UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555

January 27, 1992

Docket Nos. 50-445
and 50-446
License No. NPF-87
Construction Permit No. CPPR-127

Texas Utilities Electric Company
ATTN: W. J. Cahill, Jr.
Group Vice President, Nuclear
Skyway Tower
400 North Olive Street, L.B. 81
Dallas, Texas 75201

Gentlemen:

SUBJECT: COMANCHE PEAK CONFIGURATION MANAGEMENT INSPECTION
(50-445/91-202; 50-446/91-201)

We are forwarding the report of the configuration management inspection (CMI) conducted by the U.S. Nuclear Regulatory Commission (NRC) staff from November 18 through December 13, 1991. The activities involved are authorized by NRC Operating License NPF-87 and Construction Permit CPPR-127 for the Comanche Peak Steam Electric Station, Units 1 and 2, respectively. At the conclusion of the inspection, the team discussed the findings with you and members of your staff.

The inspection team examined both design and construction attributes and reviewed Unit 2 as-built components, systems, and structures to assess the adequacy of the design control program and ensure proper translation of design requirements. The team focused on the residual heat removal (RHR) system and power distribution systems for alternating current (ac) and direct current (dc). The team also assessed the adequacy of your self-assessment initiatives.

The team determined that the plant was staffed with competent, knowledgeable personnel who executed their duties in a professional manner and appeared capable of designing, constructing, and testing Comanche Peak Unit 2 in a satisfactory manner. However, the team identified the following deficiencies: (1) multiple examples of failures to verify or check the adequacy of design, (2) component cooling water (CCW) instrument air lines incorrectly run, (3) failure to follow procedures during construction activities, (4) failure to maintain adequate control of pipe supports during system flushing, and (5) an example of improperly installing Hilti bolt impermeable material. Although some deficiencies had implications for the operating unit, the affected Unit 1 equipment was determined operable after analysis.

The team identified a number of field discrepancies. Although these discrepancies were unrelated and did not seem indicative of programmatic

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trends, unlike punchlist items, they had not been previously identified. When the items were brought to the attention of the licensee, you often indicated that there were followup programs in place to find such discrepancies. This late in the program, we are concerned about your heavy reliance on room and system turnover programs to detect and correct plant deficiencies. Scheduling pressures could affect the quality of work if detection and correction of deficiencies are deferred to the end of construction.

The team was concerned with the number of examples of failure to verify or check the adequacy of the design (see Deficiency 50-445/91-202-01 and 50-446/91-201-01). Although none of the examples found by the team were individually safety significant, when viewed collectively they may be indicative of a more pervasive weakness. We therefore request that you review this matter and advise us as to what, if any, additional corrective actions are planned.

The team also noted several strengths, including the utility's prompt response to new generic issues and the positive results of the "Team Plus" program. The availability of detailed engineering guidelines for pipe stress and pipe support analysis and scaling calculations, the consistency of operating procedures with design-basis assumptions, and the effective integration of the site contractor organization were all considered strengths.

The Executive Summary provides an overview of the inspection and the inspection report and the appendices provide a more detailed explanation of the inspection effort and related findings.

You are requested to respond to this office within 60 days to inform us of the action taken related to deficiency 50-445/91-202-01, 50-446/91-201-01 and both unresolved items identified in the enclosed inspection report. The NRC Region IV office will issue any enforcement action that may result from this inspection.

In accordance with 10 CFR 2.790(a), a copy of this letter and its enclosures will be placed in the NRC Public Document Room. Should you have any questions concerning this inspection, please contact me or Mr. J. D. Wilcox, Jr. (301-504-2965) of this office.

Sincerely,
ORIGINAL SIGNED BY
Bruce A. Boger, Director
Division of Reactor Projects, III/IV/V
Office of Nuclear Reactor Regulation

Enclosure: Inspection Report 50-445/91-202; 50-446/91-201

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Robert Gramm for

unlike punchlist items, they had not been previously identified. When the items were brought to the attention of the licensee, you often indicated that there was a followup program in place to find such discrepancies.

We are particularly concerned about your heavy reliance on room and system turnover programs to detect and correct plant deficiencies. This practice could affect construction resources and the quality of workmanship if scheduling pressures result from work associated with turnover punchlists.

We are also concerned with the number of examples of failure to verify or check the adequacy of the design (see Deficiency 50-445/91-202-01 and 50-446/91-201-01). Although none of the examples found by the team were individually safety significant, when viewed collectively may be indicative of a more pervasive weakness. We therefore request that you review this matter carefully and advise us as to what, if any, additional corrective actions are planned.

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You made numerous commitments during the inspection. These commitments are identified throughout this report. Of particular interest was your commitment in Section 3.7.6.3 which indicated that Firezone R cable would be installed outside containment in areas where the total radiation dose is less than or equal to 50 millirads (gamma) and in areas that do not suffer the direct effects of a main steam line break.

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Office of Nuclear Reactor Regulation

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U.S. NUCLEAR REGULATORY COMMISSION

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Division of Reactor Inspection and Safeguards

NRC Inspection Report: 50-445/91-202/ License: NPF-87
50-446/91-201 Permit: CPPR-127

Dockets: 50-445 and 50-446

Licensee: Texas Utilities Electric Company

Facility Name: Comanche Peak Steam Electric Station, Units 1 and 2

Inspection at: Comanche Peak site, Glen Rose, Texas

Inspection Conducted: November 18 through 22 and December 2 through 13, 1991

Inspection Team: J.D. Wilcox, Jr., Team Leader, NRR
Hai-Boh Wang, Operations Engineer, NRR
Lloyd Zerr, Operations Engineer, NRR
John McIntyre, Mechanical Engineer, NRR
Michael Franovich, General Engineer, NRR
Stewart Magruder, Reactor Inspector, NRR
Lee Ellershaw, Regional Inspector, RIV
Tom McKernon, Reactor Inspector, RIV

Supporting Team Members: Eric Young, Department of Energy
Kim Sidey, Department of Energy
Fred Brookes, NII, U.K.
Mike Jeal, NII, U.K.

NRC Consultants: Don L. Harris, Parameter, Inc.
Nicholas Rivera, Parameter, Inc.
Herb Stramberg, Parameter, Inc.
David Waters, Parameter, Inc.

Prepared by: [signature] 1/22/92
John D. Wilcox, Jr., Team Leader — Date
Team Inspection Development Section B
Special Inspection Branch

Reviewed by: Robert A. Gramm 1/27/92
Robert A. Gramm, Section Chief — Date
Team Inspection Development Section B
Special Inspection Branch

Approved by: Robert A. Gramm for/ 1/27/92
Eugene V. Imbro, Chief — Date
Special Inspection Branch

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EXECUTIVE SUMMARY

From November 18 through December 13, 1991, a team of eight inspectors from the U.S. Nuclear Regulatory Commission (NRC), two inspectors from the U.S. Department of Energy, two inspectors from the Nuclear Installations Inspectorate of the United Kingdom, and four NRC consultants performed a configuration management inspection (CMI) at the Comanche Peak Steam Electric Station (CPSES), Units 1 and 2. With emphasis on Unit 2, the CMI team reviewed design and construction attributes of the CPSES to assess the adequacy of the design control program, to ensure proper translation of the design requirements into the as-built plant, and to determine the adequacy of the utility self-assessment initiatives. The team primarily focused on the work activities and design attributes associated with the residual heat removal system and the ac and dc power distribution systems. In addition, the team observed the interaction between the licensee and its four major contractors on site. The team also evaluated the licensee programs, such as the post-construction hardware validation program and the permanent equipment transfer program, to further determine control of the design configuration.

Although the CMI team concluded that the licensee had implemented generally effective programs to ensure the quality of design, construction, testing, and control of work activities, it did find deficiencies. For example, temporary piping supports were improperly removed and flushing criteria were insufficiently verified in the system flushing program. There were inaccuracies in the design-basis documents (DBDs) and associated calculations, such as incorrect pressures and temperatures used in Class 1 piping analysis; several examples of the licensee's failure to follow procedures; and cleanliness control problems, such as misplaced pipe caps. In addition, the licensee failed to take adequate corrective action in some cases, such as incomplete resolution of the Hilti bolt corrosion issue; and there was an example of failure to assure that the as-built configuration was in conformance with the design and construction documents. However, the licensee properly revised deficient calculations, performed operability assessments for items affecting Unit 1, and implemented other necessary corrective actions during the inspection. The team evaluated five items on Unit 1 and found no adverse effects on equipment operability of the unit.

The team was also concerned with the number of examples of failure to verify or check the adequacy of the design. Although none of the examples found by the team were individually safety significant, when viewed collectively may be indicative of a more pervasive weakness.

The licensee also displayed numerous areas of strength, including the licensee's response to new generic issues, the availability of detailed engineering guidelines for pipe stress and pipe support analysis and scaling calculations, the consistency of operating procedures with design-basis assumptions, the "Team Plus" program designed to build a strong unified working organization, and the effective integration of the site contractor organization.

The licensee voluntarily initiated two complementary self-assessment programs: the integrated design assessment (IDA) and the construction assessment team (CAT). The CAT provided a satisfactory assessment of Comanche Peak construction work, and the licensee performed a creditable job in the IDA self-assessment effort. The team substantiated the licensee's methodology for the conclusions drawn by its design and construction self-assessment effort. The DBDs appeared well conceived and should provide a valuable tool for control of the design configuration. However, several individual errors in both supporting design calculations and within the DBDs indicated that continued licensee attention was warranted to verify, in detail, the integrity of the design calculations and the DBDs.

The CMI team was further concerned about the licensee's reliance on turnover programs to detect and correct room and system deficiencies. At the time of the inspection, a large number of deficiencies had been identified and accumulated on punchlists, but corrective action was being deferred until late in the construction schedule when the turnover programs would be completed. The turnover programs were also being relied on to detect additional discrepancies of the type identified by the team. The team observed that scheduling pressures could affect the quality of work if deferred to the end of construction. NRC Region IV is aware of this concern and plans to maintain a close overview of the turnover programs to verify their effectiveness.

CONTENTS

APPENDICES

1.0 INSPECTION OBJECTIVES AND SCOPE

November 18 through December 13, 1991, the U.S. Nuclear Regulatory Commission (NRC) conducted a configuration management inspection (CMI) at Comanche Peak Steam Electric Station (CPSES), Units 1 and 2. The team consisted of eight NRC inspectors, two United Kingdom Nuclear Installations Inspectorate inspectors, two U.S. Department of Energy inspectors, and four NRC consultants. The CMI team assessed the adequacy of the utility's self-assessment initiatives and capabilities, evaluated the interface between the licensee and its four major contractors on site, and reviewed the adequacy of the design, construction, and testing associated with the residual heat removal (RHR) system and the ac/dc electrical distribution systems.

The inspection was performance based and the team concentrated on the effective implementation of programs at all levels of the licensee's organization. As part of the performance evaluation, the team observed numerous work activities, including work activities performed during backshifts and weekends. The team inspected design areas including mechanical systems and components, ac and dc electrical systems, instrumentation and control systems, and civil and structural areas. In the field environment, the team inspected testing: mechanical, electrical, instrumentation, and control aspects; and various utility programs. The team reviewed related documents and the applicable sections of the final safety analysis report and technical specifications; the Westinghouse RHR system design calculations, which formed the basis for system information contained in the design-basis documents (DBDs); and the Stone and Webster Engineering Corporation (SWEC) calculations, which confirmed that the design of the architect/engineer portion of the system interfaced appropriately to meet Westinghouse design requirements. System drawings, operating procedures, abnormal operating procedures, and emergency operating procedures pertaining to the RHR system also were reviewed to identify significant changes between the two units.

The team has characterized its negative findings within this report as deficiencies, unresolved items, or observations. Deficiencies are the apparent failure of the licensee to comply with a requirement, to satisfy a written commitment, or to conform to the provision of applicable codes, standards, guides, or accepted industry practices when they have not been made a legally binding requirement. Unresolved items are those involving a concern about which more information is required to ascertain whether it is acceptable or deficient. Observations are items considered appropriate to call to the attention of licensee management even though they have no apparent direct regulatory basis. Deficiencies will be reviewed by the NRC regional office to determine if any enforcement actions are appropriate.

The detailed inspection findings are discussed in Sections 2, 3, and 4. Section 5 addresses the exit meeting. Appendices A and B provide summaries of the inspection findings and observations, respectively. Appendices C and D are lists of the exit meeting attendees and abbreviations.

2.0 DESIGN REVIEW

The design review included an intensive review of the ac and dc power electrical power distribution system and a detailed review of the residual heat removal (RHR) system.

In the area of mechanical systems and components, the review included the Unit 2 RHR system design for both the RHR and low-head safety injection modes of operation; the hazard analysis and walkdown programs for high- and moderate-energy line breaks and internally generated missiles; design and analysis of the supporting systems for the emergency diesel generators, as part of the review to validate the licensee's integrated design assessment; the design and analysis of electrical area heating, ventilation, and air conditioning (HVAC) systems, as part of the electrical power distribution system functional inspection (EDSFI); and a review of design modifications on the Unit 1 RHR and service water systems which were applicable to Unit 2 as well.

The electrical distribution system (EDS) review included selected calculations, procedures, and records of the ac and dc systems, inspection of installed equipment, and interviews with engineering and support staff. The team reviewed a sample of electrical design attributes at each voltage level of the EDS, including verification of the reliability and stability of the offsite (grid) power system, plant load calculations for the regulation of voltage to electrical loads required for the safe shutdown of the station, and the short circuit calculations needed for proper equipment ratings.

The team also reviewed a sample of piping, pipe supports, and equipment for compliance with NRC regulations, design bases, and applicable codes and standards.

2.1 Mechanical Systems

The licensee based its design and analysis of the Unit 2 RHR system on Unit 1 design documents, identifying differences to determine if changes were required in the Unit 1 documents to make them applicable to Unit 2. DBD-ME-260, "Residual Heat Removal System," Revision 1, defined the RHR system design, and DBD-ME-261, "Safety Injection System," Revision 1, addressed the operation of the RHR system in the low-head safety injection mode. The team found that only minor differences existed in piping layout, node-point elevations used in analyses, and other key design parameters. Therefore, the design bases, system design, component design, and system operation of the RHR system were essentially the same for both units.

Although Section 11.1.3 of DBD-ME-260 contained a list of the design calculations that support the design of the RHR system along with a summary of the conclusions for each calculation and a list of the key assumptions, it did not contain reference to SWEC calculations related to RHR system parameters, such as net positive suction head and head losses under various modes of operation. The licensee agreed to include some of the SWEC calculations containing design information in the DBD. The licensee also confirmed that SWEC calculations important to the design of other systems (e.g., safety injection and reactor coolant systems) would be incorporated in the applicable DBDs. The team agreed with these actions.

2.1.1 Calculations

Instances of incorrect inputs and assumptions, inadequate calculational methods, inaccurate calculations, and inconsistent conclusions with design requirements are discussed below.

DBD-ME-260, under the heading, "Power Generation Functional Requirements," discussed the requirements of the RHR to cool down the reactor coolant system following a normal plant shutdown and gave the maximum heat sink temperature as 95°F, which was inconsistent with the maximum heat sink temperature of 102°F defined elsewhere in the DBD. The licensee determined that the assumed lower temperature was in error and agreed to make the correction in the next DBD update. The team reviewed the results and determined that the licensee's action was acceptable.

