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

August 1, 2003

C. L. Terry, Senior Vice President
and Principal Nuclear Officer
TXU Energy
ATTN: Regulatory Affairs
Comanche Peak Steam Electric Station
P.O. Box 1002
Glen Rose, Texas 76043

SUBJECT: COMANCHE PEAK STEAM ELECTRIC STATION - NRC PROBLEM IDENTIFICATION AND RESOLUTION INSPECTION REPORT 05000445/2003-006; 05000446/2003-006

Dear Mr. Terry:

On June 19, 2003, the U. S. Nuclear Regulatory Commission (NRC) completed a team inspection at the Comanche Peak Steam Electric Station, Units 1 and 2. The enclosed report documents the inspection findings, which were discussed on June 19, 2003, with Mr. J. J. Kelley, Vice President of Nuclear Engineering and Support, and other members of your staff.

This inspection examined activities conducted under your license as they relate to the identification and resolution of problems, and compliance with the Commission's rules and regulations and the conditions of your operating license. Within these areas, the inspection consisted of selected examination of procedures and representative records, observations of activities, and interviews with personnel.

On the basis of the sample selected for review, there were no findings of significance identified during this inspection. The team concluded that problems were properly identified, evaluated, and resolved within the problem identification and resolution programs.

In accordance with 10 CFR 2.790 of the NRC's "Rules of Practice," a copy of this letter and its enclosure will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Anthony T. Gody, Chief
Operations Branch
Division of Reactor Safety

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

Enclosure:
NRC Inspection Report
50-445/03-06; 50-446/03-06

cc w/enclosure:
Roger D. Walker
Regulatory Affairs Manager
TXU Generation Company LP
P.O. Box 1002
Glen Rose, Texas 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, Texas 78711

County Judge
P.O. Box 851
Glen Rose, Texas 76043

Chief, Bureau of Radiation Control
Texas Department of Health
1100 West 49th Street
Austin, Texas 78756-3189

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

Brian Almon
Public Utility Commission
William B. Travis Building
P.O. Box 13326
1701 North Congress Avenue
Austin, Texas 78701-3326

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

Electronic distribution by RIV:
Acting Regional Administrator **(TPG)**
DRP Director **(ATH)**
Acting DRS Director **(TWP)**
Senior Resident Inspector **(DBA)**
Branch Chief, DRP/A **(WDJ)**
Senior Project Engineer, DRP/A **(TRF)**
Staff Chief, DRP/TSS **(PHH)**
RITS Coordinator **(NBH)**
Mel Fields **(MBF1)**
CP Site Secretary **(vacant)**

ADAMS: ☐ Yes ☐ No Initials: ______
☐ Publicly Available ☐ Non-Publicly Available ☐ Sensitive ☐ Non-Sensitive

R:_cpses\2003\CP2003-06RP-PCG.wpd

SOE:OB	SOE:OB	RI:PBA	C:OB	C:PBA	C:OB
PCGage / lmb	TSStetka	AASanchez	ATGody	WDJohnson	ATGody
/RA/	/RA/	NA	/RA/	/RA/	/RA/
07/31/03	07/31/03	------------	8/01/03	07/31/03	8/1/03

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

ENCLOSURE

U.S. NUCLEAR REGULATORY COMMISSION
REGION IV

Dockets:	50-445; 50-446
Licenses:	NPF-87; NPF-89
Report No.:	05000445/2003-006; 05000446/2003-006
Licensee:	TXU Electric
Facility:	Comanche Peak Steam Electric Station, Units 1 and 2
Location:	FM-56 Glen Rose, Texas
Dates:	April 28 through June 19, 2003
Inspectors:	P. C. Gage, Senior Operations Engineer, Operations Branch T. F. Stetka, Senior Operations Engineer, Operations Branch A. A. Sanchez, Resident Inspector, Projects Branch A
Approved By:	Anthony T. Gody, Chief Operations Branch Division of Reactor Safety

SUMMARY OF FINDINGS

IR 05000445/2003-006; 05000446/2003-006; TXU Energy; on April 28 - June 19, 2003; Comanche Peak Steam Electric Station, Units 1 and 2; annual baseline inspection of the identification and resolution of problems.

