September 17, 1992

Docket No. 50-446

Mr. William J. Cahill, Jr.
Grooup Vice President, Nuclear
TU Electric
400 North Olive Street, L. B. 81
Dallas, Texas 75201

Dear Mr. Cahill:

SUBJECT: ISSUANCE OF SUPPLEMENT NO. 25 TO NUREG-0797 RELATED TO OPERATION OF THE COMANCHE PEAK STEAM ELECTRIC STATION, UNIT 2

The U.S. Nuclear Regulatory Commission has issued Supplement No. 25 to the Safety Evaluation Report related to the operation of Comanche Peak Steam Electric Station, Unit 2. Twenty additional copies of this report (NUREG-0797, Supplement No. 25) will be sent to you following printing.

Concurrent with this letter, copies of this report are being placed in the Commission's Public Document Room located at the Gelman Building, 2120 L Street, N.W., Washington, D.C. 20555, and the Local Public Document Room, located at the University of Texas at Arlington Library, Government Publications/Maps, University of Texas at Arlington Library, Government Publications/Maps, 701 South Cooper, P. O. Box 19447, Arlington, Texas 76019.

Sincerely,

Original Signed By

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

Enclosure:
Supplement 25

cc w/enclosure:
See next page

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NUREG–0797
Supplement No. 25

Safety Evaluation Report

related to the operation of
Comanche Peak Steam Electric Station,
Unit 2

Docket No. 50–446

Texas Utilities Electric Company, et. al.

U.S. Nuclear Regulatory Commission

Office of Nuclear Reactor Regulation

SEPTEMBER 1992

ABSTRACT

Supplement 25 to the Safety Evaluation Report related to the operation of the Comanche Peak Steam Electric Station (CPSES), Unit 2 (NUREG-0797), has been prepared by the Office of Nuclear Reactor Regulation of the U.S. Nuclear Regulatory Commission (NRC). The facility is located in Somervell County, Texas, approximately 40 miles southwest of Fort Worth, Texas. This supplement reports the status of certain issues that had not been resolved when the Safety Evaluation Report and Supplements 1, 2, 3, 4, 6, 12, 21, 22, 23, and 24 to that report were published. This supplement deals primarily with Unit 2 issues; however, it also references evaluations for several Unit 1 licensing items resolved since Supplement 24 was issued.

Supplement 5 has not been issued. Supplements 7, 8, 9, 10, and 11 were limited to the staff's evaluation of allegations investigated by the NRC Technical Review Team. Supplement 13 presented the staff's evaluation of the Comanche Peak Response Team (CPRT) Program Plan, which was formulated by the applicant to resolve various construction and design issues raised by sources external to TU Electric (applicant). Supplements 14 through 19 presented the staff's evaluation of the CPSES Corrective Action Program: large- and small-bore piping and pipe supports (Supplement 14); cable trays and cable tray hangers (Supplement 15); conduit supports (Supplement 16); mechanical, civil/structural, electrical, instrumentation and controls, and systems portions of the heating, ventilation, and air conditioning (HVAC) system workscopes (Supplement 17); HVAC structural design (Supplement 18); and equipment qualification (Supplement 19). Supplement 20 presented the staff's evaluation of the CPRT implementation of its Program Plan and the issue-specific action plans, as well as the CPRT's investigations to determine the adequacy of various types of programs and hardware at CPSES.

Items identified in Supplements 7, 8, 9, 10, 11 and 13 through 20 are not included in this supplement, except to the extent that they affect the licensee's Final Safety Analysis Report.

In one or more future supplements, the staff plans to evaluate the outstanding and confirmatory issues contained herein, and to address changes to the SER and its supplements that have resulted from the receipt of additional information from the applicant.

TABLE OF CONTENTS

TABLE OF CONTENTS (Continued)

TABLE OF CONTENTS (Continued)

APPENDICES

1 INTRODUCTION AND GENERAL DESCRIPTION OF PLANT

1.1 Introduction

The Nuclear Regulatory Commission (NRC) Safety Evaluation Report (SER), NUREG-0797, on the application of the Texas Utilities Generating Company (TUGCO)* (the applicant) for a license to operate the Comanche Peak Steam Electric Station (CPSES), Units 1 and 2, was issued in July 1981. Since then the following supplements have been issued:

- Supplement 1 (SSER 1) was issued in October 1981. It described the resolution of a large portion of the outstanding and confirmatory issues identified in the SER.

- Supplement 2 (SSER 2) was issued in January 1982. It included the report of the Advisory Committee on Reactor Safeguards (ACRS) to the NRC Chairman by letter dated November 17, 1981, which was appended as Appendix F. Applicant and staff responses to comments by the ACRS were also included.

- Supplement 3 (SSER 3) was issued in March 1983. It addressed outstanding and confirmatory issues resolved since SSER 2 was issued. The staff's evaluation of the applicant's emergency plans was also described.

- Supplement 4 (SSER 4) was issued in November 1983. It included the staff's evaluation report on design modifications made to the Westinghouse model D4 and D5 steam generators installed at CPSES.

- Supplement 5 (SSER 5) has been canceled. It was to have been limited exclusively to the CYGNA Independent Assessment Program. The issues from the CYGNA Independent Assessment Program have been addressed in the applicant's corrective action program. The staff's evaluations of the CYGNA issues are provided in the respective SSERs (14-19) for each corrective action program design workscope. Therefore, the planned supplement was never issued.

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*On January 16, 1987, TUGCO informed the NRC that it had adopted a new corporate signature and would be known as TU Electric (Texas Utilities Electric Company).

- Supplement 6 (SSER 6) was issued in November 1984. It addressed outstanding and confirmatory issues resolved since SSER 4 was issued. Noteworthy in this supplement was a partial exemption to General Design Criterion (GDC) 4 of Appendix A to Part 50 of Title 10 of the Code of Federal Regulations (10 CFR Part 50) deleting the requirement for installing jet impingement shields for the Unit 1 primary coolant loop piping at postulated break locations.

- Supplement 7 (SSER 7) was issued in January 1985. It was limited exclusively to the staff's evaluation of allegations investigated by the NRC's Technical Review Team (TRT) pertaining to plant electrical/instrumentation systems and testing programs.

- Supplement 8 (SSER 8) was issued in February 1985. It was limited exclusively to the staff's evaluation of allegations investigated by the TRT pertaining to the plant's civil/structural and other miscellaneous construction and plant-readiness testing items.

- Supplement 9 (SSER 9) was issued in March 1985. It was limited exclusively to the staff's evaluation of coating requirements inside containment and allegations of coating deficiencies investigated by the TRT.

- Supplement 10 (SSER 10) was issued in April 1985. It was limited exclusively to the staff's evaluation of allegations investigated by the TRT pertaining to the mechanical and piping areas.

- Supplement 11 (SSER 11) was issued in May 1985. It was limited exclusively to the staff's evaluation of allegations investigated by the TRT pertaining to quality assurance/quality control (QA/QC) practices in the design and construction of CPSES.

- Supplement 12 (SSER 12) was issued in October 1985. It updated the SER further by providing the results of the staff's review of information submitted by the applicant by letter and in Final Safety Analysis Report (FSAR) amendments addressing several of the issues and license conditions listed in Sections 1.7, 1.8, and 1.9 of the SER that were unresolved at the time SSER 6 was issued. SSER 12 also listed several new issues that had been identified since SSER 6 was published and that were unresolved.

- Supplement 13 (SSER 13) was issued in May 1986. It presented the staff's evaluation of the Comanche Peak Response Team (CPRT) Program Plan, which was formulated by the applicant to resolve various design and construction issues raised by the Atomic Safety and Licensing Board, allegers, the Citizens Association for Sound Energy (CASE), and NRC inspections, as well as those raised by CYGNA Energy Services during its independent design assessment.

- Supplement 14 (SSER 14) was issued in March 1988. It presented the staff's evaluation of the applicant's corrective action program related to large- and small-bore piping and pipe supports.

- Supplements 15 and 16 (SSERs 15 and 16) were issued in July 1988; Supplements 17 through 19 (SSERs 17-19) were issued in November 1988. They presented the staff's evaluation of the corrective action program as related to cable trays and cable tray hangers (SSER 15); conduit supports (SSER 16); the mechanical, civil/structural, electrical, and instrumentation and controls workscopes, and systems portions of the heating, ventilation, and air conditioning (HVAC) system workscope (SSER 17); HVAC structural design (SSER 18); and equipment qualification (SSER 19).

- Supplement 20 (SSER 20) was issued in November 1988. It presented the staff's evaluation of the CPRT implementation of the CPRT Program Plan and the issue-specific action plans, as well as the CPRT's investigations to determine the adequacy of various types of programs and hardware at CPSES.

- Supplement 21 (SSER 21) was issued in April 1989. It updated the SER further by providing the results of the staff's review of information that the applicant submitted by letter and in FSAR amendments. It addressed several of the issues and license conditions listed in Sections 1.7, 1.8, and 1.9 of the SER that were unresolved at the time SSER 12 was issued. Of note from an administrative standpoint, SSER 21 renumbered items appearing in Sections 1.7, 1.8, and 1.9, and deleted all items that were previously resolved but listed in SSER 12.

- Supplement 22 (SSER 22) was issued in January 1990. It updated the SER by presenting the results of the staff's review of information that the applicant submitted by letter and in FSAR amendments. The staff review addressed several of the issues and license conditions listed in Sections 1.7, 1.8, and 1.9 of the SER that were unresolved at the time SSER 21 was issued.

- Supplement 23 (SSER 23) was issued in February 1990 with the low-power operating license. It documented resolution of the remaining outstanding issues appearing in Section 1.7 of SSER 22.

- Supplement 24 (SSER 24) was issued with the full-power operating license for CPSES Unit 1. Confirmatory issues remaining at the time of license issuance, as well as proposed license conditions, were listed in Sections 1.8 and 1.9, respectively.

The purpose of SSER 25 is to update the SER, and subsequent SSERs, by presenting the results of the staff's review of information that the applicant submitted by letter and in FSAR amendments; specifically documenting reviews in support of the licensing of Unit 2.

Each section or appendix of this supplement is numbered and titled so that it corresponds to the section or appendix of the SER that has been affected by the staff's additional evaluations and, except where specifically noted, does not replace the corresponding SER section or appendix. Appendix A is a continuation of the chronology of correspondence between the NRC and the applicant that updates the correspondence listed in the SER and in SSERs 1 through 24. Appendix B includes references other than NRC documents and correspondence cited in this supplement.* Appendix C contains information concerning the status of NRC generic correspondence for CPSES. Appendix D contains a list of principal contributors to this supplement. Appendix E contains a list of errata identified in the SER and subsequent supplements. Appendix I contains an evaluation of diesel generator reliability and operability. Appendix EE contains guidelines for implementing Action 3 of NRC Bulletin 88-08. No changes were made to SER Appendices F, G, H, J, K, L, M, N, O, P, Q, R, S, T, U, V, W, X, Y, Z, AA, BB, CC, or DD by this supplement.

Copies of this supplement are available for public inspection at the NRC's Public Document Room, the Gelman Building, 2120 L Street, N.W., Washington, D.C. 20555; and at the University of Texas at Arlington Library, Government [illegible]tions/Maps, 701 South Cooper, P. O. Box 19447, Arlington, Texas 76019.

[illegible] roject Manager for Comanche Peak Steam Electric Station, Unit 2, is [illegible] Holian. Mr. Holian may be contacted by calling (301) 504-1334 or by [illegible] o the U.S. Nuclear Regulatory Commission, Washington, D.C. 20555.

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*Availability of all material cited is described on the inside front cover of this document.

1.7 Summary of Outstanding Issues

Section 1.7 of the SER, as supplemented, did not identify any open issues at the time SSER 24 was issued. Those issues that were resolved in previous supplements were not listed in SSER 24. As outstanding issues are resolved, they will be dropped from the list in this section.

The NRC staff has completed its review of FSAR amendments through Amendment 84. As a result of the staff's continuing review of the CPSES Unit 2 application (FSAR amendments, TU Electric letters to NRC), a number of outstanding issues have been identified that remain under review at the time of issuance of this supplement. These items are listed below. Also listed as outstanding issues are several items for which the applicant has indicated that a new or revised application is forthcoming. Not relisted in this section are those open items from Appendix C of this supplement, "NRC Generic Correspondence."

The staff will complete its review of these items before making a decision to issue or not issue an operating license for Unit 2; that review will be reported in one or more future supplements to the SER.

(1) Cable Separation Criteria; review use of one inch and one barrier for power circuits versus one inch and two barriers. (Section 1.11, Item 17)

(2) Metal Clad and Rockbestos Cables; review use of copper sheath cable; review rockbestos cable for proposed electrical separation usage. (Section 1.11, Item 16)

(3) Combined Technical Specifications; complete review and certification.

(4) Optimized Fuel Assemblies; continue review of fuel assembly design and associated safety analyses.

(5) Mild Environmental Qualification Program; complete evaluation of changes to previously approved program. (Section 1.11, Items 22 and 23)

(6) Station Blackout; complete assessment of dual-unit static blackout.

(7) Cable Tray Loading Criteria; review adequacy.

(8) Non-Class 1E Transformers in Cable Spreading Rooms; review use.

(9) Diesel Generator Post-24 Hour Load Test; review for compliance with Regulatory Guide (RG) 1.108.

(10) Initial Test Program; resolve exceptions to RG 1.68 and RG 1.108.

(11) Fire Protection Plan/Thermo-Lag; evaluate plan and implementation.

(12) Benbrook Second Circuit; verify that offsite modification is complete.

(13) Pipe Support Computer Codes; review Unit 2 applications (i.e., Code ME-215). (Section 1.11, Item 1)

(14) Piping and Pipe Support; review seismic reclassification. (Section 1.11, Item 24)

(15) RG 9.3 (Antitrust); complete "significant change" review.

(16) Leak Before Break on Reactor Coolant System (RCS) Branch Lines; complete review.

(17) Leak Before Break on Surge Line; complete review.

(18) HVAC Design Validation; review seismic damping values and structural member weld analyses. (Section 1.11, Items 6 and 7)

(19) Small-Break Loss-of-Coolant Accident (LOCA) (Mode 4); complete review of significant deficiency analysis report 86-41.

(20) Inservice Testing Program; assess revision to 1989 Code.

(21) High-Energy Line Break; review Unit 2 changes.

(22) Code Case Usage; review Unit 2 Code Cases used.

(23) Diesel Generator; perform design review/quality reverification (DR/QR) Phase II. (Appendix I)

(24) Detailed Control Room Design Review; review Unit 2 submittal.

(25) Boron Dilution Mitigation System; review Unit 2 submittal.

(26) Safe Shutdown Impoundment; review revised analyses.

(27) Interior Supports in Long Piping Runs; review current modeling methodology. (Section 1.11, Item 3)

(28) Concrete embedments; review bolt proximities. (Section 1.11, Item 13)

(29) NRC Bulletin 88-08 Temperature or Pressure Monitoring; verify Unit 2 program. (Sections 3.6.1.2 and 3.9.1)

(30) HVAC Category II Design Values; review Criteria Used. (Section 1.11, Items 8 and 10)

(31) Diesel Generator Procedural Upgrades; review changes. (Section 9.5.9 and Appendix I)

1.8 Confirmatory Issues

Section 1.8 of the SER, as supplemented, identified a total of four confirmatory issues at the time SSER 24 was issued. Two Unit 1 confirmatory issues from SSER 24 have, or will b addressed by separate letter, as referenced below:

- Unit 1 inservice inspection program for compliance with 10 CFR 50.55a(g).

- Submittal of first-cycle Unit 1 N-16 transit time flow meter performance data to NRC for review (NRC letter of September 10, 1992 to TU Electric).

Confirmatory issues that are currently outstanding are listed below. The staff will address resolution of these issues in one or more future supplements to the SER.

(1) Performance of reactor relief and safety valves for Unit 2 (Section 22.2 from SSER 24)

(2) After completion of the Westinghouse Owners Group generic analysis of the uncovered steam generator tube rupture event, if necessary, the applicant may need to docket a new plant-specific worst-case scenario (Section 15.4.4 from SSER 24)

(3) Amend Final Safety Analysis Report (FSAR) to conform with installation of approved carpeting in the control room (Section 9.5.1.6)

(4) Review implementation of fire safe shutdown analysis (FSSA) data on Unit 2 Thermo-Lag installation (Section 1.11, Item 5)

(5) Review results of metallurgical examination of emergency diesel generator engine block (Section 9.5.9 and Appendix I)

(6) Review diesel generator procedure upgrades/commitments (Section 9.5.9 and Appendix I)

(7) Review FSAR updates on instrumentation (Section 7.1)

1.9 License Conditions

In Section 1.9 of SSER 24, the staff listed three proposed license conditions. Those license conditions that were resolved in previous supplements were not listed in SSER 24. As proposed license conditions are resolved, they will be removed from the list in this section.

License conditions discussed in previous SSERs that were included in the Unit 1 license and are proposed to be included in the Unit 2 license follow:

(1) The licensee shall continue to control mineral exploration within the exclusion area; that is, at distances beyond 2250 feet from safety-related structures per GDC 4, 10 CFR Part 50, Appendix A.

(2) The licensee must implement and maintain in effect all provisions of the approved fire protection program, as described in the Final Safety Analysis Report (as amended) and as approved in the SER and its supplements, subject to the following provision: "The licensee may make changes to the approved fire protection program without prior approval of the Commission only if those changes would not adversely affect the ability to achieve and maintain safe shutdown in the event of a fire."

(3) The licensee shall fully implement and maintain in effect all provisions of the physical security, guard training and qualification, and safeguards contingency plans, previously approved by the Commission, and all amendments made pursuant to the authority of 10 CFR 50.90 and 10 CFR 50.54(p). The plans, which contain safeguards information protected under 10 CFR 73.21, are entitled: "Comanche Peak Steam Electric Station Physical Security Plan" with revisions submitted through November 28, 1988; "Comanche Peak Steam Electric Station Security Training and Qualification Plan" with revisions submitted through November 28, 1988; and "Comanche Peak Steam Electric Station Safeguards Contingency Plan" with revisions submitted through January 9, 1989.

1.11 Validation Efforts for Corrective Action Program

In response to NRC staff questions regarding the application of the Corrective Action Program (CAP) to Unit 2, the applicant submitted a report, "Validation Efforts for CPSES, Unit 2", dated April 27, 1992. The report describes the design and hardware validation programs for CPSES Unit 2. These programs are similar to the design and hardware validation programs conducted under the CAP for CPSES, Unit 1 and the areas common to Units 1 and 2, as modified to account for the findings and lessons learned from CAP. This report also identified the substantive differences between the Unit 2 programs and the descriptions of the CAP found in the NRC's SSERs 13 through 20, to the extent that such differences were not previously described in significant deficiency analysis reports (10 CFR 50.55e) submitted to the NRC.

Background

A limited work authorization was issued on October 17, 1974, allowing the applicant to begin construction of CPSES. On December 19, 1974, the construction permits were issued for CPSES. By 1982, the construction of Unit 1 was nearing completion. On December 28, 1983, the Atomic Safety and Licensing Board (ASLB) presiding over the CPSES operating license (OL) proceeding issued an order that identified concerns regarding quality assurance (QA) for the design of piping and pipe supports at CPSES. As a result, the ASLB suggested that the applicant consider performing an independent design review. In response to the ASLB decision, the applicant contracted with CYGNA Energy Services to perform an independent assessment of the adequacy of CPSES design work.

Beginning in early 1984, the NRC formed a special Technical Review Team (TRT) to evaluate in a coordinated and integrated manner the technical concerns related to the construction and the design of CPSES. In response to early TRT findings, the applicant formed the Comanche Peak Response Team (CPRT) to investigate and respond to the issues raised by the TRT. The CPRT program was subsequently revised on several occasions to examine issues raised by the following additional sources: the ASLB in the CPSES OL hearings; Citizens Association for Sound Energy (CASE) - the intervenor in those hearings; a number of additional reports issued by the NRC staff; and several self-initiated reviews of the adequacy of the design and construction of CPSES. The CPRT identified a number of findings that required corrective action. The applicant implemented a corrective action program to validate the safety-related design and construction of CPSES, Unit 1, and the common areas between the two units.

Corrective Action Program (CAP)

The purposes of the CAP were to:

- Demonstrate that the design of safety-related systems, structures, and components complied with the licensing commitments.

- Demonstrate that the existing systems, structures and components were in compliance with the design; or, if they were not in compliance, develop modifications to bring the systems, structures, and components into compliance with design.

- Develop procedures, an organizational plan, and documentation to maintain compliance with licensing commitments throughout the life of CPSES.

The CAP was a comprehensive program that validated both the design and hardware at CPSES, including resolution of specific CPRT and external issues. The design validation portion of the CAP identified the design-related licensing requirements and commitments for CPSES, Unit 1 and common areas. These requirements and commitments formed the bases for the design validation effort and were assembled in design-basis documents. The hardware validation portion of the CAP was implemented by the Post Construction Hardware Validation Program (PCHVP). The purpose of the PCHVP was to demonstrate that as-built systems, structures, and components were in compliance with the installation specifications (validated design), or to identify modifications that were necessary to bring the hardware into compliance with the validated design.

The applicant developed inspection requirements for new and modified installations. These requirements (inspection attributes) formed the basis for the PCHVP attribute matrix. This matrix was a complete set of final acceptance attributes for installed commodities. The final acceptance attributes were verified by either physical validation or engineering evaluation.

The NRC staff approved the revised CPRT program and CAP on January 22, 1988. TU Electric submitted the findings of the design validation program and a description of the PCHVP to the NRC in the form of a Project Status Report for each of the CAP disciplines. The NRC evaluated the CPRT and CAP activities for Unit 1 and common areas, and prepared SSERs 13 through 20.

CAP and Unit 2

The applicant described its approach for using the CAP at Unit 2 in letters of April 14, 1988, and May 19, 1989 (TU Electric letters TXX-88373 and TXX-89271 to NRC) as follows:

(1) The same basic approach is being taken to the validation of Unit 2 design and construction as was utilized under the CAP.

(2) In general, the review and completion of the Unit 2 design are being performed using the same relevant technical methods, technical procedures, and design control procedures used for Unit 1 and common areas.

(3) The resolution of CPRT findings, as well as the resulting corrective and preventive actions taken or committed to under the CAP, are being addressed in the validation activities for CPSES, Unit 2.

(4) To the extent that corrective actions were taken with respect to hardware on Unit 1, equivalent actions are being taken on the corresponding hardware of Unit 2. The corrective actions for Unit 2 also utilize the lessons learned from the Unit 1 program.

The NRC staff documented its evaluation of the applicant's translation of CAP commitments from Unit 1 to Unit 2 in numerous inspection reports (e.g., as stated in Tables 4-1, 5-1, and 6-1 of the applicant's Validation Efforts Report). Unit 2 implementation is routinely reviewed and inspected against what has been previously approved on Unit 1. Specifically, Inspection Report 50-446/90-35 focused on the applicant's plans and processes for completing Unit 2 design activities. That report concluded that the approach and methodology for controlling the translation of Unit 1 reverification requirements to Unit 2 were systematic and reasonable, and should be equivalent to the quality of the Unit 1 reverification effort. Additionally, a special inspection (Design Attribute Verification, documented in Inspection Report 50-446/92-13) was conducted to specifically evaluate the acceptability of the Unit 2 PCHVP results.

The design attribute verification inspection focused on the translation of the Unit 1 PCHVP results to Unit 2 activities. The NRC staff selected more than 200 attributes to assess and evaluate. This sample included attributes from the civil/structural, mechanical, electrical, and instrumentation and control disciplines. Findings from the inspection showed that the technical justifications documenting the disposition of the attributes were adequate and were consistent with the methodologies used for Unit 1. Additionally, detailed and conservative engineering evaluations were evident in the documentation of the disposition of the attributes.

As a followup to the design attributes verification, the staff audited the applicant's Validation Efforts Report. The audit reviewed SSERs 13 through 20 to assess programmatic and specific commitments relating to design and construction activities. The audit coupled a review of the SSERs and the applicant's report with an onsite review of the applicant's programs and backup documentation describing the translation of the CAP to Unit 2. The audit was performed to ensure that Unit 2 implementation of the CAP was thorough, properly controlled, and documented.