Westinghouse Calculation FRSS/SS-TBX-1076, "Comanche Peak 1 & 2 Train Cooldown Times," assumed a constant service water temperature of 102°F over the 24 to 30 hours of the cooldown, rather than assuming an increasing temperature in response to heat rejection to the heatsink. However, technical specifications (TS) required the units to be in a cold shutdown condition within 36 hours if the maximum service water temperature was exceeded. The licensee performed Calculation FSE/SS-TBX-1678, Revision 0, which assumed a worst-case scenario of one unit experiencing a design basis loss-of-coolant accident (LOCA) and the other unit being shut down. The licensee predicted the temperature increase on the basis of Table 4-4 of the study by J. E. Edinger Associates, Inc., entitled, "Hydrothermal Simulations of Comanche Peak Safe Shutdown Impoundment." The licensee performed a new analysis that showed that two-train cooldown of the nonaccident unit could be achieved. The team questioned how the licensee would cope with a TS required shutdown of both units simultaneously if excessive SWS temperature occurred. The licensee evaluated this issue with an assumed failure of one train in the service water system and determined that single train cooldown could be achieved in 28 hours. The licensee agreed to revise the Final Safety Analysis Report (FSAR) to correct the cooldown times based on the revised calculations.

Calculation ME-CA-0250-3008 evaluated the capacity of the RHR suction relief valves when used for low-temperature overpressurization and cold overpressure mitigation. However, the starting pressure used for the transient was 400 psig, which appeared to be too low based on a high-pressure alarm set point of 415 psig and an instrument error of 7 psig. The licensee stated that Calculation RXE-TA-CP1/0-021 enveloped the pressure ranges of concern and agreed to supersede Calculation ME-CA-0250-3008 with RXE-TA-CP1/0-021.

Calculation 16345-ME(B)-038 for Unit 1 established the diesel generator intake and exhaust system operating modes and temperatures and the system design temperatures. However, the licensee did not consider if an extreme cold weather temperature of 4°F would affect piping and support stress analyses. The licensee initiated a contract change notice to Unit 2 Calculation 2-ME-0244 to include the lower temperature in the analyses. The licensee had evaluated the effect of the lower temperature for Unit 1 in Stress Problem 15454-NP(S)-DO-1-167A and found that the effect of the lower temperature was not significant. Figure 2 of Calculation 16345-ME(B)-306 listed emergency diesel generator (EDG) fuel oil storage tank level set points that were inconsistent with the actual level instrument set points. The licensee agreed to change the figure.

Calculation ME-CA-0260-3118, which established the capability for full-flow testing of check valves in the RHR system using the refueling water storage tank return line, did not provide the basis for the required flow rate of the

RHR system used in the calculation. The licensee agreed to revise the calculation to include the proper technical specifications basis reference.

A LOTUS 1-2-3 spreadsheet calculation entitled "DGPROFILE" was used for temperature calculations of the diesel generator building equipment rooms. However, Calculation 2-HV-0010/X-EB-302A-2 did not specify the equations used in the spreadsheet calculations to allow design verification. The licensee agreed to perform a design verification of the spreadsheet computation and modify the calculation to include the necessary information.

Unit 1 Calculation 16345-ME(B)-337, which addressed the partially open setting of the component cooling water outlet valves on the RHR heat exchanger, indicated that the adequacy of the valve and actuator to withstand the flow-generated forces on the valve in its partially open position needed to be established. The calculation did not address the resolution of this question. The licensee provided the team with correspondence that addressed the adequacy of the valves and agreed to remove the requirement from the calculation for further evaluation of valve capability.

Unit 1 Calculation 16345-ME(b)-305 erroneously recorded the diesel generator fuel oil transfer pump drawdown elevation. The proper elevation was confirmed in other fuel oil transfer system calculations and the licensee agreed to correct the calculation.

The inspection team reviewed each licensee action associated with the above noted calculational errors and agreed with the licensee's action. The calculation errors indicated weaknesses in the design verification process and are examples of Deficiency 50-445/91-202-01 and 50-446/91-201-01, "Failure To Verify or Check Adequacy of Design."

2.1.2 Unit 2 System Design Changes

The team reviewed the heaters being installed at one of the air intakes to each Unit 2 diesel generator room to alleviate the effects of extreme cold weather on diesel generator operation and the fuel oil system cloud point. The licensee planned to rely on the use of space heaters to maintain the requisite EDG room temperature for Unit 1.

The team also reviewed several design modification packages to ensure that the modifications performed on Unit 1 were also covered on Unit 2. These programs were considered satisfactory.

2.1.3 Electrical Area HVAC Systems

The electrical area HVAC systems were designed with two safety-related trains, each shared between Units 1 and 2. DBD-ME-313, "Uninterruptible Power Supply Area Air Conditioning System," Revision 2, described that the component cooling water control valves X-PCV-H116A and B (trains A and B) were operated by a compressed air system with an integral safety-related compressed air storage tank for each valve to ensure that the valves fail in the open position. However, during a walkdown of both trains of the system, the team questioned the routing of the air lines from the storage tanks to the pilot valves of the component cooling water control valve operators.

The air lines were connected to the bottom of the horizontal air tanks instead of the middle or the top of the tanks. The as-found installation had the potential to trap moisture or debris in the lines, which could cause plugging and failure of the valves to operate as designed. The licensee found that Atwood & Morrill Co. Drawing 18120-01, "Actuator, Bailey Positioner," Revision 1, showed the air lines routed from the end of the storage tanks rather than the bottom; thus, the installations did not conform to design documents. Preliminary licensee reviews indicated that the incorrect routing originated with the valve supplier. The licensee contacted the vendor and continued to evaluate this condition for reportability.

The licensee issued ONE Form FX 91-1659 to reroute the tubing in accordance with the design drawing. The determined deficiency will not affect Unit 1 because an operability test was performed on the system every month. This condition is an example of Deficiency 50-445/91-202-02 and 50-446/91-201-02, "CCW Instrument Air Lines Incorrectly Run."

2.1.4 Hazard Analyses

ABB Impell Corporation was responsible for the licensee's programs identifying and minimizing the effects of hazards on the safe shutdown of Unit 2 in the areas of high-energy line break (HELB), moderate-energy line break (MELB), internally generated missiles (IGM), and seismic interactions between Categories I and II (seismic II/I interactions).

Impell was in the process of completing its HELB analysis of restrained and unrestrained lines at the time of the inspection. Walkdowns of the postulated break locations, to confirm analytical inputs and to define targets for subsequent evaluations, were scheduled to begin in January 1992, following completion of construction in the break areas. Impell planned to evaluate approximately 600 HELB locations inside and outside primary containment, considering approximately 35 IGM situations. A team walkdown of several break locations indicated that the process for HELB, MELB, and IGM evaluations appeared thorough.

EQE, a subcontractor to Impell, was responsible for generating walkdown packages of rooms in Unit 2 for seismic II/I interactions. The team's independent walkdown of seven rooms indicated that material conditions were generally good and the licensee's walkdowns were comprehensive and conservative in identifying potential interactions and bounding situations for analyses. The licensee's process to resolve the walkdown findings had not been initiated. In response to the team's observation that several supports for fire protection piping in Room 2-103 appeared questionable, the licensee stated that it planned a bounding analysis of a support in Room 2-94 to determine the seismic capability of all supports. The team reviewed this program concentrating on inter-organizational communication. This program appears sound to the team; however, implementation of the program was not evaluated.

2.1.5 Response to Industry Concerns

The licensee's action to respond to one NRC concern is discussed below.

- Unit 1 design engineering was addressing the issues identified by NRC Information Notice 91-56. The licensee had identified all flow paths between the RHR and containment spray systems and the refueling water storage tank. To prevent backleakage of recirculation sump fluid, the licensee identified 28 valves for analysis. The licensee was establishing the source term for recirculation sump water under the post-accident conditions and determining allowable leakage to stay within dose limitations. If required, modifications to the inservice testing (IST) program to define allowable leakage rates through valves will be made as a result of the analysis. The licensee anticipated completion of the analysis in January 1992.

2.2 Mechanical Components

2.2.1 Residual Heat Removal System

The team reviewed two RHR pipe stress calculations. The calculations for the pipe stress and pipe supports on the RHR system designated the piping systems as American Society of Mechanical Engineers (ASME) Class 2 and included 3-inch-diameter and 3/4-inch-diameter lines. Additionally, the associated pipe support calculations were reviewed. The pipe stress and support calculations were found acceptable.

When required, the licensee's architect/engineer (A/E) organization (e.g., Bechtel, Westinghouse, or Impell) effectively communicated and coordinated related work. The licensee's procedures and guidelines for interfacing of different work scope organizations were detailed, comprehensive, and effective. Communication and coordination between the various work scope A/E organizations was good.

2.2.2 Integrated Design Assessment

As a part of its integrated design assessment for the Unit 2 EDG system, the licensee had reviewed the pipe stress calculations on the EDG starting air, fuel oil, and service water jacket water cooling ASME Class 3 systems and found them acceptable. The team reviewed the results of the assessment and agreed with the licensee's conclusions.

The calculation for the ASME Class 1 system, specifically a 1½-inch safety injection line that is part of the emergency core cooling system, was generally found acceptable by the team. However, Westinghouse Calculation ID 2-0152 for pipe stress contained inconsistent values for the design temperature and pressure in different sections of the calculation. Westinghouse had issued revised temperature and pressure values that had not been entered into the Unit 2 "ACCESS" data base until after portions of the calculation had been completed. The licensee indicated that this type of discrepancy would be found during the as-built reconciliation process. However, these revised values were also applicable to the equivalent Unit 1 systems. Therefore, Westinghouse had failed to reconcile the latest available design temperature and pressure values in some of its Unit 1 final piping calculations. The licensee issued Operation Notification and Evaluation (ONE) Form FX-91-1660 to formally identify and resolve this issue. Westinghouse subsequently identified an additional 14 Unit 1 piping calculations with problems that resulted from the revised design temperature and pressure values. All 14 calculations were evaluated by the licensee and found to have sufficient margin to accommodate the revised values. This condition of using incorrect design temperature and pressure values is another example of Deficiency 50-445/91-202-01 and 50-446/91-201-01.

In addition, the team observed that the piping directly upstream from the piping qualified by Calculation 2-015Z, line number 3"-SI-2-033-2501R-1, was listed in "ACCESS" as having a design temperature of 300°F rather than the correct value of 650°F. The licensee issued Texas Utilities Evaluation (TUE) Form 9109091 and the correct value was entered into the data base. The licensee considered this an isolated case of data input error. The team agreed with the licensee's conclusion.

2.2.3 Seismic Equipment Qualification

The team reviewed a number of seismic qualification reports for ASME Class 1, 2, and 3 valves. Associated documentation and procedures relating to the seismic qualification program also were reviewed. All were found acceptable. The team determined that the seismic equipment qualification of an explosion-proof heater located in the battery rooms of Units 1 and 2 met the requirements for seismic Category I equipment set forth in Section 3.10 of the FSAR. However, in Ebasco Calculation Vol. IV, Book 52, the licensee used a weight of 900 pounds for the seismic support of the heater assembly in the computer analysis rather than the weight of 1160 pounds as indicated in vendor Drawing 66L. No justification for the use of the 900-pound weight was noted in the calculation. The licensee generated a ONE Form FX-91-1661 to address the issue for both units and to correct the calculation. There was sufficient margin in the calculation to accommodate the increased weight and this type of heater was not used elsewhere in either unit. However, this condition is another example of Deficiency 50-445/91-202-01 and 50-446/91-201-01.

2.2.4 Design Guidelines and Procedures Review

The team reviewed numerous engineering and design criteria guidelines and procedures. Procedures for design interface control were found effective. In particular, engineering Procedures 2-EP-5.12 and 2-EP-5.13, which provided the design criteria and guidelines for pipe stress and pipe supports, were detailed and comprehensive.

2.3 Instrumentation and Control

The inspection team reviewed scaling schematic diagrams, instrumentation calculations, instrument and control diagrams, procedures and Design Change Authorizations with emphasis on the RHR and ac/dc power distribution system.

The schematic diagrams reviewed had an average of four outstanding design change authorizations (DCAs) issued against each of them. Drawing E2-0063, Sheet 4, Revision CP-2, had seven DCAs that had not been incorporated. Although the requirements of Procedure 2EP-5.05 stated that drawings will be revised at the discretion of the responsible lead discipline engineer, the team observed that the number of unincorporated DCAs weakened the effectiveness of the diagrams and that consideration should be given to more frequent revision of drawings with high numbers of outstanding DCAs.

Scaling Calculation Manual 1-SC-8800 defined the technical data for the scaling calculations to be performed for Unit 2 as well as the methodology and format. The manual consisted of two parts, with 12 appendices to the second part of the manual. The appendices contained composites of the signal conditioning loops, linearization methodology, square-root conversions, head correction calculations, and other technical methods. The actual scaling calculations were predefined as much as practicable.

At the time of the inspection, the licensee had completed three RHR System scaling calculations: two calculations applied to temperature measurement and one applied to pressure measurement. The three RHR system scaling calculations (2-SC-58-01, Revision 1; 2-SC-58-04, Revision 1; and 2-SC-58-02, Revision 2) were derived from the corresponding Unit 1 calculations. The team determined that these scaling calculations accurately defined the set points for support of the RHR system operational requirements.

The design documentation, such as instrument scaling calculations, schematic diagrams, instrument and control diagrams, procedures, and design change authorizations (DCAs), indicated to the team that RHR system instrumentation and controls were adequate to ensure safe operation.

2.4 Electrical Distribution System

The electrical distribution system (EDS) review included selected calculations, procedures, and records of the ac and dc systems, inspection of installed equipment, and interviews with engineering and support staff. The team reviewed a sample of electrical design attributes at each voltage level of the EDS, including verification of the reliability and stability of the offsite (grid) power system, plant load calculations for the regulation of voltage to electrical loads required for the safe shutdown of the station, and the short circuit calculations needed for proper equipment ratings.

2.4.1 AC Distribution System

DBD-EE-038, "Offsite Power System," described the two independent offsite power sources from a 138 KV line and a 345 KV line that interface with the two preferred power transformers, XST1 and XST2. Each transformer has two windings, X and Y, which feed two 6.9 KV safety-related switchgear per unit. The Y windings are the preferred power to the switchgear and the X windings are the alternate source. In the normal operating lineup, XST1 supplies Unit 2 and XST2 supplies Unit 1.

DBD-EE-038 showed minimum and maximum voltages as 340 kV and 361 kV, respectively, for the 345 KV line. However, the "Voltage and Reactive Guidelines" documented a minimum voltage of 335 kV. In addition, short-circuit grid impedance was not described in the DBD. The licensee revised the DBD to reflect minimum voltage of 335 KV and agreed that system parameters should be coordinated with the offsite power groups and documented in the DBD with their basis to provide source information for design engineers.

