated with longstanding safety related Agastat relay problems. A similar performance concern was documented in the last problem identification and resolution assessment. The team also concluded that licensee corrective actions taken to address an historical adverse trend in human performance have not been effective.

  The team concluded that the licensee established a safety-conscious work environment at Comanche Peak Steam Electric Station. The team determined that employees and contractors felt free to enter issues into the corrective action program and raise safety concerns to their supervision, to the employees concern program, and to the NRC. All plant personnel, interviewed by the team, stated that potential safety issues were addressed by the licensee. However, the licensee had identified long-term organizational effectiveness issues within the operations department, which continued to challenge the safety-conscious work environment for shift operations personnel. The team concluded that licensee's past actions to improve operations department organizational effectiveness had not been fully effective.

B. NRC-Identified and Self-Revealing Findings

Cornerstone: Mitigating System

- (TBD) The team identified a finding and an unresolved item related to Technical Specification 3.8.1 and 10 CFR 50, Appendix B, Corrective Action, after neither the alternate nor emergency power was supplied to a 6.9 kV safeguards bus within the time assumed in the accident analysis. On October 19, 2004, an unplanned loss of the preferred offsite power caused the Unit 2, Train B, 6.9 kV safeguards bus to deenergize. A degraded Agastat relay delayed the normal power supply breaker from opening for 30 seconds. Both the emergency diesel generator and the alternate offsite AC power supplies were prevented from powering the bus due to a breaker interlock with the normal supply. This delay rendered both the emergency diesel generator and the alternate offsite AC power supplies inoperable. The 30 second delay in providing power to the safeguards bus would have resulted in the station not meeting the 10 CFR 50, Appendix K, “Emergency Core Cooling System Evaluation Models Acceptance Criteria,” for that equipment train if a design bases loss of coolant accident had occurred. The licensee had a previous opportunity to correct the degraded Agastat relay issues. On October 7, 2002, the emergency diesel generator unexpectedly started due to a degraded Agastat relay. The licensee concluded that the failure could have been caused by aging and formed a corrective action plan to replace all safety related Agastat relays that have been in service for greater than the licensee established 12-year lifetime. The relay that failed in October 2004 was 16 years old.

This finding adversely impacted the reliability of emergency power to mitigating systems. This finding is greater than minor because the reactor mitigating systems cornerstone and the equipment performance attribute to prevent core damage were affected. The licensee's failure to identify the cause and implement corrective actions to prevent repetitive failures of safety related Agastat relays was a performance deficiency. The inspectors determined that the finding had potential safety significance greater than very low because the condition represents an actual loss of a safety function for a single train greater that Technical Specification allowed outage time. This is an unresolved item pending completion of inspection required to bound the performance deficiency and determine the significance (Section 4OA2).

- (Green) A noncited violation of Technical Specification 3.3.2 was identified after the licensee failed to place an inoperable containment pressure channel isolation function in trip within 6 hours. While operating in Mode 1 on August 5, 2004, a control room containment pressure channel deviation alarm occurred. The licensee failed to recognize that the channel was inoperable. On August 6, 2004, the licensee identified that a grounded transmitter shield wire had caused the channel deviation alarm. Using a Channel Statistical Allowance analysis the licensee determined that the pressure channel became inoperable at the time of the alarm. The channel was inoperable for a total of 31 hours.

  This finding is greater than minor because, if left uncorrected, the failure to recognize inoperable mitigating systems instrumentation would become a more significant safety concern. This finding is only of very low safety significance because the condition was not a design or qualification deficiency confirmed to result in loss of function per Generic Letter 91-18; did not result in an actual loss of safety function of a system; did not increase the likelihood of a fire; and did not screen as potentially risk significant due to a seismic, flooding, or severe weather initiating event. This finding involved the failure of operations personnel to implement a Technical Specification action requirement and was associated with the crosscutting area of human performance. The licensee entered this condition into their corrective action program (SMF-2005-002752 and SMF-2005-003157) (Section 4OA2).

Cornerstone: Barrier Integrity

- (Green) A self-revealing finding associated with inadequate postmodification testing of the Unit 2 refueling machine festoon was identified. The festoon failed during refueling operations, resulting in the introduction of loose parts into the lower internals storage area of the refueling cavity.

  The licensee installed the festoon during Refueling Outage 5 to replace the older take-up reel on the refueling machine, however the festoon rails were not adequate to allow bridge travel to the mechanical stops. When the bridge was operated beyond the length of the festoon rails, the cable trolleys became compacted and enough stress was placed on the tow rods to break the welds of the base plates holding the rods in place. The postmodification test only verified festoon clearance for bridge travel to the electrical bridge stops.

  Failure of the licensee to perform a postmodification test that demonstrated that the festoon would perform satisfactorily in service was a performance deficiency. This finding is more than minor because the barrier integrity cornerstone objective to provide reasonable assurance that physical barriers (including the fuel clad) to protect the public from radionuclide releases caused by accidents or events is affected. The introduction of loose parts into the reactor cavity during refueling is associated with the fuel clad attributes of human performance and foreign material exclusion. The team analyzed the finding using Appendix G, “Shutdown Operations,” of Manual Chapter 0609, “Significance Determination Process,” Attachment 1, Checklist 4. The team concluded that the finding did not require a quantitative assessment because the condition does not increase the likelihood of a loss of reactor coolant system inventory or loss of reactor coolant system level instrumentation, does not degrade the licensee's ability to terminate a leak path or add reactor coolant system inventory when needed, and does not degrade the ability to recover decay heat removal once it is lost. Since a quantitative assessment was not required, the finding was of very low safety significance (Section 4OA2).

C. Licensee-Identified Violations

None.

REPORT DETAILS

4 OTHER ACTIVITIES (OA)

4OA2 Identification and Resolution of Problems (71152)

An inspection team completed the biennial assessment of the effectiveness of the TXU Generation Company's management systems to identify and resolve problems at the Comanche Peak Steam Electric Station (CPSES). The assessment focused on the twenty-eight month period since the previous NRC biennial assessment (February 1, 2003 through May 1, 2005). The team performed the assessment based on an independent inspection of the licensee's evaluation and disposition of 151 risk significant issues that occurred during the assessment period. The inspection scope included 11 NRC findings; 19 licensee event reports; 76 significant conditions adverse to quality; independent and external audits and assessment reports; radiation protection and security logs; items generated or addressed by the plant safety review committees; adverse trends in configuration control, human performance, and corrective action programs; and maintenance preventable functional failures that occurred during the period. Performance deficiencies that occurred during the 28 month period since the previous assessment will be referred to as current.

The team expanded the inspection scope to include the past five years for selected longstanding risk significant issues with performance deficiencies that occurred prior to the assessment period. The team used the expanded inspection scope to identify historical performance trends. Performance deficiencies which occurred prior to the current assessment period, will be referred to as historical. The assessment samples included issues representing all seven safety cornerstones.

a. Effectiveness of Problem Identification

(1) Inspection Scope

The inspectors reviewed 151 risk significant issues to determine if the licensee properly identified, characterized, and entered plant problems into the corrective action program. The team performed selected equipment walkdowns, reviewed operator, radiation protection, and security logs, work orders, plant tracking logs, and action requests for equipment deficiencies to verify that problems and issues were captured in the corrective action program (CAP). The team reviewed the audits, self-assessments, and system health reports listed in the attachment. The team conducted interviews of station personnel and evaluated corrective action documentation to determine if the licensee established the proper threshold for identifying and documenting problems in the CAP. In addition, the team reviewed the licensee's evaluation of selected industry experience information, including operating event reports, NRC Generic Letters, Bulletins, Information Notices, and generic vendor notifications to assess if issues applicable to CPSES were appropriately addressed.

(2) Assessment

The team concluded that the licensee effectively identified, characterized, and entered problems at CPSES. The licensee established a low threshold for entering items into the CAP. The licensee entered over 6,000 issues into the CAP during the 28 month assessment period. The team concluded that all of the licensee personnel interviewed clearly understood the licensee's expectation for CAP thresholds. The current team identified three examples of poor problem identification that occurred during the assessment period:

Example 1: Loose Parts in the Reactor Cavity During Refueling Operations

During prior operation with the electrical stops bypassed, the licensee had several opportunities to identify problems with the refueling machine festoon. The refueling machine festoon lacked sufficient length to accommodate full refueling bridge travel beyond the electrical stops to the mechanical stops. Damage to the festoon tow bar and brace occurred during fuel handling operations beyond the electrical stops. Some of these damaged, loose parts dropped into the reactor cavity. This issue was discussed as a finding in section 4OA2e(2)(ii) of this report.

Example 2: Relief Request Issues

The NRC identified that the licensee failed to fully comply with an NRC-approved relief request from Section XI of the ASME Code. The licensee had not implemented portions of the alternative process requiring periodic reassessment as committed in the relief request. The licensee should have identified a formal method to perform and document this assessment (NRC NCV 05000445; 05000446/2004008-002).

Example 3: Failure to Promptly Initiate a SmartForm (SMF) Following a Reactivity Event

A unit supervisor did not promptly document a reactivity event in the CAP. The unit supervisor defeated a T_{avg} loop rod control input which resulted in unplanned control rod movement. The Unit 2 supervisor's action was not consistent with operations department expectations and represented a human performance issue. The licensee entered the condition into the CAP (SMF-2005-002499) fours days after the event. The inspectors concluded that this condition was a minor finding.

b. Prioritization and Evaluation of Issues

(1) Inspection Scope

The team reviewed 76 Category 1 and 2 SmartForm reports (significant conditions adverse to quality) and 13 root cause evaluations to assess the licensee's ability to evaluate adverse conditions, determine the full extent of conditions, generic implications, common causes, and to properly prioritize issues. The team also observed management oversight of significant conditions adverse to quality at CAP meetings and reviewed operability evaluations. The team reviewed licensee evaluations of selected industry operating experience information, including NRC Information Notices and industry provided information, to assess whether issues applicable to CPSES were appropriately addressed. In addition, the team performed a five year historical review of SmartForm reports addressing operability evaluations, an adverse trend in human performance, and Agastat relay problems to determine if the licensee had appropriately addressed longstanding issues.