The inspection was conducted by two senior operations engineers and a resident inspector.

Identification and Resolution of Problems

The team identified that the licensee was effective at identifying problems and putting them into the corrective action program. The licensee's effectiveness at problem identification was evidenced by the relatively few deficiencies identified by external organizations (including the NRC) that had not been previously identified by the licensee, during the review period. The licensee effectively used risk in prioritizing the extent that individual problems would be evaluated and in establishing schedules for implementing corrective actions. Corrective actions, when specified, were implemented in a timely manner, with few exceptions. Licensee audits and assessments were found to be effective. On the basis of interviews conducted during this inspection, workers at the site felt free to input safety findings into the corrective action program.

REPORT DETAILS

4OA2 Identification and Resolution of Problems

a. Effectiveness of Problem Identification

(1) Inspection Scope

The inspectors reviewed items selected across the seven cornerstones of safety to determine if problems were being properly identified, characterized, and entered into the corrective action program for evaluation and resolution. Specifically, the inspectors selected 73 smart forms from over 3000 that had been issued between November 1, 2001, to January 31, 2003. The inspectors also reviewed several licensee audits and self-assessments associated with the corrective action program. The effectiveness of the audits and assessments was evaluated by comparing the audit and assessment results against self-revealing and NRC-identified findings.

The inspectors evaluated the smart forms to determine the licensee's threshold for identifying problems and entering them into the corrective action program. Also, the licensee's efforts in establishing the scope of problems were evaluated by reviewing pertinent control room logs, work requests, engineering modification packages, self-assessment results, system health reports, action plans, and results from surveillance tests and preventive maintenance tasks. The smart forms and other documents listed in the attachment were used to facilitate the review.

The inspectors also conducted walkdowns and interviewed plant personnel to identify other processes that may exist where problems and findings could be identified. The inspectors reviewed work requests and attended the licensee's work control meeting to understand the interface between the corrective action program and the work control process.

(2) Issues

The team determined that the licensee was effective at identifying problems and entering them into the corrective action system. This was evidenced by the relatively few deficiencies identified by external organizations (including the NRC) that had not been previously identified by the licensee during the review period. Licensee audits and assessments were of sufficient depth and identified issues similar to those that were self-revealing or raised during previous NRC inspections. Also, during this inspection, there were no instances identified where conditions adverse to quality were being handled outside the corrective action program.

The team identified no significant findings related to effectiveness of problem identification.

b. Prioritization and Evaluation of Issues

(1) Inspection Scope

The team reviewed 73 smart forms and supporting documentation, including analyses of the problem causes, to ascertain whether the licensee's evaluation of the problems identified considered the full extent of conditions, generic implications, common causes, and previous occurrences. In addition, the team reviewed the licensee's evaluation of selected industry experience information, including operating event reports and NRC and vendor generic notices, to assess if issues applicable to the Comanche Peak Steam Electric Station were appropriately addressed. In addition, the team also reviewed selected smart forms to ascertain satisfaction of the provisions of 10 CFR Part 50, Appendix B, regarding timeliness of corrective action for those action requests applying to degraded or nonconforming structures, systems, and components. The team also interviewed engineering and technical personnel concerning the actions taken on action requests. Specific items reviewed are listed in the attachment to this report.

(2) Issues

The inspectors reviewed the licensee's evaluation for gas binding of the Unit 1 centrifugal charging Pump 1-01, which occurred on December 7, 2002, (Smart Form 2002-004242-00). The licensee concluded that the binding of the centrifugal charging pump (CCP) was caused by two simultaneous events: 1) an evolution in which hydrogen gas was coming out of solution in the suction lines of the CCP, and 2) the blockage of the vent line valve for those suction lines. The significance of this issue was documented in NRC Inspection Report 50-445/2002-05; 05-446/2002-05.