To ensure that design engineers had accurate design information to perform short-circuit margin and voltage-profile calculations, the team discussed coordination and control of information regarding the offsite power parameters with members of the engineering groups. Licensee representatives stated that calculations were performed annually to demonstrate current configuration and projected growth. The licensee stated that overvoltage and undervoltage conditions were regulated with load tap changing (LTC) transformers. When the voltage approaches an operating limit, the load dispatcher performs a manual-remote action on the LTC transformers for the affected area to correct the voltage. The spokesman for voltage regulation stated that the guideline of 335 KV should not apply to Comanche Peak because minimum voltage history in the Comanche Peak area was 340 KV. The licensee was in the process of installing a device to monitor the switchyard voltages and telemeter the information to a recorder. The licensee stated load flow calculations were performed annually and coordinated with the bulk power planning group that performed short-circuit studies.

The team was impressed by the technical communication within the licensee organization and the overall level of technical understanding displayed by participants.

2.4.1.1 Quality Assurance Audits

Quality Assurance Audit QAA-91-206, which stated that the SCOPE E electrical calculations exhibited no major technical errors, referenced Calculation 16345-EE(B)-075; however, it was not actually reviewed by the licensee during the audit. The audit report did not document the calculations that were reviewed. The licensee issued a revision to the report during the inspection and submitted the auditor notes to demonstrate the auditors had performed a technical review. The notes showed that one auditor's technical information also had not been discussed in the report.

The inspection team performed a technical review of several applicable calculations and the results of their review is covered in Section 2.4.1.3.

The qualification record for an auditor showed that changes were made after the date the record was marked completed. The licensee issued TUE Form 91-2832 during the inspection to address the incomplete auditor qualification document. In addition, the licensee made the revision to the qualification package during the inspection. The errors in the qualification records are an example of Deficiency 50-446/91-201-03, "Failure To Follow Procedures During Construction Activities."

QAA 90-065 resulted in quality assurance (QA) personnel issuing three TUEs. Two of the three were closed. The other, TUE 91-342, documented that the appropriate corrective actions were completed on July 3, 1991. Procedurally, QA should have verified this TUE within 3 weeks; however, the TUE was still open. QA explained that no one was available to perform the verification because of the Unit 1 outage.

2.4.1.2 Design Basis Documents

In DBD-EE-040, Section 4.3.2.9, the 125 Vdc control fuses were specified to be a minimum of 30 amperes. However, the continuous ampere rating for the control wiring was less than the fuse rating. It was unclear how this configuration will adequately protect the wiring during overload failures. The licensee engineering staff responded that the fuse supplier recommended the fuse size and there was no trend of adverse effects. Taking into consideration the wire size and associated loads, the team concurs with the licensee.

2.4.1.3 Calculations

Calculation 2-EE-0011, Revision 2, listed a large number of penetrations that exceeded the limiting frequency to withstand as-designed fault conditions. These penetrations were not designated as "confirmation required" items in the calculation to ensure implementation of the required corrective actions. The licensee indicated that DCAs had been initiated to follow up this issue and these DCAs were included on an appropriate punchlist. The team verified that the DCAs were initiated and action was required prior to startup.

Unit 1 Calculation 16345-EE(B)-075 used 90°C for calculating cable resistance. No basis was given in the DBDs for using the 90°C temperature. The licensee issued ONE Form FX-91-1545 to revise the calculation, using a 25°C conductor temperature. Although the short-circuit design margin will be higher after the calculation is revised, the equipment rating for the switchgear was 70 kA and the results of the licensee's calculation showed the available short-circuit margin to be 48 kA. Therefore, the equipment will have sufficient margin.

Calculation EE-CA-0004-3021 for short-circuit margin and voltage profile on Unit 2 did not consider the resistance decrease for the 6.9 KV/480 V transformer tap change. Again, the short-circuit design margin was high enough so the equipment rating would not be adversely challenged. The transformer tap change will be addressed in the next revision of the calculation. In addition, no basis was given for using the emergency rating of 85°C for calculating the startup transformer resistance. Licensee personnel concluded that the calculation results would essentially remain the same. The team concurred with the licensee's conclusion.

Calculation EE-CA-0004-3018 for Unit 2 system voltages showed that adequate voltage would be available when both units are fed from the XST1 transformer and Unit 2 experiences a LOCA with Unit 1 at full load. The final results of this calculation are pending the verification of cable lengths for Unit 2.

The team asked the licensee for the calculation or analysis that demonstrated that the voltage drop margin was adequate for equipment required to mitigate a main steam line break (MSLB) outside containment. The licensee stated that no documentation existed to demonstrate that there was adequate voltage margin.

During the inspection, licensee engineering staff performed a preliminary analysis which showed that the resistance of the cable had increased by 30 percent. This suggested the voltage drop had changed, but the voltage was still sufficient to operate the equipment. The licensee agreed to formalize the calculational results. The team found that the affected components met the containment pressure transmitter equipment qualifications and the voltage loop criteria for the transmitters to operate properly under accident conditions. The errors in the calculations indicated weaknesses in the design verification process and are further examples of Deficiency 50-445/91-202-01 and 50-446/91-201-01.

2.4.1.4 AC Distribution System Control Logic

(1) Shared 480 V Motor Control Centers (MCCs)

In FSAR Section 3.1.1.5, the licensee agreed to comply with 10 CFR 50, General Design Criteria (GDC) 5, concerning the sharing of structures, systems, and components. However, the licensee had not evaluated its compliance and had no firm completion date even though the automatic transfer system for the six 480 V MCCs shared between Units 1 and 2 was energized and ready to connect to Unit 2.

The team reviewed the automatic transfer scheme and found that there was no provision to prevent an automatic transfer of a faulted 480 V MCC from occurring upon loss of the preferred power supply due to a fault on the affected shared 480 V MCC. The lack of interlocks to prevent the automatic transfer of a faulted 480 V MCC from Unit 1 to Unit 2, or vice versa, could potentially impact the operation of other safety equipment. The licensee stated that the fault would only affect one safety train (A or B) and that the other train would be available to perform the required safety functions. Nonetheless, this appeared not to comply with the intent of GDC 5. The licensee agreed to review the transfer scheme to determine if design modifications were required, this item is unresolved pending further NRC review (Unresolved Item 50-445/91-202-01 and 50-446/91-201-01, "Automatic Transfer of Faulted Motor Control Centers Between Units").

(2) EDG Control System

The EDG starting system was designed as a dual system, with each part of the system having provisions to receive two starting signals. One signal was dedicated to start the EDG on 6.9 KV Class 1E bus undervoltage leaving all EDG protective trip functions operative, while the other signal was dedicated to start the EDG if a safety injection actuation signal was initiated, leaving only two trip functions operative, (i.e., EDG high differential current and engine overspeed). The team found that the EDG starting logic was consistent with the FSAR and TS, including TS Amendment 3, License NPF-87, issued October 4, 1991, which deleted the requirement for starting the EDG upon loss of the preferred offsite power source.

2.4.1.5 Emergency Diesel Generators

In its self-initiated integrated design assessment, the licensee reviewed the EDG loading, load sequencing, and voltage regulation and noted that a dynamic analysis study was not performed as part of Calculation 2-EE-0014, Revision 3. However, the calculation tabulated all of the cumulative continuous and motor starting surge loads (real and reactive) and compared those loads with the information in the EDG vendor factory qualification test report. The team performed a detailed review and confirmed that the highest combined continuous and motor start surge loads were bounded by the highest corresponding values listed in the factory test report, which obviated the need for a dynamic analysis.

Although the Class 1E emergency power supplies were appropriately designed to perform their intended function, the calculational error below is an example of a failure to verify design adequacy (Deficiency 50-445/91-202-01 and 50-446/91-201-01).

- The EDG backup protection relay calculation did not demonstrate that EDG thermal limits would not be exceeded as a result of a potential fault while the EDG was in a surveillance test configuration. The licensee performed a supplementary calculation which determined that adequate design margin was available. The primary transformer protective relay setting meets the criteria contained in ANSI Standard C57 and Institute of Electrical and Electronic Engineers (IEEE) Standard 242. The licensee demonstrated that the protective relay characteristics, when considering the effect of the secondary protective devices in series, were appropriately bounded by the transformer damage curve. The team agreed with this conclusion.

In addition, the licensee determined that the EDG excitation system would not be adversely affected by the extended exposure to a low output voltage resulting from the postulated fault. This previously unanalyzed situation is a further example of a failure to adequately verify and check the design and is a further example of Deficiency 50-445/91-202-01 and 50-446/91-201-01.

2.4.2 DC Distribution System Design Review

2.4.2.1 Class 1E 125 Vdc Distribution System

The Class 1E 125 Vdc distribution system consisted of two electrically isolated dc buses in each train. Each separate bus was supplied by a 60 cell, 125 Vdc lead-acid, calcium grid battery and two battery chargers. The two batteries for each train were installed in a shared battery room that provided adequate ventilation and protection from environmental hazards. The batteries were connected to the dc switchboard buses through fused switches, and the battery chargers were connected to the same switchboard buses through mechanically interlocked circuit breakers. The interlock allowed one charger to supply normal power while the second charger was a ready spare. The normal battery charger supplied continuous power to the battery on float charge and periodically provided a battery cell equalizing charge at a voltage close to, but not to exceed, 140 Vdc.

The Class 1E 125 Vdc distribution system supplied emergency power to the inverter power sources of the reactor protection system (RPS) and the Class 1E 118 Vac control power subsystems and distributed power to other safe shutdown control components. Each 125 Vdc train supplied two 7.5 KVA inverters, supplying two separate RPS channels and two 10 KVA inverters that supplied separate 118 Vac buses. All inverters were connected to the 125 Vdc load centers through molded-case circuit breakers. In addition, remote circuit breaker panelboards for the 125 Vdc distribution were supplied from the load centers through 200 A fusible switching circuits.

2.4.2.2 Design-Basis Documents

DBD-EE-044, Revision 4, "Design Basis Document, DC Power Systems," contained different values than the corresponding values from Unit 2 calculations, discrepancies with Unit 1 licensing commitments and at least one other DBD. For example, paragraph 11.1.3 listed several instances where protection coordination was not achieved for Unit 1 although DBD-EE-051, Revision 4, paragraphs 4.1.8 and 4.1.15, required full coordination of protective devices. This DBD also listed instances in which containment penetration sizing requirements and voltage drop limits to Class 1E control devices were not met. This was discussed earlier in Section 2.4.1.3. The voltage drop issues were found in conflict with the committed requirements of Regulatory Guide 1.32 and IEEE Standard 308-1971. The licensee corrected the Unit 1 calculations as described below in Section 2.4.2.3. The licensee stated that the Class 1E components subject to unsatisfactory voltage levels are only used in test circuits that are not required to operate during the end of the battery duty cycle.

2.4.2.3 Short Circuit and Protective Device Coordination

The short circuit and protective device coordination calculations for Units 1 and 2 contained technical errors. The calculation failed to consider short-circuit test data of the battery vendor to determine internal cell resistances and voltages. The calculation incorrectly used a Thevenin-equivalent representation based on the 140 Vdc equalizing charge voltage, which resulted in using an unrealistically high internal battery cell resistance in the calculation.

In addition, the short-circuit current contribution for the battery charger was incorrectly assumed to be limited to 375 A by internal electronic control during the initial fault current surge. However, because the battery charger control elements are silicon-controlled rectifiers, current limiting control would not be effective until the first zero crossing of the ac supply current waveform is reached. This might take more than half a cycle depending on the ac supply circuit time constant (X/R ratio). The team was concerned that the small-frame molded-case feeder circuit breakers and feeder protection fuses would attempt to interrupt bolted fault currents in a comparable time lapse. Thus, the higher initial battery charger short-circuit contribution, combined with the battery contribution, could result in excessively high short circuit duty and/or loss of coordination between protective devices.

Class 1E 125 Vdc protective device coordination calculation for Unit 2 contained outstanding "confirmation required" items even though the 125 Vdc systems had already been turned over to the group. The licensee indicated that the "confirmation required" items were included in a startup punch list to ensure their resolution.

The errors in the Class 1E 125 Vdc short-circuit calculations is another example of Deficiency 50-445/91-202-01 and 50-446/91-202-01. The affected calculations and system configuration described in DBD-EE-044 were applicable to both Units 1 and 2. The licensee implemented timely corrective actions to avoid affecting Unit 1 restart. The licensee prepared new short-circuit and protective device coordination calculations and replaced the 200 A distribution panelboard supply circuit fuses with a type having slower blowing characteristics in the high-current region. The new short-circuit calculation correctly used the vendor's short-circuit test data together with the applicable criteria of ANSI C37.14-1979 to determine the battery cell internal resistance. The calculation showed that damage to the battery charger was possible under high fault current levels under an initial surge in excess of 5600 A if the internal rectifier protection fuses blew. IEEE 279 and IEEE 308 state, respectively, that fault induced damage to Class 1E systems should be limited and that proper coordination should be maintained. This part of the issue remains unresolved pending clarification by the licensee and/or the battery charger vendor and is identified as Unresolved Item 50-445/91-202-02 and 50-446/91-201-02, "Potential Damage of Battery Charger due to High Fault Current."

2.5 Civil and Structural

Most of the civil and structural area calculations for Unit 2 were Unit 1 calculations, only if significant changes occurred were the calculations modified and verified to the original design for Unit 2 application. The team reviewed DBD-CS-074, "Design Basis Document - Containment Liner and Penetrations," Revision 3, September 29,1988 with DCA-84570, Revision 1, April 1, 1989. These governed liner and penetration design. Several of the Impell and SWEC calculations demonstrated that the liner was adequately designed.

The team additionally reviewed structural calculations associated with the safeguards building reinforced concrete design. The team concluded that the reinforced concrete design was satisfactory and that the control of confirmation required items had been properly accomplished.

2.5.1 Design Modifications

The design modification package to install an access gate and platform for the polar crane contained a minor discrepancy. Design modification DM 89-249, "Install Access Platform," Revision 0, July 23, 1990, referenced FSAR Section 9.1.4.3.2, Item 14, rather than Section 9.1.4.2.3, Item 14.

Other miscellaneous cable tray support calculations including, Impell Calculation 0218-CT-0036, "Design Verification For Cable Tray Hangers CTH-2-13661, CTH-2-13662, and CTH-2-13663," Revision 2, July 30, 1991 were reviewed. These calculations contained a minor internal inconsistency on an assumption regarding tray design weight that had no effect on the technical conclusions.

The licensee had previously established a post-construction hardware verification program (PCHVP) to provide a controlled methodology to address the verification of construction attributes that had been a problem on Unit 1. Several PCHVP attributes were reviewed related to concrete anchorage edge distance, containment liner overlay plates, and structural openings. The team concluded that PCHVP and associated walkdown procedures were satisfactorily implemented.

2.5.2 Independent Design and Construction Assessment Program

The licensee had initiated two complementary self-assessment programs of Comanche Peak Unit 2: the integrated design assessment (IDA) and the construction assessment team (CAT).

The IDA was conducted by the licensee's Independent Safety Engineering Group (ISEG), and the results reported in ISEG Report IAR 91-09. The licensee performed a creditable job in self-assessment effort and spent a considerable amount of time and resources. All of the IDA reviewers were technically qualified for the task and each carried out a detailed, in-depth assessment. However, there were areas in the IDA process that could have been handled differently. For example, the IDA reviewer in the mechanical component area should have resolved his findings during the IDA, instead of postponing the finding resolution until the final plant design validation. The IDA report did not indicate the entire scope of the assessment and did not state the favorable findings as well as the negative. However, the overall quality of the review by the IDA was very good.

