Docket
P1-22

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

February 2, 1993

Docket No. 50-446

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

Dear Mr. Cahill:

SUBJECT: ISSUANCE OF FACILITY OPERATING LICENSE NO. NPF-88 FOR COMANCHE PEAK STEAM ELECTRIC STATION, UNIT 2

The U.S. Nuclear Regulatory Commission (NRC) has issued the enclosed Facility Operating License No. NPF-88, together with the Technical Specifications, the Environmental Protection Plan, and the Antitrust Conditions for the Comanche Peak Steam Electric Station, Unit 2 (Enclosure 1). Authorization to operate beyond 5-percent power is still under consideration by the NRC. The issuance of this license authorizing operation up to 5 percent of full power is without prejudice to future consideration by the Commission with respect to operation at power levels in excess of 5 percent.

The Technical Specifications being issued with this license are the Combined Technical Specifications for both Comanche Peak Steam Electric Station, Units 1 and 2 (NUREG-1468). The Combined Technical Specifications have been issued separately as Amendment No. 14 to the Unit 1 Operating License No. NPF-87, in response to the April 2, 1991, application, as supplemented by letters dated August 31, 1992, October 29, 1992 and December 14, 1992.

The technical basis for the license is included in the Safety Evaluation Report related to the operation of Comanche Peak Steam Electric Station, Units 1 and 2 (NUREG-0797) and Supplements 1 through 26. Supplement No. 26 (SSER 26) is provided as Enclosure 2 to this letter. All previously open issues have been reviewed by the staff and have been satisfactorily resolved.

Enclosure 3 is a copy of a related <u>Federal Register</u> notice, the original of which has been forwarded to the Office of the Federal Register for publication.

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Three copies of Amendment No. 10 to Indemnity Agreement No. B-96 are included as Enclosure 4. Please countersign all copies and return one signed copy of Amendment No. 9 to this office.

Sincerely,

Original Signed By

Jack W. Roe, Director
Division of Reactor Projects III/IV/V
Office of Nuclear Reactor Regulation

Enclosures:
1. Facility Operating License No. NPF-88
2. SSER 26
3. Notice
4. Amendment No. 10 to Indemnity Agreement No. B-96

cc w/enclosures:
See next page

OFFICE	LA:PDIV-2	PM:PDIV-2	PD:PDIV-2	NRR:ILPB	DIR:DE
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DATE	01/15/93	01/15/93	01/15/93	01/22/93	01/29/93

w/- 1/29 CGP

OFFICE	DIR:DSSA	DIR:DRCH	DIR:DRS&S	DIR:DRIL	OGC/Hearing
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DATE	02/ / /93	01/27/93	02/ / /93	01/27/93	2/ 2/93

OFFICE	OGC/Antitrust	NRR:AD/R4&5	DIR:DRPW	ADP	NRR:DIR
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*Appendix A to NPF-88 (NUREG-1468) was provided with the January 29, 1993 letter to William J. Cahill.

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*With Technical Specifications

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

TEXAS UTILITIES ELECTRIC COMPANY, ET AL.*

DOCKET NO. 50-446

COMANCHE PEAK STEAM ELECTRIC STATION, UNIT NO. 2

FACILITY OPERATING LICENSE

License No. NPF-88

1. The Nuclear Regulatory Commission (the Commission) has found that:

   A. The application for a license filed by Texas Utilities Electric Company (TU Electric) acting for itself and as agent for Texas Municipal Power Agency, (licensees), complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's regulations set forth in 10 CFR Chapter I, and all required notifications to other agencies or bodies have been duly made;

   B. Construction of the Comanche Peak Steam Electric Station, Unit No. 2 (the facility), has been substantially completed in conformity with Construction Permit No. CPPR-127 and the application, as amended, the provisions of the Act, and the regulations of the Commission;

   C. The facility will operate in conformity with the application, as amended, the provisions of the Act, and the regulations of the Commission (except as exempted from compliance in Section 2.D below);