(2) Assessment

The team concluded that the licensee's problem prioritization and evaluation processes were effective and conducted in accordance with CAP and NRC requirements. The licensee was generally self-critical and thorough in evaluating the causes of significant conditions adverse to quality for most of the problems sampled by the team. The team identified five examples of inadequate problem prioritization and evaluation.

Example 1: Agastat Relay Issues

The team identified that the licensee's prioritization and evaluation of the longstanding Agastat relay issues were inadequate. The team assessed both the licensee's current and historical management effectiveness. This issue was discussed as a finding in section 4OA2e(2)(i) of this report.

Untimely Corrective Action Plans - Historical

As discussed in NRC Problem Identification and Resolution Inspection Report 05000445/2003-006; 05000446/2003-006, the 2003 team noted that Smart Form 2002-003391 was still open (in the planning stage) and that many corrective actions were not yet scheduled. The potential aging issue was initially identified on April 18, 2002, in Smart Form 2002-001504, however, a root-cause analysis was not developed until the unexpected EDG start occurred on October 7, 2002, and an operational evaluation was not developed until a low grid response time was revealed during testing on the 480V buses on October 16, 2002. Based on this information, the 2003 team concluded that the licensee's corrective actions, while adequate, were not timely.

Inadequate Extent of Condition - Historical

As discussed in NRC Problem Identification and Resolution Inspection Report 05000445/2003-006; 05000446/2003-006, the licensee determined that there was no program to periodically replace Agastat relays prior to them exceeding their life expectancy. As a result of this determination, the licensee developed preventative maintenance tasks to periodically replace these relays (at this time on a manufacturer recommended 10-year life expectancy basis) and any other Agastat relays involved with 6.9kV bus transfers before their operating life was exceeded. The 2003 team noted that the licensee did not expand these corrective actions to include any other systems that used these relays.

Inadequate Assessment of Setpoint Drift - Current

As discussed in NRC Problem Identification and Resolution Inspection Report 05000445/2003-006; 05000446/2003-00, the licensee identified the main effect of aging on Agastat relays was an increase in setpoint drift with a maximum drift of ± 18 percent. The licensee determined that a setpoint drift of ± 18 percent would not prevent the relays from completing their intended tasks and the 2003 team agreed. However, an Agastat relay that failed in October 2004 exhibited setpoint drift in excess of the ± 18 percent maximum identified by the licensee. The relay was observed to operate in 30 seconds instead of the required .5 seconds and resulted in the relay not completing its intended task. The team noted the licensee's inaccurate assessment of setpoint drift as an example of inadequate problem evaluation.

Ineffective Failure Analysis for October 7, 2002 Event - Current

As discussed in NRC Problem Identification and Resolution Inspection Report 05000445/2003-006; 05000446/2003-006, an emergency diesel generator unexpectedly started due to a faulty Agastat relay (SMF-2002-003391). The licensee determined that the relay failures could have been caused by aging and developed plans to replace the relays. However, the team noted that the failed relay was discarded and the exact failure mechanism was not determined. A subsequent analysis of a failed Agastat relay in October 2004 revealed the presence of foreign material within the relay timing mechanism. The presence of foreign material suggests flaws in the licensee's determination that aging was the failure mechanism for previous relays and was identified by the team as an example of inadequate problem evaluation.

<u>Example 2</u>: Poor Prioritization for Degraded Equipment

The licensee did not effectively ensure timely prioritization and evaluation of all degraded equipment. The team reviewed four examples of longstanding degraded equipment issues which were not corrected and/or the corrective action delay was not justified. The team used guidance provided in Generic Letter 91-18, "Resolution of Degraded and Nonconforming Conditions" as the bases for acceptability. Generic Letter 91-18 stated: "If the licensee does not resolve the degraded or nonconforming condition at the first available opportunity or does not appropriately justify a longer completion schedule, the staff would conclude that corrective action has not been timely and would consider taking enforcement action." Three of the degraded conditions had not been corrected at the time of this inspection. While all of the degraded equipment remained operable, the licensee's problem prioritization process was not consistent with Generic Letter 91-18. The inspectors concluded that each example of longstanding degraded equipment issues was minor.

– Failure to Meet the Diesel Generator Room Temperature Licensing Bases - Current

  During 1999, the licensee identified that the licensing bases requirement to maintain minimum diesel generator room temperatures with the heating and ventilation system could not be met (SMF-1999-000248). The licensee evaluated the condition using Generic Letter 91-18. The licensee concluded that the diesel generator support equipment was operable but degraded. The licensee ensured that appropriate compensatory actions were in place. The team concluded that the corrective action delay was not appropriately justified. The degraded condition had not been corrected at the time of this inspection.

– Degraded Atmospheric Relief Block Valves - Current

  During 2003, the licensee identified that the licensing bases requirement to maintain the atmospheric relief block valves as safety-related and seismic Category I was not met (SMF-2003-000188). The licensee evaluated the condition using Generic Letter 91-18. The licensee concluded that the atmospheric relief valve block valves were operable but degraded. The licensee's corrective actions included planned modifications to bring the valves into full compliance. However, the licensee had not corrected the degraded condition at the time of the inspection nor provided an appropriate justification for the delay. The team concluded that the corrective action delay was not appropriately justified. The licensee entered this issue into the CAP as SMF-2005-001756.

– Degraded Primary Plant Ventilation Exhaust Fans - Current

  During 2003, the licensee identified that the licensing bases requirements for the primary plant ventilation exhaust fan instrument tubing were not in compliance with design bases seismic requirements (SMF-2003-002423). The licensee evaluated the condition using Generic Letter 91-18. The licensee concluded that the ventilation exhaust fans were operable but degraded. However, the licensee had not corrected the degraded condition at the time of the inspection nor provided a justification for the delay. The team concluded that the licensee did not provided an appropriate justification for the corrective action delay.

– Failure to Meet the Electrical Area Ventilation System Room Temperature Licensing Bases Requirements - Historical

During 1999, the licensee identified that the licensing bases requirement to maintain minimum electrical area ventilation system room temperature could not be met (SMF-1999-003133). The licensee evaluated the condition using Generic Letter 91-18. The licensee concluded that the electrical area ventilation system equipment was operable but degraded. The licensee ensured that appropriate compensatory measures were in place. The licensee completed a corrective action plan in 2002. However, the corrective action plan did not include a completion date. The degraded condition was corrected during 2003. Generic Letter 91-18 stated: "The licensee must establish a time frame for completion of corrective action." The team concluded that the corrective action delay was not appropriately justified.

Example 3: Inadequate Evaluation Following a Reactor Trip

The team concluded that the licensee's problem evaluation following a July 2003 reactor trip was less than adequate. The reactor trip was directly caused by a failed reactor coolant pump (RCP) motor. The outside motor stator windings, located next to the rotor, had faulted. The RCP had exhibited high vibration during the year prior to the failure. The root cause analysis did not fully consider the high vibration or failure to fully implement pump vendor recommendations as contributing factors to the event.

Specifically, in May 2002, the licensee replaced the RCP rotor. Following a June 2002 reactor trip, RCP vibration amplitude increased by 2.5 mils (SMF-2002-002233) with greater than 18.0 mil spikes (the high vibration alarm setpoint). Vibration data (TXU Vibration Report 2002-022 and SMF-EVAL-2002-002233-01) taken after the June 2002 trip was sent to the pump vendor. The pump vendor analyzed the vibration spectrum and made several recommendations. These recommendations included:

– Balance the RCP to minimize shaft vibration levels and minimize lower motor bearing wear,

– Raise the high vibration alarm setpoint to 20.0 mils, and

– Trip the RCP if vibration exceeds 20.0 mils.

In response to these vendor recommendations, the licensee increased the high vibration alarm setpoint to 20.0 mils, but did not modify operating procedures to address the new vibration setpoint. They also did not balance the RCP while the plant was offline for 12 days in May 2003. During the subsequent startup RCP vibration exceeded 22.0 mils.

The RCP motor failed in July 2003 as discussed in NRC Integrated Inspection Report 05000445/2003003 and 05000446/2003003. The team concluded that the licensee's failure to trip the plant at the vendor recommended RCP vibration setpoint and the lost opportunity to balance the pump as an example of inadequate problem prioritization. While not a regulatory requirement, this issue provided insight in to the licensee's problem evaluation process.

Example 4: Inadequate Problem Evaluation for a Plant Risk Assessment

The team concluded that the licensee's use of inappropriate failure probabilities when conducting a Technical Specification (TS) required risk assessment was an example of inadequate problem evaluation. On April 2, 2004, the licensee discovered that the last TS required surveillance on the loss of power diesel generator start instrumentation was not performed. Plant TSs required that the licensee complete the surveillance every 18 months. The licensee performed the previous surveillance during the refueling outage in the Fall of 2003. TS Surveillance Requirement 3.0.3 provided for deferral of the missed surveillance until the next refueling outage provided that the licensee assess and manage the risk impact. The licensee deferred the missed surveillance until the next refueling outage in April of 2005.

The licensee completed a risk assessment for the missed surveillance (SMF-2004-001177). The surveillance included a verification of the Agastat relay in the diesel generator start circuit. The licensee used a generic relay demand failure probability (10^{-4}) for the Agastat relay when assessing plant risk for the deferred surveillance. The licensee had plant specific historical data indicating a higher failure probability on the order of magnitude of 10^{-3}. While not a regulatory requirement, the scope and development level of models that are used in plant risk assessments should be sufficient to represent issue being evaluated. In this case, the question, whether or not to require testing, is related to the reliability of the Agastat relays, so the best available Agastat failure data should have been used.