At the time of the event (Mode 5-Solid Plant Operation), the volume control tank was bypassed while it was being mechanically degassed. The CCP 1-02 was in operation and its suction was being supplied via the letdown line in the residual heat removal system. The suction of the charging pump was, at that time, the lowest pressure in the system at 25 psig. The saturation hydrogen concentration for 25 psig is 45 cc/kg. With the reactor coolant system hydrogen concentration at approximately 55 cc/kg, hydrogen gas was coming out of solution at the suction of the charging pump. While trying to swap charging pumps from CCP 1-02 to CCP 1-01, operators discovered that the CCP 1-01 was air bound and restarted CCP 1-02. Results from performing ultrasonic testing on the piping indicate that water was present above the vent line Valve 1-HV-8220 and gas was detected below the same valve. The licensee concluded that there was some sort of blockage at that valve location. Subsequent removal of the spool piece revealed several small "pepper flakes" that may have aided in blocking or partially blocking the 1/8" diameter vent valve (the vent line itself has a 3/4" diameter).

The immediate corrective actions performed by the licensee were adequate and involved constant ultrasonic testing of the charging pump vent suction lines, an operability determination of CCP 1-01, and removing, disassembling, and inspecting the suspected valve for evidence of blockage. Long-term corrective actions include:

modifying related procedures, a design modification to re-slope the vent lines for better gas flow, and the replacement of the existing vent valves with valves that have the full 3/4" valve openings to match the pipe diameter. The licensee planned to implement the design modifications during the Unit 2 outage in the Fall of 2003, and the Unit 1 outage in the Spring of 2004.

No findings of significance were identified.

c. Effectiveness of Corrective Actions

(1) Inspection Scope

The team reviewed the Smart Forms, audits, and assessments described in Section 4OA2.a.(1) above to verify that corrective actions, related to the issues, were identified and implemented in a timely manner commensurate with safety, including corrective actions to address common cause or generic concerns. The team also conducted plant walkdowns and interviewed plant personnel to independently verify and assess the effectiveness of corrective actions implemented by the licensee. A listing of specific documents reviewed during the inspection is included in the attachment to this report.

(2) Issues

On October 7, 2002, Emergency Diesel Generator (EDG) 1-02 unexpectedly started as the result of the loss of the 345kV bus caused by switchyard testing activities. The team determined that timely notifications were made in accordance with 10 CFR 50.72 and that other plant equipment performed as required. As the result of this event, the licensee issued Smart Forms 2002-003376-00 and 2002-003391-00 to address the unexpected start of EDG 1-02. Smart Form 2002-003391-00 included a root cause analysis of Agastat relay failures. This smart form identified that the relay failures could have been caused by aging and included developing plans to replace the relays. In addition, the licensee determined at that time that the life expectancy for these relays was 12 years.

The team noted that Smart Form 2002-003391 was still open (in the planning stage) and that many corrective actions were not yet scheduled. The long-term actions to be taken by the licensee were reviewed by the team. The team noted that, in addition to the fact that the plans and schedule for relay replacement were not finalized, that there were 364 relays (182 per unit) in plant systems that were vulnerable to the effects of aging. Following record reviews and discussions with the licensee, the team determined that the licensee had already replaced 43 relays. This meant that there were 321 relays installed for greater than the assumed 12-year life expectancy period.

During review of this event by the team, it was determined that Smart Form 2002-001504, which was issued on April 18, 2002, identified that Agastat relays used in the 6.9kV bus transfer circuitry, were exhibiting setpoint drifting. The team noted that the licensee attributed this problem of setpoint drifting outside allowed tolerances to two potential factors: 1) not resetting the relay setpoints to the center of

the tolerance range and 2) relay aging. The licensee replaced the defective relays and determined that there was no program to periodically replace these 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 team noted that the licensee did not expand these corrective actions to include any other systems that used these relays.