   D. There is reasonable assurance: (i) that the activities authorized by this operating license can be conducted without endangering the health and safety of the public, and (ii) that such activities will be conducted in compliance with the Commission's regulations set forth in 10 CFR Chapter I, except as exempted from compliance in Section 2.D. below;

   E. TU Electric is technically qualified to engage in the activities authorized by this operating license in accordance with the Commission's regulations set forth in 10 CFR Chapter I;

*The current owners of the Comanche Peak Steam Electric Station are: Texas Utilities Electric Company and Texas Municipal Power Agency. Transfer of ownership from Texas Municipal Power Agency to Texas Utilities Electric Company was previously authorized by Amendment No. 8 to Construction Permit CPPR-127 on August 25, 1988 to take place in 10 installments as set forth in the Agreement attached to the application for Amendment dated March 4, 1988. At the completion thereof, Texas Municipal Power Agency will no longer retain any ownership interest.

F. The licensees have satisfied the applicable provisions of 10 CFR 140, "Financial Protection Requirements and Indemnity Agreements," of the Commission's regulations;

G. The issuance of this license will not be inimical to the common defense and security or to the health and safety of the public;

H. After weighing the environmental, economic, technical, and other benefits of the facility against environmental and other costs and considering available alternatives, the issuance of Facility Operating License No. NPF-88 subject to the conditions for protection of the environment set forth herein, is in accordance with 10 CFR Part 51 of the Commission's regulations and all applicable requirements have been satisfied; and

I. The receipt, possession, and use of source, byproduct, and special nuclear material as authorized by this license will be in accordance with the Commission's regulations in 10 CFR Parts 30, 40, and 70, except that an exemption to the provisions of 70.24 is granted as described in paragraph 2.D below.

2. Based on the foregoing findings regarding this facility, Facility Operating License No. NPF-88 is hereby issued to the licensees, to read as follows:

   A. This license applies to the Comanche Peak Steam Electric Station, Unit No. 2, a pressurized water nuclear reactor and associated equipment (the facility), owned by the licensees. The facility is located on Squaw Creek Reservoir in Somervell County, Texas about 5 miles north-northwest of Glen Rose, Texas, and about 40 miles southwest of Fort Worth in north-central Texas and is described in the licensee's Final Safety Analysis Report, as supplemented and amended, and the licensee's Environmental Report, as supplemented and amended.

   B. Subject to the conditions and requirements incorporated herein, the Commission hereby licenses:

      (1) Pursuant to Section 103 of the Act and 10 CFR Part 50 "Domestic Licensing of Production and Utilization Facilities", TU Electric to possess, use, and operate the facility at the designated location in Somervell County, Texas in accordance with the procedures and limitations set forth in this license;

      (2) Pursuant to Section 103 of the Act and 10 CFR Part 50, "Domestic Licensing of Production and Utilization Facilities", Texas Municipal Power Agency to possess the facility at the designated location in Somervell County, Texas in accordance with the procedures and limitations set forth in this license;

(3) TU Electric, pursuant to the Act and 10 CFR Part 70, to receive, possess and use at any time, special nuclear material as reactor fuel, in accordance with the limitations for storage and amounts required for reactor operation, and described in the Final Safety Analysis Report, as supplemented and amended;

(4) TU Electric, pursuant to the Act and 10 CFR Parts 30, 40 and 70, to receive, possess, and use, at any time, any byproduct, source, and special nuclear material as sealed neutron sources for reactor startup, sealed sources for reactor instrumentation and radiation monitoring equipment calibration, and as fission detectors in amounts as required;

(5) TU Electric, pursuant to the Act and 10 CFR Parts 30, 40 and 70, to receive, possess, and use in amounts as required, any byproduct, source or special nuclear material without restriction to chemical or physical form, for sample analysis or instrument calibration or associated with radioactive apparatus or components; and

(6) TU Electric, pursuant to the Act and 10 CFR Parts 30, 40 and 70, to possess, but not separate, such byproduct and special nuclear materials as may be produced by the operation of the facility.