Additionally, during October 2004 the Agastat relay on the diesel generator circuit of the opposite train actually failed when the circuit was challenged during a loss of offsite power event (discussed in Sections 4OA2b and 4OA2c of this report). The licensee did not reevaluate the demand failure of the Agastat in the risk assessment following the actual failure. The inspectors determined that use of the actual failure probability for the Agastat relay in the risk assessment would not have resulted in additional risk mitigation actions by the licensee and the finding was minor.

Example 5: Inadequate Evaluation Resulted in Failure to Identify a Failed Containment Pressure Channel

The team concluded that the failure of shift operations personnel to recognize that a containment pressure channel was inoperable was an example of inadequate problem evaluation. On August 5, 2004, a control room containment pressure channel deviation alarm occurred. The alarm was activated when one channel deviated from the other three by greater than $\pm$0.3 psig. Control room instrumentation indicated that the channel deviated 2.0 psig from the other channels. Shift operations personnel did not consider the channel inoperable and did not apply the required TS action requirements. Subsequent review revealed that the pressure channel had been inoperable for greater than 31 hours. This issue was discussed as a finding in Section 4OA2e(2)(iii) of this report.

c. Effectiveness of Corrective Actions

(1) Inspection Scope

The team reviewed licensee documentation associated with 151 significant adverse conditions and NRC findings to verify that corrective actions were properly identified and implemented in a manner commensurate with safety. The team reviewed the license's corrective actions and conducted interviews to determine if root causes and generic concerns were adequately addressed. The team also reviewed corrective actions associated with adverse historical trends in human performance and CAP effectiveness.

(2) Assessment

The team concluded that the licensee's corrective action processes were effective and conducted in accordance with CAP and NRC requirements. The team did not identify any examples of ineffective corrective actions associated with issues within the assessment period. However, the team identified three historical examples of inadequate corrective actions for problems that originated before the assessment period.

Example 1: Ineffective Corrective Actions Following Lost Environmental Samples

The licensee's corrective actions following an August 2002 lost waste monitoring tank environmental sample were not effective. In January 2004, the licensee was not able to locate a second monthly composite sample for the waste monitoring system for October 2003. This issue was previously disposition as NRC NCV 05000445;05000446/2004-009-001.

Example 2: Corrective Actions to Address the Adverse Trend in Human Performance have not been Effective

The licensee's corrective actions to address a longstanding adverse human performance trend have not been effective. During 2002, external and licensee independent assessments identified an adverse trend in human performance

(Eval-2002-008 and Eval-2003-001). This trend included five significant personnel errors in 2002 and five additional significant errors during the first part of 2003 (SMF-2004-000337). The licensee reviewed these events and concluded that increased focus on organizational processes which contributed to human performance events was needed. During 2004, a second external assessment concluded that the adverse trend had continued. The licensee's corrective actions to address the adverse trend, which were taken before the assessment period, were not effective. The inspection team identified 14 examples of poor human performance or poor use of human performance tools as significant contributing factors to events that occurred during the assessment period. Based on the continuation of the adverse human performance trend, the team concluded that the licensee's corrective actions to address this problem have not been effective. The examples considered by the team included:

- October 2002: Inadequate operational pre-job review resulted in the unplanned inoperability of a residual heat removal train and condition prohibited by TSs (LER 445-03-01 and SMF-2002-003317). This issues was closed as a NCV NCV 05000446/2002-006.

- January 2003: A personnel error resulted in the unplanned loss of a protection bus (SMF-2003-000200). Although this example provided insight in to the licensee's corrective actions, the inspectors concluded that the finding was minor.

- August 2003: Inadequate operational pre-job review resulted in the unplanned inoperability of both trains of control room air conditioning, a condition prohibited by TSs (LER 445-03-004, SMF-2003-002463, SMF-2004-000691, SMF-2004-000059, and SMF-200-002619). Although this issue provided insight in to the licensee's corrective actions, the inspectors concluded that the finding was minor.

- September 2003: An error resulted in an unplanned reactor shutdown after core criticality was outside reactivity limits (SMF-2002-004139). Although this issue provided insight in to the licensee's corrective actions, the inspectors concluded that the finding was minor.

- November 2003: A valve mispositioning resulted in the inoperability of the spray additive system (LER 446-03-003-00 and SMF-2003-003559). Although this issue provided insight in to the licensee's corrective actions, the inspectors concluded that the finding was minor.

- November 2003: Entry into a high radiation area without a briefing on radiation dose rates (SMF-2003-003594). This finding was previously disposition as NRC NCV 05000445;05000446/2004003-001.

- February 2004: Personnel error resulted in the loss of turbine load (SMF-2004-000514). This finding was previously disposition as NRC FIN 05000446/2004005-02.

- March 2004: Violation of TS 3.7.17, spent fuel assembly storage, due to personnel error (LER 445-04-001-00 and SMF-2004-000797). Although this issue provided insight in to the licensee's corrective actions, the inspectors concluded that the finding was minor.

- April 2004: A worker's failure to follow a radiation work permit requirement resulted in a violation of TSs (SMF-2004-001202. This finding was previously disposition as NRC NCV 05000446/2004003-03.

- April 2004: Inadvertent removal of the wrong lock box resulted in reactor vessel level indication system probe damage (SMF-2004-001204). Although this issue provided insight in to the licensee's corrective actions, the inspectors concluded that the finding was minor.

- May 2004: Personnel error resulted in the loss of turbine load (SMF-2004-001869). Although this issue provided insight in to the licensee's corrective actions, the inspectors concluded that the finding was minor.

- September 2004: An incorrect breaker manipulation during restoration from a containment spray pump lockout test resulted in the inadvertent start of a safety injection pump (SMF-2004-003292). Although this issue provided insight in to the licensee's corrective actions, the inspectors concluded that the finding was minor.

- October 2004: Inadequate operational pre-job review resulted in an unplanned power reduction after the loss of heater drain forward flow during the calibration of recirculation Valve 2-HV-2589B (SMF-2004-00514). This finding was previously disposition as NRC FIN 05000446/2004005-01.

- November 2004: Personnel error resulted in the loss of turbine load (SMF-2004-003636 and SMF-2004-003644). Although this issue provided insight in to the licensee's corrective actions, the inspectors concluded that the finding was minor.

Example 3: Agastat Relay Issues - Inadequate Corrective Actions

The licensee failed to take effective corrective actions to combat repetitive failures of Agastat relays. Following an event in October 2002 when an emergency diesel generator unexpectedly started due to a faulty Agastat relay, the licensee developed corrective actions to combat Agastat relay failures. These corrective actions were not sufficient to preclude repetition of a similar event as evident in October 2004 when an Agastat relay caused a safeguards 6.9KV bus to de-energize. The repeat failure in October 2004 was the result of ineffective corrective actions following the October 2002 event. Although the licensee had identified the relay for replacement, the team concluded that the licensee's failure to implement a timely replacement schedule following the October 2002 event was an example of inadequate corrective actions. This issue was discussed as a finding in section 4OA2e(2)(i) of this report.

d. Assessment of Safety-Conscious Work Environment

(1) Inspection Scope

The team conducted 36 interviews, randomly selected from a variety of plant organizations, to assess the establishment of a safety-conscious work environment at CPSES. The inspectors used the guidance provided in Inspection Procedure 71152, Identification and Resolution of Problems, Appendix, "Suggested Questions for Use in Discussions with Licensee Individuals Concerning PI&R Issues," while conducting the interviews. The team interviewed both supervisory and non-supervisory individuals from maintenance, work planning, engineering, independent assessment, security, radiation protection, and operations. The team also reviewed the results of the safety-conscious work environment and organizational assessment surveys listed in the attachment and plant safety issues submitted to the employee concerns program.

(2) Assessment

The team concluded that the licensee had established a safety-conscious work environment at CPSES. All the individuals interviewed indicated that they felt comfortable raising and pursuing safety concerns and did not feel intimidated or discouraged from initiating condition adverse to quality reports. The team concluded that the employee concerns program effectively resolved safety issues raised by plant personnel. Plant personnel who were interviewed considered the employee concerns program a viable option for pursuing safety concerns.

However, the licensee had identified long-term organizational effectiveness issues within the operations department, which continued to challenge the safety-conscious work environment for shift operations personnel.

The licensee performed a safety-conscious work environment survey of shift operations personnel in 2003. The survey revealed that a minority of shift operations personnel felt intimidated or discouraged from raising safety concerns or initiating condition adverse to quality reports. Less than 50 percent of the surveyed personnel returned the completed surveys. The survey also revealed strong indications of organizational ineffectiveness between some workers and first level supervision. The licensee implemented a corrective action plan to address these concerns.

In 2004, the licensee conducted a followup safety-conscious work environment survey with operations personnel. The followup survey was designed to assess the effectiveness of the corrective actions. The followup survey indicated safety culture and organizational improvements. However, about 30 percent of licensed reactor operators continued to express that they felt intimidated or discouraged from raising safety concerns or initiating condition adverse to quality reports. The licensee took additional corrective actions.

During this inspection, the team conducted interviews of 14 randomly selected licensed operations personnel to assess the safety-conscious work environment. All of the individuals indicated that they felt comfortable raising and pursuing safety concerns and did not feel intimidated or discouraged from initiating condition adverse to quality reports. However, about half of the licensed reactor operators interviewed stated that organizational issues have not improved.

The team concluded that the licensee's past actions to improve operations department organizational effectiveness have not been fully effective. The team concluded that without licensee management attention, these organizational issues may evolve into a safety-conscious work environment concern.

e. Specific Issues Identified During this Inspection

(1) Inspection Scope

During the reviews described in Sections 4OA2 a.(2), 4OA2 b.(2), and 4OA2 c.(2) the team identified the following findings.