2.6 Engineering Assurance

The engineering assurance (EA) organization consisted of only three people. Project Procedure for Unit 2 2PP-1.01, Section 5.2.2, defined the EA responsibilities as mostly related to documentation aspects. The EA additionally (1) coordinated QA-related monitoring of engineering contractors performing engineering and design work, (2) coordinated the project and engineering procedures to ensure adequate contractor interface and consistency, (3) interfaced with project engineering management and other engineering management personnel, (4) coordinated audits of engineering activities and followup of findings, (5) directed the development and implementation of training, and (6) handled the trending analysis.

On the basis of the EA-issued documents reviewed by the team such as meeting notices, open item lists, and a self-assessment report, the team concluded that the engineering assurance organization was performing well within its assigned scope.

2.7 Conclusion

Design documentation and the design process in the areas of mechanical systems and components, instrumentation and control, EDS, and civil and structural were acceptable. The operating procedures indicated the design basis was well maintained regarding operator actions, which were considered a strength. Although DBDs were comprehensive and would be useful for design activities, improvement was needed in some cases. Certain calculational errors indicated weaknesses in the design verification process; it appeared the licensee needed to focus more attention on design control, especially in the area of design input. The pipe stress and pipe support guidelines, and the scaling calculation program were strengths.

Although the 6.9 kV Class 1E bus control logic and the EDG control system were adequately designed, an outstanding design concern remained in the unevaluated condition of the automatic transfer scheme for 480 V MCC equipment between Units 1 and 2. Nonetheless, the offsite power system appeared very reliable and well regulated. The team was impressed by the technical communication within the licensee organization and the overall level of technical understanding displayed by participants.

The design of the electrical systems for the dc distribution system was acceptable. Although there were a number of concerns regarding the assumptions and co-tent of some of the engineering calculations, licensee personnel were receptive, responding with additional information when requested and making required corrections and improvements to the calculations in a timely manner.

3.0 CONSTRUCTION ACTIVITIES

The team's field inspection consisted of walkdowns in the areas of testing, mechanical, electrical, civil and structural, welding, instrumentation and control, and material storage and cleanliness. The team reviewed 10 CFR 50.55e and Part 21 reports, and the licensee's CAT assessment, application of quality assurance during construction, and nonconformance controls. The team verified agreement between the controlled drawings and the installed plant configuration. The RHR system and the Seismic Category I and II HVAC systems in the electrical auxiliary and EDG buildings were inspected, as well as the EDG and associated support systems.

3.1 Verification of As-Built Configuration

3.1.1 Residual Heat Removal System Walkdown

To verify agreement among controlled documents and accuracy of these documents regarding field configuration of the RHR system, the team compared installed components to the piping and instrument diagram (P&ID) M2-0260, and to Brown and Root piping system isometric drawings RH-2-RB-001-004; RH-2-SB-001, 005, 008, 010-017, 020, 023-027, 030, 034, and 035, and SI-2-SB-005. In addition, the team examined completed work packages RH-2-024-407-S22R and 14-SI-2-197-151R-2 for a seismic support and for the refueling water storage tank (RWST) to the RHR systems, respectively.

The licensee had completed the majority of RHR system installation work. However, the long construction period had exposed some components to a rigorous environment, as evidenced by a broken flexible conduit. The licensee had identified most damaged items on a punchlist. Some commodities, such as pipe supports, did not meet the installation clearances, angularity, and gimble specification requirements of CPES-P-2018. In accordance with ACP 11.5, "Component Support Fabrication and Installation," these attributes will be inspected during the system turnover inspection. The associated checklists found in Section 7.0 of the ACP appeared comprehensive. Other inspection mechanisms also existed to verify the installations, including CQP-MS-913, "System Release/Turnover Process for Construction"; 2PP 2.03, "Room/Area Walkdowns, Access Control and Completion"; 2EAP-001, "Commodity Clearance"; STA 802, "Acceptance of Station Systems and Equipment"; and STA 810, "Acceptance of Rooms, Areas, and Structures."

The field configuration of RHR system components appeared to acceptably meet design requirements; however, in addition to the above noted conditions, the inspection team noted several examples of failure to maintain system cleanliness. These examples are discussed in Section 3.1.3.

3.1.2 HVAC System Walkdown

Major components of the seismic Category I HVAC system, located in the electrical equipment and train A EDG rooms, were found installed consistent with the applicable drawings (M2-0654B, M2-0658 A and B and M2-0659).

The seismic Category II ductwork in Room 100 at the 852-foot elevation of the Unit 2 electrical safeguards building (Drawing M2-654) was partially installed at the time of the inspection. During its constructability review, the licensee had identified an interference problem between the duct and a conduit support. Work on that section of ductwork was on hold pending modifications to the conduit support and changes to the ductwork and support design documents. The team found the examined ductwork had been satisfactorily installed.

3.1.3 Diesel Systems Walkdown

Major components in the EDG fuel oil system and lube oil system were found installed in accordance with P&ID M2-0215. Other than an open and uncapped pneumatic line to the fuel shutoff cylinder, component material conditions appeared acceptable.

The jacket water system for the Unit 2 train A EDG was in good material condition with major system components in their proper locations, although the pressure sensing line from the jacket water header was open and uncapped. In addition, a ¼-inch stainless steel tube that provided continuous air venting for the engine water jacket pump discharge was strapped to a large bore pipe. This method of securing the tubing appeared questionable because CPES-I-2002, Section 3.0.3.5, "Installation of Piping/Tubing and Instrumentation," specified that "all tubing should be routed and protected so as to minimize possible physical damage." The tubing serving the same function on the Unit 1 diesel was routed in a more conservative manner, thereby providing a greater degree of protection.

The licensee's craft personnel exhibited proper control of material conditions during refurbishment of the diesel shaft driven lube oil pump.

The material condition of the starting air system for the Unit 2 train A EDG also was good. In addition, the licensee had identified a configuration deficiency in Units 1 and 2 involving the omission of a ¼-inch drain line, which could affect successful starting of the Unit 2 train A EDG. The licensee's corrective actions, addressed in letter TXX-89845, were comprehensive and complete.

Although work related to modifications and refurbishments of the areas inspected was still in progress at the time of the inspection, the major components were completed. The Unit 2 train A EDG system, room, and area were released to startup for implementation of the turnover walkdown.

During a QA audit of the room and area turnover walkdown of the diesel day tank room, 29 items were identified that had not been recorded on the turnover punchlist. Although the licensee determined that the identified items would not have compromised plant safety or operability, it agreed to assess the generic implications of the walkdown process, as described in TUE 91-2778.

During walkdowns of the RHR and EDG systems, the team found several examples of lack of control over system cleanliness that were contrary to construction specification requirements. This is an example of Deficiency 50-446/91-201-02, "Failure To Follow Procedures During Construction Activities."

The licensee corrected the individual conditions and wrote TUEs 91-3017 and 3018. The licensee also agreed to perform (1) a 100 percent walkdown from December 11 to December 19, 1991, to identify deficient material conditions and (2) random evaluations of the regular material conditions surveillance program. The licensee further agreed to emphasize in management meetings the importance of problems with maintaining system cleanliness and stated it would consider disciplinary actions, if necessary.

The team identified a number of field discrepancies. Although these discrepancies were unrelated and not indicative of any adverse programmatic trend, they had not been previously identified in the utility's punchlist. When the items were brought to the attention of the licensee, the licensee often indicated that there was a followup program in place to find such discrepancies. The licensee's heavy reliance on turnover programs to detect and correct deficiencies is identified as Observation 50-446/91-201-01, "Heavy Reliance on Turnover Programs."

The team noted an inconsistency between flow indication on Drawing BRP-RH-2-SB-023 and installed valve 2-RH-8734A. The licensee determined that the valve was installed correctly in accordance with a component modification chart (CMC) written against the controlled drawing. However, the CMC had not been incorporated in a subsequent revision of the drawing. The licensee wrote a TUE form and initiated a drawing correction. Review of several other drawings indicated that the licensee was effectively controlling design changes and the omission of the CMC appeared to be an isolated occurrence.

3.2 Testing Programs

The team reviewed system flush plan procedures for adequacy and observed in-progress RHR system flushing. The flush test procedures (2RH-5800-02A/B) did not require the measuring and test equipment (M&TE) used during the test to be recorded and did not provide objective evidence of nominal design flow rates in portions of the system and did not give instructions for flushing instrumentation root valves and some vent and drain valves. These deficiencies exhibited the licensee's noncompliance with its procedural requirements.

Although these procedural weaknesses did not invalidate the flush tests previously performed, they called into question the auditable quality of the test records. The startup test engineers indicated that the initial intent of the flushes was to verify the previously completed RHR flushes satisfactorily completed in 1985 and 1986. In addition, during the recently performed flush testing, debris was found in the strainer screens. The type of debris was typically dimensionally small and representative of debris possibly introduced during work activities performed on the system subsequent to suspension of Unit 2 work activities. The team's review of modifications performed on the safety injection and RHR systems showed that a number of vent and drain valves had been installed during the interim period, which could have introduced the debris.

The licensee's quality assurance (QA) staff had performed surveillances of prerequisite testing activities associated with flushing. During its QA surveillances performed in August and October 1991, the licensee also identified the same deficiencies noted above and other similar weaknesses. As a result, the startup engineers initiated a number of TUE forms and a flush plan review panel. The review panel made a flush matrix to identify system piping requiring flush reverifications, and the startup engineers revised the affected RHR system flush plans to correct the noted deficiencies. The team considered the licensee's efforts in (1) identifying similar deficiencies associated with other flush plans, (2) evaluating the need to reverify some of the flushes, and (3) correcting the current procedures to dispose of the noted deficiencies to be responsive to the team's concerns. This item is identified as Observation 50-446/91-201-02, "Adequacy of Flushing Program."

During RHR flush testing, the team found a number of rigid pipe supports and spring hangers had been removed from the piping. In some instances, temporary pipe supports had not been installed. The piping analysis engineers had walked down the system before the system's release to startup and had verified all rigid supports were installed. The team observed five instances in which personnel had removed piping supports and not provided temporary supports. In some instances, a length of excessive unsupported pipe span resulted. The startup group subsequently identified three additional missing pipe supports. This condition is identified as Deficiency 50-446/91-201-04, "Failure To Maintain Adequate Control of Pipe Supports During System Flushing."

In response to this condition, the licensee initiated a number of TUE forms and addressed the issue from a programmatic/repetitive aspect. The startup engineers walked down the service water system to see if similar conditions existed on a system that affected Unit 1. The licensee identified the system was properly supported. The licensee believed the condition was isolated to the RHR system.

3.3 Safety-Related Piping

Piping installation work activities were observed by the team and were found adequate. Controls were in place for fitup, grinding, welding, and maintenance of material cleanliness standards.

The team verified that the piping was installed and inspected in accordance with the applicable specifications, drawings, and procedures and that the procedures were adequate. Further, the team verified that discrepant conditions identified by craft and the quality control staff during the work activities were adequately resolved.

With the exception of not maintaining material cleanliness standards, the quality of craft work appeared acceptable. Work activities observed during backshift periods appeared well controlled and coordinated.

3.4 Concrete Expansion Anchors

The team used criteria from CPES-S-2001, "Specification for Structural Embedments," and CQP-CV-109, "Construction Procedure for Structural Embedments," and Drawing S2-0100 to perform walkdowns. The team inspected 110 bolts in a single room for anchor marking, washer installation, anchor skew, spacing to abandoned holes, and embedment plate spacing. The team inspected 14 rooms and associated corridors in the safeguards building.

The detailed review of 110 bolts revealed two instances of bolts not marked (support RH-2-026-402-S22R) and one potential case of a nut bottomed-out on the bolt thread.

In its review of the rooms, the team identified numerous embedment plate spacing violations and further nut bottom-out and thread-engagement problems. Specific problems (e.g., RHR motor stay support plate installation, missing nuts on Hilti bolts associated with support C-MS-S036, thread engagement on a bolt on support RH-2-0025-006-S2, and adequacy of Hilti bolt anchorage for S1-2-07B-404-32S) were specifically raised with the licensee. The licensee agreed to correct the noted conditions during further work activities and stated that these conditions would be identified as part of the utility's turnover program. In addition, the team addressed the issues of the field verification method (FVM), training, and corrosion with regard to Hilti bolts.

(1) Field Verification Method

The licensee supplied copies of four field verification method closure packages (CPE-EB-FVM-CS-033,CPE-SWEC-FVM-EE/ME/IC/CS-090, CPE-SWEC-FVM-EE/ME/IC/CS-089, CPE-EB-FVM-CS-001) to substantiate that 100 percent of all components had been inspected as part of the post- construction hardware validation program (PCHVP). NQI 3.09-M-001 established the criteria used in the FVM walkdowns.

While the documentation indicated that the licensee had performed an extensive and substantial inspection using acceptable criteria, it did not substantiate that 100 percent of all components had been inspected. The reports did not directly provide results of the inspection. Data could not be easily extracted from the PCHVP results to allow statistical trending or comparisons. The licensee could not provide a statistical comparison of the results of the limited initial stages of the backfit inspection with (a) the expected attribute frequencies for Unit 1 or (b) the failure frequencies for a known sample of bolt attributes for Units 1 and 2. Because the PCHVP results were not easily amenable to statistical analysis, the ability to compare the failure frequencies of Units 1 and 2 was restricted.

FVM closure package EPE-SWEC-FVM-CS-075 confirmed that verification of concrete embedments had been based on sampling rather than 100 percent inspection. The team examined licensee's process and believed it could be acceptably extended to Unit 2.

(2) Training of Bolt Users and Installers

The training course teaching aids and course content included drilling and installing bolts in a practice concrete block. The training was typically provided to multidisciplinary personnel (e.g., quality control and construction) to facilitate intergroup communication. The team determined that the course accurately reflected the specification requirements.

However, individual training records contained a large number of inaccuracies concerning documented training that was not properly signed off for previous specification revisions. This indicated a worker may not have received adequate training. The licensee issued TUE Form 91-3103 to address one instance of an installer's training record having discrepancies. The licensee stated that the installer works in accordance with construction work packages to ensure that Hilti bolts are installed to the latest standards, and quality control (QC) checks of the Hilti bolts provide further confidence that problems will be detected. In addition, the licensee was in the process of improving the accuracy of training records.

(3) Corrosion

SD-CP-91-003, "Corroded Hilti Bolts (Interim Report)," addressed the issue of three corroded bolts found in the basement area of the safeguards building. The Hurst Metallurgical Research Laboratory had investigated the cause of bolt failure and identified galvanic and crevice corrosion as the most likely cause. The team also reviewed the licensee's walkdown approach for inspection of other areas that might be susceptible to flooding.

During its walkdown, the team found pools of standing water in areas not identified as being susceptible to flooding. The licensee chemically analyzed one pool of water and found it less corrosive than the water associated with the previous bolt failures. The licensee issued a memorandum (CPSES-9129885) to require staff to report pools of standing water to the housekeeping superintendents so that such pools were removed as soon as possible.