C. This license shall be deemed to contain and is subject to the conditions specified in the Commission's regulations set forth in 10 CFR Chapter I and is subject to all applicable provisions of the Act and to the rules, regulations, and orders of the Commission now or hereafter in effect; and is subject to the additional conditions specified or incorporated below:

(1) Maximum Power Level

TU Electric is authorized to operate the facility at reactor core power levels not in excess of 170 megawatts thermal (5% of rated power) in accordance with the conditions specified herein.

(2) Technical Specifications and Environmental Protection Plan

The Technical Specifications contained in Appendix A and the Environmental Protection Plan contained in Appendix B, are hereby incorporated into this license. TU Electric shall operate the facility in accordance with the Technical Specifications and the Environmental Protection Plan.

(3) Antitrust Conditions

Applicants as defined in Appendix C shall comply with the antitrust conditions delineated in Appendix C to this license; Appendix C is hereby incorporated into this license.

D. The following exemptions are authorized by law and will not endanger life or property or the common defense and security. Certain special circumstances are present and these exemptions are otherwise in the public interest. Therefore, these exemptions are hereby granted:

(1) The facility requires a technical exemption from the requirements of 10 CFR Part 50, Appendix J, Section III.D.2(b)(ii). The justification for this exemption is contained in Section 6.2.5.1 of Supplement 26 to the Safety Evaluation Report dated February 1993. The staff's environmental assessment was published on January 19, 1993 (58 FR 5036). Therefore, pursuant to 10 CFR 50.12(a)(1), 10 CFR 50.12(a)(2)(ii) and (iii), the Comanche Peak Steam Electric Station, Unit 2 is hereby granted an exemption from the cited requirement and instead, is required to perform the overall air lock leak test at pressure P_a prior to establishing containment integrity if air lock maintenance has been performed that could affect the air lock sealing capability.

(2) The facility was previously granted exemption from the criticality monitoring requirements of 10 CFR 70.24 (see Materials License No. SNM-1986 dated April 24, 1989 and Section 9.1.1 of SSER 26 dated February 1993.) The staff's environmental assessment was published on January 19, 1993 (58 FR 5035). The Comanche Peak Steam Electric Station, Unit 2 is hereby exempted from the criticality monitoring provisions of 10 CFR 70.24 as applied to fuel assemblies held under this license.

E. With the exception of 2.C(2) and 2.C(3), TU Electric shall report any violations of the requirements contained in Section 2.C of this license within 24 hours. Initial notification shall be made in accordance with the provisions of 10 CFR 50.72 with written followup in accordance with the procedures described in 10 CFR 50.73(b), (c), and (e).

F. In order to ensure that TU Electric will exercise the authority as the surface landowner in a timely manner and that the requirements of 10 CFR 100.3(a) are satisfied, this license is subject to the additional conditions specified below: (Section 2.1, SER)

(1) For that portion of the exclusion area which is within 2250 ft of any seismic Category I building or within 2800 ft of either reactor containment building, TU Electric must prohibit the exploration and/or exercise of subsurface mineral rights, and if the subsurface mineral rights owners attempt to exercise their rights within this area, TU Electric must immediately institute immediately effective condemnation proceedings to obtain the mineral rights in this area.

(2) For the unowned subsurface mineral rights within the exclusion area not covered in item (1), TU Electric will prohibit the exploration and/or exercise of mineral rights until and unless the licensee and the owners of the mineral rights enter into an agreement which gives TU Electric absolute authority to determine all activities--including times of arrival and locations of personnel and the authority to remove personnel and equipment--in event of emergency. If the mineral rights owners attempt to exercise their rights within this area without first entering into such an agreement, TU Electric must immediately institute immediately effective condemnation proceedings to obtain the mineral rights in this area.