(2) Findings and Observations

(i) Inadequate Corrective Actions to Address Longstanding Agastat Relay Issues Resulted in the Inoperability of a 6.9 kV Safeguards Bus

Introduction. The team identified a finding and an unresolved item related to TS 3.8.1 after neither the alternate offsite AC nor the emergency diesel generator supplied power to a 6.9 kV safeguards bus within the time assumed in the accident analysis. This item is unresolved pending completion of inspection necessary to determine enforcement and the significance.

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

The licensee had a previous opportunity to correct the degraded Agastat relay issues. On October 7, 2002, the emergency diesel generator unexpectedly started due to a degraded Agastat relay. The licensee concluded that the failure could have been caused by aging and formed a corrective action plan to replace all safety-related Agastat relays that have been in service for greater than the licensee established 12 year lifetime. Licensee Evaluation 2003-001440-01-01 stated that the main effect of aging on these relays was an increase in setpoint drift. The licensee issued SMF-2002-003391 to track the root cause and corrective actions associated with the faulty Agastat relays. Also, the NRC previously identified that Agastat relays used in the 6.9 kV bus transfer circuitry were exhibiting setpoint drift (SMF-2002-001504 and Inspection Report 05000445/2003006; 05000446/2003006). The relay that failed in October 2004 was 16 years old. The team concluded that the failure to perform immediate corrective actions after the October 2002 event was an example of inadequate corrective actions.

Analysis. This finding adversely impacted the reliability of emergency power to mitigating systems. This finding is greater than minor because the reactor mitigating systems cornerstone and the equipment performance attribute to prevent core damage are affected. The licensee's failure to identify the cause and implement corrective actions to prevent repetitive failures of safety related Agastat relays was a performance deficiency. The inspectors determined that the finding has potential safety significance greater than very low because the condition represents an actual loss of a safety function for a single train greater that its TS allowed outage time.

Enforcement. TS 3.8.1 required the licensee to restore either the alternate offsite transmission source or the emergency diesel generator to the onsite Class 1E AC electrical distribution system within 12 hours. Contrary to the above, neither the alternate offsite transmission source nor the emergency diesel generator were capable of supplying the Class 1E AC electrical distribution within the response time assumed in the accident analysis. This condition existed for an extended duration, in excess of the 12 hour TS limiting condition for operation. Pending determination of the performance deficiency and the safety significance, this finding is identified as URI 05000446/2005009-01, inoperability of emergency power to a safety bus.

(ii) Inadequate Postmodification Test Resulted in the Introduction of Loose Parts into the Reactor Cavity

Introduction. The team identified a Green self-revealing finding associated with inadequate postmodification testing of the Unit 2 refueling machine festoon. The festoon failed during refueling operations, resulting in the introduction of loose parts into the lower internals storage area of the refueling cavity.

Description. The festoon tow bar broke and parts of it fell into the pool and settled in the vicinity of the reactor cavity lower internals storage area. The parts included two 20-inch austenitic stainless steel fasteners, nuts, and washers.

The licensee installed the festoon during Refueling Outage 5 to replace the older take-up reel on the refueling machine, however the festoon rails were not adequate to allow bridge travel to the mechanical stops. The postmodification test only verified festoon clearance for bridge travel to the electrical bridge stops. However, some refueling operations required bridge travel beyond the electrical stops to the mechanical stops. The operators bypassed the electrical bridge stops on several occasions. Travel beyond the length of the festoon rails caused the cable trolleys to compact and placed enough stress on the tow rods to break the welds of the base plates holding the rods in place. Engineering personnel establishing the postmodification test did not understand that some fuel handling operations required bridge travel past the electrical stops.

Analysis. Failure of the licensee to perform a postmodification test that demonstrated that the festoon would perform satisfactorily in service was a performance deficiency. This finding is more than minor because the barrier integrity cornerstone objective to provide reasonable assurance that physical barriers (including the fuel clad) to protect the public from radionuclide releases caused by accidents or events is affected. The introduction of loose parts into the reactor cavity during refueling is associated with the fuel clad attributes of human performance and foreign material exclusion. The team analyzed the finding using Appendix G, “Shutdown Operations,” of Manual Chapter 0609, “Significance Determination Process,” Attachment 1, Checklist 4. The team concluded that the finding did not require a quantitative assessment because the condition does not increase the likelihood of a loss of reactor coolant system inventory or loss of reactor coolant system level instrumentation, does not degrade the licensee's ability to terminate a leak path or add reactor coolant system inventory when needed, and does not degrade the ability to recover decay heat removal once it is lost. Since a quantitative assessment was not required, the finding was of very low safety significance.

Enforcement. No violation of regulatory requirements occurred. The team determined that the finding did not represent a noncompliance because it occurred on nonsafety related equipment. This finding was entered into the corrective action program as SMF-2003-003283 (FIN 05000446/2005009-02).

(iii) Inadequate Evaluation Resulted in Failure to Identify a Failed Containment Pressure Channel

Introduction. The team identified a Green noncited violation after the licensee failed to complete a required TS action after a containment pressure channel failed. The operating crew did not recognize that the channel had failed.

Description. While operating in Mode 1 on August 5, 2004, a control room containment pressure channel deviation alarm occurred. The alarm was activated when one channel deviated from the other three by greater than ±0.3 psig. Control room instrumentation indicated that the channel deviated -2.0 psig from the other channels. Operating Procedure OPT-102A-1, “Mode 1 and Mode 2 Shiftily Surveillances,” established a ±3.0 psig channel deviation acceptance criteria. On August 6, 2004, the licensee identified that a grounded transmitter shield wire had caused the channel deviation alarm. The licensee calculated a channel statistical allowance of ±1.5 psig for containment pressure data obtained from the plant computer. Using archived plant computer data, the licensee determined that the pressure channel became inoperable at the time of the deviation alarm and remained inoperable for greater than 31 hours. The licensee repaired and returned the channel to service. TS 3.3.2, required the licensee to place the safety injection and steamline isolation function in trip, and bypass the containment spray and containment isolation functions, within 6 hours, or place the unit in Mode 3 within 12 hours. The licensee did not meet either of the required actions. Plant operators should have requested a Quick Turnaround Evaluation, per Procedure STA-422, “Corrective Action Program,” at the time of the deviation alarm. The Quick Turnaround Evaluation would have prompted the licensee to perform the plant computer data evaluation and the inoperability of the channel could have been determined before the 6 hour TS action.

Analysis. The inspectors used the at-power situation significance determination process to analyze this finding. This finding affected the mitigating systems cornerstone because of the containment pressure channel safety function. The failure of operations personnel to place the inoperable containment pressure channel in trip/bypass within 6 hours was a performance deficiency. This finding is greater than minor because, if left uncorrected, the failure to recognize inoperable mitigating systems instrumentation would become a more significant safety concern. This finding is only of very low safety significance because the condition was not a design or qualification deficiency confirmed to result in loss of function per Generic Letter 91-18; did not result in an actual loss of safety function of a system; did not increase the likelihood of a fire; and did not screen as potentially risk significant due to a seismic, flooding, or severe weather initiating event. This finding involved the failure of operations personnel to implement a TS Action requirement and was associated with the crosscutting area of human performance.

Enforcement. TS 3.3.2, Conditions D and E required the licensee to place the safety injection and main steamline isolation functions in trip, and the containment spray and containment isolation functions in bypass, within 6 hours following an inoperable containment pressure channel or place the unit in Mode 3 within the next 12 hours. Contrary to the above, the licensee did not place the safety injection and main steamline isolation functions in trip, nor the containment spray and containment isolation functions in bypass, within 6 hours following an inoperable containment pressure channel or place the unit in Mode 3 within the next 12 hours on August 5, 2004. The containment channel was inoperable greater than 31 hours. Because the violation was of very low safety significance, and was entered into the licensee's CAP (SMF-2005-002752 and SMF-2005-003157), this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy (NCV 05000446/2005009-03).

4OA3 Event Follow-up (71153)

(Closed) License Event Report 05000446/2004-03-00: Containment Pressure Channel Inoperable due to a Secondary Ground

On August 5, 2004, the licensee failed to complete a required TS action after a containment pressure channel failed. This event and the inspectors' findings were described in Section 4OA2e(2)(iii) of this report. The inspectors reviewed the LER and no additional findings of significance were identified. This LER is closed.

4OA4 Crosscutting Aspects of Findings (71152)

Section 4OA2 documents a finding with human performance crosscutting aspects which involved the failure of shift operations personnel to recognize that a containment pressure channel was inoperable for an extended period.

4OA6 Exit Meeting

The team discussed the findings with Mr. M. Blevins, Senior Vice President and Chief Nuclear Officer, and other members of the licensee's staff on July 29, 2005. The team reviewed some proprietary information during the inspection but that information was returned to the licensee prior to the exit.