The team also noticed that Hilti bolts associated with the seismic supports for the EDG exhaust system were installed in a small depressed area on the roof of the safeguards building. These bolts would be susceptible to water contact when flooded. The licensee issued TUE Form 91-993 to shelter the bolts until the depressed areas could be filled with an impermeable material. The team examined this retrofit on Unit 1 and found that the impermeable material had shrunk away from the supports and water had penetrated below the barrier layer. Since this geometry could exacerbate any crevice corrosion that may be present, the licensee issued a ONE Form 91-3594 to address this problem. The improper installation of the impermeable material is identified as Deficiency 50-445/91-202-03, "Improper Installation of Hilti Bolt Impermeable Material."

In response to the team's concern about contaminants on stainless steel pipe, the licensee said that the materials did not present a hazard during the construction period and that the lines would be cleaned before the plant went operational. Although Unit 1 procedures addressed this, Unit 2 procedures did not. The licensee amended Procedure 2 PP 2.03 (PCN 03) to incorporate the team's concern.

3.5 Field Work Activities

The seismic Category I platform, located above the instrument thimble guide tubes, was assembled and constructed in accordance with design specifications. Drawing CWD PF-RB01533784-RB21531 and the seismic Category I welding record indicated that all required welds were successfully completed. The licensee had adhered to Construction Specification CPES-S-2006 for grating requirements. The training records indicated qualifications were complete for each person performing actual work on the structure fabrication. The civil and structural construction work performed on the seismic Category I platform was very good.

The team reviewed work documented in CWD MS-RB-155E832 concerning the fabrication of the Unit 2 equipment hatch cover, which included welding inspections, and the guidelines discussing the acceptance criteria for visual weld verifications. The structural steel field fabrication work of the equipment hatch cover was found to be completed and awaiting concrete placement. All welds had been adequately reinspected in accordance with Procedure NCIG-01, Revision 2, "Visual Weld Acceptance Criteria for AWS [American Welding Society] Structural Welding at Nuclear Power Plants," and unsatisfactory welds identified by licensee QC inspectors had been repaired.

DCA-93489 addressed the lack of stiffness in the RHR heat exchanger vessel support system and the potential for overstress in the joints of the foundation support structure. Craft personnel had procedures available at the work location, were well informed about the scope of work, and observed hold points appropriately.

Craft personnel also installed fire retardant sealant (Bisco sealant) in the piping penetrations between the emergency core cooling system (ECCS) valve and containment penetration rooms in accordance with applicable procedures and obtained sealant samples for QC verification.

3.6 Adequacy of Construction Documentation

Construction Specification CPES-H-2019, Section 4.10.1, provided adequate fabrication, installation, and construction requirements of dimensional tolerances for the HVAC systems and supports. This section of the specification also was used as a requirement in a number of other construction specifications. The requirements specified in Section 9.2.1.4, 5, 6, and 7 also appeared to meet industry standards.

The criteria for dimensional tolerances used to install HVAC systems and supports were primarily taken from the licensee's cable tray hanger measurement tolerances. The cable tray tolerances, given in Specification TNE-FVM-CS-001, Revision 5, were compiled during an industrywide study. The study was performed by a task group of the Pressure Vessel Research Committee.

Calculation M-69, job 0210-041, assessed the use of cable tray tolerances for HVAC system tolerances and found the application to be generally more conservative. Given the scope of research undertaken by the licensee, it appeared the use of Section 4.10.1 by craft personnel is appropriate.

Construction Specification CPES-S-2006, Section 4.4.2.2, which provided the QC inspection attributes for the visual inspection of welds, appeared to contain acceptance criteria less conservative than the AWS guidelines. However, Procedure NCIG-10, Revision 2, "Visual Weld Acceptance Criteria for AWS Structural Welding at Nuclear Power Plants," as committed to by the licensee had been accepted as a technically acceptable approach for visual inspection of structural weldments by the NRC. The QC inspection attributes listed in Section 4 of the specification appeared adequate.

3.7 Electrical Systems Field Review

3.7.1 Switchyard Walkdown

The team performed a walkdown of the switchyard including the 345 KV and 138 KV relay houses. No deficiencies were identified in the 345 KV switchyard. However, fuses were found missing in primary and backup potential transfer circuitry as well as emergency lighting circuits in the 138 KV relay house.

Preliminarily, the licensee ascertained that the fuses were never installed during the original equipment installation in 1988 or that the fuses were removed for acceptance testing, during the installation of a new digital fault recorder. Although the licensee determined that the missing fuses could not cause a loss of the 138 KV transmission lines, it agreed to the following corrective actions:

(1) immediate replacement of the missing fuses

(2) inspection and verification of circuits and equipment in the 138 KV substation (This task was completed prior to the exit meeting and no other deficiencies were found.)

(3) procedure revision (procedure OWI-104-18) to include operator rounds in the 138 KV relay house (Previously, rounds were made only in the 345 KV house.)

(4) conduct of a training session with Fort Worth Transmission personnel (including division personnel) reemphasizing the safety significance of work performed in support of Comanche Peak

(5) reissuance of a switchyard responsibility letter discussing organizational responsibility for switchyard work (The letter will emphasize the importance of keeping CPSES informed of work that could affect plant operations.)

The safety review, root cause analysis, and resulting corrective actions by Comanche Peak and the Fort Worth Transmission personnel adequately resolved the 138 KV fuse issues.

The team also found water accumulated on the floor of the 138 KV relay house, which could cause moisture intrusion into the relay compartments and degradation of protective circuitry. Also, the HVAC system was found de-energized, preventing proper ventilation and removal of hydrogen generated by the lead-calcium batteries located in the associated battery rooms. The licensee re-energized the HVAC, sealed the house to prevent rain damage, which was the source of water inside the 138 kV substation, and agreed to revise the operator shift round procedures (OWI-104-18) to include the 138 kV substation. These corrective actions satisfactorily resolved the team's concerns.

3.7.2 6.9 KV Switchgear

The interiors of switchgear 2EA1/Cubicle 11 for ED/G breaker 2EG1 and 2EA2/Cubicle 2 for ED/G breaker 2EG2 were in good condition. Cabinets were properly labeled with permanent device nameplates installed that identified components inside and outside the switchgear. Foundation supports and cabinet welds and electrical components, such as fuses, terminal blocks, and terminations, were in an acceptable condition. Linkage for the main breaker disconnect switch and cell switch operation functioned properly. Undervoltage and time delay relay settings matched those specified in FSAR Section 8.3 for the preferred feeder breaker for transformer XST2 to 6.9 kV bus 1EA1 (Unit 1) and XST1 to 6.9 kV bus 2EA1 (Unit 2). No deficiencies were identified in this area.

3.7.3 480 V Motor Control Centers

The team performed visual examination of the 480 V MCC compartments associated with selected RHR equipment. MCC 2EB4-1 bucket 2J for load motor-operated valve (MOV) 2-8804B and MCC 2EB2-1 bucket 2F for load MOV 2-8809B and terminations, terminals, and fuse blocks appeared in good condition. No deficiencies were identified in this area.

3.7.4 125 Vdc Distribution

The licensee responded that Class 1E batteries for both units were inspected for battery electrolyte level and temperature on a weekly basis by electrical maintenance under the surveillance program. No deficient conditions were identified for Class 1E battery rooms, battery chargers, inverters, and selected procedures for Unit 1.

However, a discrepancy was identified between the Class 1E battery duty cycle values in service test Procedure MSE-SO-5702 for Unit 2 battery CP2-EPBTED-01 and those in the sizing verification Calculation 2-EE-0005, Revision 1. Originally, the licensee intended to use the same duty cycle for the batteries of both units; however, new batteries were procured and installed for Unit 2 and therefore a new battery duty cycle applied. The licensee said there was an amendment under development to FSAR Table 8.3-4, "125 Vdc Class 1E Battery Load Requirements," to address the new battery duty cycle for Unit 2. In addition, the licensee will revise Service Test Procedure MSE-SO-5702 to reflect the new battery sizing verification.

Train A battery cell 46 was found filled a ½ inch over the electrolyte high-level-line and several train B battery cells (cells 24, 25, 28, 33, 39, 48, and 50) were below the electrolyte low-level-line, although the cell plates were not exposed to air. The licensee stated that it will monitor the situations on both batteries and that it will correct the low electrolyte conditions for the train B battery cells via Startup Deficiency Report (SDR) 1419. The licensee also will monitor the situation during equalization to preclude a potential overflow of electrolyte from the cell jar.

In addition, a seismic bumper guard was found unattached for train A battery (east) rack CP2EPBTED-01 upper level and a flange bolt was found bent on an HVAC air duct. The licensee immediately generated SDR 1422 to repair and replace the bumper guard and TUE Form 91-3122 to correct the HVAC bolt that was apparently damaged during post-inspection room construction activities.

3.7.5 Motor-Operated Valves

In coordination with design review efforts, the team visually inspected MOVs 2-8804B, 2-8809B, and 2-8105 and examined the Limitorque motor leads, terminal blocks, Raychem splices, lug work, and associated limit switches and junction boxes. An environmental qualification report QTR 155 identified the insulation material used in the EA180 series NAMCO limit switches as a glass-filled phenolic thermoset plastic. This design change to the EA180 series was necessary because the original asbestos-filled phenolic plastic for the limit switch components was no longer available. The licensee completed requalification of the glass-filled phenolic part in 1989.

MOV nameplate data, such as service factor, horsepower, voltage, and amperage for Units 1 and 2 corresponded to electrical load drawings and FSAR Section 8.3 descriptions. No discrepancies were identified during the MOV walkdown.

3.7.6 Power, Instrumentation, and Control Cables and Raceway

3.7.6.1 Cable, Cable Tray, and Conduit Separation

Spatial deviations existed for cable tray-to-tray, conduit-to-conduit, and cable tray-to-conduit arrangements, which departed from requirements of IEEE Standard 384-1974 and Regulatory Guide 1.75, Revision 1, to maintain a 3-foot vertical and 1-foot horizontal spatial separation for open ventilated, redundant, tray-to-tray arrangements in the cable spreading areas.

Through the licensee's FSAR licensing document change, the licensee requested an exemption from the number of barriers required for protection from electrical failures. These changes will reduce (1) power tray-to-tray and cable barrier from two barriers with 1-inch minimum separation to one barrier and 1 inch and (2) Class 1E conduit, located above a tray or cable, from two barriers and 1-inch minimum separation to one barrier and 1 inch.

The licensee said that several instances may exist in which the new criteria could not be met; consequently, it requested the use of a second category of separation criteria for those cases. NRC acceptance of the new separation criteria was pending a technical evaluation of the FSAR revision submitted to the NRC. After the exit, the licensee determined that the second category of separation criteria was not needed and a change to the FSAR would indicate the same.

In addition, there were deviations from thermal separation requirements specified in CPES-S-1021 for separation between cable trays and conduits and elevated temperature piping lines. For example, cable tray T23GSCF96 in Room 100 was installed inside the containment wall shake zone, contrary to the specification requirement to maintain a 3-inch minimum clearance between the containment wall and cable trays. Such items had been identified as deficiencies through the licensee's commodity clearance process, and it is the team's understanding that these cable trays and conduits are to be reworked or exempted by an engineering analysis.

3.7.6.2 Electrical Terminations and Raceways

Drawing E2-0173 indicated that the terminations in 6.9 KV cubicles 2EA1-09 and 2EA2-10 and in the remote shutdown transfer panel for cables E0200007, E0204370, E0204438, E0204371, and EG200034 were landed on the appropriate terminals. The raceways were installed and labeled correctly.

3.7.6.3 One-Hour Fire Rated 600 V Power and Control Cable

CPSES FSAR licensing document change request number SA-91-053, proposed the use of 1-hour fire rated cable (Firezone R) to meet the safe shutdown requirements of 10 CFR Part 50, Appendix R. The Firezone R cable was constructed of a continuously welded corrugated 12-mil-thick stainless steel sheath with high-temperature nickel-clad conductors, glass braid jacket, and silicon rubber insulation. However, a review of the procurement specification and the vendor's (Rockbestos) Qualification Report (QR) 9801 for the Firezone R cable revealed several issues requiring further investigation. The procurement specification (CPES-E-2027, Revision 1) stated that the proposed cable did not meet the requirement of 10 CFR Part 50, Appendix R. The cable was required to have a 1-hour fire rating and remain damage free. In addition, the revised procurement specification specified a vertical flame test be performed one time on unaged cable only, while IEEE Standard 383-1974, Section 1.3.5.2, "Aging," required type testing for design-basis event conditions (such as fire) for both non-aged and aged samples.

Based on discussions with construction personnel in the field, the team expressed concern over possible crimping damage during armored cable pulling. QR-9801 revealed that pristine cable had been used during testing and the testing did not account for the slightly degraded condition of the jacket that could result from damage during installation. At the time of the inspection, no cable of this type had been pulled. The licensee contended that the new proposed pulling procedure will alleviate this concern. The team reviewed the proposals to be incorporated into the new procedure and agreed if properly implemented the cable would not be crimped.

QR-9801 also used a generic LOCA profile (IEEE Standard 323) and did not consider other environmental conditions that may be more limiting such as atmospheric and thermal effects associated with direct exposure from a MSLB. In addition, the vendor had not tested the Firezone R cables to the typical standard radiation dose of 200 millirads for combined background and accident radiation. The Firezone R cable samples were subjected to only a radiation dose of 50 millirads. QR-9801 stated that because the cable is always shielded by an armored sheath or by a metal conduit, 90 to 99 percent of the beta radiation exposure will be attenuated. However, this did not account for the effects from the additional gamma radiation exposure. The team told the licensee that this cable should be applied with caution in containment, particularly because a radiation shielding calculation had not been done to account for radiation buildup factors for secondary and tertiary radiation or direct exposure to a higher radiation dose. However, the licensee said it was only going to install Firezone R cable outside containment in areas where the total radiation dose is less than or equal to 50 millirads (gamma) and in areas that will not be subject to the direct effects of a MSLB. This will alleviate the team's concern.

In addition, the team raised concern over the FSAR revision requesting that Firezone R cable be considered a "raceway" with regard to protection from electrical failures. Regulatory Guide 1.75, Position C.2, stipulates that armored cable should not be construed as a "raceway." This issue will be considered during the NRC review of the licensee's licensing document change.

3.7.6.4 Cable Tray Integrity

During a walkdown of the electrical safeguards building train B switchgear room, the team identified a missing cable tray siderail splice plate on tray T22KEBR59. The splice plate was used to join two segments of cable tray. The licensee issued DCA 094585 to correct the missing splice plate because it was not on a punchlist. The licensee further explained that a program was under development to address cable tray attribute verification of hangers and splice plates via a specific cable tray walkdown program performed during room area turnover.

3.7.6.5 Fiber Optic Cable

The team questioned the licensee on fiber optic cable application, separation criteria, and fire retardancy qualification. Two types of fiber optic cables, cables W-1009 and W-1043, manufactured by Chromatic Technologies and WireMasters Incorporated, were on the plant computer.

CPES-E-2004, Appendix F, did not require separation of fiber optic cables internal to equipment because the fiber optic cable used in non-Class 1E monitoring circuits carried no electrical energy and, therefore, were not required to maintain physical separation from Class 1E circuits. External to equipment, fiber optic cables were treated the same as any other instrumentation cable. For installation, a minimum of 2-inch-diameter conduits were used for ease of pulling and to avoid damage.

For flame propagation resistance, the licensee provided certificates of conformance from the vendors certifying that each fiber optic cable type met the flammability requirements of IEEE Standard 383-1974. No deficiencies were discovered.