(3) TU Electric shall promptly notify the NRC of any attempts by subsurface mineral rights owners to exercise mineral rights, including any legal proceeding initiated by mineral rights owners against TU Electric.

G. TU Electric shall implement and maintain in effect all provisions of the approved fire protection program as described in the Final Safety Analysis Report through Amendment 87 and as approved in the SER (NUREG-0797) and its supplements through SSER 26, subject to the following provision:

TU Electric 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.

H. TU Electric 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 July 21, 1992; "Comanche Peak Steam Electric Station Security Training and Qualification Plan" with revisions submitted through June 10, 1991; and "Comanche Peak Steam Electric Station Safeguards Contingency Plan" with revisions submitted through December 1988.

I. The licensees shall have and maintain financial protection of such type and in such amounts as the Commission shall require in accordance with Section 170 of the Atomic Energy Act of 1954, as amended, to cover public liability claims.

J. Amendment No. 8 to Construction Permit CPPR-127, issued August 25, 1988, authorized the transfer of 6.2% ownership interest in the facility from Texas Municipal Power Agency to TU Electric, such transfer to take place in 10 installments as set forth in the Agreement attached to the application for amendment dated March 4, 1988. At the completion of such transfer of interest, Texas Municipal Power Agency shall no longer be a licensee under this license and all references to "licensees" shall exclude Texas Municipal Power Agency.

K. This license is effective as of the date of issuance and shall expire at Midnight on February 2, 2033.

FOR THE NUCLEAR REGULATORY COMMISSION

Thomas E. Murley

Thomas E. Murley, Director
Office of Nuclear Reactor Regulation

Attachments/Appendices:
1. Appendix A - Technical Specifications (NUREG-1468)
2. Appendix B - Environmental Protection Plan
3. Appendix C - Antitrust Conditions

Date of Issuance: February 2, 1993

APPENDIX B

TO FACILITY OPERATING LICENSE NO. NPF-88

TEXAS UTILITIES ELECTRIC COMPANY

COMANCHE PEAK STEAM ELECTRIC STATION UNITS 1 & 2

DOCKET NOS. 50-445 AND 50-446

FEBRUARY 2, 1993

ENVIRONMENTAL PROTECTION PLAN

(NONRADIOLOGICAL)

COMANCHE PEAK STEAM ELECTRIC STATION

UNITS 1 AND 2

ENVIRONMENTAL PROTECTION PLAN

(NONRADIOLOGICAL)

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1.0 Objectives of the Environmental Protection Plan

The purpose of the Environmental Protection Plan (EPP) is to provide for protection of nonradiological environmental values during operation of the nuclear facility. The principal objectives of the EPP are as follows:

(1) Verify that the facility is operated in an environmentally acceptable manner, as established by the Final Environmental Statement - Operating License Stage (FES-OL) and other NRC environmental impact assessments.

(2) Coordinate NRC requirements and maintain consistency with other Federal, State, and local requirements for environmental protection.

(3) Keep NRC informed of the environmental effects of facility construction and operation and of actions taken to control those effects.

Environmental concerns identified in the FES-OL which relate to water quality matters are regulated by way of the licensee's NPDES permit.

2.0 Environmental Protection Issues

In the FES-OL, dated September 1981, the staff considered the environmental impacts associated with the operation of the two-unit Comanche Peak Steam Electric Station (CPSES). Certain environmental issues were identified which required study or license conditions to resolve environmental concerns and to assure adequate protection of the environment.

2.1 Aquatic Issues

The aquatic issues identified by the State in the FES-OL were as follows:

(1) Effects of the intake structure on aquatic biota during operation (FES-OL Section 5.5.2.3).

(2) Effects of the circulating water chlorination system on aquatic biota during operation (FES-OL Sections 4.2.4.1, 5.3.4.1, and 5.11.3.1).