In formulating its Validation Efforts Report, the applicant reviewed the SSERs and compared the method for implementing the CAP for Unit 2 to what had been approved in the preceding SSERs. Commitments were verified in the applicant's commitment tracking system. If the Unit 2 approach differed from existing documentation, the applicant determined whether or not a significant deficiency analysis report (10 CFR 50.55e) had been generated. If it did not exist, the applicant stated so in the Validation Efforts Report.

The NRC staff reviewed the Validation Efforts Report, and SSERs 13 through 20, and raised approximately 60 questions regarding Unit 2 activities. The questions, in general, requested information on Unit 2 design and construction activities in order to compare the Unit 2 action to what had been reviewed and approved in the previous SSERs.

The staff reviewed the applicant's responses to these questions during an onsite audit. Programmatic aspects of the CAP, as well as the verification of engineering details (as referenced in the SSERs), were checked for implementation.

The staff also reviewed SSER supplemental review sheets, which the applicant completed to document a potential difference in implementation when compared to that described in an SSER. The staff found several discrepancies on these backup documentation sheets (e.g., items marked as "open," yet that were not included in the Validation Efforts Report). However, further review revealed that plant implementation did not differ from the referenced SSER discussion.

The staff audit was conducted to verify that the applicant performed a thorough assessment in reviewing the translation of the Unit 1 CAP to Unit 2 activities. The audit revealed that the applicant has properly controlled Unit 2 implementation of the CAP and has adhered to the standards reviewed and approved on Unit 1. The following items summarize differences between Unit 1 and Unit 2 CAP validation. An NRC staff evaluation/action is included with each item.

(1) The computer codes used in the design validation of Unit 2 piping design are different from those used in Unit 1 (in SSER 14). This item is listed in Section 1.7, as Outstanding Issue 13.

(2) SSER 14 states that Hilti bolt embedment lengths from the design drawings were used to calculate allowable loads for qualification of pipe supports. At the time of Unit 1 design validation, the design drawings contained as-built information. At the time of Unit 2 validation activities, the design drawings did not contain as-built information. Therefore, for Unit 2, the as-built embedment lengths were obtained by field walkdowns and used to calculate actual allowable loads for the supports. These actual allowable loads were then compared with the allowable loads calculated based on the embedment lengths specified on the design drawings and the lower of the two allowable loads was used in the qualification of the anchor bolts. This action is conservative and acceptable.

(3) SSER 14 describes a concern related to the underprediction of loads and stresses at interior supports in long runs of pipe with a series of adjacent supports modeled with moment-restraining capability. The applicant assessed this concern according to the current modeling methodology and determined that case-by-case evaluation is not necessary because the current modeling methodology would not underpredict stresses or loads. The staff is reviewing this further; it is listed in Section 1.7, as Outstanding Issue 27.

(4) SSER 15 states that cable deadweight for qualification of Unit 2 cable tray supports is based on 100-percent cable tray fill. The applicant stated that 100-percent fill was used to simplify cable tray support design validation. In general, the cable deadweight used for Unit 2 cable tray support qualification is based on 100-percent fill. However, as-built cable fill is used to qualify the supports when they can not be qualified using 100-percent fill. During the audit the applicant stated that approximately 20 percent of the cable tray supports have been qualified using as-built cable fill. The majority of instances where as-built data was used (vice 100-percent fill) are on thermolag installations (due to the additional weight of the thermolag). The use of as-built cable fill to qualify cable tray supports, although not as conservative as using 100 percent fill, meets the applicant's commitment as stated in the FSAR and is acceptable.

(5) SSER 16 states that walkdowns of conduit systems to determine the weight of installed Thermo-Lag would be performed to obtain as-built information for the validation of conduit support design. As of March 1992, no fire protection material had been installed on Unit 2 electrical raceways. Therefore, to determine the weight of Thermo-Lag to be installed on Unit 2 conduits, the extent of the Thermo-Lag installation will be identified through use of the Fire Safe Shutdown Analysis (FSSA). This information is used for design validation of Unit 2 conduits and supports for the Thermo-Lag weight. Therefore, use of the FSSA, with proper quality control, is acceptable. This item is listed in Section 1.8, as Confirmatory Issue 4; it will be reviewed for proper implementation.

(6) SSER 18 states, in part, that the amplified response spectra curves (damping values) used in HVAC design validation were the 2-percent curve for the operating basis earthquake (OBE) and the 4-percent curve for the safe shutdown earthquake (SSE). For Unit 2, damping values of 4 percent for the OBE and 7 percent for the SSE were used for evaluation of HVAC duct systems. The applicant stated that the Unit 2 HVAC system design consists of bolted construction, vice welded construction for Unit 1. The use of damping values other than 2 percent for the OBE and 4 percent for the SSE was described in a letter of August 30, 1989 (TU Electric letter TXX-89511 to NRC). TU Electric's design basis document allows the use of the 4-percent curve for the OBE and the 7-percent curve for the SSE based on Regulatory Guide 1.61 Guidelines. This item is being reviewed further and is listed in Section 1.7, as Outstanding Issue 18.

(7) SSER 18 states that, for Unit 1, analysis of the welds between HVAC structural members was performed using ANGLEWELD, a contractor personal computer program. For Unit 2, analysis of these welds is being performed using the P-Delta STRUDL computer program. The applicant stated that P-Delta STRUDL, like ANGLEWELD, considers the bending effects caused by eccentricities between the centroidal axes of the attached members and the weld. This item is being reviewed further and is listed in Section 1.7, as Outstanding Issue 18.

(8) SSER 18 indicates that the allowable normal tensile stress cannot exceed 0.9 F_y and the allowable shear stress cannot exceed 0.50 F_y for member evaluations for seismic Category I HVAC duct support evaluations. Seismic Category II duct supports are not addressed. The applicant stated that the criteria for Seismic Category II duct supports are different than the criteria for seismic Category I supports. (i.e., normal tensile stress is limited to 1.0 F_y and shear stress to 0.577 F_y for member evaluations for Seismic Category II HVAC duct supports). The applicant stated that this is a standard industry practice and has been previously accepted by the NRC staff. This item is being reviewed further and is listed in Section 1.7, as Outstanding Issue 30.

(9) SSER 17 describes "relocating one pressure tap for the differential pressure switch downstream of the gravity dampers" in the diesel generator area ventilation system. Upon subsequent detailed review of the committed-to modifications, it was determined that these actions were not required. The NRC was notified of this in a letter of April 8, 1991 (TU Electric letter TXX-91119 to NRC). In this letter, the applicant described the availability of redundant fans and dampers, and also reported indicators that would identify gravity damper failure. The letter committed to an annual maintenance activity to provide additional assurance of gravity damper operability. On the basis of the discussion and commitments described in the applicant's letter, this change is acceptable.

(10) SSER 18 states, "For the HVAC design validation of Hilti expansion anchors, a factor of safety of four for SSE load conditions and a factor of safety of five for OBE load conditions are used." The applicant was concerned that it could be inferred that these criteria apply to seismic Category II duct support evaluations. For seismic Category II duct supports, however, only the SSE load case is evaluated; and a factor of safety of three is used. SSER 18, Appendix A, Section 3.1 states that "Seismic Category II HVAC supports, which are not required to maintain the functionality of the HVAC system during or after an SSE, but are required to maintain their structural integrity, are designed and analyzed for SSE only." Therefore, SSER 18 is considered to adequately describe the use of the SSE load case only. However, SSER 18 did not differentiate between Category I and II factors of safety.

The use of a factor of safety of three is less than the factor of four or five, depending on anchor type, specified in IE Bulletin (IEB) 79-02 for Category I supports. However, IEB 79-02 applies only to Category I systems. The factor of safety of three has been proposed for the evaluation of some equipment anchorages in the resolution of unresolved safety issue (USI) A-46. This item is being reviewed further and is listed in Section 1.7, as Outstanding Issue 30.

(11) SSER 17 states that, "Two duplex strainers and two sampling connections were added in the diesel generator fuel oil transfer system design..." This modification was later determined to be unnecessary and the NRC was notified in a letter of August 28, 1989 (TU Electric letter TXX-89604 to NRC). Each diesel has two fuel transfer pumps which discharge through separate simplex strainers. The strainers have differential pressure alarm features which provide adequate operator notification should a strainer become clogged. This design was submitted with FSAR Amendment 77, and is acceptable.

(12) SSER 17 postulated a double-ended guillotine pipe break in the non-safety portions of the component cooling water system and the effects it would have on the safety portion. The conclusion of the original analysis committed to positioning throttle valve XCC-0080. Subsequently, TU Electric reviewed Standard Review Plan (SRP) Section 3.6 and determined that a double-ended guillotine break need not be postulated. Since the component cooling water system is a moderate-energy system, and the non-safety related piping and supports are designed for either seismic category I or II, only a crack need be postulated. The applicant performed calculations for Unit 1 and Unit 2 that demonstrate for a crack in this system, no valve throttling is required. The staff concurs that SRP acceptance criteria are met, and therefore, only a crack need be postulated; therefore, this change is acceptable.

(13) SSER 17 identifies a concern regarding evaluation of Hilti-bolts which were installed in close proximity to through-bolts and stated that the applicant would identify the location of all adjacent attachments and the loadings on them. For Unit 1, an engineering walkdown of concrete embedments was performed and engineering evaluations were prepared to justify accepting all embedments based on this sample evaluation, as discussed in a letter of June 23, 1989 (TU Electric letter TXX-89193 to NRC). For Unit 2, the same approach was used. Engineering evaluation of a sample of concrete embedments provided the same confidence level regarding the acceptability of concrete embedments as was achieved for Unit 1. This item is listed in Section 1.7 as Outstanding Issue 28; it will be reviewed for proper implementation.

(14) For both units, the embedment plates to which the steam generator upper lateral beams are bolted, are anchored to concrete walls by 18 No. 18 steel reinforcing bars (not 16 as stated in SSER 17). This change is considered editorial and is listed in Appendix E, "Errata."

(15) SSER 17 lists control circuits as a proposed hardware modification. Modifications were not made to ac and dc control circuits for either Unit 1 or Unit 2. The circuits were evaluated, and adequate voltage is available to operate the control devices without modifying or redesigning the control circuits. This item is acceptable.

(16) SSER 17 states that "Cables for which Thermo-Lag was used as a fire barrier were rerouted or replaced with larger cables or a combination of both if required to comply with ampacity design criteria." For Unit 2, either Thermo-Lag or one-hour-fire-rated cable is being used. The adequacy of this fire-rated cable has been demonstrated by tests. This item is listed in Section 1.7, as Outstanding Issue 2.

(17) SSER 17 states that double enclosures are required for power cables whenever the normal separation criteria cannot be achieved. The CPSES separation criteria, allow certain power-to-power configurations in which the minimum required separation is one inch and one barrier. This item is listed in Section 1.7, as Outstanding Issue 1.

(18) The indicated resolution for insufficient voltage at an inverter static transfer switch, when fed from a bypass panelboard supplied by a transformer with minimum output voltage as stated in SSER 17, Appendix B, included replacement calculations and appropriate subsequent followup actions. Subsequent modifications were made in both units which dedicated the existing startup transformers to the emergency safety buses. These modifications were described in SSER 17, Section 4.2.2.1. Voltage profile calculations based on the new scheme, performed by the applicant, showed that adequate voltage is available to the inverter static transfer switch when connected to the bypass panelboard supplied by a transformer. Therefore, this change is acceptable.

(19) SSER 17 describes the relocation of eight differential-pressure-indicating switches to a place downstream of the dampers to automatically start backup battery room fans. Upon subsequent detailed review of the committed modifications (similar to Item 9, this section), the applicant determined that these actions were not required based on the safety significance of the issue, the probability of damper failure, the indications available of damper failure, and a periodic maintenance activity. The NRC was notified in a letter of April 8, 1991 (TU Electric letter TXX-91119 to NRC). On the basis of the discussion and commitments described in the applicant's letter, this item is acceptable.

(20) The addition of 41 cables to provide inputs from the existing instrument circuits to the emergency response facility computer is described in SSER 17. Upon subsequent review of the modification, the applicant determined that only 12 of the additional inputs were required. The remaining variables are either already monitored or are not required to be monitored for postaccident conditions. This is a clarification to SSER 17 and is acceptable.

(21) SSER 17 describes a modification to the auxiliary feedwater pump turbine control circuit to disconnect the manual speed control station on a safety injection signal. Upon detailed review of the control circuit, the applicant determined that disconnecting the manual speed control station on safety injection signal would not be necessary on either Unit 1 or 2 for the following reasons:

(a) The speed control loop is fully qualified and the loss of Class 1E power or instrument air will cause the turbine governor valve to go to its full open position.

(b) A safety injection signal does not start the pump and, hence, is not required to isolate the speed control signal.

(c) Should speed indication be lost, pressure and flow indications are available to ensure sufficient flow to the steam generators during emergency initiation of the pump.

The intent of the proposed modification in SSER 17 was to ensure that the feedwater pump turbine control circuit would be properly isolated. The above analysis shows that isolation is not necessary since safety injection signal performance will not be affected. Therefore, this change is acceptable.

(22) SSER 19 describes the design validation process for environmental qualification of Class 1E equipment located in a mild environment. The equipment qualification program was revised and equipment qualification of Class 1E equipment located in a mild environment was deleted from the environmental equipment qualification (EQ) program, as described in a letter of March 6, 1991 (TU Electric letter TXX-91102 to NRC). This item is listed in Section 1.7, as Outstanding Issue 5.

(23) The applicant revised the environmental EQ program (as described in SSER 19) to include the following sentence regarding relative humidity into the CPSES definition of harsh environment: "The equipment will be considered to be located in a mild environment if relative humidity is the only harsh environment parameter for an area and evaluation concludes that subject equipment can perform its safety-related function(s) when exposed to the postulated relative humidity environment." This change was included in FSAR Amendment 82 and will be reviewed in conjunction with item (22), above.

(24) SSER 14 describes the seismic analysis of non-seismic piping as being limited to only those piping systems located in seismically analyzed buildings. In a letter of March 4, 1992 (TU Electric letter TXX-92063 to NRC), the applicant describes the reclassification of a portion of the steam generator blowdown piping and pipe supports in the turbine

building from non-seismic to seismic Category II. The piping and piping supports are completely supported by seismic Category I walls. This item is being reviewed further as part of FSAR Amendment 85; it is listed in Section 1.7, as Outstanding Issue 14.

(25) An expanded discussion of IE Bulletin 79-14 reconciliation was provided in the Validation Efforts Report. This reconciliation either is performed at the end of the process based upon the results of IE Bulletin 79-14 walkdowns (as was done on Unit 1), or it is performed during preparation of stress analyses using a combination of as-built and as-designed data (as is being done on Unit 2). Discussions with the applicant indicate that a 100 percent review of subsequent installations is being performed to ensure that the as-designed data are consistent with the subsequent as-built installations. This process is different between Units 1 and 2 due to the timing of the validation process, as compared to construction activities. This process is acceptable since IE Bulletin 79-14 requires reconciliation to as-built data; however, final implementation acceptability will be discussed in a future Inspection Report (reference Appendix C, Bulletin 79-14).

In summary, the NRC staff reviewed the application of the CAP on Unit 2, emphasizing the differences fostered by the "lessons learned" on Unit 1. On the basis of this review and inspections that were conducted, the staff concludes that the differences, as discussed above, are acceptable. (Open or confirmatory issues will be addressed in a future SSER.) Additionally, the translation of the CAP from Unit 1 and common systems to Unit 2 was sufficiently comprehensive and effectively implemented.

2 SITE CHARACTERISTICS

2.3 Meteorology

2.3.3 Onsite Meteorological Measurement Program

In SSER 22, the staff concluded that the operational onsite meteorological program will satisfy the emergency preparedness requirements of Appendix E to 10 CFR Part 50 and Supplement 1 to NUREG-0737. SSER 22 states that the data collected by both the primary and backup meteorological systems would be available on the RM-21 computer. In Amendment 83 to the Final Safety Analysis Report (FSAR), the applicant proposed replacing the RM-21 computer with an upgraded meteorological report processor computer. The new compter provides for acceptable meterological data collection and processing, therefore, this proposed change is acceptable.

2.4 Hydrologic Engineering

2.4.6 Groundwater

In Amendments 79 and 80 to the FSAR, the applicant changed the design-basis groundwater elevations to 793 ft-0 in. for the service water intake structure (SWIS) and 810 ft-0 in. for other safety-related structures. All safety-related structures have been designed for these groundwater levels. In Amendment 79, the applicant stated the actual measured groundwater levels adjacent to the SWIS were between elevations 782 ft-3 in. and 783 ft-2 in. during 1988, and that this translated into the probable maximum flood level at elevation 793 ft-0 in. for the safe shutdown impoundment including wave run-up at the SWIS. In Amendment 80, the applicant stated that no groundwater was encountered during excavation and construction of the plant structures.

The previous FSAR commitment for the design-basis groundwater elevation was at elevation 775 ft-0 in. for the whole plant. The ground elevation of the plant is at 810 ft-0 in. The applicant has raised the original design-basis groundwater level from elevation 775 ft-0 in. to 793 ft-0 in. for the SWIS and 810 ft-0 in. for other safety-related structures. On the basis of the information and justification given in Amendments 79 and 80, the new design-basis groundwater levels are reasonable and conservative and, therefore, are acceptable.

3 DESIGN CRITERIA FOR STRUCTURES, SYSTEMS, AND COMPONENTS

3.2 Classification of Structures, Systems, and Components

During the review of Amendment 83 to the FSAR, the staff became concerned about the applicant's classification of valve operators on passive safety-related valves. The amendment included a revision to FSAR Table 17A-1, "List of Quality Assured Structures, Systems and Components," whereby the applicant added Note 79 to clarify the safety classification, seismic category, and quality assurance requirements of valve operators for certain safety-related valves. The note indicates that the valve operators of passive valves are classified as seismic Category "None" and are not subject to 10 CFR Part 50, Appendix B quality assurance requirements. The associated piping and valves are classified as seismic Category I and are subject to Appendix B quality assurance requirements. The staff questioned the applicant's classification of passive valve operators.

The staff discussed this issue with the applicant to confirm that the Unit 2 valves were properly classified and to document the basis on which the valve operators had been classified. The applicant stated that the classification of passive valve operators is based on the interpretation that either the valve disc and seat are performing a passive safety function, or the position of the valve is of no importance for safety. For a passive valve that must remain in position, it was determined that no credible failure of the operator could cause the valve to change position. The applicant concluded that its current classification for valve operators on passive safety-related valves is appropriate.

The staff concurs with the applicant's methodology for classifying the subject valve operators and, therefore, finds that the addition of Note 79 to FSAR Table 17A-1 as submitted in Amendment 83 is acceptable.

3.6 Protection Against Dynamic Effects Associated With the Postulated Rupture of Piping

3.6.1 Inside Containment

3.6.1.2 Systems Other Than RCS Main Loop

In a letter of February 14, 1992 (TU Electric letter TXX-92075 to NRC), the applicant requested the elimination of the dynamic effects of certain postulated high-energy pipe ruptures from the design basis of Unit 2 using "leak before break" (LBB) analysis as permitted by General Design Criterion

(GDC) 4 of 10 CFR Part 50 Appendix A. Specifically, the request applied to the accumulator lines, pressurizer surge line, and residual heat removal (RHR) piping. This SSER provides the staff's review of the RHR piping. The staff's evaluation of the accumulator lines and pressurizer surge line will be incorporated in a future supplement to the SER.

GDC 4 allows the use of the LBB analysis to eliminate having to consider the dynamic effects of postulated pipe ruptures in high-energy piping from the design basis in nuclear power units. The NRC permits licensees with approved LBB analyses to remove pipe-whip restraints and jet impingement barriers. The acceptance criteria for the LBB analysis are defined in NUREG-1061 and Standard Review Plan (SRP) Section 3.6.3, and are summarized, in part, as follows:

(1) The LBB analysis should provide materials data including material specifications, age-related degradation such as thermal aging, and material limitations. The piping materials must be free from brittle, cleavage-type failure over the full range of the system operating temperature.

(2) The analysis should consider forces and moments of pressure, deadweight, thermal expansion, operating basis earthquake, and safe shutdown earthquake (SSE). The analysis should identify the location(s) at which the highest stresses occur coincident with the poorest material properties for base metals, weldments, and safe-ends.

(3) The analysis should postulate a through-wall flaw at the highest stressed locations. The flaw size should be large enough so that the leakage is assured of detection with at least a margin of 10, using the minimum installed leak detection capability when the pipe is subjected to normal operational loads.

(4) The analysis should show that the postulated leakage flaw is stable under faulted condition (normal plus SSE loads). The leakage flaw should also be stable under larger loads at least 1.4 times the normal plus SSE loads. However, the margin of 1.4 may be reduced to 1.0 if the individual normal and SSE loads are summed absolutely.

(5) Under normal plus SSE loads, the safety margin should be at least a factor of 2 between the leakage-size flaw and the critical-size flaw to account for the uncertainties inherent in the analyses and leakage-detection capability.

(6) The analysis should include operating experience to show that the pipe will not experience stress-corrosion cracking, fatigue, or water hammer. The operating history should include system operational procedures; system or component modification; water chemistry parameters, limits, and controls; resistance of piping material to various forms of stress corrosion; and performance of the pipe under cyclic loadings.

The staff has completed its evaluation of the applicant's analysis of the residual heat removal (RHR) piping. The evaluation is as follows:

(1) The RHR lines at CPSES, Unit 2 have a nominal diameter of 12 inches (Schedule 140) and a minimum wall thickness of 1.0125 inch. The two RHR lines are connected to loop 1 and loop 4 of the reactor coolant system. The piping and weld materials are A376/TP316, A403/WP316, A312/TP304, and A182/TP316. The welds are made by gas tungsten arc welding for root passes and followed by either submerged arc welding or shielded metal arc welding.

(2) The applicant used forces and moments of pressure, deadweight, seismic, and thermal expansion in the flaw stability analysis to assess margins for a postulated pipe rupture at the faulted condition. The highest stress nodes are located at the welds of the loop 4 RHR line.

(3) The applicant stated that CPSES, Unit 2 has leak detection systems for the reactor coolant pressure boundary that satisfy the guidelines of RG 1.45 so that a leakage of 1 gallon per minute (gpm) in 1 hour can be detected. The calculated leak rate through the postulated flaw is large relative to the staff's required sensitivity of the plant's leak detection systems. The applicant used a margin of 10 on leakage in calculating the leakage flaw size. This is consistent with the LBB criteria in NUREG-1061.

(4) The applicant described the material properties of the RHR lines from the certified materials test report and the ASME Code. The applicant used the ASME Code minimum tensile properties and the lower-bound stress-strain properties in the flaw stability evaluations. For the leakage rate calculations, the average stress-strain properties were used. The applicant showed that the postulated leakage flaw is stable under normal plus SSE loads. In the stability analysis, the normal loads and faulted loads were summed algebraically and absolutely. The safety margin in terms of applied loads was shown to comply with NUREG-1061.

(5) The staff verified that the margin between the leakage-size flaw and the critical-size flaw exceeds a factor of 2 for the load combination of the RHR lines. This satisfies NUREG-1061. However, the staff noticed that the applicant's contractor did not use the most conservative Z-factor in its crack stability analysis. The Z-factor calculation uses the outside diameter of the pipe; however, for pipes that are 24 inches or less, 24 inches should be used in the calculation according to Appendix C (C-3320) to ASME Code, Section XI. The applicant's contractor used the actual outside diameter, 12.75 inches, in the calculation. The staff verified that with the correct, higher Z-factor, the safety margin on the crack size is still acceptable.

(6) The applicant indicated that stress-corrosion cracking, water hammer, erosion/corrosion, and cleavage failure in the RHR pipes will not be a concern; however, the applicant noted that the RHR lines may experience thermal cycling and stratification based on previous PWR operating experiences. NRC Bulletin 88-08, "Thermal Stresses in Piping Connected to Reactor Coolant Systems," reports thermal fatigue in RHR piping as a result of leaking isolation valves. The bulletin requires that applicants provide assurance that RHR lines will not be subjected to cyclic stresses, including thermal cyclic stresses associated with leaking valves. The staff reviewed the applicant's response to Bulletin 88-08 as reported in Section 3.9.1 below. The staff concludes that the applicant's proposed inservice inspection (ISI) program at CPSES, Unit 2 is not acceptable and that the applicant should implement temperature or pressure monitoring on the Unit 2 RHR lines in accordance with Supplement 3 to Bulletin 88-08.