ATTACHMENT

PARTIAL LIST OF PERSONS CONTACTED

Licensee

I. Ahmad, Generic Letter 91-18 Program Owner
J. Audas, Manager, Safe Team
M. Blevins, Senior Vice President and Chief Nuclear Officer
D. Bozeman, Manager, Emergency Planning
R. Flores, Vice President, Operations
T. Gilder, Manager, Corrective Action Program
T. Hope, Manager, Regulatory Performance
R. Kidwell, Licensing Engineer
M. Lucas, Vice President, Nuclear Engineering
F. Madden, Manager, Regulatory Affairs
T. Mavrey, Manager, Equipment Reliability
R. Smith, Manger, Operations
B. Turnipseed, Valve Team Supervisor
T. Weyandt, System Engineer
D. Wilder, Manager, Radiation and Industrial Safety, Radiation and Industrial Safety

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

05000446/2005009-01	URI	Inadequate Corrective Actions to Address Longstanding Agastat Relay Issues Resulted in the Inoperability of a 6.9 kV Safeguards Bus (Section 4OA2e(2)(i))

Opened and Closed

05000446/2005009-02	FIN	Inadequate Postmodification Test Resulted in the Introduction of Loose Parts into the Reactor Cavity (Section 4OA2e(2)(ii))
05000446/2005009-03	NCV	Inadequate Evaluation Resulted in Failure to Identify a Failed Containment Pressure Channel (Section 4OA2e(2)(iii))

Closed

05000446/2004-03-00	LER	Containment Pressure Channel Inoperable due to a Secondary Ground (Section 4OA3)

LIST OF DOCUMENTS REVIEWED

PLANT PROCEDURES

Procedure	Title
CHM-517	Chemistry Control of Liquid Waste Systems, Revision 9
CHM-708	ODCM Surveillance of the Low Volume Waste Pond, Revision 6
ECE 6.02-01	Procurement Levels, Revision 4, December 17, 2002
ECE 6.02-05	Technical and Quality Assurance Requirements, Revision 6, December 8, 2004
ECE 6.02-03	Critical Characteristics Development, Revision 5B, January 10, 2003
ECE 6.02-06	Preparation of Verification Plans, Revision 3, December 17,2002
INC-214 I	Installation of Electrical Conductor Seal Assemblies, Revision 0
NQA 3.09-11.03	Receiving Inspection, Revision 14, April 11, 2005
NQA 6.02	Quality Review of Procurement Documents, Revision 10, January 15,1999
RPI-602	Radiological Surveillance and Posting, Revision 24
RPI-606	Radiation Work and General Access Permits, Revision 12
RPI-618	Operation of the Filter Shear System, Revision 3
RPI-713	Collection, Preparation, and Shipment of Radiological Environmental Samples, Revision 4
STA-124	Human Performance Program, Revision 0

STA-421	Initiation of Smart Forms, Revision 11
STA-422	Processing Smart Forms, Revision 19
STA-424	Self-assessment and Benchmarking Programs, Revision 2
STA-426	Industry Operating Experience Program, Revision 0
STA-428	Station Issue/Event Trending, Revision 0
STA-690	Risk Informed - Inservice Testing, Revision 2
TRA 17	Inspection Personnel Certification Program and Materials Test Lab Personnel Qualification Program, Revision 4, May 17, 2005

Receipt Reports

RR 31042	Strainer, VP-NEM1119-01, March 9, 2005
RR 31074	Terminal Block, VP-NEE0623-02, March 24, 2005
RR 31216	Unistrut Screw, VP-NEM0870-01, April 3, 2005
RR 31237	U-Bolt, VP-NEM1343-01, March 29, 2005
RR 31409	Grout, VP-NES0002-01, July 7, 2005
RR 31412	Solder, Rosin Core, VP-NEE0596-01, July 9, 2005
RR 31436	04/08/05, Integrated Circuit, VP-NEE0730-01
RR 31554	06/02/05, Capacitor, VP-NEI0273-02
RR 31559	Receipt Report, Fitting, Conduit Nipple VP-NEE0665-01, June 18, 2005
RR 31571	Pressure Gage, VP-NEM1072-01, June 28, 2005

RR 31573	Pressure Gage, VP-NEM1072-01, June 28, 2005
RR 31574	Connector, VP-NEE0603-01, June 18, 2005
RR 31579	Conduit, VP-NEE0566-01, June 18, 2005
RR 31583	Copper Fittings and Tubing, VP-NEM1375-01, May 31, 2005
RR 31596	06/17/05, Unistrut Nut, VP-NEM0870-01
RR 31619	Light Assembly, VP-NEE0636-01, June 14, 2005
RR 31642	Terminal Block Jumper, VP-NEE0714-01, June 27, 2005
RR 31661	O-Rings, VP-NEM1053-01, July 14, 2005
RR 31676	AR440AR Relay, VP-WEST611-01, June 27, 2005
RR 31715	Turbine Oil, VP-NEC0176-02, July 11, 2005
RR 31743	Flexitallic Gasket, VP-NEM1078-01, July 15, 2005
RR 31744	Mounting Bracket, VP-NEM1030-01, July 21, 2005

NRC Inspection Reports

IR 05000445/2003-006; 05000445/2003-006
IR 05000445/2004-003; 05000446/2004-003
IR 05000445/2004-008; 05000446/2004-008
IR 05000445/2004-009; 05000446/2004-009

SmartForms

SMF-1999-000704	SMF-1999-002772	SMF-2001-000728
SMF-1999-002579	SMF-1999-002776	SMF-2001-000889
SMF-1999-002655	SMF-2000-001115	SMF-2001-001015
SMF-1999-002720	SMF-2000-002242	SMF-2001-001268
SMF-1999-002740	SMF-2001-000345	SMF-2001-001861
SMF-1999-002755	SMF-2001-000686	SMF-2001-002122

SMF-2001-002531	SMF-2003-001075	SMF-2004-000049
SMF-2001-002635	SMF-2003-001120	SMF-2004-000059
SMF-2002-000122	SMF-2003-001161	SMF-2004-000060
SMF-2002-000255	SMF-2003-001345	SMF-2004-000062
SMF-2002-000270	SMF-2003-001365	SMF-2004-000069
SMF-2002-000532	SMF-2003-001369	SMF-2004-000100
SMF-2002-000616	SMF-2003-001384	SMF-2004-000120
SMF-2002-000859	SMF-2003-001452	SMF-2004-000151
SMF-2002-001047	SMF-2003-001479	SMF-2004-000329
SMF-2002-001057	SMF-2003-001486	SMF-2004-000330
SMF-2002-001504	SMF-2003-001545	SMF-2004-000337
SMF-2002-001523	SMF-2003-001567	SMF-2004-000471
SMF-2002-001642	SMF-2003-001773	SMF-2004-000509
SMF-2002-001842	SMF-2003-001857	SMF-2004-000514
SMF-2002-001879	SMF-2003-001992	SMF-2004-000566
SMF-2002-002151	SMF-2003-002037	SMF-2004-000620
SMF-2002-002156	SMF-2003-002106	SMF-2004-000691
SMF-2002-002233	SMF-2003-002120	SMF-2004-000693
SMF-2002-002456	SMF-2003-002142	SMF-2004-000742
SMF-2002-002480	SMF-2003-002158	SMF-2004-000774
SMF-2002-003317	SMF-2003-002187	SMF-2004-000797
SMF-2002-003376	SMF-2003-002196	SMF-2004-000836
SMF-2002-003391	SMF-2003-002356	SMF-2004-000908
SMF-2002-003448	SMF-2003-002435	SMF-2004-001024
SMF-2002-003504	SMF-2003-002463	SMF-2004-001177
SMF-2002-003534	SMF-2003-002517	SMF-2004-001193
SMF-2002-003579	SMF-2003-002619	SMF-2004-001202
SMF-2002-003665	SMF-2003-002756	SMF-2004-001204
SMF-2002-003792	SMF-2003-002912	SMF-2004-001264
SMF-2002-003880	SMF-2003-003018	SMF-2004-001350
SMF-2002-003915	SMF-2003-003077	SMF-2004-001419
SMF-2002-003916	SMF-2003-003253	SMF-2004-001427
SMF-2002-003951	SMF-2003-003264	SMF-2004-001440
SMF-2002-004008	SMF-2003-003283	SMF-2004-001457
SMF-2002-004026	SMF-2003-003309	SMF-2004-001581
SMF-2002-004064	SMF-2003-003479	SMF-2004-001610
SMF-2002-004118	SMF-2003-003514	SMF-2004-001662
SMF-2002-004139	SMF-2003-003559	SMF-2004-001677
SMF-2002-004167	SMF-2003-003594	SMF-2004-001685
SMF-2002-004242	SMF-2003-003599	SMF-2004-001869
SMF-2002-004318	SMF-2003-003604	SMF-2004-001927
SMF-2003-000152	SMF-2003-003675	SMF-2004-002120
SMF-2003-000200	SMF-2003-003853	SMF-2004-002244
SMF-2003-000439	SMF-2003-003898	SMF-2004-002269
SMF-2003-000571	SMF-2003-003918	SMF-2004-002357
SMF-2003-000604	SMF-2003-003965	SMF-2004-002391
SMF-2003-000754	SMF-2003-004016	SMF-2004-002411
SMF-2003-000931	SMF-2003-004075	SMF-2004-002488

SMF-2004-002568
SMF-2004-002679
SMF-2004-002752
SMF-2004-002831
SMF-2004-002852
SMF-2004-002865
SMF-2004-002903
SMF-2004-002938
SMF-2004-002962
SMF-2004-003187
SMF-2004-003192
SMF-2004-003292
SMF-2004-003306
SMF-2004-003399
SMF-2004-003413
SMF-2004-003485
SMF-2004-003495
SMF-2004-003528
SMF-2004-003610
SMF-2004-003636
SMF-2004-003644
SMF-2004-003833
SMF-2004-003883
SMF-2004-003917
SMF-2004-003932
SMF-2004-004007
SMF-2004-004026
SMF-2004-004033
SMF-2005-000032
SMF-2005-000038
SMF-2005-000069
SMF-2005-000085
SMF-2005-000114
SMF-2005-000119
SMF-2005-000164
SMF-2005-000257
SMF-2005-000259
SMF-2005-000267
SMF-2005-000273
SMF-2005-000284
SMF-2005-000288
SMF-2005-000292
SMF-2005-000296
SMF-2005-000323
SMF-2005-000350
SMF-2005-000377
SMF-2005-000527
SMF-2005-000591
SMF-2005-000722
SMF-2005-000806
SMF-2005-000870
SMF-2005-001070
SMF-2005-001152
SMF-2005-001223
SMF-2005-001253
SMF-2005-001308
SMF-2005-001343
SMF-2005-001361
SMF-2005-001392
SMF-2005-001468
SMF-2005-001486
SMF-2005-001512
SMF-2005-001521
SMF-2005-001528
SMF-2005-001529
SMF-2005-001549
SMF-2005-001557
SMF-2005-001574
SMF-2005-001619
SMF-2005-001641
SMF-2005-001666
SMF-2005-001689
SMF-2005-001692
SMF-2005-001704
SMF-2005-001740
SMF-2005-001756
SMF-2005-001781
SMF-2005-001787
SMF-2005-001835
SMF-2005-001854
SMF-2005-001875
SMF-2005-001895
SMF-2005-002113
SMF-2005-002228
SMF-2005-002399
SMF-2005-002437
SMF-2005-002471
SMF-2005-002499
SMF-2005-002681
SMF-2005-002717
SMF-2005-002739
SMF-2005-002834
SMF-2005-002929