Since relay aging was a concern, and continuously energized relays were more susceptible to aging failures, the team asked the licensee to provide the number of these relays that were continuously energized. Furthermore, to ensure that equipment controlled by these Agastat relays remained operable or that a relay failure would not prevent a safety function from being accomplished, the team inquired whether any relay failure operational evaluation was performed. The licensee informed the team that an operational evaluation was performed as one of the corrective actions in Smart Form 2002-003579-00 that was issued on October 16, 2002. The team reviewed this smart form and discussed the results of the evaluation with licensee personnel. Based on this review and discussions, the team noted that the licensee planned on replacing only a limited number of relays (e.g., only 36 ‘B’ train relays were to be replaced during the upcoming 2RF07 refueling outage). Therefore, the team requested a relay listing that provided the relay replacement priority for the remaining 321 relays. When this listing was provided by the licensee, it was noted that the operational evaluation performed in 2002-003579-00 only covered 143 of the 321 relays. Therefore, in addition to the number of these relays that were continuously energized, the team requested an operational evaluation that encompassed the balance of the 321 relays and a risk assessment that established the relay replacement priority.

Subsequent to the onsite inspection activities, the licensee submitted Evaluations 2002-003391-06-01 and 2003-001440-01-01 to the team. Evaluation 2002-003391-06-01 provided details regarding the relay aging issue. As the result of reviewing environmental qualification testing data, the licensee concluded that the relay service life was 41 years in lieu of the originally proposed 12 years. In addition, this testing data indicated that the relays had the capability to operate up to 32,120 cycles. Since the relay installations were from 13 to 18 years and the relays were subjected to a maximum of 200 cycles per year (or 8400 cycles in 41 years), the licensee concluded that the presently installed relays were not near the end of their life expectancy and, therefore, remained capable of performing their intended tasks.

Evaluation 2003-001440-01-01 provided the operational evaluation details. This evaluation determined that none of these relays were continuously energized. It further determined that 152 of the 364 relays did not perform any safety-related function. Therefore, the licensee concluded that these 152 relays were not subjected to their periodic replacement program but were part of their maintenance rule program. The remaining 212 relays did involve safety-related functions, however, two of these relays

were spare relays and, therefore, were not used. This left 210 relays that involved safety-related operations. Since the main effect of aging on these relays was an increase in setpoint drift with a maximum drift of $\pm$ 18 percent, the licensee determined that a setpoint drift of $\pm$ 18 percent would not prevent the relays from completing their intended tasks.

The team reviewed these evaluations and the relay tabulation that was a part of Evaluation 2003-001440-01-01, and concurred with the licensee's conclusions. While the licensee's corrective actions as documented in Smart Forms 2002-003391 and 2002-3579, and Evaluation 2003-001440-01-01 were adequate, the licensee's response to this event was untimely. 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 team concluded that the licensee's corrective actions, while adequate, were not timely. The effort to address the potential aging issue and its effect on plant operation was not addressed until a self-revealing emergency diesel generator start occurred almost 6 months later. Furthermore, an operability determination that included all of the affected relays and a detailed relay aging study was not conducted until licensee personnel were prompted by the NRC inspection team.

Based on these reviews, the team concluded that the main effect of aging on the Agastat relays was that of setpoint drift. Since the relays were tested as a part of the routine surveillance program, the licensee minimized the time that the relays were out of tolerance. Although the licensee's corrective actions were not timely, the team determined that operability of the relays was never adversely affected and no future relay operability issues were expected. In addition, the team determined that no safety related operations were compromised as the result of this issue. Therefore, the team concluded that no findings of significance were identified.

d. Assessment of Safety-Conscious Work Environment

(1) Inspection Scope

The team interviewed several members of the licensee's staff, which represented a cross-section of functional organizations and supervisory and non-supervisory personnel, regarding their willingness to identify safety issues. These interviews assessed whether conditions existed that would challenge the establishment of a safety-conscious work environment.

(2) Issues

The team concluded, based on information collected from these interviews, that employees were willing to identify issues and accepted the responsibility to pro-actively identify and enter safety issues into the corrective action program. This employee willingness to identify issues was reflected by the fact that over 3000 smart forms had been generated in the 14-month period covered by the inspection.