The NRC staff has performed independent flaw stability calculations to evaluate the applicant's LBB analysis of the RHR piping in CPSES, Unit 2. The staff concludes that the applicant's LBB analysis is consistent with the criteria in NUREG-1061, Volume 3, and, therefore, the analysis complies with GDC 4. Thus, the probability of large pipe breaks occurring in the RHR line is sufficiently low so that dynamic effects associated with postulated pipe breaks need not be included in the design basis for CPSES, Unit 2. However, the staff's conclusion on the acceptability of the applicant's request is pending resolution of the issues associated with Bulletin 88-08 discussed above (Section 1.7, Outstanding Issues, Item 29).

3.8 Design of Seismic Category I Structures

3.8.1 Concrete Containment

In a letter of January 15, 1990 (TU Electric letter TXX-90011 to NRC), the applicant notified the NRC of a change to the FSAR for CPSES, Unit 2. The change involved adding an exception to the American Society of Mechanical Engineers (ASME)-American Concrete Institute (ACI) Code paragraph 5523.1 of ASME-ACI 359. This paragraph addresses inspection criteria for liquid penetrant testing (PT) or magnetic particle testing (MT) of full penetration attachment welds to the containment liner inserts. This change came about because of differing nondestructive examination (NDE) inspection requirements between the liner procurement specification and the code requirements as listed in the FSAR (ASME-ACI 359, trial use and comments issue). The procurement specification required 100- percent visual examination and 2-percent to 10-percent spot MT of the total weld length. The code requirement was for 100-percent MT or PT of the weld length. Because of the inspection requirement differences, no NDE documentation exists that meets the FSAR.

The affected components are shop-fabricated, full-penetration welds. These welds are the connecting welds between the thickened liner plate inserts and the structural supports for in-containment equipment that is supported from the containment liner.

As a qualification measure, the applicant has performed field inspection (MT or PT) of accessible welds (and accessible portions thereof) using the FSAR acceptance criteria. Additionally, analytical qualification employing fracture toughness evaluations in accordance with ASME Code Section III, Appendix G has been performed. The original procurement inspection findings combined with the re-inspections and the fracture mechanics analysis gives the applicant a high degree of confidence concerning the integrity of the welds.

The applicant was able to inspect each of the most highly loaded, and thus most critical, welds. Of the total population of containment welds, 30 percent were examined. This represents an adequate sample population, since all of the most highly loaded welds were inspected. The inspection revealed no unacceptable indications and no repairs were required. This demonstrates that the shop welding technique was well controlled and of uniformly good quality. Acceptance criteria and test sensitivity were appropriately conservative, considering material properties and design loadings. This gives confidence that any undetected flaws would be small and unlikely to grow during the lifetime of the unit.

For the reasons stated above, the staff concludes that the proposed change to the FSAR is acceptable.

3.9 Mechanical Systems and Components

3.9.1 Special Topics for Mechanical Components

3.9.1.1 NRC Bulletin 88-08

Background

In a letter of February 24, 1992 (TU Electric letter TXX-92078 to NRC), the applicant submitted the findings of the thermal fatigue evaluation by the Westinghouse Electric Corporation (W) of those systems in Unit 2 that are potentially susceptible to the thermal stress phenomena described in Bulletin 88-08 and its Supplements. In its report WCAP-13211, "Evaluation of Auxiliary Piping for Comanche Peak Unit 2," W addressed the normal charging, alternate charging, auxiliary spray, and the cold-leg safety injection lines; in WCAP-13212, "Evaluation of Thermal Stratification from Postulated Valve Leakage for the Comanche Peak Unit 2 RHR Lines," W addressed the residual heat removal lines. In these reports, W stated that the applicant had implemented a temperature-measuring program in Unit 1 to monitor the thermal history of the unisolable sections of these systems, in accordance with the second option of Action 3 of Bulletin 88-08. W reviewed the data collected during the first fuel cycle and concluded that there was no evidence of currently leaking valves in these systems. Based on this conclusion, W (1) redefined the potential thermal cycling due to leaking isolation valves as a "postulated condition"; (2) concluded that temperature monitoring at Units 1 and 2 by instrumentation of these lines is not necessary; and (3) proposed to provide the required assurance against thermal cycling due to potential leaking isolation valves by an augmented inservice inspection (ISI) program.

Evaluation

In support of the proposed ISI program, W has performed thermal and stress analyses of the unisolable sections of the above systems to determine the temperature and stress distributions necessary for performing ASME Code Section III Class 1 fatigue analyses of these sections. Fatigue cycling was attributed to design conditions and a combination of isolation valve leakage and variable loop turbulent penetration. These analyses determined the time required for crack initiation. Fatigue crack growth analyses, based on the ASME Code Section XI fracture mechanics method, were also performed to determine the time of crack propagation to 60 percent of the wall thickness, assuming an initial crack size of 10 percent of the wall thickness. W described these analyses verbally. Minimal analytical or numerical data has been provided to support its conclusions, or to permit an independent staff assessment and verification of its results. Such an assessment is necessary, since the phenomena described in Bulletin 88-08 are currently not addressed in the standard design and safety evaluation of ASME Code Class 1 piping.

The W analysis shows that the normal charging, the alternate charging, and the safety injection lines are all determined to exceed the design fatigue allowable value for Class 1 piping (cumulative usage factor (CUF) of 1.0) after 10 years from the start of continuous isolation valve leakage, based on ASME Code Section III Class 1 fatigue calculations. This is the time interval at which a crack can be expected to initiate at the highest stressed location in these lines.

For the auxiliary spray line, W indicated that the ASME design fatigue allowable value was not exceeded during the life of the plant. Therefore, no crack initiation is expected during the life of the plant. However, this conclusion conflicts with a similar (proprietary) calculation performed by another licensee, which indicates that the ASME fatigue allowable value could be exceeded at the same location, under similar circumstances, in a much shorter time.

For the residual heat removal (RHR) lines, W determined from the monitored data in Unit 1 that the temperature distributions of the loop 1 and the loop 4 RHR lines were significantly different from each other. W also identified certain thermal transients, not associated with valve leakage. The temperature of the loop 1 RHR line was found to be almost the same as the hot-leg temperature. The temperature of the loop 4 RHR line was found to decay to ambient temperature with distance from the hot-leg nozzle. This difference was hypothesized to be caused by uneven turbulent penetration in these lines. (However, another explanation might be that there was leakage through the loop 1 RHR isolation valve, although no stratification was observed during normal power operation.) W performed thermal, stress, and fatigue analyses in accordance with ASME Code Section III Class 1 requirements, based on postulated thermal cycling, and concluded that the design fatigue allowable value for the loop 1 RHR line would not be exceeded for the life of the plant. For the loop 4 RHR line, subjected to the same postulated thermal cycling, the design fatigue allowable value would be exceeded, but no time interval was provided when this would happen.

Based on the W recommendation, the applicant has proposed not installing temperature-measuring instrumentation in Unit 2, but to implement an augmented ISI program in place of temperature monitoring. The applicant has submitted no details of this program.

Action 3 of Bulletin 88-08 requested that licensees offer continuing assurance that unisolable sections of piping connected to the RCS will not be subjected to thermal cycling from valve leakage that could cause fatigue failure during the life of the plant. Options for supplying this assurance specifically exclude ISI. This exclusion is based on GDC 14 of 10 CFR Part 50, Appendix A, which states that "the reactor coolant pressure boundary (RCPB) shall be designed so as to have an extremely low probability of abnormal leakage." The events described in Bulletin 88-08 and the calculations performed by W indicate that the probability of experiencing abnormal leaking cracks due to thermal cycling from valve leakage is not low and this thermal cycling is, therefore, considered an unanalyzed design condition. ISI is applicable to the detection of random cracks or flaws of finite size and unknown origin and, therefore, conflicts with the basic intent of the criterion which is to preclude the initiation of cracks from known causes. Furthermore, Supplements 1 and 2 of Bulletin 88-08 also show that ISI is not always reliable for locating or detecting flaws (or both) before flaws develop into leaking cracks. The staff, therefore, considers ISI to be an unacceptable method for satisfying the provisions of Action 3 of Bulletin 88-08.

In its analyses, W has postulated the thermal cyclic frequency for fatigue analysis based on the hydraulic phenomenon of turbulent penetration. The nuclear industry is currently actively researching this, since the phenomenon is neither well understood nor quantified. Little data are available in the literature, and none has been submitted to justify the postulated frequency. Likewise, the interaction of this penetration and stratified leaking flow is also not well understood. Therefore, the staff concludes that turbulent penetration theory or empirical evidence as currently available does not constitute an adequate and reliable basis for fatigue analysis.

Conclusion

The staff concludes that:

(1) The proposed augmented ISI program is not an acceptable means for satisfying the provisions of Bulletin 88-08.

2. The applicant should provide continuing assurance that unisolable sections of piping will not experience abnormal thermal cycling due to leaking isolation valves in accordance with the options stated in Action 3 of Bulletin 88-08 (Section 1.7, Outstanding Issues, Item 29). Suggested guidelines for temperature or pressure monitoring are given in Appendix EE to this supplement.

3.9.1.2 NRC Bulletin 88-11

In a letter of February 24, 1992 (TU Electric letter TXX-92077 to NRC), the applicant responded to NRC Bulletin 88-11, "Pressurizer Surge Line Thermal Stratification", for CPSES Unit 2. The response consisted of a Westinghouse study, WCAP-13210, "Evaluation of Thermal Stratification for the Comanche Peak Unit 2 Pressurizer Surge Line," dated February 1992.

NRC Bulletin 88-11 recommended that all licensees and applicants for pressurized water reactors take the following actions:

2.a Demonstrate that the pressurizer surge line (PSL) meets the applicable design codes and other FSAR and regulatory commitments for the licensed life of the plant before the issuance of the low power license. If this cannot be demonstrated, then Actions 2.b through 2.d are to be completed.

2.b Evaluate operational alternatives or piping modifications needed to reduce fatigue and stresses to acceptable levels.

2.c Monitor the PSL for the effects of thermal stratification, beginning with hot functional testing; or obtain data through collective efforts to assess the extent of thermal stratification, thermal striping, and line deflections.

2.d Update stress and fatigue analyses, as necessary, to ensure Code compliance.

Action 2.a has been addressed by TU Electric in the subject letter. W performed a study evaluating the adequacy of the CPSES, Unit 2 PSL taking into consideration the effect of thermal stratification and thermal striping during its 40-year service life. The effect of stratification was taken into consideration by redefining the 200 design heatup-cooldown cycles with new heatup and cooldown transients developed from the actual monitoring data from several PWR plants. Using the ANSYS and WECAN computer codes, 11 stress analysis cases of PSL thermal stratification were performed for CPSES, Unit 2. Additional stress analysis cases of stratification were solved by interpolation. The results showed that the existing as-built piping and support layout remain in compliance with the applicable code requirements for the design life of the plant. The maximum stresses due to thermal expansion (with stratification), pressure and weight meet ASME B&PV Code Section III (Section III) NB-3600 Equation 12 limits for the existing as-built piping layout and support configuration, which was the original licensing commitment.

W also provided the fatigue analysis of the CPSES Unit 2 PSL to ensure compliance with the applicable Code and license commitments. The fatigue usage factors were evaluated based on the requirements of Subsections NB-3600 and NB-3200 of Section III. Five worst-case locations in the PSL were selected for the calculation. W used its own WECEVAL computer code for this part of the analysis. The maximum usage factor was found to be 0.75 at the reactor coolant loop (RCL) nozzle safe-end.

In a report dated June 1990, the Westinghouse Owners Group (WOG) submitted WCAP-12639 "Pressurizer Surge Line Thermal Stratification Generic Detailed Analysis" for staff review. By letter dated August 6, 1991, the staff issued its Safety Evaluation regarding WCAP-12639 to the WOG, concluding that the methodology used to analyze and evaluate the stress and fatigue effects due to thermal stratification and thermal striping was found to be acceptable.

We have reviewed the applicant's submittal (WCAP-13210) and find that the methodology used to analyze the effects of thermal stratification and striping in the PSL are consistent with that of the W generic detailed analysis (WCAP-12639). Accordingly, we conclude that the applicant has satisfied the provisions of Action 2.a of Bulletin 88-11.

3.9.6 Inservice Testing of Pumps and Valves

The Code of Federal Regulations, (10 CFR 50.55a(g)), requires that inservice testing (IST) of certain ASME Code Class 1, 2, and 3 pumps and valves be performed in accordance with Section XI of the ASME Boiler and Pressure Vessel Code and applicable addenda, except where specific written relief has been requested by the licensee and granted by the NRC pursuant to Sub-sections (a)(3)(i), (a)(3)(ii), or (g)(6)(i) of 10 CFR 50.55a. In requesting relief, the licensee must demonstrate that (1) the proposed alternatives would produce an acceptable level of quality and safety; (2) compliance would result in hardship or unusual difficulty without a compensating increase in the level of quality and safety; or (3) conformance with certain requirements of the applicable code edition and addenda is impractical for its facility.

In letters of February 3, 1992, and April 6, 1992 (TU Electric letters TXX-92040 and TXX-92174 to NRC), the applicant submitted an IST program relief request regarding preservice testing of main steam and pressurizer safety valves for Unit 2. This relief request contained a proposal for testing the safety valves before initiating electric power generation in accordance with a proposed change to ASME OM Part 1. The applicant stated that this proposed change is anticipated to appear in the 1993 Addenda to the ASME OM Code.

RELIEF REQUEST V-1

The applicant requested relief from the ASME OM Part 1 requirement for preservice testing of the following safety valves:

Main Steam Safety Valves

2MS-0021, 0022, 0023, 0024, 0025, 0058, 0059, 0060, 0061, 0062, 0093, 0094, 0095, 0096, 0097, 0129, 0130, 0131, 0132, 0133

Pressurizer Safety Valves

2-8010A, 8010B, 8010C

ASME OM-1, Section 7.2, "Testing After Installation Prior to Initial Electric Power Generation," requires, in part, in situ testing of Class 1 safety valves and main steam safety valves. The applicant requested relief to have the option of either testing at a lab or in situ.

Basis for Requesting Relief

The removal of the pressurizer safety valves and main steam safety valves from the system for testing at a lab can yield valid test results and offers some distinct advantages over in situ testing. In particular, valves can be maintained and adjusted more easily in the testing lab environment. For example, the pressurizer and main steam safety valves are known to experience seat leakage after cycling. After set pressure verification, the valves often must be disassembled (while retaining spring compression) so that the disc insert and nozzle seating surfaces can be lapped. If the set pressure verification was performed in place, the subsequent seat leakage repairs would entail cooldown and depressurization of the reactor coolant and main steam systems. Once the valves are repaired and reassembled, the systems would then have to be reheated and repressurized to conduct a valve seat leakage retest, since OM-1 requires seat leakage testing to be done under the same temperature conditions and using the same fluid medium as are observed for the set pressure verification.

Pressurizer and main steam safety valve testing and maintenance can be performed at a testing lab instead of in situ, thereby eliminating the need to cycle the entire reactor plant. The test lab facilities allow the exact operating conditions (i.e., fluid media, temperature stability, and ambient temperature) of the valves to be simulated for testing and permit easy access to the valves should any maintenance be required. Actual set pressure on steam can be verified at a testing lab without using an assist device. The additional activities associated with testing the valve at a lab, such as valve removal, shipping, and reinstallation, can be performed safely by applying the procedural and quality controls normally required for such work.

The valves are rigged, boxed, and shipped in the vertical position and are inspected upon receipt both at the testing lab and upon their return to the plant. Reinstallation involves the routine closure of gasketed joints, which is subsequently verified through inservice leakage testing.

Thus, a valid OM-1 performance test of the pressurizer and main steam safety valves can be accomplished through either in-place testing or testing in a lab.

For the purpose of accomplishing main steam and pressurizer safety valve testing before initiating electric power generation, the following Code requirements apply:

(1) Within 6 months of initial fuel loading, each pressurizer safety valve shall have its set pressure verified.

(2) Either before or after installation and within 6 months before initial reactor criticality, each main steam safety valve shall be tested for set pressure verification and compliance with the owner's seat tightness criteria.

Documentation of items (1) and (2), above, should be maintained in plant records. Further NRC review, if any, will be performed by inspection or audit.

Evaluation

ASME OM-1, Section 7.2, "Testing After Installation Prior to Initial Electric Power Generation," requires, in part, in situ testing of pressurizer safety valves. The applicant proposed instead to test these valves in a testing lab environment or in situ.

The applicant stated that lab testing can yield acceptable test results. The applicant's test lab facilities allow the valves to be tested under exact operating conditions relating to temperature and fluid media. The risk associated with testing the valves at a lab, such as valve damage during shipping and reinstallation, can be minimized by observing procedural and quality controls. The valves are inspected upon their return from the test lab; and, following reinstallation, are tested for inservice leakage.

Conclusion

In situ testing of these safety valves can represent a hardship because of the problems associated with maintenance activities and with the need to cycle the plant. The proposed lab testing, combined with the application of procedural and quality control of shipping and reinstallation activities, offers adequate assurance that these valves will be capable of performing their design safety function. Requiring in-place testing without an option of testing at a lab environment would be a hardship for the applicant without a compensating increase in the level of safety.

Having determined that the proposal offers reasonable assurance of valve performance, and that compliance with the ASME code would result in hardship without a compensating increase in the level of safety, relief is granted as requested pursuant to 10 CFR 50.55a(a)(3)(ii). Granting relief is authorized by law, will not endanger life or property or the common defense and security, and is otherwise in the public interest.

3.11 Environmental Qualification of Safety-Related Electrical Equipment

3.11.3 Staff Evaluation

3.11.3.3 Service Conditions

3.11.3.3.4 Chemical Spray

In Section 3.11.3.3.4 of SSER 22, the staff stated that 2100 ppm boron buffered with sodium hydroxide solution to a pH in the range of 8.5 to 10.5 was the composition of the chemical spray inside containment that equipment needed to be qualified to meet. In Amendment 81 to the FSAR, the applicant stated that a 200-ppm boron concentration span was necessary to avoid operational constraints associated with a 1-hour technical specification Action statement. Therefore, the upper limit of boron concentration could reach 2200 ppm. The necessary equipment inside containment was reviewed to ensure qualification under such conditions. Because the equipment is qualified for a higher concentration than 2200 ppm boron, the staff concludes that the revised composition is acceptable.

5 REACTOR COOLANT SYSTEM

5.2 Integrity of Reactor Coolant Pressure Boundary

5.2.2 Overpressure Protection

5.2.2.2 Low-Temperature Operation

The applicant was notified by W in a letter of May 25, 1988, of a potentially unanalyzed condition at CPSES. The notification was generated by a review of the cold overpressure mitigation system (COMS) conducted by the Westinghouse Safety Review Committee. The committee concluded that a potential existed for the COMS to actuate during a main steamline break (MSLB) or steam generator tube rupture (SGTR) event given a single failure in the COMS circuitry. The applicant submitted a SDAR (required by 10 CFR 50.55(e)) to the NRC by letter of July 18, 1988 (TU Electric letter TXX-88567 to NRC).

Subsequently, in a letter of October 5, 1988 (TU Electric letter TXX-88688 to NRC), the applicant updated SDAR 88-30 with a licensing-basis analysis that classified the COMS failure as a "random simultaneous independent failure." The NRC forwarded questions regarding the COMS failure in a letter of October 9, 1990. The applicant responded to the questions in a letter of December 14, 1990 (TU Electric letter TXX-901049 to NRC), and concluded that the random simultaneous independent failure of the wide-range temperature channel (thereby affecting COMS) is not considered a "credible" failure during an MSLB or SGTR event.

Background

In general, the COMS is automatically "armed" if the reactor coolant system (RCS) temperature drops below 350 °F and then actuates if the RCS pressure is above an allowable pressure setpoint. The allowable pressure setpoint is determined by RCS temperature which is measured by resistance temperature detectors (RTDs) located in the hot and cold legs of the RCS loops. The logic is divided so that a signal from each division is required before the pressure operated relief valves (PORVs) will actually open. One logic division will respond to the measured hot-leg temperature (T_{hot}) and the other logic division will respond to the measured cold-leg temperature (T_{cold}) of the same loop. If the RCS pressure exceeds the allowable pressure, as determined by the loop temperatures, the COMS will actuate.

Evaluation

Westinghouse identified two events in which one train of COMS logic would be "armed" by event-induced plant conditions and, coincident with a single failure in the other logic train, would cause the COMS to open the PORVs. The two events are an MSLB and an SGTR. The staff reviewed the COMS logic and circuitry to determine what indications and COMS failures could be expected before and during the two events.

At this point, it should be emphasized, that Westinghouse and the applicant submittals state that the plant conditions necessary to "arm" or "actuate" the COMS circuitry only occur at specific points in the MSLB and SGTR events and only occur in the cold legs of the affected RCS loop. The affected RCS loop would be the loop associated with the faulted steam generator (SG). This point is important, since it considerably narrows the review focus and defines what components must fail and at what time in the event the failure will be of concern.

Alarms and Indications

If a single failure occurred in the COMS circuitry so that the COMS was "armed," a variety of annunciators would be available to alert the operator to the COMS condition. Among failures and indications are the following:

(1) A power supply failure would cause the COMS logic to fail into the "armed" state. The power supply is configured so that each logic division is powered from a separate, safety-related power train through its associated inverter. The inverter is backed up by batteries and an emergency diesel generator (EDG). If a single failure of the inverter is assumed, one of the COMS logic divisions will "arm." With the loss of an inverter, numerous indications would be available to the operator. Among indications are bus voltages, alarms, and the effects of a power loss on all instrumentation connected to the failed inverter.

(2) Certain COMS circuitry failures would "arm" the COMS and would also cause an alarm to annunciate. These failures are

(a) a temperature element (TE) failed low

(b) the pressure transmitter (PT) failed high

(c) the function generator failed low

(d) the auctioneering unit used to generate reference pressure failed low

In these cases, alarm window 2.11, "at Lo temp PORV approaching LMT Press," would illuminate. This alarm would indicate that one division of the COMS logic was "armed," thereby indicating to the operators that the potential exists for PORV actuation. This alarm is addressed in the annunciator response book as a potential COMS failure that could lead to the opening of a PORV. In accordance with Regulatory Guide (RG) 1.53, "Application of Single-Failure Criterion to Nuclear Power Plant Protection Systems," these failures would be considered detectable.

(3) Certain COMS circuitry failures would "arm" the COMS and would not cause an alarm to annunciate. These failures are

(a) the temperature auctioneering unit fails low

(b) pressure comparator fails high

(c) temperature comparator fails low

(d) failure of the "and" function

However, in their letter of December 14, 1990, the applicant committed to modify the circuitry so that if any of the four actuation or arming relays changes position, an alarm would annunciate in the control room. This modification has been completed on both units. This alarm not only provides alarm indication for the four failures noted above, but also has an additional indication for the failures noted in item 1 and item 2 above, in this SSER section. Furthermore, a 31-day surveillance is performed on the COMS circuitry which would indirectly detect these failures and the failures noted in item 2. With the installation of the relay alarm function and in consideration of the surveillance testing, these failures would also be considered detectable in accordance with RG 1.53.

(4) An additional indication not noted above, but that is relevant to this review, is the "PORV 455A/456 not closed" alarm. This alarm annunciates when the PORV is open. Although this alarm would not directly indicate a COMS failure, it would indicate the end result of such a failure.

Instrumentation Functions Before and After the Onset of an MSLB or SGTR

If one of the failures noted above occurred before the onset of an MSLB or an SGTR, the indications noted would be available to alert the operators to the potential for a PORV to open. At this point, a plant condition does not exist that will actually cause COMS to open a PORV (excluding the "and" logic failure). Since the MSLB or the SGTR event has not yet occurred, there is reasonable assurance that the operators will initiate the appropriate COMS repair requests and will maintain a heightened awareness to the potential for a PORV opening (annunciator book). In the event of an "and" logic failure, the PORV open alarm would annunciate and it is reasonable to assume that the operators will respond according to the training and procedures that address an inadvertent PORV actuation-type event.