Miscellaneous

ACTN-MAN-2004-003528-04

ACTN-MAN-2004-003528-03

AOV Component Health Report 2nd Quarter, 2004

AOV Component Health Report 3rd Quarter, 2004

CLS-2-04-01660

CPSES Component Status, 1st Quarter, FY 2005

CPSES Safeguards Events Log, Site Location #218 Quarter Beginning 07-01-2003

CPSES Safeguards Events Log, Site Location #218, Quarter Beginning 04-01-2004

CPSES Safeguards Events Log, Site Location #218, Quarter Beginning 04-01-2005

CPSES Self Assessment Program Assessment SA-2004-056

CPSES Safeguards Events Log, Site Location #218, Quarter Beginning 10-01-2004

CPSES Safeguards Events Log, Site Location #218, Quarter Beginning 07-01-2004

CPSES Safeguards Events Log, Site Location #218, Quarter Beginning 01-01-2005

CPSES Safeguards Events Log, Site Location #218 Quarter Beginning 01-01-2004

CPSES Safeguards Events Log, Site Location #218 Quarter Beginning 04-01-2003

CPSES System Status, Unit 1, Main Steam, 1st Quarter, FY 2005

CPSES System Status, Unit 2, Main Steam, 1st Quarter, FY 2005

CPSES Quarterly Trend Summary Report, 3rd Quarter 2004

CPSES Quarterly Trend Summary Report, 4th Quarter 2004

CPSES Quarterly Trend Summary Report, 1st Quarter 2005

Drawing Number M1-2941, Revision CP-4

Drawing Number M2-2941, Revision CP-4

Failure Analysis of Agastat Time-Delay Relay Southwest Research Institute Report

Final Design Authorization FDA-2003-003283-01-00

Fuel Storage and Handling, Design Basis Document DBD-ME-080, Revision 17

Radiation Protection Guideline 6-3, Crud Burst Trending, Revision 3

Radiation Protection Power Operations Detail Report, July 11, 2005

SA-2003-020, STARS Alliance Round Robin Nuclear Safety Focus, April 24, 2003

Trend Analysis of Rad Worker Practices, Second Quarter 2005

Trend Analysis of ODCM and Related Smart Forms, Second Quarter 2005

Trend Analysis of Radiation and Industrial Safety Personnel/Manager's Trend Errors, June/Second Quarter 2005

TXU Energy Report: Stevenville Switching Station OB. 4060 - Investigation Findings Following Unwanted Trip Operation

TXU Engineering Calculation EE-CA-0008-0871

TXU Power Cause Analysis Handbook, Revision 6, July 13, 2004

NRC Publications

NUREG-1022, Revision 2
Regulatory Guide 1.97, Revision 3
Information Notice 88-89, Degradation of Captain Electrical Insulation
Information Notice 98-21, Potential Deficiency of Electrical Cable/Connection Systems

Assessment of Safety-Conscious Work Environment Surveys Reviewed

NOD Departmental Survey, 2005
Operations Department Nuclear Safety Culture Survey
Safe Team Program Audit, 2003-129
Safe Team Employee Survey results, December 2004
Safety Conscious Work Environment Survey with shift operations personnel, 2003
Safety Conscious Work Environment Survey with shift operations personnel, 2004
TUX Organizational Assessment Survey, 2002, NU-003

Independent Assessments

EVAL-2001-000728-01	EVAL-2003-000022	EVAL-2004-000025
EVAL-2002-001368-03	EVAL-2003-000031	EVAL-2004-000027
EVAL-2002-002233-01	EVAL-2003-001440-01	EVAL-2004-000030
EVAL-2002-003391-03	EVAL-2003-001440-01	EVAL-2004-001000-01
EVAL-2002-003391-06	EVAL-2003-002886-01	EVAL-2004-002676
EVAL-2002-003391-06	EVAL-2004-000009	EVAL-2004-003528-06
EVAL-2002-003579-01	EVAL-2004-000011	EVAL-2005-001361-01
EVAL-2002-004167-02	EVAL-2004-000015	EVAL-2005-001574-01
EVAL-2003-000019	EVAL-2004-000016	EVAL-2005-002113-02
EVAL-2003-000021	EVAL-2004-000021	

Work Orders

WO-3-03-326804
WO-3-03-327774-01
WO-4-03-150145
WO-4-05-160956-00
WO-5-01-505017-AB
WO-5-03-501451-AA
WO-5-03-501452-AA
WO-5-03-501453-AA

Licensee Event Reports

LER-445-03-001	LER-445–04-03	LER 446-04-002-01
LER-445-03-002	LER 446-03-001	LER 446-04-003
LER 445-03-003-00	LER 446-03-002	LER 446-05-001
LER 445-03-004	LER 446-02-003-01	LER 446-05-003
LER-445-04-001	LER 446-03-003	
LER 445-04-002	LER 446-04-001	

INFORMATION REQUESTS

From: Michael S. Peck
Sent: Monday, May 16,
To: Snow, Douglas W
Subject: Information Request 1, Comanche Peak Comanche Peak Steam Electric Station PIR Inspection

Dear Mr. Snow:

The inspection will cover the period of Jun 19, 2003 to June 1, 2005. All requested information should be limited to this period unless otherwise specified. To the extent possible, please provide the information in electronic media in the form of CDs (Corel WordPerfect 8, Presentations, Quattro Pro, MS Word, Excel, Power Point, and Adobe Acrobat (.pdf) text files).

Please provide the following information to the following address by May 31, 2005.

NRC Resident Inspector Office, Callaway Nuclear Plant, ATTN: Michael Peck, 8201 NRC Road, Steedman, MO 65077

I am planning a pre-inspection site visit June 28th and 29th.
Thank you,
msp

1. Summary list and a copy of all condition reports of significant conditions adverse to quality opened or closed during the period

2. Summary list of all condition reports of conditions adverse to quality opened or closed during the period

3. Summary list of all condition reports which were down-graded or up-graded during the period

4. Summary list of operator work arounds, engineering review requests and/or operability evaluations, temporary modifications, and control room and safety system deficiencies

5. A list of all corrective action documents that subsume or “roll-up” one or more smaller issues for the period

6. List of all root cause analyses completed during the period

7. List of root cause analyses planned, but not complete at end of the period

8. List of plant safety issues raised or addressed by the employee concerns program during the period

9. List of action items generated or addressed by the plant safety review committees during the period

10. All quality assurance audits and surveillances of corrective action activities completed during the period

11. A list of all quality assurance audits and surveillances scheduled for completion during the period, but which were not completed

12. All corrective action activity reports, functional area self-assessments, and non-NRC third party assessments completed during the period

13. Corrective action performance trending/tracking information generated during the period and broken down by functional organization

14. Current revision of the following procedures: LI-102, 01-S-03-9, 01-S-06-5, 01-S-06-44, 01-S-06-2, 01-S-06-5

15. Any additional governing procedures/policies/guidelines for:
    a. Condition Reporting
    b. Corrective Action Program
    c. Root Cause Evaluation/Determination
    d. Deficiency Reporting and Resolution

16. A listing of all external events and operating experience evaluated for applicability at Grand Gulf during the period

17. Condition Reports or other actions generated for each of the items below:

    1. Part 21 Reports

    2. NRC Information Notices and Bulletins

    3. All LERs issued by Grand Gulf during the period

    4. NCVs and Violations issued to Grand Gulf during the period

18. Radiation protection event logs

19. Current system health reports or similar information

20. Current predictive performance summary reports or similar information

21. Corrective action effectiveness review reports generated during the period

From: Michael S. Peck
Sent: Monday, June 5, 2005 2:54 PM
To: Snow, Douglas W
Subject: Information Request 2 - Comanche Peak Comanche Peak Steam Electric Station PIR Inspection

Dear Mr. Snow:

Please provide the following information to support the Comanche Peak PI&R. If practical, I could pick an electronic copy of the requested information during my on-site visit June 20th.

Thank you,
msp

1. Please provide the root cause analysis and a list of corrective actions (including design modifications) following the centrifugal charging pump gas binding issues (Smart Form 2002-004242). Please include a list of any subsequent gas binding issues at CP with corrective actions.

2. Please provide a list of complete corrective actions and root cause analysis following relay failures (Smart Form 2002-003391). Please include a list of any subsequent age related relay failures at CP with corrective actions.

3. Please provide corrective actions and root cause analysis following the failure to maintain design control over a safety class boundary isolation (Smart Form SMF-2003-001773-00).

4. Please provide corrective actions and root cause analysis following the failure to fully implement Commission granted relief and alternative requirements (Smart Form SMF-2004-003883-00).

5. Please provide the root cause analysis and corrective actions following the loss of Unit 2 turbine load due to missed step in transferring control to manual hydraulic control (SMF-2004-3638-00 and SMF-2004-3644-00).

6. Please provide the root cause analysis and corrective actions following the Unit 2 downpower due to loss of heater drain forward flow during calibration of 2-HV-2589B (SMF-2004-3413-00).

7. Please provide a summary list of all problem evaluation requests related to significant conditions adverse to quality that were opened or closed between January 1, 2003 and June 19, 2003.

8.   Please provide a summary list of all problem evaluation requests related to conditions adverse to quality that were opened or closed between January 1, 2003 and June 19, 2003.

9. Please provide a list of all root cause analyses completed during the period between January 1, 2003 and June 19, 2003.