No findings of significance were identified.

4OA3 Event Follow-up

1. (Closed) Licensee Event Report 50-00445/02-004-00, Two Pressurizer Safety Valves Found With Unsatisfactory Lift Setpoints

   On October 23, 2002, the licensee discovered that two Unit 1 pressurizer safety relief valves, 1-8010A and 1-8010C, failed the “as found” lift pressure setpoint surveillance by lifting at a pressure of 2 and 1.6 percent, respectively, below the Technical Specification 3.4.10.1 setpoint of 2485 psig. The reason for the failure was determined to be setpoint drift. All pressurizer safety relief valves were reworked by the vendor, installed in the plant, and the technical specification surveillance requirements were successfully met. The licensee event report was reviewed by the inspectors and no findings of significance were identified. The licensee documented the issue in Smart Form 2002-003745-00. This licensee event report is closed.

2. (Closed) Licensee Event Report 445/02-002-00, Technical Specification Report for Steam Generators Meeting C-3 Category

   On September 28, 2002, Comanche Peak Steam Electric Station, Unit 1, was shutdown for the ninth refueling outage. During this outage, non-destructive examination of the steam generator tubes was conducted as required by the technical specifications. This examination revealed that greater than 1 percent of the tubes in three of the four steam generators were defective. The majority of the defects were attributed to stress corrosion cracking. The licensee plugged or sleeved all of the defective tubes and documented the event in Smart Form 2002-003142-00. Details of this event and the licensee event report were reviewed during a NRC special team inspection documented in NRC Inspection Report 50-445/02-09. This licensee event report is closed.

3. (Closed) Licensee Event Report 445/02-003-01, Auto Start of the CPSES Unit 1 Train B Emergency Diesel Generator

   On October 7, 2002, Emergency Diesel Generator 1-02 unexpectedly started as the result of the loss of the 345kV bus caused by switchyard testing activities. The team determined that timely notifications were made in accordance with 10 CFR 50.72 and that other plant equipment performed as required. As the result of this event, the licensee issued Smart Forms 2002-003376-00 and 2002-003391-00 to address the unexpected start of Emergency Diesel Generator 1-02. Smart Form 2002-003391-00 included a root-cause analysis of the Agastat relay failures. This smart form identified that the relay failures could have been caused by aging and included developing plans to replace the relays. Details of this event and the licensee event report were reviewed during this NRC team inspection. The results of that review are documented in Section 4OA2c(2) of this report. This licensee event report is closed.

.4OA6 Meetings, including Exit

The team discussed these findings with Mr. J. J. Kelley, Vice President of Nuclear Engineering and Support, and other members of the licensee's staff on June 19, 2003. Licensee management provided no further comment on the findings.

Licensee management did not identify any materials examined during the inspection as proprietary.

ATTACHMENT

KEY POINTS OF CONTACT

Licensee

C. Beerck, Senior Nuclear Specialist
J. Kelley, Vice President, Nuclear Engineering and Support
M. Lucas, NOD Manager
F. Madden, Nuclear Licensing Manager
D. Reimer, Technical Support Manager
D. Snow, Senior Regulatory Compliance Specialist
R. Sorrell, System Engineer
M. Sunseri, System Engineering Manager
J. White, Programs Engineering

NRC

D. Allen, Senior Resident Inspector

ITEMS CLOSED DISCUSSED

Closed

LER 50-00445/02-004-00	Two Pressurizer Safety Valves Found With Unsatisfactory Lift Setpoints
LER 445/02-002-00	Technical Specification Report for Steam Generators Meeting C-3 Category
LER 445/02-003-01	Auto Start of the CPSES Unit 1 Train B Emergency Diesel Generator

DOCUMENTS REVIEWED

The following documents were selected and reviewed by the inspectors to accomplish the objectives and scope of the inspection and to support any findings:

Procedures:

IPO-005A, “Plant Cooldown from Hot Standby to Cold Shutdown,” Revision 20
SOP-103A, “Chemical and Volume Control System,” Revision 13
STA-422, “Processing SmartForms,” Revision 18
STA-421, “Initiation of SmartForms,” Revision 10
RPI-232, “Charcterizing Radioactive Material for Shipment,” Revision 4
RPI-242, “Radioactive Waste Characterization and Classification,” Revision 4
RPI-528, "Multiple Dosimetry Badging," Revision 8
RPI-602, "Radiological Surveillance and Posting," Revision 22

Smart Forms:

2000-001693	2002-001330	2002-002601	2002-003875
2001-000677	2002-001332	2002-002612	2002-003915
2001-001567	2002-001408	2002-002796	2002-003955
2001-002738	2002-001504	2002-003042	2002-003973
2001-002842	2002-001534	2002-003142	2002-003975
2001-002940	2002-001543	2002-003170	2002-004013
2002-000328	2002-001563	2002-003238	2002-004114
2002-000489	2002-001616	2002-003273	2002-004158
2002-000524	2002-001673	2002-003329	2002-004167
2002-000548	2002-001873	2002-003368	2002-004211
2002-000611	2002-002050	2002-003376	2002-004220
2002-000731	2002-002158	2002-003391	2002-004227
2002-000738	2002-002169	2002-003406	2002-004228
2002-000758	2002-002181	2002-003436	2002-004242
2002-000777	2002-002254	2002-003521	2002-004264
2002-000889	2002-002300	2002-003579	2002-004350
2002-000965	2002-002303	2002-003745	2003-000758
2002-001106	2002-002566	2002-003791	2003-001440
2002-001272			

Preventative Maintenance (PM)

343410
343411
343412
343413

Work Orders (WO)

WO 3-01-318222-01	WO 3-00-306229-01	WO-4-02-144019-00
WO 3-01-318223-01	WO 4-02-144710-00	WO-4-01-138937-00
WO 3-01-318224-01	WO 5-01-502507-AA	WO-4-02-143026-00
WO 3-01-318225-01	WO 3-02-343413-01	WO-4-02-145755-00
WO 2-02-142986-00	WO 3-02-343410-01	

Licensee Event Reports

050-445/02-004-00
050-445/02-002-00
050-445/02-003-01

General Access Permits (GAPs)

2003-03	2003-06
2003-04	2003-22

Audits and Assessments:

SA-2003-020
Corrective Action Program Health Report 1st Quarter 2003
Corrective Action Program Health Report 4th Quarter 2002

Miscellaneous

Pages 20 and 21 of the Comanche Peak S.E.S. Qualification Testing of Two Representative Auxiliary & Protective Relay Racks to IEEE STD. 323-1974, dated 4/23/1982

2RF06 Mid Outage Human Performance/Safety Agenda

Radiation Survey 02-04-01686

Radiation Protection Guideline 6-5, Pre-Job Briefings, Revisions 0, 1, and 2

Radiation Protection Guideline 6-10, Refueling Outage Guideline and Checklist, Revision 0

Westinghouse Electric Company letter 01TB-G-008 dated March 30, 2001, “Welded Top Nozzle Material”

Westinghouse Electric Company letter 01TB-G-018 dated May 29, 2001, “Comanche Peak Spent Fuel Pool Chemistry Data Review”

OE13514 and OE13480, Control Rod Drive Mechanism Nozzle Circumferential Flaws and Material Voids at Davis-Bessie, 3/8/2002

Significant Operating Experience Report (SOER) 02-4, Reactor Pressure Vessel Head Degradation at Davis-Besse Nuclear Power Station, November 11, 2002

EPRI letter dated December 3, 2002, Seabrook Axial Cracking at Tube Support Plate :and Contact Points

DOCUMENTS REQUESTED

Information Request
Comanche Peak PIR Inspection (IP 71152) 2003-06

The inspection will cover the period of November 1, 2001 to January 31, 2003. All requested information should be limited to this inspection period, unless otherwise specified. The information may be provided in either electronic or paper media or a combination of these. Information provided in electronic media may be in the form of e-mail attachments or 3 ½ inch floppy disks. The agency's text editing software is Corel WordPerfect 8; however, we have documenting viewing capability for Adobe Acrobat(.pdf) text files.