If one of the failures noted in the previous section occurs after the onset of one of these two events but before the corresponding plant conditions are reached, a number of factors must be considered. During both of these events, there will be many alarms and varying indications in the control room.

Therefore, the ability of the operator to specifically detect a COMS failure (i.e., identify the COMS alarm) will depend on the operator's ability and the progression of the ongoing event. However, at this point, the COMS is "armed" and not actuated. In fact, particular T_{cold} loop temperatures must be reached before actuation.

In case of the SGTR, the applicant's procedures require that operators depressurize the RCS to obtain an RCS pressure less than or equal to the pressure in the faulted steam generator (SG). The applicant performed an analysis and determined that the RCS loop temperature required to actuate COMS would not be reached until one minute before the PORVs were intentionally opened by the operators. The applicant stated that it could find no adverse effects from the early opening. Further, when the operators depressurize the RCS, they take manual control of the PORVs. When in the manual mode, the COMS signal will have no effect on the PORVs. It is not until the PORVs are placed back into the automatic mode that the COMS can then attempt to reopen the PORVs.

If the COMS were to open the PORVs, either before depressurization or after, there is reasonable assurance that the operators would be aware of a failure for the following reasons: (1) the still-present COMS alarms, (2) the PORV open alarm, (3) the operator attentiveness to the PORVs during the SGTR event, and (4) the changing plant conditions. It should also be noted that the consequences of such a failure can be easily mitigated by closing the PORVs manually or by closing the associated block valve, or both.

Furthermore, the emergency operating procedures (EOPs) instruct the operator to maintain the RCS at or below the faulted SG pressure using the PORVs. The effect of the open PORV (until closed) would be to lower RCS pressure below SG pressure.

In the case of the MSLB, the plant conditions necessary to actuate the COMS will occur at a specific point in the event and only in the cold leg of the affected loop. Once the PORV is open, there is reasonable assurance that the operator can identify the control failure for the following reasons: (1) the still-present COMS alarms, (2) the PORV open alarm, (3) the heightened attentiveness to plant conditions and indicators during the MSLB, and (4) the overall effect on the plant parameters. In addition, some immediate corrective actions are at the operator's disposal. The operator can close the PORV manually, which will also defeat the COMS signal or close the block valve. The applicant stated that the PORV closure time is approximately 3 seconds and the block valve closure time is approximately 10 seconds. Although these times do not include operator response times, the applicant stated that limited RCS depressurization is expected in these time frames and, therefore, minimum effect on the plant is also expected. In addition, plant procedures and training are already in place to handle an inadvertent PORV-opening type event. In consideration of the available indication, the symptom-oriented procedures, and the operator training, there is reasonable assurance that the operators will be able to detect and mitigate the consequences of a COMS failure in this scenario.

Calibration

The standard Westinghouse setpoint methodology is used in determining the trip setpoint. The applicant stated that with all the rack uncertainties and rack drift combined, the maximum temperature setpoint would be 362.25°F (it usually is 350°F). The applicant stated that this trip value would not significantly affect any of the analysis already performed in assessing COMS failure scenarios.

Instrumentation for the COMS (e.g., RTDs) is calibrated in accordance with Technical Specifications (TS) and procedures. The TS surveillance and calibration intervals are consistent with industry standards and as part of TS, define a reasonable assurance of instrument operability and accuracy.

Conclusion

FSAR analyses of the MSLB and SGTR events considered single failures in the systems required for accident mitigation in accordance with the requirements of 10 CFR 50, Appendix A. Regarding the postulated random failure of a wide range temperature channel during a MSLB or SGTR event, which results in COMS actuation, this particular failure does not occur in a system required to mitigate the initiating event, and is neither a consequence of the initiating event nor an undetectable failure. Should such a failure occur, this evaluation verified that there is sufficient instrumentation and indication to alert the operators to a COMS failure. There are also mitigation techniques readily available to the operator should a COMS failure lead to the opening of a PORV. Furthermore, the operators are trained in an inadvertent PORV actuation-type event and, when coupled with the symptom-oriented EOPs, there is additional assurance of the ability to detect and mitigate the consequences of a COMS failure; therefore, SDAR 88-30 is closed.

5.2.5 Reactor Coolant Pressure Boundary Leakage Detection System

In Section 5.2.5 of the SER, the staff indicated that unidentified leak-detection methods are capable of detecting a leak rate of 1 gallon per minute (gpm) in approximately 1 hour. Although, this is generally true (as noted in Amendment 83 to the FSAR), the sensitivity of the airborne particulate and gas monitors for detecting 1 gpm is dependent on the primary coolant activity level and the background radiation level, which vary with reactor power.

Under certain conditions (small activity levels in the primary coolant or elevated gaseous background radiation levels), the ability of the radioactive gas monitors to detect 1 gpm may be unreliable or partially masked. However, the sensitivity of the radioactive gas monitor is still within the guidance of RG 1.45. During periods when the response time to detect 1 gpm unidentified leakage may be unreliable, other methods are available for detecting 1 gpm within approximately 1 hour (see Technical Specification 3.4.5.1). Therefore, the intent of RG 1.45 is met with respect to instrument sensitivity and response time (1 gpm in less than 1 hour). The staff's conclusions in the SER with respect to meeting the requirements of GDC 30 are, therefore, still valid, and the system is acceptable.

5.3 Reactor Vessel

5.3.1 Reactor Vessel Materials

In Section 5.3.1.2 of the SER and SSER 1, the staff indicated that paragraph II.B of Appendix H requires that the reactor vessel material surveillance program comply with the requirements of the American Society for Testing and Materials (ASTM) Standard E-185-73, "Standard Recommended Practice for Surveillance Tests for Nuclear Reactor Vessels," (1973 Edition). In Section 5.3.1.3, the staff concluded that the applicant needed to submit additional information to demonstrate Unit 2 compliance with paragraph II.B of 10 CFR Part 50 Appendix H.

In a letter of December 16, 1985 (TU Electric letter TXX-4649 to NRC), the applicant submitted Westinghouse (W) report WCAP-10684, "Comanche Peak Unit No. 2 Reactor Vessel Radiation Surveillance Program." This report provided details of the reactor vessel material surveillance program at Unit 2 for staff review.

In WCAP-10684 W indicated that the Unit 2 surveillance program is designed to ASTM E-185-82 (1982 Edition) in lieu of ASTM E-185-73. The latest edition of 10 CFR Part 50 Appendix H states that test procedures and reporting requirements for each capsule withdrawal after July 26, 1983, must meet the requirements of ASTM E-185-82 to the extent practical; therefore, the staff finds acceptable the use of ASTM E-185-82 in lieu of ASTM E-185-73, as required by the SER and SSER 1.

The staff evaluated the information submitted by the applicant for compliance with the requirements stated above and concludes that the applicant has met the reactor vessel material surveillance program requirements of 10 CFR Part 50 Appendix H for CPSES Unit 2.

6 ENGINEERED SAFETY FEATURES

6.2 Containment Systems

6.2.4 Combustible Gas Control System

In SSER 24, the staff estimated that the hydrogen recombiners would have to be started within 13 days following a design-basis LOCA. The staff also found acceptable the applicant's more conservative estimate that resulted in a start time of 12 days. In Amendment 84 to the FSAR, the applicant provided a revised analysis which included additional sources of hydrogen production. The applicant also stated that the hydrogen recombiners may need to be operated within 11 days following a LOCA. This reduced time does not affect the operability of the recombiners and is based on more conservative assumptions than the previous analysis. The staff, therefore, concludes that the applicant's revised value (11 days) is acceptable.

7 INSTRUMENTATION AND CONTROLS

7.1 General

Staff review of Amendment 79 to the FSAR revealed proposed changes to Tables 7.1-2.3 and 7.1-2.4 to eliminate GDC 54 applicability to the auxiliary feedwater system instrumentation. This is not acceptable, and was discussed with the applicant. The applicant responded in a letter of May 21, 1992 (TU Electric letter TXX-92223 to NRC), and committed to delete these changes from the FSAR.

Staff review of Amendment 84 to the FSAR, Figure 7.3-4, revealed that the figure should indicate that the high steam pressure rate instrumentation is rate-lag compensated. The applicant committed to update the FSAR. Both of these commitments are listed in Section 1.8 as Confirmatory Issue 7.

7.5 Safety Related Display Instrumentation

7.5.2 Postaccident Monitoring

The containment isolation valve position indication design described in SSER 23 Section 7.5.2 states that "The applicant provided documentation which states that all manually operated containment isolation valves are administratively controlled and locked in the closed position. Thus, the operator is aware of the position of these valves in a postaccident situation. Because the operator is aware that these valves are locked closed and has indication for the automatically operated isolation valves, the staff finds the instrumentation provided for containment isolation valve position acceptable."

NRC staff review of Amendment 84 revealed that the local manually operated isolation valves have no valve position indication. Valve operation is administratively controlled and the valves are locked in the closed position. This is consistent with the discussion included in SSER 23. Contrary to this, Amendment 84 indicates that the remote manually operated valves are equipped with valve position indication and the valves are not locked in either the closed or open position.

Because the operator is aware that the local manual valves are locked closed and has indication for the automatically and remote manually operated isolation valves, the staff concludes that the CPSES design satisfies the recommendation of RG 1.97 regarding containment isolation valve position indication.

9 AUXILIARY SYSTEMS

9.2 Water Systems

9.2.2 Reactor Auxiliaries Cooling Water System (Component Cooling Water System)

In Section 9.2.2 of the SER and SSER 22, the staff discussed cross-tie isolation valves between the safeguards loops of the component cooling water (CCW) system and concluded that the design met the separation requirements of GDC 5. In Amendment 83 to the FSAR, the applicant revised the design to remove the three Unit 2 safeguards isolation valves used for cross-unit isolation and blind flanged the piping. Removal of the cross-tie capability is an interim measure to prevent cross-unit leakage during the Unit 2 preoperational testing. Before fuel is loaded into Unit 2, the cross-tie capability will be restored. The applicant is also permanently removing CCW cross-tie isolation valves between the spent fuel pool heat exchangers.

Neither of the cross-tie isolation capabilities is required for licensing, and the system design will still meet all the general design criteria identified in the SER and SSER 22 including GDC 5. For these reasons, the staff concludes that the CCW system design is acceptable, with or without the cross-tie capability. However, because each unit's system has only two pumps, the safeguards cross-tie capability is desirable for two-unit operation to decrease core-melt probabilities should CCW be lost.

9.4 Heating, Ventilation, and Air Conditioning (HVAC) Systems

9.4.3 Auxiliary Building and Radwaste Area Ventilation System

In Section 9.4.3 of the SER, the staff indicated that the eight non-safety-related air-supply fans of the primary plant ventilation (PPV) system would be isolated following a loss of offsite power (LOOP) or a design-basis accident (e.g., LOCA). As a matter of clarification, six of these supply fans will be automatically isolated following a LOOP or a LOCA. These are the six units that are associated with the non-safety-related exhaust units of the PPV system. The two air-supply fans associated with the safety-related exhaust units can be manually isolated if the exhaust units must be operated in order to maintain negative pressure in the safeguards building.

The applicant made this clarification in Amendment 79 to the FSAR. The staff reviewed this clarification and finds that the conclusions reached in Section 9.4.3 of the SER and SSER 22 are still valid and the system is, therefore, acceptable.

9.4.4 Safeguards Building Ventilation System

In Sections 9.4.4 and 15.4.5 of the SER and SSER 22, the staff indicated that subsequent to a LOCA coupled with a loss of offsite power (LOOP), the engineered safety features (ESF) ventilation system would maintain a negative pressure in the mechanical equipment areas of the safeguards building. During normal plant operation, the primary plant ventilation system maintains the safeguards building at a negative pressure.

In Amendment 79 to the FSAR, the applicant indicated that a boron injection tank room (BITR) ventilation system was added to provide adequate cooling to the BITR during a LOCA with a LOOP. As a result, this room will be maintained at a slight positive pressure in lieu of a slight negative pressure. Because this room has no internal radiation sources, the effect on offsite calculations is negligible. The positive pressure prevents an influx of radiation from adjacent areas. The staff, therefore, concludes that maintaining the BITR (Room 100) at a slight positive pressure following a LOCA with a LOOP is acceptable. Therefore, the added BITR ventilation system is acceptable.

9.5 Other Auxiliary Systems

9.5.1 Fire Protection

9.5.1.6 Fire Protection of Specific Plant Areas

In Section 9.5.1.6 of SSER 12, the staff stated that the applicant would install carpeting that has ASTM E-84 ratings of 30 for flame spread, 30 for fuel contribution, and 100 for smoke development in the control room. The staff concluded this was an acceptable deviation from Section C.7.b of Branch Technical Position (BTP) CMEB 9.5-1.

In Amendment 83 to the FSAR, the applicant indicated that in lieu of ASTM E-84, the control room carpet was purchased to comply with Class II, or higher, interior floor finish requirements of National Fire Protection Association (NFPA) Code 101, 1991 Edition. However, the staff requires that Class I (not Class II) interior floor finish testing requirements be met. A minimum critical radiant heat flux of 0.45 watts per square centimeter, tested in accordance with NFPA-253, is the criterion for a Class I interior floor. The minimum critical heat flux for a Class II floor is 0.22 watts per square centimeter, which is less conservative. The staff has previously approved Class I floor finishes at other plants where the carpeting was purchased to NFPA 101 requirements in lieu of ASTM E-84.

The staff had previously determined, in NRC Inspection Report 50-445/91-42; 50-446/91-42 that the installed carpet is equivalent to requirements previously approved by the NRC and is, therefore, acceptable. However, the applicant should revise the FSAR to conform with the approved installation. This item will be followed as a confirmatory issue (See Confirmatory Issue 3 in Section 1.8.)

9.5.6 Emergency Diesel Engine Starting System

In Section 9.5.6 of SSER 22, the staff stated that the air compressors, after-coolers, and air dryers were designed as seismic Category II components. In Amendment 80 to the FSAR, the applicant clarified that only the anchors and supports of these components are seismic Category II. This does not change the staff's conclusions and the design is still acceptable because, despite a seismic event, the components will not fail due to a seismic event in a manner that will affect safety-related components in accordance with the guidelines of RG 1.29.

9.5.8 Emergency Diesel Engine Combustion Air Intake and Exhaust System

In Section 9.5.8 of SSER 22, the staff stated that the exhaust air flexible connections, exhaust relief valve, and exhaust piping on the roof of the diesel building were designed as seismic Category II components. The staff also stated that these exhaust system components were acceptable because they had been seismically analyzed to remain functional during and after a seismic event. As a matter of clarification, the applicant stated in Amendment 80 to the FSAR (Table 17A-1) that the flexible connectors and exhaust relief valves were classified as belonging to the non-nuclear safety (NNS) category. Because the exhaust systems will still remain functional during and subsequent to a seismic event, the staff concludes that the NNS classification is acceptable.

9.5.9 Emergency Diesel Generator Reliability

Design-Review and Quality-Revalidation Program

SSER 6 contained, as Appendix I, a contractor report entitled "Review and Evaluation of Transamerica Delaval, Inc. (TDI) Diesel Engine Reliability and Operability - Comanche Peak Steam Electric Station, Unit 1." This report documented the Pacific Northwest Laboratory's (PNL's) technical evaluation of the TDI Owners Group's generic program, as well as CPSES-specific evaluation, related to the reliability of the TDI diesel generators.

After SSER 6 was issued (August 1986), the staff issued NUREG-1216, "Safety Evaluation Report Related to the Operability of Emergency Diesel Generators Manufactured by Transamerica Delaval, Inc." NUREG-1216 endorsed, with specific exceptions, PNL-5600, "Review of Resolution of Known Problems in Engine Components for Transamerica Delaval, Inc., Emergency Diesel Generators," dated December 1985. PNL-5600 addressed two phases of TDI diesel generator review. Phase I covered known generic problem areas with major engine components which must be resolved before plant operation. Phase II covered a design review/quality revalidation of a large set of important engine components which can be completed subsequent to initial plant startup. These two phases together are often referred to as the "DR/QR program". PNL-5600 and NUREG-1216 contain specific actions to be taken by owners of TDI diesel generators to ensure the generators are acceptable for service.

The staff evaluated the applicant's actions to demonstrate compliance with the recommendations of PNL-5600 and NUREG-1216 relative to the TDI diesel generators at CPSES; the staff's evaluation appears in Appendix I to this supplement.

On the basis of its review, the staff concludes that with the exception of the open issues pertaining to the engine block metallurgical examination and procedural upgrades/commitments as discussed in Appendix I, the applicant has satisfactorily demonstrated compliance with the recommendations and requirements of PNL-5600 and NUREG-1216 regarding the TDI diesel generator Phase I components. These issues (Section 1.7, Item 31; Section 1.8, Items 5 and 6) should be completed before fuel is loaded. Upon satisfactory completion of these actions, the staff will find that the EDGs for CPSES Unit 2 are acceptable for nuclear standby service.

11 RADIOACTIVE WASTE MANAGEMENT

11.2 System Description

11.2.2 Gaseous Waste Processing System

11.2.2.5 Conformance With Federal Regulations and Branch Technical Positions

In Amendment 82 to the FSAR, the applicant clarified an exception to Regulatory Guide (RG) 1.140 which applies to the in-place leak testing of the containment preaccess filtration unit. The staff did not address this exception with other RG 1.140 exceptions, which were addressed in SSER 22. This is a non-safety-related unit that is used to reduce airborne contamination inside the containment before personnel enter the containment. The preaccess filtration unit is a 100-percent-recirculation unit, and the entire system is located inside the containment. Therefore, in accordance with ASME/ANSI N510-1980, Table 1, Notes 2 and 5, periodic in-place leak testing is not required if the other provisions of Note 5 are complied with. Because the applicant has committed to meeting Notes 2 and 5 of Table 1 of the ASME/ANSI standard, the staff concludes that the testing program is acceptable and meets the guidance of RG 1.140. This clarification does not alter any of the staff's conclusions reached in the SER or previous SSERs.

13 CONDUCT OF OPERATIONS

13.1 Organizational Structure and Qualifications

13.1.1 Management and Technical Resources

TU Electric is a subsidiary of Texas Utilities Company. In Amendment 83 to the FSAR, TU Electric's corporate structure was revised to include the following divisions: Operations; Operations & Market Support; Engineering Bulk Power; Production; Finance, Accounting & Regulation; and Corporate Services. The Production Division, headed by the Executive Vice President-Production replaces the functions previously performed by the Generating Division. As such, the Production Division has assumed corporate responsibility for the design, construction, and operation of CPSES.

Within the Production Division, the nuclear group, designated as Nuclear Engineering and Operations Group (NEO), provides the design, engineering, construction, licensing, operation, and fuel management support for CPSES. In Amendment 81 to the FSAR, the NEO was reorganized into four organizations to better focus resources on the completion of CPSES, Unit 2. These four organizations are Engineering and Construction, Nuclear Operations, Nuclear Engineering, and Support Services. The Engineering and Construction Group is headed by a Senior Vice President who is responsible for completion of CPSES, Unit 2.

In Amendment 79 to the FSAR, the name of the Support organization was changed to Support Services. In Amendments 79-83 to the FSAR, a number of other organizational changes were made at the plant level; however, these changes did not affect the overall levels of technical resources and support. The new organizational structure is shown in revised FSAR Figure 13.1-2.

The changes to the corporate organization made by the applicant in Amendments 79-83 primarily reflect an organizational restructuring to focus resources on the completion of CPSES, Unit 2. All matters affecting CPSES, Unit 2, are now under the oversight of the Senior Vice President (Engineering and Construction). The Vice President-Nuclear Operations now reports directly to the Group Vice President-NEO, except in those matters affecting CPSES, Unit 2, operations, for which he reports to the Senior Vice President. The new lines of management authority and communication have been clearly defined. Other changes made to the corporate organization reflect changes in name, not in function. Therefore, they do not change the staff's previous conclusion that the corporate level management structure is acceptable.

The staff concludes that the revised organization continues to meet the acceptance criteria of Section 13.1.1 of the Standard Review Plan (SRP) (NUREG-0800) for appropriate lines of authority, and is, therefore, acceptable. The staff notes that the Group Vice President-Nuclear Engineering and Operations also is acting as Vice President-Nuclear Engineering on an interim basis.

13.1.2 Operating Organization

In Amendment 83 to the FSAR, the applicant noted the appointment of a new Shift Operations Manager. The applicant provided supplemental information on the Shift Operations Manager's qualifications on May 29, 1992. The new Shift Operations Manager has a Bachelor's Degree in Nuclear Engineering, 12 years of nuclear power plant experience, an SRO license, and experience both as a Shift Technical Advisor and as a Shift Supervisor.

The applicant previously committed to the guidelines of RG 1.8-R (1977) which endorses ANS 18.1-1971 for qualifications of plant personnel. The qualifications of the new Shift Operations Manager noted above exceed those specified in the ANS standard. Therefore, the staff concludes that the new Shift Operations Manager is qualified for this position.

22 TMI-2 REQUIREMENTS

II.K.3.10 Proposed Anticipatory Trip Modification

Position

The anticipatory trip modification proposed by some licensees to confine the range of use to high-power levels should not be made until it has been shown on a plant-by-plant basis that the probability of a small-break LOCA resulting from a stuck-open PORV is substantially unaffected by the modification.

Clarification

This evaluation is required for only those licensees/applicants who propose the modification.

Discussion and Conclusions

In a letter of August 23, 1989 (TU Electric letter TXX-89614 to NRC), the applicant proposed to implement a modification. This change was subsequently incorporated in Amendment 77 to the FSAR and submitted for staff review in September 1989. The modification was found acceptable; however, the staff did not revise its SER to reflect this change. The CPSES design includes the standard Westinghouse (W) P-9 interlock which blocks the direct reactor trip on a turbine trip at or below 50 percent of rated power. Analysis performed by W for CPSES demonstrates that a turbine trip without a direct reactor trip at or below 50 percent of rated power does not pose any undue risk or additional challenges to the pressurizer PORVs. This modification and analysis satisfy the NUREG-0737 guidelines and, are, therefore, acceptable.

APPENDIX A

CONTINUATION OF CHRONOLOGICAL LIST OF CORRESPONDENCE

This appendix continues the chronological listing of routine licensing correspondence, regarding Unit 2 and Unit 1/Unit 2 common issues, between the U.S. Nuclear Regulatory Commission (NRC) staff and the applicant (Texas Utilities Electric Company) since Supplement 24 was issued.

April 10, 1990	Letter from applicant discussing offsite power availability for Automatic Switch Company solenoids for main steam isolation valves.
April 10, 1990	Letter to applicant forwarding Augmented Inspection Report 50-445/90-11; 50-446/90-11.
April 12, 1990	Letter from applicant forwarding Endorsement 9-11 to MAELU Certificate MW-190, Endorsement 8-10 to NELIA Certificate NW-167 and Endorsement 33 to NELIA Policy NF-274.
April 17, 1990	Letter from applicant forwarding emergency preparedness public information program.
April 25, 1990	Letter to applicant transmitting Generic Letter (GL) 90-04, "Request for Information on the Status of Licensee Implementation of Generic Safety Issues Resolved with Imposition of Requirements or Corrective Actions."
April 25, 1990	Letter to applicant advising of proposed date acceptable to conduct 1990 annual emergency exercise.
April 27, 1990	Letter to applicant forwarding Operational Readiness Assessment Team Inspection Report 50-445/90-14; 50-446/90-14.
May 2, 1990	Letter from applicant forwarding revised response to GL 88-17, "Loss of Decay Heat Removal."
May 3, 1990	Letter from applicant forwarding response to GL 90-01, "Request for Voluntary Participation in NRC Regulatory Impact Survey."
May 8, 1990	Letter from applicant forwarding revised response to GL 88-17.