3.7.7 Fuse Control for Unit 2

Procedure XCP-EE-08 governed the licensee's fuse control program for Unit 2, in response to Information Notice 91-51. The procedure specified that the size and ratings of fuses, relays, starter, switches, and control transformers be verified during control circuit testing. If fuse data was missing on the design drawing or if the installed fuse did not match the design data and the correct data could not be determined, an SDR was to be initiated to identify the condition. Design drawings typically cross reference a data sheet, such as E2-0024, Sheet 4, which stipulates the manufacturer, type, and catalog number, rating, and references to other drawings for the fuses.

During its examination of fuse removal and installation practices, the safety-related storage area, and the fuse control log, the team found that pulled fuses were properly sealed in plastic containers, tagged, and entered in the fuse control log book. The procedure and fuse control sheets are well defined and good communication existed among startup, construction, and operations personnel for fuse control.

The licensee had implemented several safety practices to prevent plant personnel from live circuit hazards, especially those circuits under functional testing. These practices include use of danger tags with multisized insulation (red colored) caps for fuse block contacts and safety (red colored) straps for the front panels of energized 480 V MCC buckets.

3.8 Welding Process

During the walkdowns of the RHR and ac/dc distribution systems, numerous welding activities were ongoing. The team noted that the licensee did not always comply with the welding parameters specified in the weld technique sheet (WTS). The two examples of welders failing to follow procedures are discussed below.

(1) Maximum Amperage Exceeded During a Fillet Weld

The maximum amperage permitted by Welding Procedure Specification (WPS) 18013, Revision 8/ICN 0, was 80 amperes. However, during a welding parameter surveillance the actual recorded amperage was 92 amperes.

This particular weld joined a stainless steel stanchion to a piece of carbon steel plate. The design specification for ASME component supports did not require impact testing for carbon steel or sensitization testing for stainless steel material. Therefore, the fact that the amperage range was exceeded did not significantly affect the ability of the materials to perform their intended design function.

(2) Minimum Preheat Temperature Not Maintained

WTS 11032, Revision 19/ICN 1, required a minimum preheat temperature of 200°F. However, for support RC-2-135-408-C41K, the temperature minimum measured was 174°F. The licensee issued documentation to remove and replace the existing weld.

These conditions in which the welders did not comply with the weld technique sheets are examples of Deficiency 50-446/91-201-03, "Failure To Follow Procedures During Construction Activities."

The team observed the licensee's quality control inspector taking amperage, voltage, and interpass temperature measurements, using a calibrated amperage and voltage meter and contact pyrometer. The team also observed the bead size width and travel speed during the welding process. There were no additional instances identified in which a welder failed to comply with the welding parameters specified in the WTS. However, discussions with individual welders indicated that they were minimally aware of the parameters identified in the appropriate WTS. One welder stated that he had not looked at the WTS and he could not describe the ranges established for each of the parameters. Four of the other welders did not know the established ranges for amperage, voltage, or travel speed, and additionally, one of these welders also did not know the maximum interpass temperature. With the exception of the first welder, each of the other welders provided a response that indicated some awareness of the values of the variables they should have been using. Each of the welders considered their experience to be the dominant factor in producing an acceptable weld. However, it appeared to the team that, as a minimum, the welders should be aware of the welding variables contained in the appropriate WPS. The licensee discussed this issue with craft personnel. A review of a sample of welds by the NRC indicated that the weld quality was acceptable. This is therefore primarily a procedural issue. Per discussions with NRC Region IV, the welding specialist will follow this item during upcoming inspections.

3.9 Cleanliness and Safety-Related Equipment Storage

The team noted several areas where proper controls were not being maintained in safety-related and clean storage areas. Examples of these deficiencies that were identified and continued to exist throughout Unit 2 are given below.

(1) The team found the wall mounting plate for seismic snubber CC-2-028-411-S33K laying in the corner of room 63 of the electrical safeguards building. This snubber was one of the supports in the component cooling water system. The storage location was not posted in accordance with housekeeping procedures. Other than the identification number etched on the item, the team could find no markings that indicated its ASME class designation or the status of the associated work package.

(2) The containment spray pump room, in a housekeeping Zone 3, cleanliness Level B area, contained coats, a face shield, and welding machine.

(3) Safety-related storage area outside the Unit 2 equipment hatch had uncovered and unprotected piping and instrument lines, unlabeled equipment, and trash and food in the storage area.

These are only a few examples of observed deficiencies that were contrary to ECC-608.7, "Control of Material, Parts, and Components," Section 6.2; ECC-232, "Plant Housekeeping"; ACP-14.2, "Handling, Storage and Preservation of Code Material." These conditions are further examples of Deficiency 50-446/91-201-03.

3.10 Conclusion

Construction appeared to be completed safely and in a quality manner; many deficiencies identified during the system walkdowns already had been identified by the licensee with corrective action pending. However, the lack of control over area cleanliness appeared to be a programmatic and repetitive problem that warranted management attention. This was also identified by the licensee during their self-assessment program. In addition, the team felt that the licensee was relying heavily on followup programs (such as room area and system walkdowns before turnover to operations and punchlists) to detect and resolve work discrepancies. The team was concerned that deferring the correction of known problems until late in the construction cycle would create a potentially stressful situation under which corrective actions are completed. This may cause errors that could otherwise be avoided.

The team found that craft personnel followed the app..icable procedures, documented deficient conditions, and requested QC verifications where appropriate. In addition, the team considered the control and coordination of backshift work activities a strength.

The RHR and ac/dc distribution systems were adequately installed, tested, and configured in accordance with applicable construction specifications and system drawings. The fuse control program for Comanche Peak Unit 2 is considered a strength. The safety practices for personnel working in areas with energized circuits also was a strength. However, the team found numerous examples of plant personnel not following procedures, of inadequate controls during testing, and of inadequate corrective actions for the Hilti bolt corrosion issue.

4.0 CORRECTIVE ACTION PROGRAM

The team focused its review of the licensee's corrective action program on the RHR system and included mechanisms for identifying and resolving problems concerning TUE forms, nonconformance reports (NCRs), quality accountability and trending, the commitment tracking system, the construction appraisal team (CAT), the quality assurance program, 10 CFR 50.55(e) and 10 CFR Part 21 reporting program, and the permanent equipment transfer (PET) program.

The licensee's corrective actions program was strong and comprehensive with corrective actions implemented in a timely manner. The licensee's staff appeared particularly responsive in correcting problems when programmatic or repetitive conditions existed.

4.1 TU Evaluation Forms

A TUE form is used by plant personnel to document a deficient condition for Unit 2. The team reviewed a sample of TUE forms to ascertain the correctness of the disposition, evaluations of the degree of safety significance, and the generic impact, and the adequacy of the root-cause analysis. Nineteen TUE forms were examined. Three of the seven open programmatic and repetitive TUE forms (90-276, "Pipe Stress and Support Calculations"; 91-2699, "Uncontrolled Material Transfer"; and 91-2776, "Deficiencies in Unit 2 Flushing Activities") indicated no problems. Obviously, the TUE forms had received a high level of attention from appropriately qualified licensee staff. The root-cause analyses were particularly comprehensive. Corrective action reports (CARs) CAR-87-051 R1 on Hilti bolt spacing, CAR-87032 R1 on Hilti bolt inadequacies, and CAR-87-014 R2 on concrete anchors, which are the precursors to the programmatic and repetitive TUEs, appeared adequate. Administrative aspects of the closeout of the documents were discussed with licensee staff and no problems were found.

During field examinations, some examples of missing TUE tags were identified; however, the team determined that the deficient commodities were still tracked within a nonconformance data base.

4.2 Nonconformance Reports

Twelve nonconformance reports (NCRs), both open and closed, were selected to review proper dispositioning, administrative aspects, and plant consideration. Four NCRs involved nonconforming conditions that no longer existed but the NCRs had not been closed out. The licensee informed the team that a significant number of old NCRs remained outstanding and that these usually would be closed out during the room and area or system turnover process. The deferral of NCR closeout could contribute to an excessive burden on the licensee personnel during the turnover process. However, it appeared the licensee had made a concerted effort to reduce the number of outstanding NCRs.

The remaining open deficiency reports (DRs) and the three closed DRs (C-87-19310 R2, C-88-4750, C-89-1849) indicated no construction deficiency problems.

4.3 Quality Accountability and Trending

Licensee personnel in the quality accountability and trending area reviewed TUEs for trends on the basis of their QA perspective and the assistance of a computer program. QC personnel used key words to effectively assign trend codes to identify the event. These codes were cross-checked before being entered into the computer. The trend review was considered satisfactory.

4.4 Commitment Tracking System

The commitment tracking system indicated that the licensee had satisfactorily tracked and implemented its commitments. Implementation of the limited number of commitments reviewed appeared complete.

4.5 Construction Appraisal Team

The licensee performed a CAT assessment during July and August 1991 to examine Unit 2 construction for conformance to implementing design documents, regulatory requirements and industry practices. The team reviewed the documented CAT assessment to assess the effectiveness of the CAT and performed walkdowns with some of the CAT members and inspection to check that the licensee had taken appropriate corrective action in response to the CAT findings.

With regard to the CAT, the NRC team noted the items addressed below:

(1) In CAT Report IAR 91-12, the licensee indicated that the assessment adhered to the methodology of NRC Inspection and Enforcement Manual Chapter 2920. However, the actual CAT assessment methodology was not formally documented. Through interviews with the CAT leader and a number of CAT team members, the NRC established that the NRC methodology had been used.

(2) Comparison of the CAT scope with that suggested in NRC Manual Chapter 2920 revealed that, because of the stage of construction, the licensee could not include a review of system turnover from construction to operation and could examine instrumentation and control (I&C) activities only in a limited way.

(3) The CAT was comprised of a multi-disciplined team that included members of the independent safety engineering group (ISEG) and staff from other departments selected on the basis of relevant qualifications and experience. While ISEG members satisfied the qualifications and experience criteria outlined in NQA 1.20, "Independent Safety Engineering Group Member Qualifications and Responsibilities," the other members of the team were not required to satisfy these criteria. Interviews with two ISEG and two other CAT members confirmed that all members of the team were adequately qualified to perform the CAT activities.

(4) In addition to the absence of a written methodology, there was an absence of documentation covering the CAT planning, the selection and guidance and training of team members, the selection criteria for items of plant and procedures inspected, and the recording and assessment of the significance of observations made during the course of the CAT. Interviews with the CAT team leader, the ISEG assessment manager, and four CAT team members established that, despite the absence of formal documentation, all items had been considered and informal notes existed. In addition, early drafts of the assessment report also established the existence of the information.

(5) ISEG Assessment Report IAR 91-12 gave the results of the CAT assessment. It contained a number of conclusions and recommendations and requested a response to these recommendations from the Unit 2 project manager. These recommendations were entered on the ISEG tracking system and will be tracked to completion. The Unit 2 project management responded to the report through memorandum (CPES 9127801) to address each of the issues. This response stated that all TUE forms and housekeeping reports generated by the CAT had been closed. Although the team found one housekeeping item (Item 105) open at the time of the CMI, the work had actually been completed.

(6) The eight CAT items were examined to verify the corrective action had been completed for each of the CAT findings. These are discussed below.

- Item 14 - Although the corrective action was completed on fan motor CP2-VAFNCB-05M, TUE 2501 documentation had been closed out without the TUE tag being removed from the motor. Documentation indicated the tag could not be found.

- Item 105 - the housekeeping work was completed.

- Item 178 - The CAT team questioned acceptability of gaps between the base plate and the foundation for CP2-CCAHHX-02 and noted chipped paint on the hold-down bolts as a housekeeping issue. The licensee considered the gaps acceptable (see NCR CM 87-7509-5). However, although the NRC found the chipped paint had not been repaired, the associated housekeeping report and the paint scope sheet revealed that the work had been signed off as completed. Further investigation revealed that craft had misunderstood the paint scope sheet and the heat exchanger had been repainted in lieu of the hold-down bolts. The licensee informed the team that they would paint the bolts.

- Items 246, 247, 275, and 279 - The engineering work was ongoing.

- Item 262 - Corrosion on battery cells CP2-EPBTED-03 was confirmed during a subsequent preventive maintenance inspection and SDR 1276 was issued; however, the necessary corrective action had not been taken. The NRC team noted that the preventive maintenance task list had incorrectly recorded the location of the batteries in the wrong room, and the SDR records designated incorrect system identifier for the batteries.

4.6 Quality Assurance

The team examined the licensee's annual assessment of the overall effectiveness of the QA for 1990 (CPSES-9104374, QQM-735). This report fulfills FSAR commitment and other licensee requirements to perform an annual evaluation of the QA program effectiveness. The assessment revealed a detailed analysis of significant QA-related events during 1990, concluding that the licensee's QA program had been effectively implemented.

In addition to its own assessment, the licensee is subject to an annual independent assessment through participation in the joint utility management audit (JUMA) program. The report of the most recent JUMA assessment (February 25 through March 1, 1991, CPSES QA Section) commented favorably on the licensee's QA program.

An additional aspect of the licensee's internal QA assessments are the two weekly quality accountability meetings. Participants of these meetings address both construction and design/engineering issues. During the engineering quality accountability meeting on December 10, 1991, participants examined trends in calculation reviews, DCAs, TUEs, specifications, outstanding master control drawings, and design change authorization causes. In addition, they reviewed the status of QA audits and surveillances, training, TUE forms, new procedures, and procedure changes. The team found the meeting provided a useful early analysis of trends in quality performance and also facilitated a crossflow of information between the various engineering groups and was considered a strength.

4.7 10 CFR 50.55(e) and 10 CFR Part 21 Reporting Program

Procedure 2PP-9.01, "Evaluating and Reporting Adverse Conditions Under 10 CFR 50.55(e) and 10 CFR 21," Revision 2, dated November 6, 1991, was found very well written and provided excellent guidance to licensee personnel. Discussions with personnel indicated that the process begins when a TUE form is initiated by plant personnel to document a deficient condition. These forms are reviewed and eventually evaluated by the cognizant engineering organization. In parallel with this process, a TUE form review committee meets on a daily basis. This committee reviews every TUE form generated since the last meeting and determines whether any followup actions are required. The criteria used for determining whether an item requires followup are Unit 1 impact, programmatic aspects, or NRC reportability.

For 35 TUE forms that had been evaluated during two meetings of the review committee, the committee determined that none required followup; the team agreed.

To evaluate the licensee's process to determine reportability to the NRC, the team reviewed a TUE form that the committee had selected for followup because it was potentially reportable to the NRC. The evaluation package contained a thorough evaluation and the proper threshold for reportability had been applied.

4.8 Permanent Equipment Transfer Program

Procedure STA-685, "Permanent Equipment Transfer" (PET), Revision 2, dated September 21, 1990, provided adequate guidance for licensee personnel. The 16 closed PET packages verified that an evaluation of the existing equipment on site had properly determined that equipment could be transferred or replaced. The package contained sufficient information to document the closure. In addition, for a package to be considered closed, a replacement for the substitute equipment must have been purchased and properly installed in the plant.

Of the 16 PET packages, 10 indicated, during the walkdown, that the replacement items for Unit 2 had been correctly installed. The team also verified that 4 of the 10 items walked down in Unit 2 were correctly installed in Unit 1.