Please provide the following information to Paul Gage in the Region IV Arlington Office by March 24, 2003. If you have any questions or comments, please contact myself at (817) 860-8273 or e-mail me at pcg@nrc.gov.

NOTE: In an effort to keep the requested information organized please submit the information to us using the same numbering/lettering system below. Thank you up-front for the support.

1. Summary list of all smart forms generated during the specified period and sorted by:

   chronology
   initiating organization
   responsible organization

2. All quality assurance audits and surveillances of corrective action activities since November 1, 2001.

3. All corrective action activity resulting from functional area self-assessments since November 1, 2001.

4. Corrective action performance trending/tracking reports generated since November 1, 2001, including the current predictive performance summary reports.

5. Current revision of the following procedures:

   "Initiation of Smart Forms"
   "Processing of Smart Forms"
   "Disposition of Smart Forms Identifying Potential Adverse Conditions"
   "Root Cause Analysis."

6. Any additional governing procedures/policies/guidelines for:

   Condition Reporting
   Corrective Action Program
   Probable (or apparent) Cause Evaluation/Determination

7. For each of the items applicable to Comanche Peak listed below please provide the following:

- ☐ Full text of the smart form (please indicate any findings that did not result in a smart-form or corrective actions)
- ☐ Any “Roll-up” or “Aggregating” smart forms related to the generic communication or smart form.
- ☐ Root Cause analysis report (if applicable)
- ☐ Risk significance assessments
- ☐ Probable Cause evaluation (if applicable)
- ☐ Approved corrective actions
- ☐ Basis for extending originally approved due dates
- ☐ Evidence of corrective action completion for those items deemed to be closed (work packages, design change documentation, temporary modifications, training lesson plans/material, training attendance records, procedure revisions, etc.)

1. <u>Part 21 Reports:</u>

2002-13	5/15/02	loose fan blade in UPS
2002-17	7/24/02	pressure transmitter calibration
2002-23	8/30/02	damping circuit capacitor failures
2002-24	9/9/02	dp transmitter not meeting specification

b. <u>NRC Information Notices:</u>

2002-01	1/18/02	metalclad switchgear failures
2002-02	1/8/02	plugged SG tubes
2002-04	1/10/02	wire degradation at breaker cubicle hinge
2002-09	2/13/02	fuel assembly top nozzle separation
2002-10	3/7/02	SG water level setpoints
2002-11	3/12/02	reactor pressure vessel head degradation
2002-13	4/4/02	reactor pressure vessel head degradation
2002-14	4/8/02	owner-controlled area evacuation
2002-18	6/6/02	adding gas effects on NPSH
2002-21	6/25/02	SG tube cracking
2002-22	6/28/02	degraded EDG bearing surfaces
2002-25	8/26/02	prompt notification during EP event
2002-29	10/15/02	pneumatic system design problems
2002-35	12/20/02	quality assurance program changes
2003-02	1/16/03	RCS leakage & boric acid corrosion
2003-03	1/27/03	inadequate staked capscrew on RHR pump

c. <u>NRC Bulletins:</u>

2001-01	8/3/01	cracking of reactor vessel head nozzles
2002-01	3/18/02	reactor coolant pressure boundary integrity
2002-02	8/9/02	vessel head & penetration inspection

d. <u>NRC Regulatory Issue Summaries:</u>

2002-06	4/16/02	individual occupational dose
2002-10	7/9/02	10 CFR part 20 skin dose limit
2002-12a	8/19/02	power reactors protective measures
2002-12i	10/3/02	transportation of spent nuclear fuel
2002-14	8/28/02	safety system unavailability indicator
2002-18	10/3/02	physical protection measures

e. All NCVs and NOV's issued since November 1, 2001

8. Listing of plant safety issues generated through the employee concerns program since November 1, 2001

9. Listing of action items generated by the plant safety review committees since November 1, 2001