May 9, 1990	Letter to applicant forwarding Supplement 1 to GL 90-03 regarding relaxation of staff position in GL 83-28, Item 2.2, Part 2, "Vendor Interface for Safety-Related Components."
May 9, 1990	Letter to applicant forwarding questions to support review of facility pressurizer surge line thermal stratification issue.
May 15, 1990	Summary of May 7, 1990, meeting with applicant concerning future updates of figures and tables in the Final Safety Analysis Report (FSAR).
May 18, 1990	Letter to applicant requesting assessment of Citizens for Fair Utility Regulation concerns of April 12, 1990, regarding deficiencies in public education and information program and alert notification system for plant based on survey.
May 21, 1990	Summary of May 9, 1990, meeting on problems with valves in auxiliary feedwater and main feedwater system.
May 21, 1990	Letter from applicant forwarding public version of revised emergency plan procedures.
May 21, 1990	Letter from applicant advising of completion of implementation of requirements of GL 89-13.
May 22, 1990	Summary of January 31, 1990, meeting on facility markups to final draft Technical Specifications.
May 24, 1990	Letter to applicant forwarding information on generic fundamentals exam section of operator licensing written exam.
May 30, 1990	Letter from applicant forwarding status of facility design and construction activities.
May 31, 1990	Letter to applicant forwarding plans for dissolving Comanche Peak Project Division and realigning organizational structure for licensing and inspection of plants.
May 31, 1990	Letter from applicant advising that utility has revised FSAR Section 15.1.2 and Question Response 32.108 per 10 CFR 50.59.
June 1, 1990	Letter from applicant forwarding Revision 7 to physical security plan.
June 7, 1990	Letter to applicant forwarding Supplement 1 to GL 89-10.
June 12, 1990	Letter to applicant forwarding GL 90-05 regarding guidance for performing temporary noncode repair of ASME Code Class 1, 2 and 3 piping.

June 15, 1990	Letter from applicant forwarding additional information on emergency preparedness.
June 20, 1990	Letter from applicant forwarding additional information regarding pressurizer surge line thermal stratification and leak-before-break evaluation.
June 20, 1990	Letter to applicant transmitting GL 90-06 regarding resolution of Generic Issue 70, "PORV and Block Valve Reliability" and Generic Issue 94, "Additional Low-Temperature Overpressure Protection for LWRs."
June 20, 1990	Letter from applicant forwarding endorsements 4 and 5 to NELIA Certification N-90, Endorsements 5 and 6 to MAELU Certification M-90, and Endorsements 34, 35, 36, 37, 38 and 39 to NELIA Policy NF-274.
June 22, 1990	Letter from applicant advising that utility safeteam investigation of allegations completed.
June 26, 1990	Letter from applicant forwarding discussions on modifications/rework to auxiliary feedwater system check valves.
June 26, 1990	Letter from applicant responding to GL 90-04.
June 28, 1990	Letter from applicant forwarding advance changes for future FSAR amendment incorporating simplified cable separation criteria.
June 29, 1990	Letter from applicant advising that documentation and results of Allegation 4-90-A-0032 are available for inspection at the plant site.
July 2, 1990	Letter to applicant transmitting Supplement 3 to GL 88-20.
July 12, 1990	Letter to applicant expressing appreciation for volunteering to participate in emergency response data system (ERDS).
July 17, 1990	Letter from applicant forwarding results of remote shutdown panel environmental survey.
July 18, 1990	Letter from applicant responding to NRC Bulletin 90-01.
July 23, 1990	Letter from applicant forwarding information regarding temporary security measures to expedite alternate access point expansion.
July 26, 1990	Letter from applicant forwarding decommissioning financial assurance certification report.
July 31, 1990	Letter to applicant forwarding Supplement 2 to GL 89-10.

July 31, 1990	Letter from applicant forwarding Amendment 79 to FSAR.
August 2, 1990	Summary of July 24, 1992, meeting with applicant concerning fuel reload methodology.
August 3, 1990	Letter to applicant advising that NRC draft document regarding concerns associated with inspection report 50-445/89-60 and 50-446/89-60 are being placed in PDR.
August 3, 1990	Letter from applicant advising staff of status of exam activity and revised completion schedule for portion of exam.
August 8, 1990	Letter to applicant forwarding GL 90-07.
August 8, 1990	Letter to applicant forwarding GL 90-08.
August 9, 1990	Letter from applicant forwarding fitness-for-duty program performance data for the first half 1990.
August 23, 1990	Letter from applicant forwarding public version of revised emergency plan and corporate emergency response procedures.
August 27, 1990	Letter from applicant forwarding Endorsements 40 and 4 to NELIA Policy NF-274 and MAELU Policy M-90 and Endorsements 10, 11, 12, 13, 14, and 15 to MAELU Policy MF-131.
August 28, 1990	Letter to applicant advising that responses to NRC Bulletin 88-04 are acceptable.
August 30, 1990	Letter from applicant forwarding objectives and guidelines for 1990 emergency preparedness exercise.
August 31, 1990	Letter to applicant forwarding safety evaluation regarding facility DCRDR.
September 10, 1990	Letter from applicant forwarding Revision 8 to physical security plan.
September 14, 1990	Letter from applicant forwarding response to NRC unresolved item on emergency response training.
September 17, 1990	Letter from applicant discussing reload analysis program regarding feedback on NRC schedule for review of topical reports.
September 18, 1990	Summary of September 6, 1990, meeting with applicant concerning Class 1E cable and raceway separation.
September 21, 1990	Letter from applicant transmitting annual report of changes in peak cladding temperatures.

September 21, 1990	Letter from applicant updating information for Recommended Action III of GL 89-13.
September 27, 1990	Letter from applicant responding to GL 90-03.
September 28, 1990	Letter from applicant forwarding 1990 full scale field exercise scenario manual.
September 28, 1990	Letter from applicant transmitting Revision 12 to CPSES Emergency Plan.
October 9, 1990	Letter to applicant requesting additional information on facility cold overpressure mitigation system actuation during accident events.
October 10, 1990	Letter from applicant re supplemental report on Limitorque actuator spring packs.
October 17, 1990	Letter from applicant forwarding Comanche Peak Steam Electric Station Unit 1 Section XI Inservice Program Plan.
October 22, 1990	Letter to applicant transmitting Supplement 3 to GL 89-10.
October 24, 1990	Letter from appplicant submitting information on modification to inspection program for connecting rods on facility Train A diesel generator.
November 5, 1990	Letter from applicant forwarding Revision 9 to physical security plan.
November 26, 1990	Letter to applicant forwarding summary of NRC understanding of current status of unimplemented generic safety issues.
November 27, 1990	Letter from applicant forwarding Revision 6 to security training and qualification plan.
November 30, 1990	Letter from applicant forwarding Amendment 80 to FSAR.
November 30, 1990	Letter to applicant advising that discarded drawings do not appear to be safeguards or security related per applicant's of November 13, 1990.
November 30, 1990	Letter from applicant resubmitting Endorsement 12 to MAELU MW-190, Endorsement 4 to NELIA N-90 and Endorsement 5 to MAELU Certificate M-90.
December 10, 1990	Letter from applicant responding to GL 90-03, "Relaxation of Staff Position in Generic Letter 83-28, Item 2.2, Part 2, Vendor Interface for Safety-Related Components."

December 20, 1990	Letter from applicant forwarding corrected fitness-for-duty program performance data for the first half of 1990.
December 21, 1990	Letter from applicant forwarding response to Generic Letter 90-06, "Resolution of Generic Issue 70 re PORC and Block Valve Reliability" and Generic Issue 94, "Additional Low Temperature Overpressure Protection for LWRs."
December 21, 1990	Letter from applicant forwarding Revision 1 to "Process Control Program."
December 28, 1990	Letter from applicant forwarding Topical Report RXE-90-005, "Control Rod Worth Analysis."
December 28, 1990	Letter from applicant forwarding proprietary Topical Report RXE-88-102-P, Supplement 1, "TUE-1 DNB Correlation."
January 7, 1991	Letter from applicant informing staff that baseline data collection for designated service water system exam sites is expected to be completed during scheduled April 1991 outage per GL 89-13.
January 18, 1991	Letter from applicant forwarding Endorsement 41 to NELIA Policy NF-274, Endorsement 16 to MAELU Policy MF-0131, Endorsements 7 and 13 to MAELU Certificates M-0090 and MW-0190, respectively, and Endorsements 6 and 11 to NELIA Certificates N-0090 and NW-0167, respectively.
January 31, 1991	Letter from applicant forwarding Topical Report RXE-90-007, "Large Break LOCA Analysis Methodology" per December 1988 and July 1990 meetings regarding reload.
February 1, 1991	Letter to applicant advising that its response to GL 90-03 meets guidance and is acceptable.
February 4, 1991	Letter from applicant forwarding Supplement 1 to RXE-88-102-NP, "TUE-1 DNB Correlation" giving results of reload analysis program.
February 14, 1991	Letter from applicant forwarding list of licensing document change requests and schedule for upcoming submittals for licensing documents.
February 18, 1991	Letter from applicant forwarding second half of 1990 fitness-for-duty program performance data.
February 20, 1991	Letter from applicant forwarding advance QA changes to be incorporated into updated FSAR Section 17 in future amendments.

February 28, 1991	Letter from applicant forwarding non-proprietary and proprietary reports, "Power Distribution Control Analysis and Overtemperature N-16 and Overpower N-16 Trip Setpoint Methodology."
February 28, 1991	Letter from applicant fowarding RXE-91-001, "Transient Analysis Methods for Comanche Peak Steam Electric Station Licensing Applications."
March 1, 1991	Letter from applicant requesting concurrence for performing containment coating inspection walkdown once every fuel cycle opposed to each refueling outage.
March 5, 1991	Letter from applicant forwarding non-proprietary WCAP-10272, Supplement 3 and proprietary WCAP-10271, Supplement 3, "Evaluation of Effect of Surveillance Frequencies and Out of Service Times on Unavailability of N-16 Reactor Trips and Refueling Water Storage."
March 6, 1991	Letter from applicant forwarding draft revised FSAR pages to be included in future FSAR amendment which will remove electrical mild equipment from plant environmental qualification program.
March 13, 1991	Letter from applicant establishing extension allowance for general employee training and radiation worker training.
March 15, 1991	Letter from applicant forwarding ANI/MAELU and Nuclear Electric Insurance Ltd. certificates of insurance.
March 21, 1991	Letter from applicant forwarding Amendment 81 to FSAR.
March 22, 1991	Letter from applicant forwarding information regarding auxiliary feedwater system check valves causing overheating.
April 4, 1991	Summary of March 14, 1991, meeting with applicant concerning review schedule for reload analysis methodology reports.
April 5, 1991	Letter from applicant discussing revised definition of RCS water level for reduced inventory conditions.
April 15, 1991	Letter from applicant forwarding Revision 11 to security plan.
April 15, 1991	Letter from applicant forwarding changes to security training and qualification plan.
April 23, 1991	Letter from applicant describing verification and inspection process for types of new and modified seismic Category II installations.

April 26, 1991	Letter to applicant forwarding safety evaluation accepting surveillance frequency for protective coatings inside containment revision from each refueling outage to once every fuel cycle.
April 26, 1991	Letter from applicant forwarding response on how scaling activities will be performed on CPSES Unit 2.
April 29, 1991	Letter to applicant forwarding request for additional information regarding Topical Report RXE-89-003, "Steady State Reactor Physics Methodology."
May 1, 1991	Summary of April 22, 1991, meeting with applicant concerning proposed technical specifications.
May 1, 1991	Letter from applicant responding to regulatory effectiveness review inspection.
May 6, 1991	Letter to applicant informing that applicant's response to GL 89-19 is complete.
May 20, 1991	Letter from applicant forwarding additional information on Topical Report RXE-89-003, "Steady State Reactor Physics Methodology."
May 24, 1991	Letter from applicant forwarding Topical Report RXE-91-004, "Small Break LOCA Analysis Methodology."
May 30, 1991	Letter to applicant requesting schedule for submittal of technical issues which will be required for review and approval before licensing.
May 31, 1991	Letter from applicant forwarding Topical Report RXE-91-005, "Methodology for Reactor Core Response to Steamline Break Events."
May 31, 1991	Letter from applicant forwarding supplemental deficiency report CP-84-04 regarding grounded secondary windings on ferroresonant transformers in Westinghouse safety-related inverters.
May 31, 1991	Letter from applicant forwarding Topical Report RXE-91-002, "Reactivity Anomaly Events Methodology."
June 10, 1991	Letter from applicant forwarding Revision 7 to security training and qualifications plan.
June 14, 1991	Letter from applicant forwarding supplemental information to demonstrate adequacy of large bore non-nuclear non-ASME class 5 piping systems to be applied to Unit 2.
June 21, 1991	Letter from applicant summarizing relief requested from original commitment to replace swing arms in Borg-Warner/International Pump, Inc. check valves.

June 21, 1991	Letter from applicant forwarding Endorsement 42 to NEILA Policy NF-274 and Endorsements 17, 14, and 8 to MAELU Policies MF-131, MW-190, and MW-90, respectively.
July 1, 1991	Letter to applicant requesting additional information regarding Topical Report RXE-89-002, "Vipre-01 Core Thermal-Hydraulic Analysis Methods."
July 15, 1991	Letter from applicant forwarding additional information regarding utilization of Westinghouse optimized fuel assemblies in Unit 2.
July 17, 1991	Summary of June 19, 1991, meeting with applicant concerning licensing schedule.
July 24, 1991	Summary of June 12, 1991, meeting with applicant concerning Borg-Warner/International Pump, Inc. check valve swing arm replacement program.
July 24, 1991	Letter from applicant transmitting cable tray separation criteria.
July 25, 1991	Letter to applicant forwarding safety evaluation concluding that applicant's physics methods are acceptable.
July 25, 1991	Letter from applicant forwarding fitness for-duty program performance data for January 1-June 30, 1991.
July 29, 1991	Letter to applicant forwarding safety evaluation concluding that applicant can use information contained in Topical Report "Reload Analysis Methodology (Control Rod Swap Methodology)" and in Topical Report RXE-90-005 "Control Rod Worth Analysis."
July 29, 1991	Letter from applicant regarding RCS water level for reduced inventory conditions.
July 29, 1991	Letter from applicant forwarding advance FSAR change regarding metal-clad cable in certain non-safety applications.
July 31, 1991	Letter from applicant forwarding report of changes or errors discovered in ECCS calculations of peak cladding temperature.
July 31, 1991	Letter from applicant forwarding Amendment 82 to FSAR.
August 1, 1991	Letter from applicant responding to NRC Bulletin 89-01, Supplement 2 regarding failure of Westinghouse steam generator tube mechanical plugs.
August 9, 1991	Letter from applicant forwarding comparison of RETRAN-02 analyses to current FSAR analyses.

August 12, 1991	Letter from applicant notifying staff of withdrawal of request for NRC review and approval of Supplement 1 to Topical Report RXE-88-102-P.
August 19, 1991	Letter from applicant forwarding objectives and guidelines for 1991 emergency preparedness excercise.
September 12, 1991	Letter from applicant forwarding response to allegation regarding cause of nonradioactive condensate water spill in turbine building.
September 17, 1991	Letter from applicant forwarding Revision 0 to Calculation 0218-SQ-0030, "Liner Attachment Welds Serviceability."
September 17, 1991	Summary of August 22, 1991, meeting with applicant concerning methodologies used for the large- and small-break LOCA topical reports.
September 19, 1991	Letter from applicant forwarding 1991 field exercise.
September 20, 1991	Letter from applicant forwarding facility design verification program.
September 30, 1991	Letter to applicant acknowledging withdrawal of April 5, 1991, letter revising definition of reduced inventory condition for facility.
October 11, 1991	Letter from applicant forwarding amendment to decommis sioning funding agreement.
October 28, 1991	Letter from applicant fowarding implementation plan for emergency response data system.
October 28, 1991	Letter from applicant responding to GL 91-06, "Resolution of Generic Issue A-30, Adequacy of Safety-Related DC Power Supplies."
November 1, 1991	Letter from applicant responding to preparation for facility licensing
November 6, 1991	Letter from applicant regarding derived voltage values vs. measured test results.
November 22, 1991	Letter to applicant regarding communications and cooperation at current stage of activity at facility.
November 25, 1991	Letter to applicant regarding request for relief from visual exam requirements for portions of RCS during system leakage test.
November 26, 1991	Letter from applicant forwarding response to NRC Bulletin 89-02.

December 9, 1991	Letter from applicant addressing seismic Category II HVAC methodology.
December 19, 1991	Letter from applicant forwarding results of utility review of NRC SER regarding operability and reliability of emergency diesel generators.
December 20, 1991	Letter from applicant forwarding Amendment 83 to FSAR.
December 20, 1991	Letter from applicant forwarding response to request for additional information regarding Topical Report RXE-90-0006.
December 20, 1191	Letter from applicant responding to GL 88-20, Supplement 4.
January 2, 1992	Letter from applicant forwarding proposed revisions to NUREG-1399 (CPSES Unit 1 TS) to incorporate Unit 2.
January 14, 1992	Letter to applicant forwarding request for additional information regarding Topical Report RXE-91-002.
January 15, 1992	Letter from applicant responding to req[illegible] for additional regarding addition of exception [illegible]E-ACI 359 document for liquid penetrant or magnetic [illegible]article exam of full-penetration attachment welds.
January 17, 1992	Letter from applicant forwarding advance FSAR change regarding accident monitoring program.
January 27, 1992	Letter to applicant forwarding configuration management inspection report.
January 28, 1992	Letter from applicant requesting new name and address be used on NRC mailing labels.
January 30, 1992	Summary of January 9, 1992, meeting with applicant concerning licensing actions and commitments.
February 3, 1992	Letter from applicant forwarding response to GL 91-11.
February 3, 1992	Letter from applicant requesting that latest construction completion date for CPPR-127 be extended.
February 3, 1992	Letter from applicant forwarding issues that affect development of Unit 2 Inservice Testing Plan.
February 4, 1992	Letter from applicant forwarding proposed changes to technical requirements manual.
February 4, 1992	Letter from applicant advising of completion of performance review of N16 transit time flow meter during first operating cycle.

February 5, 1992	Letter from applicant forwarding response to Regulatory Guide 9.3 updating activities that have occurred since antitrust operating license review.
February 5, 1992	Letter from applicant requesting review and approval of Supplement 1 to Topical Report RXE-88-102-P.
February 8, 1992	Summary of January 31, 1991, meeting with applicant concerning Unit 1 diesel generator rack teeth inspection schedule.
February 10, 1992	Letter to applicant advising that response to NRC Bulletin 89-01, Supplement 2 is acceptable.
February 10, 1992	Letter from applicant forwarding fitness-for-duty performance data for July-December 1991.
February 10, 1992	Letter from applicant forwarding Endorsements 18, 12, 15 and 9 to Policies MF-131, MW-0190, and M-0090, respectively and Endorsement 43 to Policy NF-274.
February 14, 1992	Letter from applicant forwarding response to request for additional information regarding Topical Report RXE-91-002.
February 14, 1992	Letter from applicant forwarding non-proprietary WCAP-13101 and proprietary WCAP-13100, "Technical Justification for Eliminating Pressurizer Surge Line Rupture from Structural Design Basis for Comanche Peak Unit 2."
February 14, 1992	Letter from applicant forwarding non-proprietary WCAP-13166 and proprietary WCAP-13165, "Technical Justification for Eliminating RHR Lines Rupture as Structural Design for Comanche Peak Nuclear Power Plant - Unit 2."
February 14, 1992	Letter from applicant forwarding non-proprietary and proprietary reports, "Technical Justification for Eliminating 1-Inch Accumulator Lines Rupture for Comanche Peak Nuclear Plant Unit 2."
February 19, 1992	Letter to applicant forwarding marked-up draft version of plant combined Technical Specifications.
February 24, 1992	Letter from applicant forwarding non-proprietary WCAP-13218 and proprietary WCAP-13211, "NRC Bulletin 88-08 Evaluation of Auxiliary Piping for Comanche Peak Unit 2."
February 24, 1992	Letter from applicant forwarding non-proprietary WCAP-13219 and proprietary WCAP-13212, "Evaluation of Thermal Stratification from Postulated Valve Leakage for Comanche Peak Unit 2 RHR Lines."

February 24, 1992	Letter from applicant forwarding non-proprietary WCAP-13217 and proprietary WCAP-13210, "Evaluation of Thermal Stratification for Comanche Peak Unit 2 Pressurizer Surge Line."
February 27, 1992	Letter to applicant forwarding safety evaluation and requesting additional information regarding station blackout.
February 28, 1992	Letter from applicant forwarding Amendment 84 to FSAR.
February 28, 1992	Letter from applicant forwarding Revision 13 to emergency plan.
March 3, 1992	Letter from applicant forwarding Revision 12 to physical security plan.
March 4, 1992	Letter from applicant forwarding advance FSAR change to reclassify portion of 8-inch steam generator blowdown piping and pipe supports to seismic Category II.
March 6, 1992	Letter from applicant forwarding additional information on FSAR Section 3.10.
March 12, 1992	Letter from applicant forwarding MAELU Policies 91198 and 92198R and certificates of property insurance/stabilization and decontamination liability insurance.
March 16, 1992	Letter from applicant forwarding response to request for additional information related to resolution of Generic Issue 130, "Essential SW System Failures at Multi-Unit Sites."
March 16, 1992	Letter from applicant forwarding clarification of groundwater withdrawal rates in request for extension of construction permit.
March 17, 1992	Letter from applicant forwarding draft version of Unit 2 FSAR update for optimized fuel assembly and accident analyses methodologies.
March 19, 1992	Letter from applicant forwarding request for authorization for use of Code Case N-496 to repair steam generator manway bolt hole threads in ASME Class 1, 2, and 3 components.
March 19, 1992	Letter to applicant notifying of NRC plans to administer generic fundamentals exam section of written operator licensing exam.
March 24, 1992	Letter to applicant forwarding draft version of plant combined Technical Specifications for review.

March 25, 1992	Letter to applicant informing that B. Holian is newly appointed Senior Project Manager.
March 27, 1992	Letter from applicant forwarding response to configuration management inspection report.
March 31, 1992	Letter from applicant forwarding control room temperature analysis in response to station blackout safety evaluation.
March 31, 1992	Letter from applicant forwarding advance FSAR submittal regarding changes to Unit 2 initial startup test program.
March 31, 1992	Letter to applicant forwarding results of review of emergency response data system implementation plan.
March 31, 1992	Letter from applicant forwarding response to request for additional information regarding Topical Report RXE-91-002.
March 31, 1992	Letter from applicant forwarding request for relief from preservice exam requirements for component supports.
April 1, 1992	Letter from applicant forwarding advance FSAR submittal on one hour fire rated cable acceptability.
April 1, 1992	Letter from applicant forwarding "Comanche Peak Steam Electric Station Unit 2 Control Room Simulator 10 CFR 55 Certification Initial Report."
April 2, 1992	Letter to applicant advising that applicant's response to GL 91-11 is acceptable.
April 6, 1992	Letter from applicant forwarding response to request for clarification of Relief Request V-1 regarding differences between in situ testing and shop testing.
April 7, 1992	Letter from applicant forwarding listing of small-break LOCA peak cladding temperature changes/errors greater than 50 °F.
April 10, 1992	Letter from applicant forwarding advance FSAR submittal on electrical separation for large power cables acceptability barrier.
April 27, 1992	Letter from applicant forwarding response regarding fracture toughness of feedwater system materials.
April 27, 1992	Letter from applicant forwarding "Validation Efforts for Comanche Peak Steam Electric Station Unit 2."
April 30, 1992	Letter from applicant forwarding supplemental response to NRC Bulletin 88-04.

May 1, 1992	Letter from applicant forwarding discussion of confirmatory testing of Thermo-Lag fire barrier system.
May 4, 1992	Letter from applicant forwarding Revision 12 to physical security plan.
May 5, 1992	Letter to applicant soliciting interest in workshop in Rockville (Md.) regarding current licensing basis.
May 5, 1992	Letter to applicant forwarding request for additional information regarding application of leak-before-break methodology to justify elimination of accumulator line pipe whip restraints.
May 6, 1992	Letter from applicant forwarding results of evaluation of Thermo-Lag 330-1 fire barrier system.
May 13, 1992	Letter from applicant forwarding information to support use of 1-hour fire-rated cable and clarifying provosions of automatic fire suppression and detection capability in areas where cable is installed.
May 18, 1992	Letter from applicant forwarding additional information regarding NUREG-0737, Item II.D.1 concerning testing of relief and safety valves.
May 21, 1992	Letter from applicant forwarding Revision 8 to "ODCM for Comanche Peak Steam Electric Station Units 1 and 2."
May 21, 1992	Letter from applicant forwarding additional information regarding Amendment 79 to FSAR.
May 29, 1992	Summary of April 23, 1992, meeting with applicant concerning licensing actions.
June 1, 1992	Letter from applicant responding to request for additional information for preservice inspection relief request F-1.
June 5, 1992	Letter from applicant responding to request for additional ifnromation regarding Unit 2 accumulator line analysis.
June 5, 1992	Letter from applicant forwarding proposed changes to first draft on CPSES Units 1 and 2 combined technical specifications for station service water system.
June 11, 1992	Letter to applicant forwarding safety evaluation on Topical Report RXE-88-102-P, "TUE-1 Departure from Nucleate Boiling Correlation."
June 16, 1992	Letter from applicant forwarding proposed changes to first draft on CPSES Units 1 and 2 combined technical specifications for Cycle 1 Core Operating Limits Report.