However, discrepancies were found between the PET documentation package and the installed item in four instances.

(1) PET 1762 - RHR Pump Motor - Tag No. TCX-RHAPRH-02

The model number and serial number from the PET package were different from the pump motor numbers. The licensee determined that the numbers in the PET package were actually for the pump, not the motor, and were probably taken from the original receiving record for the pump assembly.

(2) PET 1956 - Condensate Storage Tank Level Transmitter - Tag No. 2-LT-2478

The serial number from the PET package was different from the number on the transmitter. The licensee noted that the PET package serial number was identical to the one that had been removed from Unit 1 and theorized that the worker just copied the wrong number down.

(3) PET 2309 - Fused Disconnect, Auxiliary Feedwater System - Tag No. X-HV-5526

The serial number from the PET package was different than the disconnect number. The licensee researched the work order that installed the replacement part and discovered that two disconnects were installed in the same cabinet. The worker who installed them apparently reversed the serial numbers on the documentation.

(4) PET 2566 - Heater Drain Valve Operator - Tag No. 2-LV-2514AO

The serial number from the PET package was different from the number on the operator. Although this was supposed to be a closed package, the air lines were not connected. In addition, the PET tag was still hanging on the operator. The licensee examined the replacement operator installation work order and discovered that the serial number written on the PET package was actually a drawing number from the installation package.

These discrepancies, discovered during the walkdown, indicated that personnel who completed the donor equipment replacement form portion of the PET form made several mistakes. The licensee planned to make changes to the PET procedure to ensure that the information written on the PET package is subsequently verified.

The purchase orders and receiving records for 7 of the 16 PET items reviewed showed that all the items were replaced by identical items and were purchased and received properly.

Materials Management Organization Procedure MMD 6.02-02, "Procurement Engineering Review of Procurement Documents," Revision 5, dated August 21, 1991, contained excellent guidance to evaluate an acceptable identical, alternate, or substitute replacement. It also provided details for classifying a nonidentical item and the requirements that must be met in order to purchase and eventually install the new item. The six packages for replacement items that had been evaluated by the procurement engineering staff were well documented and contained excellent technical evaluations.

4.9 Conclusions

An effective program was in place for controlling nonconforming conditions, permanent equipment transfers, 10 CFR 50.55(e) and 10 CFR Part 21 reporting. Noted progress had been made to reduce the number of outstanding NCRs, but the reliance upon room, area, and system turnover processes to close out the NCRs may prove to be a burden on the licensee. The team's assessment of the CAT program was hindered by the lack of formal documentation regarding the CAT methodology; however, the team concluded that the CAT provided a satisfactory assessment of Comanche Peak construction work. The team was impressed with the interaction and early analysis of trends that took place during a quality accountability meeting. The forum for these meetings was considered a strength.

5.0 EXIT MEETING

On December 13, 1991, the team conducted an exit meeting at the CPSES site. The licensee and NRC personnel attending this exit are listed in Appendix C. The team did not provide any written material to the licensee during this inspection. The licensee did not provide any material identified as proprietary to the inspection team during the inspection. During the exit meeting, the team summarized the scope and findings of the inspection.

APPENDIX A

CONTENTS

APPENDIX A

SUMMARY OF INSPECTION FINDINGS

DEFICIENCY 50-445/91-202-01, 50-446/91-201-01

Finding Title: Failure To Verify or Check the Adequacy of Design

Description of Condition:

The licensee's design-basis documents (DBDs) and supporting design calculations contained a number of false assumptions and erroneous calculations and computations. Some of these findings are discussed below.

1. Incorrect design temperature and pressure values were used in vendor-provided Class 1 piping analyses for the emergency core cooling system (ECCS). Westinghouse Calculation ID 2-015Z for pipe stress contained inconsistent values for the design temperature and pressure in different sections of the calculation. Westinghouse had issued revised temperature and pressure values that had not been entered into the Unit 2 "ACCESS" data base until after portions of the calculation had been completed. Vendor Calculation 2-015Z used design temperature and pressure values (2735 psig and 300°F) that differed from the correct values listed in the licensee's "ACCESS" data base (2485 psig and 650°F) and provided by Westinghouse in its letter WPT-12394. These revised values were also applicable to the equivalent Unit 1 systems. Therefore, Westinghouse had failed to reconcile the latest available design temperature and pressure values in some of its Unit 1 final piping calculations. The licensee issued Operation Notification and Evaluation (ONE) Form FX-91-1660 to formally identify and resolve this issue. Westinghouse subsequently identified an additional 14 Unit 1 piping calculations with problems that resulted from the revised design temperature and pressure values. All 14 calculations were evaluated by the licensee and found to have sufficient margin to accommodate the revised values. The team concurred with the licensee's determination that sufficient margin to accommodate the revised value were present.

2. The Class 1E 125 Vdc short circuit calculations and associated protective device coordination failed to consider the contribution of the battery charger which resulted in a lack of coordination and the replacement of 125 Vdc distribution panel protective fuses. The short circuit and protective device coordination calculations for Units 1 and 2 failed to consider short- circuit test data of the battery vendor to determine internal cell resistances and voltages. The calculation incorrectly used a Thevenin-equivalent representation based on the 140 Vdc equalizing charge voltage, which resulted in using an unrealistically high internal battery cell resistance in the calculation. In addition, the short-circuit current contribution for the battery charger was incorrectly assumed to be limited to 375 A by internal electronic control during the initial fault current surge. However, because the battery charger control elements are silicon-controlled rectifiers, current limiting control would not be effective until the first zero crossing of the ac

supply current waveform is reached. This might take more than half a cycle depending on the ac supply circuit time constant (X/R ratio). There was a concern that the small-frame molded-case feeder circuit breakers and feeder protection fuses would attempt to interrupt bolted fault currents in a comparable time lapse. Thus, the higher initial battery charger short-circuit contribution, combined with the battery contribution, could result in excessively high short circuit duty and/or loss of coordination between protective devices. The licensee implemented timely actions to avoid affecting Unit 1 restart. The licensee prepared new short-circuit and protective device coordination calculations and replaced the 200 A distribution panelboard supply circuit fuses with a type having slower blowing characteristics in the high-current region. The new short-circuit calculation correctly used the vendor's short-circuit test data together with the applicable criteria of ANSI C37.14-1979 to determine the battery cell internal resistance. The team concurred with the licensee actions.

3. Analyses to ensure that electrical components or cables met the design basis requirements of DBDs EE-031,-052 and 10 CFR 50.49.d had not been performed. The calculation or analysis that demonstrated that the voltage drop margin was adequate for equipment required to mitigate a main steam line break (MSLB) outside containment. The licensee stated that no documentation existed to demonstrate that there was adequate voltage margin. Licensee engineering staff performed a preliminary analysis that the resistance of the cable had increased by 30 percent, which suggested the safety margin had changed. The preliminary analysis and supporting documentation revealed that components met the containment pressure transmitter equipment qualifications and the voltage loop criteria for the transmitters to operate properly under accident conditions. The licensee agreed to formalize the calculational results. The team determined that the licensee actions were appropriate.

4. An incorrect service water temperature was used in a vendor performed RHR cooldown analysis. Westinghouse Calculation FRSS/SS-TBX-1076, "Comanche Peak 1 & 2 Train Cooldown Times," assumed a constant service water temperature of 102°F over the 24 to 30 hours of the cooldown, rather than assuming an increasing temperature in response to heat rejection to the heatsink. However, technical specifications (TS) required the units to be in a cold shutdown condition within 36 hours if the maximum service water temperature was exceeded. The licensee performed Calculation FSE/SS-TBX-1678, Revision 0, which assumed a worst-case scenario of one unit experiencing a design basis loss-of-coolant accident (LOCA) and the other unit being shut down. The licensee predicted the temperature increase on the basis of Table 4-4 of the study by J. E. Edinger Associates, Inc., entitled, "Hydrothermal Simulations of Comanche Peak Safe Shutdown Impoundment." The licensee performed a new analysis that showed that two-train cooldown of the nonaccident unit could be achieved. The team reviewed the new calculation and agrees with the licensee's conclusion.

5. During the design review, the team found eight calculations that contained nonconservative assumptions, inconsistent information with other calculations, incomplete information, or errors. Although these

calculation deficiencies were not safety significant, reanalysis was required in several instances to confirm design adequacy. In the case of the residual heat removal (RHR) cooldown analyses and the diesel generator intake temperature stress analyses, previous design margins were reduced.

6. The team also found an error in the Calculation TNE-EE-CA-0008-267, Revision 1 of the backup protective relay (device 51 V) settings for the EDGs. The computation of the 6.9 KV bus short circuit voltage level (Vb) incorrectly used the 2000 KVA transformer per unit impedance instead of the EDG impedance. This error resulted in improper application of device 51 V characteristics in the associated coordination curves shown in the calculation. During isolated emergency operation, the EDG protective devices were bypassed, with the exception of differential and overspeed protection. However, the EDG needed adequate protection to support surveillance testing while in parallel with the preferred power sources. In response, the licensee performed a supplementary calculation that showed that in this scenario the fault current contribution of the system would result in shorter fault clearing time. The shorter fault exposure would not exceed the EDG thermal limits, thus resulting in acceptable protection. The licensee agreed to correct the calculation. The team agreed with the licensee's actions and future corrections.

7. The licensee's seismic support calculation (Ebasco Calculation No. Vol IV, Book 52) for the battery room explosion proof heater used an incorrect heater assembly weight. The licensee used a weight of 900 pounds for the seismic support of the heater assembly in the computer analysis rather than the weight of 1160 pounds as indicated in vendor Drawing 66L. No justification for the use of the 900-pound weight was noted in the calculation. The licensee generated a ONE Form FX-91-1661 to address the issue for both units and to correct the calculation. There was sufficient margin in the calculation to accommodate the increased weight and this type of heater was not used elsewhere in either unit. The team reviewed the licensee action and agreed that sufficient margin in the calculation was present.

8. Another potentially adverse effect of the high primary transformer protective device setting was the extended (approximately 4.5 seconds) EDG exposure to a fault in the transformer secondary terminals. Such a fault could result in EDG loss of excitation due to low output voltage (approximately 60%) with attendant loss of the 6.9 KV bus. The team considered this an unanalyzed condition of the Class 1E emergency power supplies of the generating station, requiring resolution in support of continued plant operations. The licensee consulted with the EDG exciter vendor who stated that the excitation system would not collapse under the extended low voltage exposure caused by the postulated fault condition. This was attributed to the EDG time constant of five seconds and the vector summing design of the excitation system. The licensee then determined that adequate design margin was present. The team agreed with their determination.

Requirement:

Criterion III of Appendix B to 10 CFR Part 50, requires that design control measures be established for verifying or checking the adequacy of design, and for assuring that applicable regulatory requirements and the design basis are correctly translated into applicable specifications, drawings, procedures, and instructions.

References:

TU Electric Quality Assurance Manual, Section 3

FRSS/SS-TBX-1076, "Comanche Peak 1 and 2 Train Cooldown Times," January 8, 1988

ME-CA-0260-3118, "Evaluation of Using RHR Return Line to RWST for Full Flow Check Valve Testing," Revision 0

ME-CA-0250-3008, "Evaluation of RHR Relief Valves Use for COMS," Revision 0

16345-ME(B)-337, "Partial-Open-Position Setpoint of 1HV-4572 and 1HV-4573," Revision 0

16345-ME(B)-306, "DG FO Storage Tank Level Setpoints," Revision 4

16345-ME(B)-038, "Establish DG Intake and Exhaust System Operating Modes and Temperatures and System Design Temperature," Revision 2

2-HV-0010, "Temperature Summary for Diesel Generator Building Equipment Rooms," Revision 0 with CCN-1

X-EB-302A-2, "Temperature Summary for Diesel Generator Building Equipment Rooms," Revision 4

16345-ME(B)-305, "Suction Lift of Fuel Oil Transfer Pump," Revision 11

Ebasco Calculation No. Vol. IV, Book 52

DEFICIENCY 50-445/91-202-02, 50-446/91-201-02

Finding Title: CCW Instrument Air Lines Incorrectly Run

Description of Condition:

In some instances, the licensee's as-built installations did not agree with the as-designed configurations. For example, the instrument air lines from air accumulators on the component cooling water (CCW) control valves for trains A and B uninterruptible power supply (UPS) air conditioning system were installed incorrectly in a drain port location, which had the potential for acting as a trap. The UPS air conditioning system was designed with two safety-related trains, each shared between Units 1 and 2. Page 12 of DBD-ME-313 described that the CCW control valves X-PCV-H116A and B (trains A and B) were operated by a compressed air system with a built-in safety-related compressed air storage tank for each valve to ensure that the valves would fail in the open position. However, walkdown of both trains of the system revealed that the air lines from the storage tanks to the pilot valves of the control valve operators came off the bottom of the horizontal tanks, instead of the middle or the top of the tanks. The vendor drawing (A&M Co. 18-120-01) showed the air lines routed from the end of the storage tanks rather than the bottom; thus, the installation did not conform to the design documents.

Preliminary licensee reviews indicated that the incorrect routing originated with the valve supplier. The licensee issued ONE Form FX 91-1659 to reroute the tubing in accordance with the design drawing and evaluated this condition of reportability. The determined deficiency will not affect Unit 1 because an operability test was performed on the system every month. The inspection team agreed with the licensee's actions.

Requirement:

Criterion X of Appendix B to 10 CFR Part 50 requires that inspections of quality assurance activities to verify conformance with documented drawings shall be performed.

References:

DBD-ME-313, "Uninterruptible Power Supply Area Air Conditioning System," Revision 2 with DCAs and DCNs as of October 2, 1991

Atwood and Morrill Co. Drawings 18-120-02, "Actuator Bailey Positioner," Revision 1

M1-0313, "Flow Diagram-Ventilation-Control Building-UPS Area A/C Systems," Revision CP-10

DEFICIENCY 50-446/91-201-03

Finding Title: Failure To Follow Procedures During Construction Activities

Description of Condition:

During the inspection, the team identified instances in which the licensee's staff failed to follow controlling instructions. Examples included:

1. Procedures governing "Q" storage requirements and maintenance of material cleanliness during work activities on systems were not followed. Several examples are:

   (a) The wall mounting plate for seismic snubber CC-2-028-411-S33K was laying in the corner of room 63 of the electrical safeguards building. This snubber was one of the supports in the component cooling water system. The storage location was not posted in accordance with housekeeping procedures. Other than the identification number etched on the item, the team could find no markings that indicated its ASME class designation or the status of the associated work package.

   (b) The containment spray pump room contained coats, a face shield, and welding machine in a housekeeping Zone 3, cleanliness Level B area.

   (c) Safety-related storage area outside the Unit 2 equipment hatch had uncovered and unprotected piping and instrument lines, unlabeled equipment, and trash and food in the storage area.

2. Instances of welders using excessive amperage while making an ASME support weld and not maintaining adequate interpass and preheat temperatures during welding of another support were observed. The two examples of welders failing to follow procedures are:

   (a) Maximum Amperage Exceeded During a Fillet Weld

   The maximum amperage permitted by Welding Procedure Specification (WPS) 18013, Revision 8/ICN 0, was 80 amperes. However, during a welding parameter surveillance the actual recorded amperage was 92 amperes.