From: **Michael S. Peck**
Sent: **Monday, June 16, 2005**
To: **Snow, Douglas W**
Subject: **Information Request 3, Comanche Peak Comanche Peak Steam Electric Station PIR Inspection**

Dear Mr. Snow:

Please provide the following additional information to support the Comanche Peak PI&R. If practical, I could pick an electronic copy of the requested information during my on-site visit June 20th.

Thank you,
Michael

1. A Smart forms and root analysis generated over the past five years associated with:

- Offsite power line and switchyard reliability
- RCS leakage detection systems, including suspected voiding of piping, and algae blocking an orifice in
    the containment cooler leakage detection system
- Adverse trends with configuration control stemming from valve, switch, and component mis-positionings
- Steam Generator ARVs.
- Loose parts in the secondary side of the Unit 2 S/G's
- TDAFWP governor valve issues
- Adverse trends in occupational Radiation Safety

2. Smart Forms:

- SMF-2004-1264
- SMF-2004-062
- SMF-2004-0471
- SMF-2003-3594
- SMF-2004-1202.

From: **Michael S. Peck**
Sent: **Monday, June 22, 2005**
To: **Snow, Douglas W**

Subject: Information Request 4, Comanche Peak Comanche Peak Steam Electric Station PIR Inspection

Dear Mr. Snow:

Please provide the following information to support the upcoming Comanche Peak PI&R Inspection.

Thank you,
Michael

1. The first information request, item “#10,” included “All quality assurance audits.” The CD did not include any adits. Where any adits performed between February 1, 2003 and May 1, 2005?

2. Please provide a copy of the following Surveillance Reports (performed between February 1, 2003 and May 1, 2005) and related corrective action documents:

- Surv_CM_Configuration_and_Design_Control
- Surv_ER_Equipment_Reliability
- Surv_LP_Emergency_Preparedness
- Surv_LP_Fire_ProtectionSurv_LP_Problem_ID_&_Resolution
- Surv_LP_Security
- Surv_OP_Operations
- Surv_WM_Maintenance
- Surv_WM_Rad_Protection

3. The first information request, item “#20" included “Condition reports associated with maintenance preventable functional failures during the period.” None were provided on the CD. Did the plant have any maintenance preventable functional failures between February 1, 2003 and May 1, 2005? If so, how where they documented?

4. Please provide a copy of the following LERs:

- 2-04-002-01 (SMF-2004-003495) 10/19/04 Autostart of 2-02 EDG Ervin
- 2-05-001-00 (SMF-2004-004007) 01/18/05 Containment Airlock Door Inoperable
- 2-05-002-00 (SMF-2005-000722) 02/23/05 AFW Autostart Due to Loss of XST1
- 2-05-003-00 (SMF-2005-001666) 04/27/05 Two Pressurizer Safety Valves Failed Surveillance
- 1-04-001-00 (SMF-2004-000797) 03/03/04 Violation of TS 3.7.17 Spent Fuel Assembly Storage
- 1-04-002-00 (SMF-2004-001177) 04/02/04 Missed Surveillance on Loss of Power EDG Start Instrumentation
- 1-04-003-00 (SMF-2004-002244) 07/26/04 RCS Leakage Detection Instrumentation Inoperable
- 2-04-001-00 (SMF-2004-000100) 01/13/04 RWST Level Channel 2-L-0932 Inoperable
- 2-04-002-00 (SMF-2004-003495) 10/19/04 Autostart of 2-02 EDG
- 2-04-003-00 (SMF-2004-002752) 11/23/04 Containment Pressure Channel 2-PI-0935 Inoperable

- 1-02-002-01 (SMF-2002-003142) 10/06/02 Unit 1 SGs in TS Category C-3
- 1-03-001-00 (SMF-2002-003317) 01/06/03 U1 Train B RHR Made Inop Due To Testing
- 1-03-002-00 (SMF-2003-000754) 03/16/03 Unit 1 Rx Trip Due to Loss of Main Feedwater
- 1-03-003-00 (SMF-2003-001365) 05/15/03 Dual Unit Turbine/Reactor trips due to a loss of 345KV switchyard.
- 1-03-004-00 (SMF-2003-002463) 08/20/03 TS 3.0.3 Entered When Both Trains of Control Room Air Conditioning System Were Inop per LCO 3.7.11.
- 2-03-001-00 (SMF-2003-001992) 07/09/03 Reactor trip due to loss of Reactor Coolant Pump
- 2-03-002-00 (SMF-2003-002196) 07/25/03 AFW autostart due to trip of both main FW pumps.
- 2-03-003-00 (SMF-2003-003559) 11/02/03 Spray Additive System inoperable due to mispositioned valves.
- 2-03-004-00 (SMF-2003-003599) 11/05/03 Containment pressure channel 2-pi-0935 inoperable
- 2-03-005-00 (SMF-2003-004016) 12/22/03 Reactor Trip Due to Strobescope Cover Falling Into Main Generator Exciter

5. Please provide a copy of the following Smart Forms, including attachments:

SMF-2005-001666-01, Evaluation of the Pressurizer Safety Valve Setpoint Drift,
SMF-2005-001343-00, Initial Licensed Operator Class Throughput / Pass Rate Was inadequate.,
SMF-2005-000722-00, Unit 2 Black out Due to a Lightning Strike in West Texas.,
SMF-2005-000032-00, Perform a Collective Review of the Issues with the Unit 1 and 2 Containment Personnel Airlocks,
SMF-2004-004007-00, Unit 2 Pal Inner Door Seal Failure.
SMF-2004-003644-00, Unit Two Experienced a 464 Mwe Load Reduction.,
SMF-2004-003528-00, During Loss of Xst1, 2ea2-1 Breaker Did Not Open in Required Time.
SMF-2004-003495-01, Loss of 138 Switchyard (Xst1) Supply to Safeguard Buses Unit 2. This Revision Is to Correct a Typographical Error in Eval-2004-003495-03 Which Reference an Incorrect Smf Number.,
SMF-2004-003413-00,During the Calibration of 2-fv-2589b-ip1, 2-fv-2589a Failed Open Causing a Heater Drain System Transient That Resulted in the Loss of Forward Flow Heater Drains.
SMF-2004-003292-00,Incorrect Breaker Manipulation During Restoration from Containment Spray Pump 2-02 86 Lockout Test Resulted in Inadvertent Start of the 2-02 Safety Injection Pump.
SMF-2004-002852-00,Unit 2 Mfp 2b Speed Drifting above Commanded Setpoint.
SMF-2004-002752-00,Cable Shield, Grounded at Both Ends, Caused Intermittent Ground Loop and Erroneous Indication. Intermittent Ground Caused by Dripping Mineral Deposit Material.
SMF-2004-002244-00,Unit One Containment Sump Flow Counter Inoperable
SMF-2004-001177-00,Ts Surveillance Requirement (Sr) 3.3.5.3, Channel Calibration Was Not Completed Within the Required Frequencies for All Functions Specified on Table 3.3.5-1
SMF-2004-000797-00,Violation of Ts 3.7.17 `Spent Fuel Assembly Storage`
SMF-2004-000514-00,During Replacement of U1 Ehc System Dc to Dc Converter, Experienced Approximately 300 Mwe Load Reject

SMF-2004-000100-00,Received Channel Iii Rwst Level Low Computer Alarm and after Comparing to Other Three Channels Dispatched Prompt Team to Investigate Channel Iii.
SMF-2003-004016-00,Unit Two Reactor/turbine Trip
SMF-2003-003675-00,Questionable CP Air Pressure Test Rig That Is Used to Check the Seals of the Shipping Container for Air Leakage.
SMF-2003-003599-00,Loop 2-p-0935 Was Found to Be Inoperable. It Was Discovered at 0945 11/05/2003 That it Had Been Inoperable since 0530 11/03/2003.
SMF-2003-003559-00,During Performance of Opt-205b Containment Spray Sys Vpv, Found 2ct-0030 and 2ct-0034 Closed.
SMF-2003-003283-00,Refueling Machine Festoon Brace Broke and Fell into Lower Internals Storage Stand.
SMF-2003-002463-00,Technical Specification Lco 3.0.3 Entered When Both Trains of Control Room Air Condition System Were Identified as Inoperable per Ts Lco 3.7.11.
SMF-2003-002356-00,Circ Water Pump 2-01 Tripped, Resulting in a Loss Unit Two Output of 15 Mw.
SMF-2003-002196-00,Feed Water Pump 2b Tripped on Low Suction Pressure after Feed Heaters 5b & 6b Were Unisolated. Turbine Was Manually Tripped.
SMF-2003-002120-00,Improper Bearing Installation Performed During Rebuild of Saftey Chiller 2-06.
SMF-2003-001384-00,Leakage Indicated from Unit 2 Primary Water System into Unit 2 Main Generator.
SMF-2003-000754-00,Unit 1 Manual Reactor Trip Initiated Due to Loss of Main Feedwater.
SMF-2003-000571-00,Fire Pump X-04 Unexpected Start. 11,500 Gallons of Water Pumped into Mmo Building (2k3). Reportable to Tceq. 50.72 to Nrc Issued
SMF-2002-004167-00,Rod Control System Malfunction Which Caused Shutdown Bank B Rod G-13 to Fully Insert.
SMF-2002-004139-00,Unit 1 Reactor Achieved Criticality Outside the 500 Pcm Limit, but above the Rod Insertion Limit.