June 17, 1992	Letter from applicant forwarding corrective actions for interim deficiency report regarding scope of plant modifications resulting from project pipe support validation program.
June 19, 1992	Letter from applicant notifying of implementation of GL 89-13, "Service Water System Problems Affecting Safety Related Equipment."
June 26, 1992	Letter from applicant forwarding marked up pages of first draft version of CPSES combined technical specifications.
June 30, 1992	Summary of June 4, 1992, meeting with applicant concerning licensing actions.
June 30, 1992	Letter from applicant forwarding Revision 8 to technical requirements manual.
July 1, 1992	Letter from applicant forwarding status of diesel generator actions items for the Design Review/Quality Revalidation Phase II activities.
July 2, 1992	Letter from applicnt forwarding inservice testing plan for pumps and valves in the first interval.
July 2, 1992	Letter from applicant forwarding response to Revision 1 to GL 92-01, "Reactor Vessel Structural Integrity."
July 7, 1992	Letter from applicant forwarding interim deficiency report regarding backleakage through auxiliary feedwater system check valves.
July 8, 1992	Letter from applicant forwarding supplemental response to NRC Bulletin 90-01, "Loss of Fill-Oil in Transmitters Manufactured by Rosemount."
July 9, 1992	Letter from applicant forwarding response to Bulletin 92-01, "Failure of Thermo-Lag 330 Fire Barrier System to Maintain Cabling in Wide Cable Trays and Small Conduits Free from Fire Damage."
July 10, 1992	Letter from applicant forwarding response to startup testing program.
July 13, 1992	Letter from applicant forwarding Revision [illegible] to fire protection report.
July 20, 1992	Letter to applicant forwarding staff request for additional information concerning FSAR Chapters 4 and 15, Amendments 83 and 84.
July 20, 1992	Letter to applicant forwarding staff request for additional information concerning RETRAN Model Qualification.

July 20, 1992	Letter from applicant fowarding proposed changes to Proof and Review Common Technical Specifications.
July 21, 1992	Letter from applicant forwarding first half 1992 fitness-for-duty program performance data.
July 21, 1992	Letter from applicant forwarding Revision 13 to physical security plan.
July 24, 1992	Letter from applicant forwarding deficiency report regarding isolation of non-Class 1E components in Class 1E battery chargers.
July 31, 1992	Letter from applicant fowarding Revision 6 to "Comanche Peak Steam Electric Station Units 1 and 2 Fire Protection Report."
August 3, 1992	Letter from applicant forwarding revision to data point library resulting from installation and testing of computer per GL 89-15.
August 5, 1992	Letter from applicant forwarding major milestone schedule and portions of the Part 21 open items list.
August 6, 1992	Letter from applicant forwarding response to petition to intervene on construction permit amendment.
August 7, 1992	Letter from applicant forwarding response to request for information regarding pressurizer surge line leak-before-break analysis.
August 7, 1992	Letter from applicant regarding comprehensive confirmatory test program for Thermo-Lag barriers.
August 14, 1992	Summary of July 13, 1992, meeting on Thermo-Lag testing program.
August 19, 1992	Letter from applicant forwarding response to request for information regarding FSAR Chapters 4 and 5.
August 21, 1992	Letter from applicant forwarding deficiency report regarding defect in two welds on containment spray pump suction vent piping.
August 26, 1992	Letter to applicant granting relief request to use helical coil threaded inserts.

APPENDIX B

BIBLIOGRAPHY

Miscellaneous

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PNL-5600, "Review of Resolution of Known Problems in Engine Components for Transmerica Delaval, Inc., Emergency Diesel Generators," December 1985.

FaAA-84-9-11.1, "Design Review of TDI-R-4 and R-4 Series Emergency Diesel Generator Cylinder Blocks," December 1984.

TDI Owners Group, letter from J. B. George to H. R. Denton (NRC) forwarding Revision 2 to "TDI Owners Group Appendix II; Generic Maintenance Matrix and Justifications, May 1, 1986.

National Fire Protection Association (NFPA) Code 101, "Code for Safety to Life from Fire to Buildings and Structures," 1991 Edition.

National Fire Protection Association NFPA-253, "Standard Method of Test for Critical Radiant Flux of Floor Covering Systems Using a Radiant Heat Energy Source," 1984 Edition.

NRC Bulletins

See Appendix C.

NRC Generic Letters

See Appendix C.

NRC Letters

See Appendix A.

NRC NUREG-Series Reports

NUREG-0737, "Clarification of TMI Action Plan Requirements," October 1980.

NUREG-0800, "Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants," July 1981.

NUREG-1061, "U.S. Nuclear Regulatory Commission Piping Review Committee," Volume 5, April 1985.

NUREG-1216, "Safety Evaluation Report Related to Operability and Reliability of Emergency Diesel Generators Manufactured by Transamerica Delaval, Inc.," August 1986.

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Regulatory Guide 1.8, "Qualification and Training of Personnel for Nuclear Power Plants," Revision 2, April 1987.

Regulatory Guide 1.29, "Seismic Design Classification," Revision 3, September 1978.

Regulatory Guide 1.45, "Reactor Coolant Pressure Boundary Leakage Detection Systems," May 1973.

Regulatory Guide 1.53, "Application of the Single-Failure Criterion to Nuclear Power Plant Protection Systems," June 1973.

Regulatory Guide 1.68, "Initial Test Programs for Water-Cooled Nuclear Power Plants," Revision 2, August 1978.

Regulatory Guide 1.97, "Instrumentation for Light-Water-Cooled Nuclear Power Plants to Assess Plant and Environmental Conditions During and Following an Accident," Revision 3, May 1983.

Regulatory Guide 1.108, "Periodic Testing of Diesel Generator Units Used as Onsite Electric Power Systems at Nuclear Power Plants," Revision 1, August 1977.

Regulatory Guide 1.140, "Design, Testing, and Maintenance Criteria for Normal Ventilation Exhaust System Air Filtration and Adsorption Units of Light-Water-Cooled Nuclear Power Plants," Revision 1, October 1979.

Regulatory Guide 9.3, "Information Needed by the AEC Regulatory Staff in Connection with Its Antitrust Review of Operating License Applications for Nuclear Power Plants," October 1974.

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WCAP-13212, "Evaluation of Thermal Stratification from Postulated Valve Leakage for the Comanche Peak Unit 2 RHR Lines," February 1992.

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ASTM Standard E-84-84, "Test Method for Surface Burning Characteristics of Building Materials," 1984.

APPENDIX C

NUCLEAR REGULATORY COMMISSION GENERIC CORRESPONDENCE

TABLE OF CONTENTS

OVERVIEW

In this appendix, the staff has summarized the status of Generic Letters and Bulletins issued since SSER 24 was published. Generic Letters and Bulletins for which Comanche Peak Steam Electric Station (CPSES) Unit 2 verification of action is necessary are also included.

ISSUES: Nuclear Regulatory Commission Bulletins (NRCB)

NRCB 89-02 Stress-Corrosion Cracking of High-Hardness Type 410 Stainless Steel Internal Pre-loaded Bolting in Anchor Darling Model S350W Swing Check Valves or Valves of Similar Design

Several operating plants reported stress-corrosion-induced cracks on the bolts which secure the check valve swing arm to the valve body of Anchor Darling swing check valves, Model S350W. Bulletin 89-02 asked licensees to disassemble and inspect all safety-related Anchor Darling Model S350W swing check valves supplied with internal retaining block studs of ASTM specification A193 Grade B6 Type 410 stainless steel, and to disassemble and inspect other safety-related check valves which use similar designs and materials.

Inspection Report 50-446/91-66 documents that Texas Utilities (TU) Electric had not purchased any Anchor Darling Model S350W swing check valves, nor any check valves with highly stressed, pre-loaded, internally wetted pins or threaded members which use Type 410 martensitic stainless steel or 17-4 Ph stainless steel.

This issue is closed.

NRCB 90-01 Loss of Fill-Oil in Transmitters Manufactured by Rosemount

On March 9, 1990, the NRC issued Bulletin 90-01, "Loss of Fill-Oil in Transmitters Manufactured by Rosemount." By letter dated July 8, 1992 (TXX-92300), TU Electric verified that all corrective actions previously specified have been completed.

All Model 1153 Series B and D transmitters manufactured prior to July 11, 1989, have been returned to Rosemount. Some of the Model 1153 transmitters were returned for credit and replaced with the new Model 1154 Series H transmitters. The remaining transmitters have been refurbished by Rosemount with sensor modules manufactured after July 11, 1989. The letter "A" has been added to the serial number of the refurbished transmitters to provide identification. There are no Model 1154 Transmitters used in Unit 2 which were manufactured prior to July 11, 1989. All Rosemount transmitters installed in Unit 2 are either new or refurbished.

This issue is closed.

ISSUES: Generic Letters (GL)

GL 88-05 Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components in PWR Plants

On March 17, 1988, the staff issued Generic Letter 88-05 requesting information about operation when reactor coolant leakage below Technical Specifications (TS) limits develops and the coolant containing dissolved boric acid comes in contact with and degrades low-alloy carbon steel components. On June 24, 1988, the licensee submitted a response to GL 88-05. As stated in SSER 24, the staff reviewed the licensee's response and determined that it satisfied the staff's intent and was acceptable.

On March 23, 1990, the licensee submitted a revised response to Generic Letter 88-05. TU Electric has re-evaluated its GL 88-05 program and determined that some responses required clarification or change. TU Electric changed the responses to GL Items 2, 3, and 4. The new response to Item 2 moved some commitments to the response to Item 3. In the revised response to Item 3, TU Electric eliminated the reference to a specific boric acid failure analysis or trending program. TU Electric determined that the revised problem identification and evaluation processes at the plant provide methods for identifying and evaluating both leakage, and adequate corrective measures. The response to Item 4 was revised to state that a review of boric acid corrosion industry operating experience was completed, with no recommended modifications identified. Future programmatic and hardware corrective actions will be evaluated on a case-by-case basis.

The NRC staff has reviewed TU Electric's revised response to GL 88-05 and concludes that the clarifications/changes are primarily administrative, and that the program continues to meet the intent of GL 88-05. Further, TU Electric states that all procedural controls are in place.

This issue is closed.

GL 89-13 Service Water System Problems Affecting Safety-Related Equipment

Generic Letter (GL) 89-13 recommended that licensees and applicants do the following for their service water systems: adopt biological-fouling surveillance and control measures, conduct heat transfer testing, perform routine inspection and maintenance of piping, perform single-failure walkdown inspections, and review procedures to reduce human error. GL 89-13 requested each licensee or applicant to provide the NRC with a commitment to each of the five recommendations or equivalent alternatives, and a confirmation that initial activities had been completed and ongoing programs had been established.

The licensee first responded to GL 89-13 in a letter of January 26, 1990. In that response the licensee committed to each of the five recommended actions of GL 89-13, or to an equally effective alternative course of action for one or more of them. In SSER 24, Appendix C, the staff accepted the response as fulfilling the reccomendations of GL 89-13. SSER 24 requested the licensee to provide a written response within 30 days after completion of all action items.

By letter dated June 19, 1992, TU Electric stated that it completed implementation of the recommended actions of GL 89-13 for Unit 2.

This issue is closed.

GL 90-06 Resolution of Generic Issue 70, "Power-Operated Relief Valve and Block Valve Reliability," and Generic Issue 94, "Additional Low-Temperature Overpressure Protection for Light-Water Reactors," Pursuant to 10 CFR 50.54(f)

The Commission issued Amendment No. 11 to the CPSES Unit 1 TS on June 29, 1992, in response to Generic Letter 90-06. The amendment revises the CPSES TS by including additional provisions for power-operated relief valve and block valve reliability and low-temperature overpressure protection. The amendment will be incorporated in the combined TS for Units 1 and 2 upon issuance of a low-power operating license for Unit 2.

This issue is closed.

GL 91-13 Request for Information Related to the Resolution of Generic Issue 130, "Essential Service Water System Failures at Multi-Unit Sites," Pursuant to 10 CFR 50.54(f)

On September 16, 1991, the NRC issued Generic Letter (GL) 91-13 which contained the staff resolution of Generic Issue 130. The GL required that the applicable facility review the recommended Technical Specifications (TS) and procedural improvements discussed in the generic letter and review the applicability and safety significance of these improvements for its facility. Each licensee or applicant was requested to state whether the proposed TS changes are applicable to its facility, and whether it will commit the improvements.

In a letter of March 16, 1992, TU Electric responded to the GL and indicated that TS changes would be submitted. In letters of June 5 and August 31, 1992, TU Electric submitted its proposed changes to the TS, to be incorporated into the combined TS for CPSES, Units 1 and 2, when issued. The staff has reviewed TU Electric's March 16, 1992, response and finds that the response meets the reporting requirements of GL 91-13.

This issue is closed.

GENERIC LETTERS

The following table, Table 1, shows the status of Generic Letters: their date of issue, a brief description of the issue, the revisions and supplements and their dates where applicable, whether or not the issue applies to CPSES, whether or not the issue requires action from TU Electric, the correspondence identification, date of response from TU Electric, and the NRC status. The table is current as of this SSER, and will be updated in a future supplement.

Table 1: Generic Letters

Generic Letter	Description	Applies/ Action Required	Licensee Response	Date of Response	Status
88-05 03/17/88	Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components In PWR Plants	Yes/Yes	TXX-88481 TXX-90110	06/24/88 03/23/90	Closed in SSER 25.
88-14 08/08/88	Instrument Air Supply Problems Affecting Safety-Related Equipment	Yes/Yes	TXX-89052 TXX-89191 TXX-89461 TXX-89561 TXX-90062	02/06/89 05/11/89 07/31/89 08/09/89 02/09/90	Addressed in SSER 24. TU to notify NRC when U2 Actions complete.
89-06 04/12/89	Task Action Plan Item I.D.2 - Safety Parameter Display System - 10 CFR 50.54(f)	Yes/Yes	TXX-89445	07/11/89	Open. TU owes certification letter for Unit 2.
89-13 07/18/89 89-13, S1 04/04/90	Service Water System Problems Affecting Safety-Related Equipment	Yes/Yes	TXX-90031 TXX-90186 TXX-90347 TXX-91004 TXX-92268	01/26/90 05/21/90 09/21/90 01/07/91 06/19/92	Closed in SSER 25.
90-01 01/18/90	Request for Voluntary Participation in NRC Regulatory Impact Survey	Yes/Yes	TXX-90082 TXX-90154	03/01/90 05/03/90	Closure Not Required.

Generic Letter	Description	Applies/ Action Required	Licensee Response	Date of Response	Status
90-02 02/01/90 90-02, S1 07/31/92	Alternative Requirements for Fuel Assemblies in the Design Features Section of Technical Specifications	Yes/No	---	---	Closure Not Required.
90-03 03/20/90 90-03, S1 05/14/90	Relaxation of Staff Position in Generic Letter 83-28, Item 2.2 Part 2 "Vendor Interface for Safety-Related Components"	Yes/Yes	TXX-90353 TXX-901046	09/27/90 12/10/90	Closed by NRC letter of 02/01/91.
90-04 04/25/90	Request for Information on the Status of Licensee Implementation of Generic Safety Issues Resolved with Imposition of Requirements or Corrective Actions	Yes/Yes	TXX-90217	06/26/90	Closure not required.
90-05 06/15/90	Guidance for Performing Temporary Non-Code Repair of ASME Code Class 1, 2, and 3 piping	Yes/No	---	---	Closure not required.

Generic Letter	Description	Applies/ Action Required	Licensee Response	Date of Response	Status
90-06 06/28/90	Resolution of Generic Issue 70, "Power-Operated Relief Valve and Block Valve Reliability," and GSI 94, "Additional Low-Temperature Overpressure Protection for Light-Water Reactors," Pursuant to 10 CFR 50.54(f)	Yes/Yes	TXX-901053 TXX-91427 TXX-92255	12/21/90 11/27/91 05/27/92	Closed in SSER 25.
90-07 08/10/90	Operator Licensing National Examination Schedule	Yes/Yes	TXX-90329	09/14/90	Closure not required.
90-08 08/10/90	Simulation Facility Exemptions	Yes/No	---	---	Closure not required.
90-09 12/11/90	Alternative Requirements for Snubber Visual Inspection Intervals and Corrective Actions	Yes/No	TXX-91323	09/06/91	Closure not required.
91-01 01/04/91	Removal of the Schedule for the Withdrawal of Reactor Vessel Material Specimens from Technical Specifications	Yes/No	---	---	Closure not required.
91-02 12/28/90	Reporting Mishaps Involving Low-Level Waste (LLW) Forms Prepared for Disposal	Yes/Yes	---	---	Closure not required.

Generic Letter	Description	Applies/ Action Required	Licensee Response	Date of Response	Status
91-03 03/06/91	Reporting of Safeguards Events	Yes/No	---	---	Closure not required.
91-04 04/02/91	Changes in Technical Specification Surveillance Intervals to Accommodate a 24-Month Fuel Cycle	Yes/No	---	---	Closure not required.
91-05 04/09/91	Licensee Commercial Grade Procurement and Dedication Programs	Yes/No	---	---	Closure not required.
91-06 04/29/91	Resolution of Generic Issue A-30, "Adequacy of Safety-Related DC Power Supplies," Pursuant to 10 CFR 50.54(f)	Yes/Yes	TXX-91390	10/28/91	Closed by NRC letter of 07/02/92.
91-07 05/02/91	Generic Issue-23 "Reactor Coolant Pump Seal Failures" and Its Potential Impact on Station Blackout	Yes/No	TXX-91363	10/01/91	Closure not required.
91-08 05/06/91	Removal of Component Lists from Technical Specifications	Yes/No	---	---	Closure not required.
91-09 06/27/91	Modification of Surveillance Interval for the Electrical Protective Assemblies in Power Supplies for the Reactor Protection System	No/No	---	---	Closure not required.

Generic Letter	Description	Applies/ Action Required	Licensee Response	Date of Response	Status
91-10 07/08/91	Explosives Searches at Protected Area Portals	No/No	---	---	Closure not required.
91-11 07/18/91	Resolution of Generic Issues 48, "LCOs for Class 1E Vital Instrument Buses," and 49, "Interlocks and LCOs for Class 1E Tie Breakers," Pursuant to 10 CFR 50.54(f)	Yes/Yes	TXX-92055	02/03/92	Closed by NRC letter of 04/02/92.
91-12 08/27/91	Operator Licensing National Examination Schedule	Yes/Yes	TXX-91374	10/14/91	Closure not required.
91-13 09/19/91	Request for Information Related to the Resolution of Generic Issue 130, "Essential Service Water System Failures at Multi-Unit Sites," Pursuant to 10 CFR 50.54(f)	Yes/Yes	TXX-92120 TXX-92260 TXX-92410	03/16/92 06/05/92 08/31/92	Closed in SSER 25.
91-14 09/23/91	Emergency Telecommunications	Yes/Yes	---	---	Closure not required.
91-15 09/23/91	Operating Experience Feedback Report, Solenoid-Operated Valve Problems at U.S. Reactors	Yes/No	---	---	Closure not required.

Generic Letter	Description	Applies/ Action Required	Licensee Response	Date of Response	Status
91-16 10/03/91	Licensed Operators' and Other Nuclear facility Personnel Fitness for Duty	Yes/No	---	---	Closure not required.
91-17 10/17/91	Generic Safety Issue 29, "Bolting Degradation or Failure in Nuclear Power Plants"	Yes/No	---	---	Closure not required.
91-18 11/07/91	Information to Licensees Regarding Two NRC Inspection Manual Sections on Resolution of Degraded and Nonconforming Conditions and on Operability	Yes/No	---	---	Closure not required.
91-19 12/19/91	Information to Addressees Regarding New Telephone Numbers for NRC Offices Located in One White Flint North	Yes/No	---	---	Closure not required.
92-01 03/06/92	Reactor Vessel Structural Integrity 10 CFR 50.54(f) Rev. 1	Yes/Yes	TXX-92319	07/02/92	Open. NRC reviewing response.
92-02 03/06/92	Resolution of Generic Issue 79, "Unanalyzed Reactor Vessel (PWR) Thermal Stress During Natural Convection Cooldown"	No/No	---	---	Closure not required.

Generic Letter	Description	Applies/ Action Required	Licensee Response	Date of Response	Status
92-03 03/19/92	Compilation of Current Licensing Basis. Request for Voluntary Participation in Pilot Program	Yes/No	---	---	Closure not required.
92-04 08/19/82	Resolution of the Issues Related to Reactor Vessel Water Level Instrumentation in BWRs Pursuant to 10 CFR 50.54(f)	No/No	---	---	Closure not required.
92-05 09/04/92	NRC Workshop on the Systematic Assessment of Licensee Performance (SALP) Program	Yes/No	---	---	Closure not required.
92-06 09/16/92	Operator Licensing National Examination Schedule	Yes/No	---	---	Closure not required.

NRC BULLETINS

The following table, Table 2, shows the status of NRC Bulletins: their date of issue, the revisions and supplements and their dates where applicable, a brief description of the issue, whether or not the issue applies to CPSES, whether or not the issue requires action from TU Electric, the correspondence identification, date of response from TU Electric, and the NRC status. The table is current as of this SSER, and will be updated in a future supplement.

Table 2: NRC Bulletins

NRC Bulletin	Description	Applies/ Action Required	Licensee Response	Date of Response	Status
79-14 07/02/79 79-14, R1 07/18/79 79-14, S1 08/15/79 79-14, S2 09/07/79	Seismic Analysis for As-Built Safety Related Piping Systems	Yes/Yes	TXX-3062 TXX-3597 TXX-4729	10/25/79 12/03/82 04/03/86	Open. Addressed in 50-446/ 88-14. Unit 2 verification needed.
88-01 02/05/88	Defects in Westinghouse Circuit Breakers	Yes/Yes	TXX-88377 TXX-89080	04/08/88 02/17/89	Addressed in 50-446/ 89-36 and 89-37. TU committed to inspect and replace. TU owes implementation letter.
88-04 05/05/1988	Potential Safety-Related Pump Loss	Yes/Yes	TXX-88556 TXX-88817 TXX-89140 TXX-89251 TXX-89708 TXX-92197	07/08/88 11/30/88 03/13/89 05/26/89 09/20/89 04/30/92	Addressed in 50-446/ 89-37. TU owes implementation letter.

NRC Bulletin	Description	Applies/ Action Required	Licensee Response	Date of Response	Status
88-05 05/06/88 88-05,S1 06/15/88 88-05,S2 08/03/88	Non-Conforming Materials Supplied by Piping Supplies, Inc. at Folsom, New Jersey and West Jersey Manufacturing Company at Williamstown, New Jersey.	Yes/Yes	TXX-89005 TXX-89163 TXX-90039 TXX-90059 TXX-90088	01/11/89 03/31/92 01/26/92 02/02/90 03/02/90	Addressed in 50-446/ 89-20 and 50-446/ 89-37. TU owes letter following testing.
88-08 06/22/88 88-08, S1 06/24/88 88-08, S2 08/04/88 88-08, S3 04/11/89	Thermal Stresses in Piping Connected to Reactor Coolant Systems	Yes/Yes	TXX-88740 TXX-88766 TXX-89246 TXX-89566 TXX-89710 TXX-89805 TXX-90113 TXX-92010 TXX-92009	10/21/88 10/31/88 05/09/89 08/09/89 09/18/89 11/17/89 03/27/90 02/07/92 03/23/92	Addressed in SSER 25 and in 50-446/ 89-37.
88-10 11/22/88 88-10, S1 08/03/89	Nonconforming Molded-Case Circuit Breakers	Yes/Yes	TXX-89160 TXX-89640	03/31/89 09/08/89	Closed in SSER 24. Actions were completed for both units. Addressed in 50-446/ 89-84 and 89-37.
88-11 12/20/88	Pressurizer Surge Line Thermal Stratification	Yes/Yes	TXX-91389 TXX-92076 TXX-92077	11/25/91 02/14/92 02/24/92	Closed in SSER 25. Addressed in 50-446/ 89-37.