The second issue above, "Effects of the circulating water chlorination system on aquatic biota during operation (FES-OL Sections 4.2.4.1, 5.3.4.1, and 5.11.3.1)," no longer applies because the EPA NPDES permit no longer requires that such a study be performed.

Aquatic matters are addressed by the effluent limitations, monitoring requirements, and the Section 316(b) demonstration requirement contained in the effective NPDES permit issued by the U.S. Environmental Protection Agency (Region VI). The NRC will rely on this agency for regulation of matters involving water quality and aquatic biota.

2.2 Terrestrial Issues

The terrestrial issue identified by the staff in the FES-OL was as follows:

(1) Potential impacts resulting from the use of groundwater by the station during operation (FES-OL Section 5.3.1.2).

NRC requirements with regard to the terrestrial issue are specified in Subsection 4.2 of this EPP.

3.0 Consistency Requirements

3.1 Plant Design and Operation

The licensee may make changes in station design or operation or perform tests or experiments affecting the environment provided such activities do not involve an unreviewed environmental question and do not involve a change in the EPP*. Changes in station design or operation or performance of tests or experiments which do not affect the environment are not subject to the requirements of this EPP. Activities governed by Subsection 3.3 are not subject to the requirements of this Section.

Before engaging in additional construction or operational activities which may significantly affect the environment, the licensee shall prepare and record an environmental evaluation of such activity. Activities are excluded from this requirement if all measurable nonradiological environmental effects are confined to the onsite areas previously disturbed during site preparation and plant construction. When the evaluation indicates that such activity involves an unreviewed environmental question, the licensee shall provide a written evaluation of such activity and obtain prior NRC approval. When such activity involves a change in the EPP, such activity and change to the EPP may be implemented only in accordance with an appropriate license amendment as set forth in Subsection 5.3 of this EPP.

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*This provision does not relieve the licensee of the requirements of 10 CFR 50.59.

A proposed change, test, or experiment shall be deemed to involve an unreviewed environmental question if it concerns: (1) a matter which may result in a significant increase in any adverse environmental impact previously evaluated in the FES-OL, in environmental impact appraisals, or in any decisions of the Atomic Safety and Licensing Board; or (2) a significant change in effluents or power level; or (3) a matter, not previously reviewed and evaluated in the documents specified in (1) of this Subsection, which may have a significant adverse environmental impact.

The licensee shall maintain records of changes in facility design or operation and of tests and experiments carried out pursuant to this Subsection. These records shall include written evaluations which provide bases for the determination that the change, test, or experiment does not involve an unreviewed environmental question or constitute a decrease in the effectiveness of this EPP to meet the objectives specified in Section 1.0. The licensee shall include as part of the Annual Environmental Operating Report (per Subsection 5.4.1) brief descriptions, analyses, interpretations, and evaluations of such changes, tests, and experiments.

3.1 Reporting Related to the NPDES Permit and State Certification

Changes to, or renewals of, the NPDES permit or the State certification shall be reported to the NRC within 30 days following the date the change or renewal is approved. If a permit or certification, in part or in its entirety, is appealed and stayed, the NRC shall be notified within 30 days following the date the stay is granted.

The licensee shall notify the NRC of changes to the effective NPDES permit that are proposed by the licensee by providing NRC with a copy of the proposed change at the same time it is submitted to the permitting agency. The licensee shall provide the NRC with a copy of the application for renewal of the NPDES permit at the same time the application is submitted to the permitting agency.

3.3 Changes Required for Compliance with Other Environmental Regulations

Changes in plant design or operation and performance of tests or experiments which are required to achieve compliance with other Federal, State, and local environmental regulations are not subject to the requirements of Subsection 3.1.