SMF-2002-004064-00,Unit 1 Manual Shut Down. During Hot Torque Activity on 1ms-0063, a Loud Popping Noise Came from Valve Body and Graphoil Dust Covered the Inner Side of Yoke.
SMF-2002-004026-00,Primary Water Pump Inboard Labyrinth Seal Leaking.
SMF-2002-003951-00,Packing Leak on 1-hv-2336a During Packing Consolidation.
SMF-2002-003916-00,Multiple Cycling of U2 Main Turbine Control Valves Resulted in a Secondary Transient, Stabilizing at Approximately 950 Mw with Turbine Control on Mhc.
SMF-2002-003915-00,Ran Rhrp 1-02 for Approximately Five Minutes with the Discharge Valve Closed.
SMF-2002-002151-00,Unit Two Reactor Tripped on Pw Pump Shaft Vibration Signal
SMF-2003-000200-00,Personnel Error Caused Loss of Protection Bus 1pc2 During Restoration of Iv1pc2.
SMF-2003-001567-00,Since August 6, 2002, Seven Incidents of Safeguards Information Being Improperly Stored, Unattended, or Containers Left Open.
SMF-2003-001857-00,Declared Sswp 2-01 Inoperable Due to Failure of Opt-207b.
SMF-2003-002158-00,`Yellow` Soer 03-02, `Managing Core Design Changes` Requires Assessment per Nqa-2.30 and Requires a 150 Day Response.
SMF-2003-002435-00,Through Wall Leak on Fire Protection Pipe.
SMF-2003-003018-01,While Removing 2-hs-6554a an Energized Cable Was Discovered.

SMF-2003-003264-00,Area for Improvement from 2003 Inpo Radiological Protection Assessment
SMF-2003-003479-00,Unit 2 Tdafwp Would Not Control Speed During Opt-206b.
SMF-2003-003898-00,Self-assessment Afis and Issues - 2002 Inpo Findings
SMF-2004-000620-00,Individual Entered a Posted High Rad Area Without First Contacting Rp as Specified on the Associated Posting.
SMF-2004-000774-00,Performance Indicator for Unplanned Scrams per 7000 Hours Is above Site Threshold
SMF-2004-001024-00,Source Range Channel N31 Did Not Respond During the Plant Shutdown for 1rf10
SMF-2004-001193-00,2cs-8386b Failed
SMF-2004-001204-00,Inadvertent Removal of Wrong Lock Box Led to Damage of Rvlis Probe.
SMF-2004-001350-00,A Damaged Control Rod Was Discovered During Ut Inspections. One Rodlet Remains in Assembly L11.
SMF-2004-001419-00,During Performance of Opt-435a the Recorder at Safety Chiller 1-06 Malfunctioned Failing to Capture Acceptance Criteria Data.
SMF-2004-001427-01,Diesel Generator 1-02 Phase C Linear Reactor Overheated During Start Up.
SMF-2004-001581-00,Stud Can Hit During Control Rod Shaft Installation.
SMF-2004-001869-00,Testing of Unit 1 Turbine Generator Digital Controls Causes 260 Mwe Load Reduction.
SMF-2004-001927-00,Surveillance for –16 PMM Response Time (5-04-501803-aa) Did Not Meet Response Time Allowable Range Criterion as Specified in Inc-7662a
SMF-2004-002391-00,In Trending of Unit 2 Tpcw for June 2004, Copper and Suspended Impurities Were Noted to Have Increased at a Rate Much Greater than Anticipated.
SMF-2004-002679-00,Quality Assurance Deficiencies Identified During Performance of Nuclear Overview Audit of Maintenance Procedures and Documents.
SMF-2004-002831-00,Increase in Fission Product Gas Observed in Unit 1 Rcs Sample.
SMF-2004-002865-00,Procedures Not Being Maintained Current
SMF-2004-002938-00,This Smartform Is to Request a Look at the Following Events and the Challenges They Presented to Determine If There Is a Common or Programmatic Issue That Needs to Be Addressed.
SMF-2004-002962-00,Adverse Trend Identified
SMF-2004-003187-00,2-p-0935 Indicates Low after Performance of Routine Maintenance.
SMF-2004-003306-00,Discovery of Unposted Radiation Area in 790` Auxiliary Building Corridor. Good Catch for S. J. Stalling.
SMF-2004-003485-00,Secondary System Air Operated Valve Failures Are Causing Challenges to Plant Operation. ,Weaknesses in Corrective Actions from Focused Self-assessment Results
SMF-2004-004026-00,Inpo Has Re-issued a Wano Report on Loss of Grid and it Is Listed as Soer 99-01, Addendum. This Report Needs to Be Assessed per Sta-426.
SMF-2005-000323-00,Issues Were Identified During Nuclear Overview Audit Eval-2005-031, `Procurement and Materials Management`
SMF-2005-000591-00,Scaffold Erection Within Flash and Limited Approach Boundary of 345 Kv Buss on 2mt2
SMF-2005-001392-00,Diesel Fire Pump X-06 Had Oil Leak from Center Head Cover Gasket.
SMF-2005-001486-00,Fuel Handling Crew Latched on to an Incorrect Assembly During Fuel Assembly Oxide Measurement Activities.

SMF-2005-001521-00,While Filling and Venting U2 Train B Rhr 2rh-0011 Was Left Open Resulting in Water Draining from the Refueling Cavity into the Containment 808`
SMF-2005-001574-00,Collectively Assess Large Motor Off-site Repair Shop Expectations and Post Repair Shop in Plant Installation Challenges.
SMF-2005-001689-00,During Equipment Walkdown of Ssw Pump 2-02 Motor, Smart 3 Electrician Noticed Oil in Level Gage Appeared to Be Abnormal in Color.
SMF-2005-001692-00,Entry Made into Unit 2 808` Incore Room to Work Barrier Modification Was Not in Accordance with the Rwp Requirements.

From: Michael S. Peck
Sent: Monday, July 6, 2005 9:59 AM
To: Snow, Douglas W
Subject: Information Request 5, Comanche Peak Comanche Peak Steam Electric Station PIR Inspection

Dear Mr. Snow:

Please provide the request data. We can pick up the larger files on-site Monday.

Thank you,
Michael

ABN-401, “Main Turbine Malfunction”
EVAL-2004-003638-02-00 - Unit 2 Main Generator “A”
Evaluations 2003-001440, 2002-003579, and 2002-003391-06, Agastat relays issue
Smart Form associated with residue in the vicinity of CRDM for rod G-13
SMF 2002-001504, Relay issues
SMF- 2002-003376, Relay issues
SMF 2002-003448 and SMF 2004-000060, NCV IR 2004009
SMF associated with FIN 05000446/2004005-01, Unit 2 Downpower Due to Loss of Heater Drain Forward Flow During Calibration of 2-HV-2589B.
SMF associated with FIN 05000446/2004005-02, Loss of Unit 2 Turbine Load Due to Missed Step in Transferring Control to Manual Hydraulic Control
SMF-2001-00728-01
SMF-2002-003579, Relay issues
SMF-2003-001773, NCV IR 2004008
SMF-2003-001773-00, NCV from IR 2004008
SMF-2003-002567-00
SMF-2003-003755-00
SMF-2003-003755-00 - UNIT 1 CONTAINMENT SUMP
SMF-2003-3594, NCV IR 2004003
SMF-2003-3898
SMF-2004-001709-00
SMF-2004-002202-00 - Unit 1 Containment Sump
SMF-2004-002360-00 - Unit 2 containment sump
SMF-2004-003639-00 - UNIT 2 LOST 'A' PHASE MAI
SMF-2004-003833, Weaknesses in Corrective Actions from Focused Self-assessment Results
SMF-2004-003883, NCV IR 2004008
SMF-2004-0069 NCV IR 2004003
SMF-2004-062 and SMF2004-0471, NCV IR 2004003
SMF-2004-1202 , NCV IR 2004003
SMF-2004-2865
SMF-2004-3306
SMF-2004-4026
SMF-2005-000155-00
SMF-2005-000652-00 - Multiple transients
SMF-2005-000679-00 - INPO Area For Improvement

SMF-2005-000948-00
SMF-2005-001149-00
SMF-2005-001390-00
SMF-2005-001400-00
SMF-2005-001662-00
SMF-2005-0032
SMF-2005-1343, not in the subdirectory
SMF-2005-1486
SMF-2005-169
SOP-401B 6 - TURBINE CONTROL FLUID SYSTEM
The Smart Form associated with Unit 2 LER-04-002-00
W.O. 4-04-155609-00
W.O. 4-04-155680-00

Please make the following data available to the team on-site Monday morning.

CLS-2-04-01660	SMF-2003-3853	SMF-2005-001308-00
EVAL-2002-001368-03-00	SMF-2004-000059	SMF-2005-001361-00
EVAL-2004-001000-01	SMF-2004-000151	SMF-2005-001549
EVAL-2004-009	SMF-2004-000691	SMF-2005-001689
EVAL-2005-001361-01-00	SMF-2004-001610	SMF-2005-001704
EVAL-2005-002113-02	SMF-2004-001662-00	SMF-2005-001781
SMF-2001-001861	SMF-2004-001677-00	SMF-2005-001835
SMF-2002-000859-00	SMF-2004-001685	SMF-2005-001854
SMF-2002-001842-00	SMF-2004-002269	SMF-2005-002113
SMF-2003-000152	SMF-2004-002411	WO-3-03-326804
SMF-2003-001075	SMF-2004-003917	WO-3-03-327774-01
SMF-2003-001161	SMF-2004-004033	WO-4-03-150145
SMF-2003-001479	SMF-2004-2568	WO-4-05-160956-00
SMF-2003-002142	SMF-2004-836	WO-5-01-505017-AB
SMF-2003-002187	SMF-2005-000069	WO-5-03-501451-AA
SMF-2003-002619	SMF-2005-000119	WO-5-03-501452-AA
SMF-2003-002756	SMF-2005-000164	WO-5-03-501453-AA
SMF-2003-003309-00	SMF-2005-000527-00	
SMF-2003-2106	SMF-2005-000870-00	

ACRONYMS

AC	alternating current
CPSES	Comanche Peak Steam Electric Station
CAP	corrective action program
RCP	reactor coolant pump
SDP	significance determination process
SMF	SmartForm
TS	Technical Specification