NRC Bulletin	Description	Applies/ Action Required	Licensee Response	Date of Response	Status
89-02 07/19/89	Stress Corrosion Cracking of High-Hardness Type 410 Stainless Steel Internal Preloaded Bolting in Anchor Darling Model S350W Swing Check Valves or Valves of Similar Design	Yes/Yes	TXX-89677 TXX-91434	10/12/89 11/26/91	Closed in SSER 25. Addressed in 50-446/ 91-66.
89-03 11/21/89	Potential Loss of Required Shutdown Margin During Refueling Operations	Yes/Yes	TXX-89873	01/05/90	Unit 2 action to be completed prior to Unit 2 fuel load. Addressed in 50-446/ 90-02.
90-01 03/09/90	Loss of Fill-Oil in Transmitters Manufactured by Rosemount	Yes/Yes	TXX-90238 TXX-92300	07/18/90 07/08/92	Closed in SSER 25.
90-02 03/20/90	Loss of Thermal Margin Caused by Channel Box Bow	No/No	___	___	Addressed to BWR licensees only.
91/01 10/18/91	Reporting Loss of Criticality Safety Controls	No/No	___	___	Addressed to Fuel Cycle and uranium Fuel R&D licensees only.

NRC Bulletin	Description	Applies/ Action Required	Licensee Response	Date of Response	Status
92-01 06/24/92 92-01, S1 08/28/92	Failure of Thermo-Lag 330 Fire Barrier System to Maintain Cabling in Wide Cable Trays and Small Conduits Free from Fire Damage	Yes/Yes	TXX-92331	07/09/92	Open.

APPENDIX D

LIST OF PRINCIPAL CONTRIBUTORS

Contributor	Organization
I. Ahmed	Office of Nuclear Reactor Regulation Instrumentation and Control Systems Branch
F. Allenspach	Office of Nuclear Reactor Regulation Performance and Quality Evaluation Branch
F. Ashe	Office of Nuclear Reactor Regulation Electrical Systems Branch
K. Dempsey	Office of Nuclear Reactor Regulation Mechanical Engineering Branch
K. Desai	Office of Nuclear Reactor Regulation Reactor Systems Branch
K. Eccleston	Office of Nuclear Reactor Regulation Radiation Protection Branch
C. Fairbanks	Office of Nuclear Reactor Regulation Materials and Chemical Engineering Branch
G. Garten	Office of Nuclear Reactor Regulation Instrumentation and Control Systems Branch
M. Hartzman	Office of Nuclear Reactor Regulation Mechanical Engineering Branch
B. Holian	Office of Nuclear Reactor Regulation Project Directorate IV-2
G. Hornseth	Office of Nuclear Reactor Regulation Materials and Chemical Engineering Branch
R. Latta	Region IV Resident Inspector
W. LeFave	Office of Nuclear Reactor Regulation Plant Systems Branch

Contributor	Organization
J. Ma	Office of Nuclear Reactor Regulation Structural and Geosciences Branch
M. McBrearty	Office of Nuclear Reactor Regulation Mechanical Engineering Branch
D. Naujock	Office of Nuclear Reactor Regulation Materials and Chemical Engineering Branch
E. Peyton	Office of Nuclear Reactor Regulation Project Directorate IV-2
J. Rajan	Office of Nuclear Reactor Regulation Mechanical Engineering Branch
D. Roth	Office of Nuclear Reactor Regulation Project Directorate IV-2
R. Schaaf	Office of Nuclear Reactor Regulation Project Directorate IV-2
H. Shaw	Office of Nuclear Reactor Regulation Mechanical Engineering Branch
W. Swenson	Office of Nuclear Reactor Regulation Human Factors Assessment Branch
E. Tomlinson	Office of Nuclear Reactor Regulation Technical Specification Branch
J. Tsao	Office of Nuclear Reactor Regulation Materials and Chemical Engineering Branch
J. Wu	Office of Nuclear Reactor Regulation Mechanical Engineering Branch

APPENDIX E

ERRATA TO COMANCHE PEAK SAFETY EVALUATION REPORT AND SUPPLEMENTS

The following errata are applicable to the Comanche Peak SER and its supplements:

Supplement 17	Change
Page 4-17, line 9	Change "16" to "18"

Supplement 24	Change
Page 3-3, line 32	Add "certain" before "certified"
Page 3-4, line 9	Add "installed" before "safety-related"
Page 3-5, line 20	Change "testing for" to "testing of the material heats representing"
Page 3-6, lines 22-26	Delete
Page 3-7, line 4	Add "installed" before "flange"
Page 3-9, lines 27-28	Change "are not" to "may not be"
Page 10-1, line 24	Change "10.3.3" to "10.3.6"
Page 14-3, line 18	Change "50" to "30"
Appendix C, page 60, line 8	Add "(Superseded by GL 83-10C)" under "Description"
Appendix C, page 60, line 13	Add "(Superseded by GL 83-10C)" under "Description" Regulation

APPENDIX I

REVIEW AND EVALUATION OF TRANSAMERICA DELAVAL, INC., DIESEL GENERATOR RELIABILITY AND OPERABILITY

1 BACKGROUND

In August 1983, a crankshaft failed in an emergency diesel generator (EDG) at the Shoreham plant. The EDG was manufactured by Transamerica Delaval, Inc., (TDI).* As a consequence of this failure, the staff initiated an extensive review of TDI diesel generator design and manufacture to determine the acceptability of TDI diesel generators for use at nuclear power plants. The results of this review are documented in NUREG-1216, "Safety Evaluation Report Related to the Operability and Reliability of Emergency Diesel Generators Manufactured by Transamerica Delaval, Inc.," dated August 1986. NUREG-1216 endorsed, with specific exceptions, PNL-5600, "Review of Resolution of Known Problems in Engine Components for Transamerica Delaval, Inc., Emergency Diesel Generators," prepared by Pacific Northwest Laboratory (PNL) and dated December 1985. PNL-5600 and NUREG-1216 contain specific actions to be taken by owners of TDI diesel generators to ensure that their generators are acceptable for nuclear service. The applicant committed to adopt these specific actions in TU Electric letters of February 13, 1987 (TXX-6236), and February 24, 1989 (TXX-89077). This evaluation covers the actions taken by TU Electric (the applicant) to demonstrate compliance with the recommendations of PNL-5600 and NUREG-1216 relative to the TDI diesel generators at the Comanche Peak Steam Electric Station (CPSES).

2 STAFF APPROACH

In a letter of December 19, 1991 (TXX-91336), the applicant documented its conformance with the requirements of PNL-5600 and NUREG-1216. The staff reviewed the applicant's submittal, and audited records and documents at the CPSES site which pertain to actions taken to demonstrate the acceptability of the TDI emergency diesel generators (EDGs) at CPSES.

PNL-5600 addressed two phases of TDI diesel generator review. Phase I covers known generic problem areas with major engine components; areas that must be resolved before plant operation. Phase II covers a design review/quality revalidation (DR/QR) of a large set of important engine components. Phase II

*On November 18, 1988, Cooper Industries purchased the Enterprise Division from IMO-Delaval, Inc. (previously owned by Transamerica Delaval, Inc.) and renamed the company Enterprise Engine Services, a Division of Energy Services Group of Cooper Industries. In the interest of continuity, however, the staff will continue to use the term "TDI" throughout this evaluation.

can be completed subsequent to unit startup. This evaluation covers only the applicant's compliance with the requirements in Phase I of the program for the EDGs at CPSES Unit 2. (An evaluation of Phase I for CPSES Unit 1 is documented in SSER 22.) Evaluation for compliance with the requirements in Phase II for Unit 1 and Unit 2 will be addressed in a future supplement (Section 1.7, Outstanding Issue 23).

In Supplement 22 to the Safety Evaluation Report (SER) related to the operation of CPSES Units 1 and 2 (NUREG-0797), the staff evaluated applicant responses to a number of items relating to diesel generators manufactured by TDI. These items, originally identified in Supplement 6 to the CPSES Units 1 and 2 SER were divided into the three categories listed below. The purpose of this supplement is to review these items for applicability to CPSES Unit 2. The three categories are:

(A) Seventeen items which the applicant committed to complete before fuel load, and three items which the applicant committed to complete before exceeding 5-percent power.

(B) Seven items for which the staff required the applicant to submit additional information. Staff acceptance of the submittals on four of these items was required before exceeding 5-percent power. For the other three, the staff required the applicant to provide confirmation of completion with satisfactory results before exceeding 5-percent power.

(C) Items for which the applicant was required to provide additional information and which required staff acceptance before Unit 1 fuel load.

In Category A, Items 2 and 3 were only required to be performed on one diesel generator for both units. Consequently, these items will not be addressed again in this supplement for Unit 2. In Supplement 22 to the SER, the staff concluded that the applicant was not required to take any further action for Items 4, 9, and 10. This staff conclusion is also valid for Unit 2. Category A, Items 1, 5, 6, 7, 8, 11, 12, 15, 17, 18, 19, and 20 are Phase I items that are also applicable to Unit 2. These items were completed as part of the Unit 2 DR/QR Phase I effort. The staff evaluation of the applicant's actions relative to these items is included in this safety evaluation (SE). Category A, Items 13 and 14 are Phase II items which are applicable to Unit 2 and which will be addressed as part of the staff evaluation of Unit 2 DR/QR, Phase II. Lastly, Item 16 pertains to preoperational testing for Unit 1 only. It is not applicable to Unit 2.

In Category B, Items 1, 4, and 6 are unique to one diesel engine in Unit 1. These items will not be addressed for Unit 2. Item 3 was only required to be performed on one cylinder liner. The results, which were acceptable, are applicable to all cylinder liners for the diesel generators in both units. Items 2 and 7 are Unit 2 DR/QR Phase I issues which were completed. The staff evaluation of applicant actions relative to these items is included in this SE. Item 5 pertains to an applicant commitment to implement the recommendations of Revision 2 of the TDI Owners' Group Maintenance and Surveillance (M/S) Plan. Since the M/S Plan is applicable to all TDI diesel generators, the staff considers this applicant commitment to be applicable to Unit 2 also (Section 1.8, Confirmatory Issue 6).

Category C items pertain to load limitations on TDI diesel generators, and to applicant responses to staff questions regarding specific portions of the CPSES Final Safety Analyses Report (FSAR). The staff considers these items to be generic, and the staff conclusions regarding them are, therefore, also applicable to Unit 2.

<u>DSRV Connecting Rods</u> (NUREG-1216, Section 2.1.3.6)

The Owners' Group recommendation that connecting rod bow be measured for conformance to the recommended limit before placing the EDGs in service is endorsed in PNL-5600. For the EDGs at CPSES Unit 2, connecting rod bow measurements were included as part of Work Order (WO) C90-5747. The measurements were taken and results evaluated in accordance with a Failure Analysis Associates (FaAA) procedure as described in a FaAA letter dated November 21, 1990. The staff has reviewed the documentation associated with the rod bow measurements and concludes that the connecting rods for the Train A and Train B EDGs are within the tolerance established for connecting rod bow.

A second Owners' Group recommendation endorsed in PNL-5600 is that connecting rod eyes and bushings be nondestructively examined for flaws. The bushings were inspected in accordance with the recommendation under WO C90-5747 and found to be free of flaws. The staff has reviewed the documentation associated with this part of C90-5747 and concludes that the connecting rod bushings are acceptable. With respect to the rod eyes themselves, the applicant has not inspected any rod eyes. In a letter of December 19, 1991 (TXX-91336), the applicant stated that the rod eyes would be inspected for flaws at the first major engine disassembly. This is in conformance with the conclusions in PNL-5600 (Section 4.3.4.3) and, therefore, is acceptable.

The Owners' Group has recommended that the bolt holes in the connecting rod link boxes be nondestructively examined for flaws before operation. This recommendation is endorsed in PNL-5600. The applicant has performed an eddy current examination of the bolt holes using FaAA Procedure NDE 11.5. No flaws were found. The examination was performed under WO C90-5747. The staff has reviewed the documentation associated with the eddy current examination of link box bolt holes and concludes that the connecting rods are acceptable with respect to flaws in the link box bolt holes.

Several recommendations regarding connecting rod bolts were made by the Owners' Group and endorsed in PNL-5600. These recommendations include magnetic particle testing (MT) of the bolts, use of proper lubricant on bolts, and checking bolts for adequate elongation subsequent to installation to ensure proper torquing of the bolts. All connecting rod bolts (and studs) were magnetic particle tested under WO C90-5747 and found to be free of flaws. Proper lubricant for bolts (and studs) is stated in Procedure MSM-GO-3039 which is referenced in WO C90-5593 (Rev. 1). With respect to ultrasonic determination of bolt (and stud) length, this has been done to establish a baseline for future measurements, but not to establish proper torquing of bolts. For the Unit 2 EDGs, the applicant has substituted studs for the link box bolts, and has used a prestressing technique as recommended by the vendor to establish proper torquing of bolts and studs. This prestressing is detailed in Procedure MSM-GO-3039. The staff reviewed this procedure and finds it acceptable. The staff reviewed the documentation associated with these work orders and concludes that the recommendations regarding MT of the bolts and use of proper lubricant were met, and the intent of the recommendation regarding bolt torque was also met through use of prestressed bolts and studs. The connecting rod bolts and bolt installation are, therefore, acceptable.

Another recommendation made by the Owners' Group regarding connecting rods was to verify that the link rod to link pin clearance is zero when the link rod bolts are torqued to the vendor specification. This recommendation is also endorsed in PNL-5600. The vendor stated that the excessive clearance between the link rod and the link pin was caused by a link rod to link pin locating dowel that was too long. When this dowel is too long, it bottoms out in the link pin counter bore and prevents the link rod from contacting the link pin as designed. The applicant measured the dowel lengths and counter bore depths and determined that no interference existed. Consequently, there is nothing to prevent the link rod from contacting the link pin (zero clearance) when the bolts are properly torqued. The staff reviewed the applicant's position and concludes that it constitutes compliance with the Owners' Group recommendation and is, therefore, acceptable.

PNL-5600 contains a recommendation that connecting rod bolt length should be measured electronically before disassembly or, alternately, the break away torque should be measured. If the bolt tension by either method is determined to be less than 93 percent of the value at installation, the cause should be determined and appropriate corrective actions should be initiated. At CPSES, procedures MSM-CO-3038 and MSM-CO-3830 cover connecting rod assembly and disassembly. MSM-CO-3038 includes the requirement to evaluate the cause of bolt tension less than 93 percent of installed value, should it occur. This item conforms with the PNL-5600 recommendation and therefore, the staff finds this acceptable.

The Owners' Group recommended that the contact between mating surfaces of the link rod box serrated joint be checked to ensure 75 percent contact (vendor's minimum). PNL-5600 endorses this recommendation with the addition of a requirement to recheck the surface contact on a periodic basis. In NUREG-1216, the staff found the one-time inspection of mating surface contact to be acceptable. For the Unit 2 EDGs, this mating surface check was performed under WO C90-5747. The results of this inspection, however, were evaluated independent of this audit. The staff evaluation is provided in NRC letter to TU Electric dated February 8, 1991.

In Section 2.2.1 of PNL-5600, PNL concluded that periodic M/S actions pertaining to DSRV connecting rods warrant special emphasis in view of the mixed results of known non-nuclear experience, the unknown level of conservatism in the Owners' Group stress analysis of the connecting rods, and the difficulties inherent in inspecting threaded bolt holes. The applicant has adopted the M/S actions recommended in PNL-5600. These M/S actions involve inspection of connecting rod assemblies at each major engine overhaul. The documents containing the commitments and procedures for implementation were reviewed by the staff and found acceptable. The applicable documents reviewed are indicated below following a description of each requirement:

(a) The surface of the rack teeth shall be inspected for signs of fretting. If fretting has occurred, it shall be subject to an engineering evaluation for appropriate corrective action. (Results Engineering Instruction Manual (REI) REI-503, Component No. 02-340 A/B, Item No. 7)

(b) All connecting rod bolts shall be lubricated in accordance with vendor recommendations and torqued to vendor specifications, or pretensioned in accordance with vendor specifications. The length of the two pairs of bolts (or studs) above the crack pin shall be measured ultrasonically before and after tensioning. (REI-503, Component No. 02-340 A/B, Item 9 and Procedures MSM-CO-3039 and MS-CO-3830)

(c) The lengths of the two pairs of bolts (or studs) above the crankpin shall be measured ultrasonically before detensioning and disassembly of the bolts (or studs). If the bolt (or stud) tension is less than 93 percent of the value at installation, the cause shall be determined, appropriate corrective action shall be taken, and the interval between checks of bolt (or stud) tension shall be reevaluated. (REI-503, Component No. 02-340 A/B, and Procedures MSM-CO-3830, MSM-CO-3038, and MSM-CO-3039)

(d) All connecting rod bolts (and studs) shall be visually inspected for thread damage (e.g., galling) and the two pairs of connecting rod bolts (or studs) above the crankpin shall be inspected by magnetic particle testing to verify the continued absence of cracking. All washers used with bolts (or studs) shall be examined visually for signs of galling or cracking, and replaced if damaged. (REI-503, Component No. 02-340 A/B, Item No. 10)

(e) A visual inspection shall be performed of all external surfaces of the link rod box to verify the absence of any signs of service-induced stress. (REI-503, Component No. 02-340 A/B, Item No. 11)

(f) All of the bolt holes in the link rod box shall be inspected for thread damage (e.g., galling) or other signs of abnormalities. In addition, the bolt holes subject to the highest stresses (i.e., the pair immediately above the crankpin) shall be examined with an appropriate nondestructive method to verify the continued absence of cracking. Any indications shall be recorded for engineering evaluation and appropriate corrective action. (REI-503, Component No. 02-340 A/B, Item No. 12)

DSRV-16 Crankshafts (NUREG-1216, Section 2.1.3.10)

The TDI Owners' Group has concluded that the crankshafts for the EDGs at CPSES are acceptable for loads up to the full-rated load of 7000 KW, and to 110 percent of rated load for the percentage of the operating time allowed by the vendor. This conclusion is endorsed in PNL-5600 and in NUREG-1216. The conclusion of acceptability is based on torsional stresses in the crankshaft at rated speed and load. To avoid potentially harmful stresses that could develop at lower speeds, PNL-5600 contains a recommendation that EDG operation at less than rated speed be avoided. The applicant is aware of the concern regarding crankshaft stresses, and has incorporated precautions into site procedures (CPSES REI-503 and CPSES System Operating Procedure Manual SOP-609A) regarding operation of the EDGs below 440 rpm. The staff finds this acceptable.

Torsional analysis of the crankshaft has shown that engine imbalance could have a significant effect on crankshaft stresses. Therefore, PNL-5600 endorses a recommendation that cylinder exhaust temperatures be monitored as a means of determining engine imbalance. The difference between individual cylinder temperatures and the average temperature for all cylinders should be within the range recommended by the engine vendor. In addition, cylinder firing pressure should be measured periodically. The applicant has included a requirement to monitor and trend cylinder pressures and exhaust temperatures in REI-503. The data collection and trending are to be in accordance with the TDI Owners' Group Maintenance/Surveillance Matrix. The staff reviewed the applicable documentation and concludes that it is responsive to the recommendations in PNL-5600 and is, therefore, acceptable.

In PNL-5600, a concern is raised regarding operation of an EDG in a severely unbalanced condition. Should this occur, PNL recommends that the applicant evaluate the need for an immediate inspection of crankshaft oil holes for cracks. The applicant has included a requirement in REI-503 to reinspect the oil holes for fatigue cracks if an EDG operates in a severely unbalanced condition. This reinspection is to be conducted within a timeframe determined by the applicant considering the particular circumstances of the abnormal condition. Severe engine imbalance has been identified in other documentation as two or more cylinders misfiring. Cylinder misfiring would be noticeable by an increase in engine vibration and a significant difference in cylinder exhaust temperature between firing and non-firing cylinders. At CPSES, operators are instructed to monitor cylinder exhaust temperatures, and to notify the system engineer in the event of increased vibrations or if the exhaust temperature difference between any two cylinders exceeds 150°F. Since the difference in exhaust temperature between firing and non-firing cylinders would greatly exceed 150°F, the staff concludes that these operator instructions, contained in SOP-609B, are adequate to identify any severe imbalance condition. Based on its review of REI-503 and SOP-609B, the staff concludes that the documentation is responsive to the PNL recommendation and is, therefore, acceptable.

PNL-5600 contains a recommendation that the crankshaft oil holes and fillets should be inspected at 5-year intervals using fluorescent liquid penetrant and, as appropriate, eddy current testing. In NUREG-1216, the staff found the 5-year inspection interval overly conservative, and concluded that an inspection interval corresponding to the 10-year major engine overhaul is acceptable. The applicant has included requirements in REI-503 to inspect the fillets and oil holes of three main bearing journals and three crankpin journals using liquid penetrant, or other nondestructive examination (NDE) methods if indications are evident. This is acceptable. However, the frequency for these inspections, as stated in REI-503, differs from frequency recommended in NUREG-1216. This inconsistency was discussed with the applicant, who committed to revise REI 503 (Section 1.8, Confirmatory Issue 6). The applicant referenced item 9.4 in its letter TXX-91336 which states that "TU Electric will inspect the crank pin and main journals on a frequency corresponding to the 10-year major engine overhaul schedule." The staff has reviewed the applicable items in TXX-91336, and concludes that the applicant's commitment is acceptable. On the basis of requirements contained in REI-503 and the schedule described in TXX-91336, the staff concludes that the program for inspecting crankshaft oil holes and fillets is consistent with NUREG-1216 and is, therefore, acceptable.

PNL-5600 also includes a recommendation that crankshaft hot and cold web deflections be measured at each refueling outage. Requirements to measure crankshaft web deflections at each refueling have been incorporated into REI-503. The staff finds this to be acceptable.

In addition to the above, an initial inspection has been conducted of the Unit 2 EDGs for crankshaft scoring and wear, and for cracking around fillets and oil holes. These inspections were carried out under WO C90-5670 for the Train A EDG, and WO C91-0245 for the Train B EDG. The staff reviewed the results of these inspections and found no deficient conditions; therefore, this item is acceptable.

Engine Block (NUREG-1216 Section 2.1.3.13)

In PNL-5600, the recommendation was made that the engine blocks be metallurgically examined to ensure that the microstructure is characteristic of typical grey cast iron of the grade specified for the block. The engine blocks for the Unit 2 Train A and Train B EDGs had not been metallurgically examined at the time of the staff review. Absent this examination and results which indicate the engine blocks do not contain any degraded microstructure, the staff is unable to reach a conclusion regarding the acceptability of the engine blocks for their intended function. The staff will find the Unit 2 Train A and Train B engine blocks acceptable from the metallurgical perspective on confirmation that the above examination has been conducted, there is no degraded microstructure in the engine blocks, and appropriate documentation has been submitted to the staff and found acceptable (Section 1.8, Confirmatory Issue 5).

In PNL-5600, it is recommended that cylinder blocks be inspected on a regular basis for certain types of cracks. This recommendation is endorsed in NUREG-1216. Certain key maintenance/surveillance actions pertinent to the DSRV 16 cylinder blocks are required to be performed. REI-503 includes the requirement to perform additional inspections in accordance with DR/QR Report 02-315A, and references procedure MUDGAA-60. The staff reviewed the applicable documentation and concludes that they satisfy the inspection requirements cited.

PNL-5600 endorsed the Owners' Group recommendation that engine blocks with known or assumed ligament cracks be inspected following each operation in excess of 50-percent of full load to verify the continued absence of stud-to-stud or stud-to-end cracks. In NUREG-1216, the staff endorsed this recommendation with the modification that boroscope inspections are an acceptable alternative to eddy current testing, and that inspections are to be performed within 48 hours following engine shutdown. REI-503 includes a requirement to conduct visual and boroscopic inspections of the block top at each refueling, as well as after any period of operation exceeding 50 percent load. In addition, REI-503 includes a requirement to visually inspect the block top during surveillance runs, and on a daily basis during any period of continuous operation. The staff finds this acceptable.