   This particular weld joined a stainless steel stanchion to a piece of carbon steel plate. The design specification for ASME component supports did not require impact testing for carbon steel or sensitization testing for stainless steel material. Therefore, the fact that the amperage range was exceeded did not significantly affect the ability of the materials to perform their intended design function.

(b) Minimum Preheat Temperature Not Maintained

WTS 11032, Revision 19/ICN 1, required a minimum preheat temperature of 200°F. However, for support RC-2-135-408-C41K, the temperature minimum measured was 174°F. The licensee issued documentation to remove and replace the existing weld.

The inspection team determined through conversations with Region IV that these were isolated instances and the team agreed with the licensee's actions.

3. An isolated example where a qualification record for an auditor involved with QA audit 90-065 contained errors and was not submitted to nuclear training in a timely manner. While the original record had been approved on December 3, 1990, required training was subsequently completed on February 2, 1991 and the auditor had not signed the documentation in several locations.

4. There were numerous areas where system cleanliness was not being maintained. The following components were open and not capped:

- The hot leg injection flow transmitter (2-FT-0988) low pressure root line
- containment spray line, 4-CT-2-110-301R-2
- instrument air lines to the diaphragm of the train B RHR heat exchanger bypass flow control valve (2-FCV-0619)
- two tubes in the EDG system (one to the shutdown cylinder and the other to the hydraulic sensing for the diesel trip logic)

Requirement:

Criterion V of Appendix B to 10 CFR Part 50 requires that procedures appropriate to the circumstances for activities affecting quality shall be established and followed.

References:

TU Electric Quality Assurance Manual, Section 5

CP-SAP-24, "System Cleanliness Requirements and Control"

CPES-M-2003, "Piping Mechanical Installation Specification"

CPES-I-2002, "Instrumentation Installation Specification"

ACPs-11.1,-11.2,-14.2; "ASME Construction Procedures"

CDP-ME-101, "Construction Discipline Procedure"

CQP-IC-102, "Construction Quality Procedure"

NQA-3.07, "Nuclear Quality Assurance Procedure"

DEFICIENCY 50-446/91-201-04

Finding Title: Failure To Maintain Adequate Control of Pipe Supports During System Flushing

Description of Condition:

During the performance of RHR system flush test 2RH-5800-07A/B it was observed that a number of rigid pipe supports and spring hangers were missing. A followup discovered that the construction group had removed the supports after the system had been verified adequately supported by the pipe stress analysis engineers and released to the startup group for testing. The flush boundary support verification and associated walkdown was completed by the licensee on September 14 and 23, 1991. This condition appeared to be a programmatic/repetitive problem and an apparent disconnect in coordination between the startup and construction groups. Further, the problem was an apparent failure by the construction group to follow the applicable administrative controls of CP-SAP-06, Section 4.1.4. In addition, some instances were also noted in which the construction group failed to install temporary supports in accordance with the CDP-ME-102-3 requirements for unsupported pipe spans and, in one instance, inappropriately removed a previously installed temporary support. In response to this condition, the licensee initiated a number of TUE forms and addressed the issue from a programmatic/repetitive aspect. The startup engineers walked down the service water system to see if similar conditions existed on a system that affected Unit 1. The licensee identified the system was properly supported. The licensee believed the condition was isolated to the RHR system. The team agreed with the licensee's actions.

Requirement:

Criterion XI of Appendix B to 10 CFR Part 50 requires, in part, that tests are performed under suitable environmental conditions and that provisions for such prerequisites are met.

References:

TU Electric Quality Assurance Manual, Section 11

CP-SAP-03A, "Release of Station Components from Construction to Startup"

CP-SAP-06, "Control of Work on Station Components After Release from Construction to Startup"

XCP-ME-04, "Prerequisite Flush Test Procedure"

CDP-ME-102-3, "Temporary Supports"

CPES-P-2018, "Construction Piping Specification"

TUEs 91-2920,-2946,-2947,-2948,-2994,-2996,-3001

DEFICIENCY 50-445/91-202-03

Finding Title: Improper Installation of Hilti Bolt Impermeable Material

Description of Condition:

During the inspection, the team observed a number of concrete expansion anchors (Hilti bolts) exposed to standing water conditions. The issue had been previously identified by the licensee as a potential problem in significant deficiency SD-CP-91-003 and significant deficiency analysis report, SDAR 91-993. The licensee had performed walkdowns of areas susceptible to water accumulation. One of the corrective actions taken was to environmentally seal the Unit 1 EDG exhaust muffler support bolts on the safeguards building roof. The team observed that the sealing method was unsuccessful as the impermeable material had shrunk and the standing water was still present to induce bolt crevice corrosion.

Requirement:

Criterion XVI of Appendix B to 10 CFR Part 50, requires that corrective measures shall assure that the cause of a deficient condition is corrected sufficiently to preclude repetition.

Reference:

TU Electric Quality Assurance Manual, Section 16

SD-CP-91-003, "Corroded Hilti Bolts - (Interim Report)"

Walkdown proposal ZIM-5.21, 5.24

SDAR-TUE-91-993

ONE Form 91-3594

UNRESOLVED ITEM 50-445/91-202-01, 50-446/91-201-01

Unresolved Item Title: Automatic Transfer of Faulted Motor Control Centers Between Units

Description of Condition:

FSAR Section 3.1.1.5 contained a commitment by the licensee to comply with 10 CFR 50, General Design Criteria 5. Structures, systems, and components important to safety shall not be shared among nuclear power units unless it can be shown that such sharing will not significantly impair their ability to perform their safety functions, including, in the event of an accident in one unit, an orderly shutdown and cooldown of the remaining units. The team requested documentation from the licensee to show compliance with GDC 5. The licensee's evaluation of GDC 5 compliance was in the process at the time of the inspection, with no firm completion date established. However, the automatic transfer system for the six 480 V MCCs shared between Units 1 and 2 (i.e., XEB1-1 & 2, XEB2-1 & 2, XEB3-2 and XEB4-2) were energized and available for connection to Unit 2.

The team reviewed the automatic transfer scheme and found that there was no provision to prevent an automatic transfer of a faulted 480 V MCC from occurring upon loss of the preferred power supply due to a fault on the affected shared 480 V MCC. The lack of interlocks to prevent the automatic transfer of a faulted 480 V MCC from Unit 1 to Unit 2, or vice versa, could potentially impact the operation of other safety equipment.

The licensee stated the fault would only affect one safety train (A or B) and that the other train would be available to perform the required safety functions. The team remained concerned that the design allowed the automatic transfer of a faulted MCC from one unit to the other without a full evaluation having been performed by the licensee to address the potential consequences.

The licensee agreed to further review the automatic transfer scheme to determine whether it is satisfactory or if design modifications are required.

Requirements:

10 CFR Part 50, Appendix A, Criterion 5, states: "Structures, systems and components important to safety shall not be shared among nuclear power units unless it can be shown that such sharing will not significantly impair their ability to perform their safety functions, including, in the event of an accident in one unit, an orderly shutdown and cooldown of the remaining units."

Reference:

FSAR Section 3 1.1.5

UNRESOLVED ITEM 50-445/91-202-02, 50-446/91-201-02

Unresolved Item Title: Potential Damage of Battery Charger due to High Fault Current

Description of Condition:

The licensee's Class 1E 125 Vdc short circuit calculations indicated that, under fault conditions with initial current surges in excess of 5600 amperes, a potential for damage to the battery chargers existed. IEEE Standard 279 states that Class 1E systems should be protected. This item requires further evaluation by the licensee and the battery charger vendor.

Reference:

DBD-EE-044, Revision 4, "Design Basis Document, DC Power Systems"

IEEE-308, 1974, "Class 1E Power Systems for Nuclear Power Generating Stations"

APPENDIX B

CONTENTS

APPENDIX B

OBSERVATIONS

OBSERVATION 50-446/91-201-01

Observation Title: Heavy Reliance on Turnover Programs

Description of Condition:

The licensee had completed the majority of RHR system installation work. However, the long construction period had exposed some components to a rigorous environment, as evidenced by a broken flexible conduit. The licensee had identified most damaged items on a punchlist. Some commodities, such as pipe supports, did not meet the installation clearances, angularity, and gimble specification requirements of CPES-P-2018. In accordance with ACP 11.5, "Component Support Fabrication and Installation," these attributes will be inspected during the system turnover inspection. The associated checklists found in Section 7.0 of the ACP appeared comprehensive. Other inspection mechanisms also existed to verify the installations, including CQP-MS-913, "System Release/Turnover Process for Construction"; 2PP 2.03, "Room/Area Walkdowns, Access Control and Completion"; 2EAP-001, "Commodity Clearance"; STA 802, "Acceptance of Station Systems and Equipment"; and STA 810, "Acceptance of Rooms, Areas, and Structures."

Heavy reliance was placed on turnover programs to detect and correct room/system deficiencies. There were a large number of deficiencies being accumulated on punchlists and corrective actions were being deferred until later in the construction schedule when the turnover programs are completed.

The team identified a number of field discrepancies. Some examples are:

- Junction box JB2S-73 and attached conduit C23K05382 were not grounded in accordance with CPES-E-2004 section 3.9.
- Hydraulic fluid was found covering a small section of stainless steel RHR system pipe RH-2-RB-001.
- The angle between the pipe clamp and strut of support RH-2-020-403-S22K was incongruent with specifications in CPES-P-2018, Section 6.3.1.4.
- A pin was missing from pipe hanger strut RH-2-025-403-S32R.
- Pipe hanger strut RH2-015-402-S32R lacked swivel as discussed in CPES-P-2018, Section 6.3.1.7.

Although these discrepancies did not indicate any pattern of trouble, they had not been previously identified in the utility's punchlist. When the items were brought to the attention of the licensee, the licensee often indicated that there was a followup program in place to find such discrepancies.

The team was concerned about the potential impact of scheduling pressures on the quality of work which was deferred to the end of construction.

OBSERVATION 50-446/91-201-02

Observation Title: Adequacy of Flushing Program

Description of Condition:

During the inspection, a number of deficiencies were noted in the flushing program. These deficiencies included such items as omission of recording measuring and test equipment used during the flush tests, objective evidence of nominal design flow rates in portions of the system and instructions for flushing instrumentation root valves and some vents and drain valves.

In followup to these deficiencies, it was determined that the licensee's QA staff had performed surveillances of prerequisite testing activities associated with flushing. During its QA surveillances performed in August and October 1991, the licensee also identified the same deficiencies noted above and other similar weaknesses. As a result, the startup engineers initiated a number of TUE forms and a flush plan review panel. The review panel made a flush matrix which identified system piping requiring flushing reverifications, and the startup engineers revised the affected RHR system flush plans to correct the noted deficiencies. The licensee's actions to identify the problems and implement corrective actions in a timely manner were responsive and commendable.

APPENDIX C

ATTENDANCE SHEET

EXIT MEETING - DECEMBER 13, 1991

NAME	TITLE
Licensee Personnel	
P. H. Anderson	Unit 2 Overview
M. R. Blevins	Director of Nuclear Overview
R. W. Braddy	Engineering Manager
L. Bradshaw	Secretary
H. D. Bruner	Senior Vice President
W. J. Cahill	Group Vice President, Nuclear
H. M. Carmichael	Unit 2 EA Manager
R. J. Daly	TU Start-up Manager
W. G. Guldemond	Manager, Site Licensing
S. W. Harrison	Manager, Unit 2 Project Overview
J. C. Hicks	Project Manager, Tech Support Rates
T. A. Hope	Unit 2 Licensing Manager
A. J. Indigo	Unit 2 Asst SIV Manager
F. W. Madden	Unit 1 Design Engineer
D. M. McAfee	Manager, QA
J. W. Muffett	Project Engineer, DEO
D. E. Pendleton	Unit 2 Regulatory Services Manager
C. W. Rau	Unit 2 Project Manager
A. H. Saunders	Assessment Manager
R. L. Spence	Unit 2 QC Manager
W. M. Taylor	Executive Vice President, TU Electric
C. L. Terry	Chief Engineer
O. L. Thero	Consultant/Citizens Association for Sound Energy
R. D. Walker	Manager of Nuclear Licensing
D. L. Webster	TU Construction Manager
K. F. Williamson	Asst Proj. Construction Eng., Brown & Root
J. E. Woods	Unit 2 Systems PE
J. E. Wren	Construction QA Manager
NRC/DOE Personnel	
F. A. Brookes	Nuclear Installations Inspectorate, UK
D. Chamberlain	NRC/RIV/DRS
J. W. Clifford	NRC/NRR/Project Manager
M. Fields	NRC/NRR/PD4-2
M. X. Franovich	NRC HQ General Engineer
R. A. Gramm	NRC/NRR/DRIS/RSIB/Section Chief
B. K. Grimes	NRC/NRR/DRIS/Division Director
T. P. Gwynn	NRC/RIV/DRP/Deputy Director
D. L. Harris	Parameter
E. V. Imbro	NRC/NRR/DRIS/Branch Chief
M. L. Jeal	Nuclear Installations Inspectorate, UK
J. M. McIntyre	NRC/NRR
T. O. McKernon	NRC/RIV

N. N. Rivera	Parameter
K. O. Sidey	DOE HQ
H. Stramberg	Parameter
R. L. Twigg	NRC/NRR/PD4-1
M. J. Virgilio	NRC/NRR/ADR4-5
H. Wang	NRC/NRR/DRIS/RSIB
D. Waters	Parameter
J. D. Wilcox	NRC/NRR/DRIS/RSIB/Team Leader
E. S. Young	DOE HQ
L. Zerr	NRC/NRR/DRIS/RSIB

APPENDIX D

ABBREVIATIONS

A/E	architect/engineer
ANSI	American National Standards Institute
ASME	American Society of Mechanical Engineers
AWS	American Welding Society
CAR	corrective action report
CAT	construction assessment team
CCN	contract change notice
CCW	component cooling water
CMC	component modification chart
CMI	configuration management inspection
CPSES	Comanche Peak Steam Electric Station
DBD	design-basis document
DCA	design change authorization
DR	deficiency report
EA	engineering assurance
ECCS	emergency core cooling system
EDG	emergency diesel generator
EDS	electrical distribution system
EDSFI	electrical power distribution system functional inspection
FVM	field verification method
FSAR	final safety analysis report
GDC	general design criteria
HELB	high energy line break
HVAC	heating, ventilation, and air conditioning
I&C	instrumentation and control
IDA	integrated design assessment
IEEE	Institute of Electrical and Electronic Engineers
IGM	internally generated missiles
ISEG	Independent Safety Engineering Group
IST	inservice testing
JUMA	joint utility management audit
LOCA	loss-of-coolant accident
LTC	load tap changing
MCC	motor control center
MELB	moderate-energy line break
MSLB	main steam line break
M&T	measuring and test equipment
MOV	motor-operated valve(s)

NCR	nonconformance report
NRC	Nuclear Regulatory Commission
P&ID	piping and instrument diagram
PCHVP	post-construction hardware verification program
PET	permanent equipment transfer
QA	quality assurance
QAA	quality assurance audit
QC	quality control
QR	qualification report
RHR	residual heat removal
RPS	Reactor Protection System
RWST	refueling water storage tank
SDR	startup deficiency report
SWEC	Stone and Webster Engineer Corporation
TS	Technical Specifications
TU	Texas Utilities
WPS	welding procedure specification
WTS	welding technique sheet