The engine blocks at CPSES Unit 2 were inspected for cracks on the block top and cylinder liner landing area, and for proper dimensions of the cylinder liners and cylinder liner landing area. These inspections were conducted under WO C90-5799 for Train A and WO C91-0256 for Train B. No cracks were found, and all dimensions were within tolerance. The staff reviewed the applicable documentation and concludes that the engine blocks are acceptable. This acceptance by the staff is based on the absence of stud-to-stud or stud-to-end cracks. If such a crack should develop, however, the applicant should declare the affected EDG inoperable and inform the NRC of the crack, regardless of the crack depth. The affected EDG will remain inoperable until the proposed disposition and/or corrective actions have been approved by the staff. These actions to take, upon crack development, should be proceduralized. (Section 1.7, Outstanding Issue 31).

PNL-5600 contains a recommendation that cylinder liner landings be inspected for circumferential cracks any time a liner is removed. If cracks are found, they should be characterized through appropriate nondestructive examination, and evaluated relative to FaAA's predictions for circumferential crack behavior. REI-503 includes a requirement to perform additional cylinder block inspections per DR/QR Report 02-315A. The referenced report includes a requirement to inspect the cylinder liner landing surface using liquid penetrant (LP) examination. The staff reviewed the applicant's documentation and concludes it is responsive to the PNL recommendations and is, therefore, acceptable.

PNL-5600 contains a recommendation that cylinder liner wear be monitored through visual inspection at each refueling outage. The staff has, in general, endorsed the recommendations in PNL-5600 as stated in NUREG-1216. However, NUREG-1216 does not include a specific reference to cylinder liner inspection. It does, however, include a specific reference to Revision 2 of the DR/QR M/S matrix which establishes a frequency based on piston removal and reinstallation. REI-503 contains a requirement to inspect cylinder liners at a frequency that is consistent with Revision 2 of the M/S matrix. Given that NUREG-1216 is the controlling document, the staff concludes that cylinder liner inspection frequency in accordance with Revision 2 of the M/S matrix, which is reflected in REI-503, is acceptable.

As noted in Table 2.1 of NUREG-1216, the engine (cylinder) blocks are among those components that the NRC staff and PNL have concluded warrant special attention from an M/S standpoint. Accordingly, the staff concluded that the following periodic inspections of the cylinder blocks should be required as part of the plant-specific M/S program:

- Cylinder blocks shall be inspected for "ligament" cracks, "stud-to-stud" cracks, and "stud-to-end" cracks as defined in a report by FaAA entitled "Design Review of TDI-R-4 and R-4 Series Emergency Diesel Generator Cylinder Blocks" (FaAA Report No. FaAA-84-9-11.1) dated December 1984. (Note that the FaAA report specifies additional inspections to be performed for blocks with "known" or assumed" ligament cracks.) The inspection intervals (i.e., frequency) shall not exceed the intervals calculated using the cumulative damage index model in the subject FaAA report. In addition, inspection methods shall be consistent with or equivalent to those identified in the subject FaAA report.

- In addition to inspections specified in the aforementioned FaAA report, blocks with "known" or "assumed" ligament cracks (as defined in the FaAA report) shall be inspected at each refueling outage to determine whether or not cracks have initiated on the top surface, which was exposed because of the removal of two or more cylinder heads. This process shall be repeated over several refueling outages until the entire block has been inspected. Liquid penetrant testing or a similarly sensitive nondestructive testing technique shall be used to detect cracking, and eddy current testing shall be used as appropriate to determine the depth of any cracks discovered.

- If inspection reveals cracks in the cylinder blocks between stud holes of adjacent cylinders ("stud-to-stud" cracks) or "stud-to-end" cracks, this condition shall be reported promptly to the NRC staff and the affected engine shall be considered inoperable. The engine shall not be restored to "operable status" until the proposed disposition and/or corrective actions have been approved by the NRC staff.

The applicant's implementing procedures and commitments relative to the cylinder block inspections at CPSES Unit 2 are provided in REI-503. The staff reviewed this document and finds that the applicant is in compliance with cylinder block inspection requirements.

Cylinder Head Studs (NUREG-1216, Section 2.1.3.14)

PNL concluded that cylinder head studs of either the straight shank or necked-down shank design are acceptable for use in TDI diesel generators provided the studs are installed in accordance with vendor recommendations. This involves placing a lock washer in the bottom of the threaded stud hole, threading in the stud, and torquing the stud to a specific value. At CPSES Unit 2, the cylinder head studs for Train A and Train B EDGs were installed under WOs C90-5593 and C91-015, respectively. Both WOs reference Procedure MSM-CO-3830 which, in turn, includes the proper instructions for cylinder head stud installation. The staff has reviewed the applicable documentation and concludes that the Train A and Train B EDG cylinder head studs are properly installed.

In addition to installation of the studs, WO C90-5593 included provisions for a material comparator test on four studs and a material hardness test on one stud. These tests were conducted by FaAA, and test results show the studs, which are the necked-down design, have the proper material properties. The staff has reviewed the applicable documentation and concludes that the cylinder head studs for Train A and Train B EDGs are acceptable. (Note: the material tests discussed above were conducted on studs for the Train A EDG; this is acceptable per the DR/QR, and duplicate testing on Train B EDG studs is not required.)

Engine Base (NUREG-1216, Section 2.1.3.15)

PNL-5600 recommended that engine bases be inspected visually in the area of stud nut pockets of the bearing saddles at every refueling. The purpose of the inspection is to determine if any cracks have formed in that area. In NUREG-1216, the staff modified the PNL recommendation to extend the inspection interval to every major overhaul period for those engine bases that have been inspected and determined to be crack free. At CPSES Unit 2, the engine bases for Train A and Train B EDGs were inspected and found to be free of cracks. The inspection was performed under WO C90-5670 which references Procedure MSM-CO-3340. The staff reviewed these documents and finds this item acceptable.

With respect to the inspection of the engine base at every major overhaul, CPSES has included this requirement in the engine base inspection manual under Instruction No. REI-503 of the CPSES Results Engineering Instruction Manual. In addition, REI-503 contains the requirement to investigate any cracks found during an inspection prior to returning the EDG to service. The staff finds this to be consistent with NUREG-1216 and, therefore, acceptable. NUREG-1216 also contains a recommendation that engine bases should be checked to determine if the material is typical for American Society for Testing and Materials (ASTM) A48 Class 40 grey cast iron, and that no degenerative microstructure exists. The bases for the Train A and Train B EDGs were checked by FaAA under WO C90-5670 and found to be free of degenerate microstructure. The staff reviewed the documentation associated with checking the engine base material and finds it acceptable.

Turbocharger (NUREG-1216, Section 2.1.3.23).

As discussed in Section 4.19.4.3 of PNL-5600, PNL has endorsed the Owners' Group recommendation for installation and implementation of the drip and full-flow prelubrication system. The installation of the drip lubrication system is documented in applicant's Design Change Authorization No. 97586 and the implementation for lubrication during planned starts and engine coastdown is documented in applicant's System Operating Procedure SOP-609A. The staff reviewed these documents and concludes that the system has been properly installed and implemented.

PNL endorsed a number of other Owners' Group recommendations relative to the turbocharger. These were as follows:

- Inspection of the thrust bearings after the initial 100 starts and after every 40 non-prelubed starts. The staff reviewed the requirements, which are documented in Procedure REI-503, and finds them acceptable.

- Monitoring the rotor axial clearance during the turbocharger overhaul. The staff reviewed applicable documents (REI-503 and MSM-CO-3346) and finds them acceptable.

- Performance of a spectrochemical and ferrographic lube oil analysis on a quarterly basis and paying close attention to copper levels and particulate size as an indicator of bearing degradation. These items are documented in Procedures REI-503 and MSM-CO-3346. The staff reviewed these items and finds them acceptable.

- Monitoring of exhaust gas temperatures at turbocharger inlet (1200 °F limit). Alternately, individual cylinder exhaust temperatures can be monitored and maintained at or below 1050 °F. The applicant's procedures for monitoring these exhaust gas temperature limits are documented in Procedures REI-503 and SOP-609A. The staff reviewed these procedures and finds them acceptable.

- Visual inspection of nozzle ring, inlet guide vanes and bearings per DR/QR maintenance and surveillance schedule; performance of liquid penetrant test on stationary nozzle rings for signs of wear and cracking. The pertinent applicant procedures and work orders for these action items are REI-503, WO C90-5092(R), WO C91-0239(R), WO C90-5012(L) and WO C91-0240(L). The staff reviewed these documents and finds them acceptable.

Connecting Rod Bearing Shells (NUREG-1216, Section 2.1.3.4)

The Owners' Group recommended (Revision 2 of DR/QR Appendix II M/S program) and the staff accepted that all connecting rod bearing shells be inspected at each 10-year overhaul and a one-time sample inspection be performed after approximately 5 years. The Owners' Group and PNL recommended that as part of Phase I requirements the applicant gives consideration to increasing the lube oil pressure with the object of prolonging bearing life. The applicant's letter dated December 19, 1991, (TXX-91336) provides the commitment for CPSES Unit 2.

Other Phase I recommendations include performance of visual and dimensional inspections within 500 hours of operation. The staff reviewed these inspection procedures (REI-503) and finds them acceptable. The applicant performed a radiographic inspection of all bearing shells prior to installation. These inspection results are documented in WOs C90-5779, 667-70031, Supplement 5 and C91-0258, 667-70031, Supplement 5 for Trains A and B respectively. The staff reviewed these documents and finds the inspection results acceptable. As part of Phase I recommendations, the applicant is also committed to performing spectro-chemical and ferrographic lube oil analysis, as an indicator of bearing degradation. These analyses will be performed quarterly and are documented in Procedures REI-503 and MMP-360. The staff reviewed these documents and finds them acceptable.

The quality revalidation (QR) recommendations relative to the connecting rod bearing shells also include visual, dimensional and radiographic inspections. In addition, eddy current inspections to identify surface discontinuities and liquid penetrant inspections on bearing shells from one engine are part of the QR recommendations. These inspections are documented in WOs C90-5779 and C91-0258. The staff reviewed this documentation and finds it acceptable.

Piston and Piston Skirts (NUREG-1216, Section 2.1.3.18).

PNL has endorsed the quality revalidation inspections recommended by the Owners' Group in the plant DR/QR reports. As recommended by PNL, however, the staff requires that these quality revalidation inspections be completed on all AE piston skirts before initial plant operation. The applicant is utilizing Type AE skirts in the TDI EDGs at CPSES Unit 2. This is documented in WO C90-5428 which was reviewed by the staff and found to be acceptable. Other Phase I and QR recommendations relative to piston skirts are liquid penetrant inspections of the stud boss area of the skirt, rib area near the wrist pin boss and intersection of the rib and wrist pin boss. These inspections are documented in WO C90-5428. The staff reviewed this work order and finds it acceptable.

Air Start Valve Capscrews (NUREG-1216, Section 2.1.3.2)

PNL has endorsed the Owners' Group recommendations that capscrew length be verified as part of the DR/QR process for each engine and that capscrews be torqued in accordance with TDI recommendations discussed in Section 4.1.3.2 of PNL-5600. The latter recommendation has been incorporated by the Owners Group as part of DR/QR Appendix II M/S program. At CPSES Unit 2, Phase I recommendations include installation of the air start valve capscrews per TDI SIM-360 utilizing 3/4-10 x 2-3/4 capscrews. The applicant's documentation for the installation (WO C90-5782), was reviewed by the staff and found acceptable. In addition, the QR recommendations include performance of a material comparitor test on a sample basis and checking of the material hardness. These tests are also documented in WO C90-5782. Based on staff review, these tests were found acceptable.

Cylinder Heads (NUREG-1216, Section 2.1.3.13)

PNL has endorsed the recommendation of the Owners' Group consultant, FaAA, that all cylinder heads be inspected as part of the quality revalidation inspection. However, the Owners' Group recommendation as expressed in plant-specific DR/QR reports is that a 25-percent sample inspection is sufficient for Group III heads (i.e., heads cast after September 1980). In a letter to the NRC of May 1, 1986, from J. B. George, the Owners' Group has stated that Group III heads are much less prone to manufacturing defects than Group I or Group II heads. The Owners' Group has further stated that Group III head castings have been subjected to magnetic particle inspections in accordance with TDI procedures since April 1984. In addition, the machined surface of the fire deck was subjected to magnetic particle inspection during this same period. The applicant recommended utilizing Group III heads (in its letter (TXX-91236) of December 19, 1991) at CPSES Unit 2. The staff notes that Group III heads cast between September 1980 and April 1984 appear not to have received these inspections. However, on the basis of good operating experience to date with Group III heads and subject to continued implementation of air-roll tests, the staff finds the proposed 25-percent sample inspection for Group III heads acceptable.

The Owners' Group has proposed that the post-operational air-roll tests recommended by PNL be discontinued after the first operating cycle provided all heads are Group III heads and the heads demonstrated leak-free performance up to that time. In NUREG-1216, Section 2.1.3.13, the staff accepted this proposal with the following added requirements:

(1) Quality revalidation inspections should be completed for <u>all</u> cylinder heads.

(2) The air-roll test be discontinued only after confirmation with TDI.

The applicant's procedures regarding air-roll tests, stated in SOP-609A are in compliance with the requirements stated above. Finally, as a point of clarification, the staff required that the PNL-recommended air-roll tests should not be performed when the plant is in the Action statement of Technical Specification 3/4.8.1. In other words, it is not the staff's intent that an engine should intentionally be put into a condition where it cannot receive a start signal if the diesel engine(s) or other AC sources are already inoperable. The applicant should upgrade procedures to verify air roll tests are properly conducted (Section 1.7, Outstanding Issue 31).

PNL has recommended in Section 4.10.4.3 of PNL-5600 that cylinder heads with any through-wall weld repair of the fire deck should not be placed in nuclear standby service if the repair is performed from one side only (i.e., a "plug weld"). The staff concurred with this recommendation and concluded in NUREG-1216, that it should be incorporated into appropriate plant M/S procedures, but need not be incorporated as a license condition. The applicant has complied with this requirement.

The applicant's procedure for engine barring/air-rolling for water checks, documented in Procedure SOP-609A, were reviewed by the staff and found acceptable. Other inspections that include liquid penetrant inspection of the valve seats and magnetic particle inspection of the fire deck are documented in applicant inspection reports RIR 88-0532, 88-0668, 88-0677 and 88-0678. The staff reviewed these reports and found them acceptable. The ultrasonic measurements of the fire deck thickness at six locations which are identified in the QR report for cylinder heads are documented in applicant's inspection reports RIR 24178, RIR 24356, RIR 25814, and RIR 86-0925. The inspection findings are acceptable. The applicant checked the heads for through-wall weld (plug weld) repairs. These inspections are documented in FaAA Reports VL-1180 and PO 661-74943,44. The staff reviewed these reports and finds the heads and the plug weld repair procedures acceptable.

Fuel Injection Tubing (NUREG-1216, Section 2.1.3.16)

The Owners' Group and PNL concluded that fuel lines have adequate fatigue resistance. This finding of adequate fatigue resistance is subject to implementation of the Owners' Group recommendations for preservice inspections, acceptance criteria, and maintenance/surveillance as documented in the plant DR/QR reports and the generic Appendix II, Revision 2, of the DR/QR reports. In addition, PNL and the Owners' Group recommended that plant maintenance programs should include the manufacturer's instructions concerning the installation and inspection of the fuel line fittings if this has not already been done (see Section 4.14.4.2 of PNL-5600).

The applicant has elected to utilize shrouded fuel injection lines as recommended by PNL. This is documented in Procedure REI-503. The installation and inspections per TDI recommendation, are documented in WO C90-5781 and Procedure MSM-PO-3374. These documents are in compliance with the Owners' Group and PNL recommendation relative to the fuel injection tubing and are, therefore, acceptable.

Push Rods (NUREG-1216, Section 2.1.3.21)

The NRC staff concurs with PNL's findings in Section 4.17.4.3 of PNL-5600 that the forged head and friction-welded push rod designs are acceptable for nuclear service and that the ball-end design is not acceptable.

The generic DR/QR Appendix II M/S program, Revision 2, incorporates PNL's recommendations for preservice and periodic inservice inspection of push rods. Because each push rod of the friction-welded design will be liquid penetrant inspected before it is placed in service, the staff considers PNL's suggestion concerning radiograph inspections an optional item to be implemented at the utility's discretion. The staff also concludes that destructive examination of friction-welded push rods should be the utility's option.

The performance of liquid penetrant inspections of the friction welds are documented in WO C90-5560 and Procedure MSM CO-3339. The staff reviewed these documents and finds them acceptable.

<u>Rocker Arm Capscrews</u> (NUREG-1216, Section 2.1.3.22)

The NRC staff concurs with PNL's findings in Section 4.18.4.3 of PNL-5600 regarding the acceptability of the rocker arm capscrews for nuclear service assuming they are properly torqued. The staff notes that the generic DR/QR Appendix II M/S program, Revision 2, addresses the need for verifying proper torquing. The applicant's installation and torquing procedures are documented in WO C90-5592, REI-503 and MSM-CO-3339. The staff reviewed these procedures and finds them acceptable. The magnetic particle inspection, and material check and hardness test procedures are documented in C90-5560. The staff reviewed this document and finds it acceptable.

<u>Jacket Water Pump</u> (NUREG-1216, Section 2.1.3.17)

PNL has endorsed the findings of the Owners' Group and its consultant, Stone and Webster Engineering Corporation (SWEC), as discussed in Section 4.15.4.3 of PNL-5600. This represents an endorsement of design changes for the DSR-48 engines and of the jacket water pump periodic maintenance items that are recommended by the Owners' Group and are contained in the generic DR/QR Appendix II M/S program, Revision 2. The applicant's installation and torquing procedures are documented in WO C90-5171 and Procedure MSM CO-3325. Other inspections and tests include visual inspection of drive gear, check of key to keyway interface and shaft to impeller for proper fit, hardness test of pump shaft and liquid penetrant inspection of drive gear teeth and gear/shaft interface. These tests and procedures are documented in WO C90-5171. The staff reviewed the applicable documents and finds them acceptable.

4 CONCLUSIONS

In summary, the staff concludes that the applicant has satisfactorily demonstrated compliance with the recommendations and requirements of PNL-5600 and NUREG-1216 relative to the TDI diesel generator Phase I components with the exception of the following actions which should be completed to the staff's approval prior to fuel loading of CPSES Unit 2.

(1) <u>Engine Block</u> (NUREG-1216, Section 2.1.3.13). The applicant should document the results of the metallurgical examination conducted to verify that there is no degraded microstructure in the engine blocks (Section 1.8, Confirmatory Issue 5).

(2) The applicant should verify commitments and upgrade procedures as discussed in this Appendix (Section 1.7, Outstanding Issue 31 and Section 1.8, Confirmatory Issue 6).

Upon satisfactory completion of the confirmatory and outstanding issues stated above and its review of the documentation, the staff will find the EDGs for CPSES Unit 2 acceptable for nuclear standby service.

APPENDIX EE

GUIDELINES FOR IMPLEMENTING ACTION 3 OF BULLETIN 88-08

1.0 OBJECTIVE

To provide continuing assurance for the life of the plant that unisolable sections of reactor coolant system (RCS) will not be subjected to stratification and thermal cycling due to leaking isolation valves that could cause fatigue failure of the piping.

2.0 PURPOSE

To provide guidelines for acceptable procedures and criteria for preventing crack initiation in susceptible unisolable piping.

3.0 IDENTIFICATION OF POTENTIALLY SUSCEPTIBLE PIPING

(1) Sections of injection piping systems, regardless of pipe size, which are normally stagnant and have the following characteristics:

A. The upstream pressure is higher than the RCS pressure during normal plant operating conditions.

B. The piping sections contain long horizontal runs.

C. The piping systems are isolated by one or more check valves and a closed isolation valve in series.

D. For sections connected to the RCS:

a. Water injection is top or side entry, or any inclination in-between.

b. The first upstream check valve is located less than 25 pipe diameters from the reactor coolant loop (RCL) nozzle.

Examples of such sections in PWRs are the safety injection lines and charging lines between the RCL and the first upstream check valve, and the auxiliary pressurizer spray line between the charging line and the main pressurizer spray line.

(2) Sections of other piping systems connected to the RCS, regardless of pipe size, which are normally stagnant and have the following characteristics:

A. The downstream pressure is lower than RCS pressure during normal plant operating conditions.

B. The piping systems are isolated by a closed isolation valve, or a check valve in series with a closed isolation valve.

C. There is a potential for external leakage from the isolation valve.

Examples of piping containing such unisolable sections in PWRs are the residual heat removal (RHR) lines. Examples of such piping for BWRs are the RHR lines and the core spray injection lines.

4.0 ACCEPTABLE ACTIONS

The following actions are considered as acceptable responses to Bulletin 88-08, Action 3 and Supplement 3, as applicable, provided that the requirements of Bulletin 88-08, Action 2 have been satisfied.

(1) Revise system operating conditions to reduce the pressure of the source upstream of the isolation valve below the RCL pressure during normal operation.

(2) Relocate the check valves closest to the RCL to be at a distance greater than 25 pipe diameters from the nozzle.

(3) Install temperature monitoring instrumentation for valve leakage detection.

A. Selection of locations:

a. Temperature monitoring should be performed by installing resistance temperature detectors (RTDs).

b. RTDs should be located on a horizontal section between the first elbow (elbow closest to the RCL) and the first check valve (check valve closest to the RCL).

c. For the auxiliary pressurizer spray line, RTDs should be installed on a horizontal section close to the "tee" connection to the main pressurizer spray line or in the cold portion (ambient temperature) of the line.

d. RTDs should be located within one diameter from the welds.

e. At each location, an RTD should be positioned on top and bottom of the pipe cross-section.

B. Determination of baseline temperature histories:

After RTD installation, temperature should be recorded during normal plant operation at every location over a period of 24 hours. The resulting temperature time-histories represent the baseline histories at these locations and should meet the following criteria:

a. The maximum top-to-bottom temperature difference should not exceed 50 °F.

b. Top and bottom temperature time-histories should be in-phase.

c. Peak-to-peak temperature fluctuations should not exceed 60 °F.

C. Monitoring time intervals:

a. Monitoring should be performed at the following times:

1. at the beginning of Mode 1 operation, after startup from a refueling shutdown

2. at least at six-month intervals between refueling outages

b. During each monitoring period, temperature readings should be recorded continuously for a 24-hour period.

c. Temperature histories should correspond to the initially recorded baseline histories.

D. Exceedance criteria:

Actions should be taken to modify piping sections or to correct valve leakage if the following conditions occur:

a. The maximum temperature difference between the top and the bottom of the pipe exceeds 50 °F.

b. Top and bottom temperature histories are in-phase but the peak-to-peak fluctuations of the top or bottom temperatures exceed 60 °F.

c. Top and bottom temperature time-histories are out-of-phase and the bottom peak-to-peak temperature fluctuations exceed 50 °F.

d. Temperature time-histories do not correspond to the initially recorded baseline time histories.

(4) Detect leakage by pressure monitoring.

(Pressure monitoring is not the preferred method since pressure measurements cannot provide a reliable indication of thermal stratification or cycling.)

A. Type and location of sensors:

a. Pressure sensors should preferably be pressure transducers.

b. Pressure transducers should be installed upstream and downstream of the first check valve.

c. For systems having a pressure higher than the RCS pressure, pressure transducers may be installed upstream and downstream of the first closed isolation valve. (The downstream section is the pipe segment between the isolation valve and the check valve.)

B. Monitoring time intervals:

a. Monitoring should be performed at the following times:

1. at the beginning of power operation, after startup from a refueling shutdown

2. at least at six-month intervals thereafter, between refueling outages

b. Pressure readings should be recorded continuously for a 24-hour period.

C. Exceedance criteria:

Actions should be taken to modify piping sections or to correct valve leakage if the following conditions occur:

a. For pressure measurements across a check valve, the downstream pressure (RCS pressure) is equal to or less than the upstream pressure at any time during power operation.

b. For pressure measurements across a closed isolation valve, the downstream pressure is equal to or greater than the upstream pressure any time during power operation.