4.0 Environmental Conditions

4.1 Unusual or Important Environmental Events

Any occurrence of an unusual or important event that indicates or could result in significant environmental impact causally related to plant operation shall be recorded and reported to the NRC within 24 hours, followed by a written report per Subsection 5.4.2. The following are examples of such events: excessive bird impaction events, onsite plant or animal disease outbreaks, mortality or unusual occurrence of any species protected by the Endangered Species Act of 1973, fish kills, increase in nuisance organisms or conditions, and unanticipated or emergency discharge of waste water or chemical substances.

No routine monitoring programs are required to implement this condition.

4.2 Environmental Monitoring

4.2.1 Groundwater Levels and Station Water Use Monitoring

Groundwater levels in the onsite observation wells identified as OB-3 and OB-4 in the FES-OL (Figure 4-3) shall be monitored and recorded monthly when the groundwater pumpage rate by CPSES is less than or equal to 30 gallons per minute (gpm) and weekly when the CPSES average monthly rate exceeds 30 gpm for the previous month. Water levels shall be read and recorded on approximately the same day of the month when monitoring monthly and on the same day of the week when monitoring weekly (an aid in interpreting the results by minimizing the influence of cyclic water use patterns of the aquifer by others on the observed water levels).

A monthly record of the total number of gallons pumped from each of the onsite production wells shall be maintained, including an average monthly pumpage rate in gpm.

A monthly record showing the rate and total amount of surface water processed by the onsite water treatment facility shall be maintained by the licensee on a monthly basis. This record shall include the process rate in gallons per minute and the total amount in gallons.

The licensee shall include the results of this monitoring program as part of the Annual Operating Report (see Subsection 5.4.1).

4.2.2 Water Treatment Facility Outages Impact Assessment and Reporting

The following outage of the onsite water treatment facility shall be reported to the NRC:

(1) Routine or unplanned outages that exceed 30 consecutive days.

(2) Any outage of at least 24 hours duration, beginning with the third such outage in a calendar year, if these outages are accompanied by an increase in the monthly average groundwater pumpage to a rate exceeding 30 gpm. When it is determined that either routine or unplanned outages will exceed 30 consecutive days and when the groundwater pumpage rate will be greater than 30 gpm when averaged over the outage period, the licensee will prepare and submit a report to the NRC within 15 days after a determination of the extended outage is made. This report shall

include (1) a discussion of the reason for the extended outage, (2) the expected duration of the outage, (3) an estimate of the date or the time required to return the onsite water treatment facility to operation, (4) a determination of the potential for lowering the groundwater levels in offsite wells, (5) an assessment of the impact of the projected groundwater level decline, and (6) a proposed course of action to mitigate any adverse effects.

5.0 Administrative Procedures

5.1 Review and Audit

The licensee shall provide for review and audit of compliance with the EPP. The audits shall be conducted independently of the individual or groups responsible for performing the specific activity. A description of the organization structure utilized to achieve the independent review and audit function and the results of audit activities shall be maintained and made available for inspection.

5.2 Records Retention

Records and logs relative to the environmental aspects of station operation shall be made and retained in a manner convenient for review and inspection. These records and logs shall be made available to NRC on request.

Records of modifications to station structures, systems, and components determined to potentially affect the continued protection of the environment shall be retained for the life of the station. All other records, data and logs relating to this EPP shall be retained for 5 years or, where applicable, in accordance with the requirements of other agencies.

5.3 Changes in Environmental Protection Plan

Requests for changes in the EPP shall include an assessment of the environmental impact of the proposed change and a supporting justification. Implementation of such changes in the EPP shall not commence prior to NRC approval of the proposed changes in the form of a license amendment incorporating the appropriate revision to the EPP.

5.4 Plant Reporting Requirements

5.4.1 Routine Reports

An Annual Environmental Operating Report describing implementation of this EPP for the previous year shall be submitted to the NRC prior to May 1 of each year. The initial report shall be submitted prior to May 1 of the year following issuance of the operating license. The period of the first report shall begin with the date of issuance of the operating license.

The report shall include summaries and analyses of the results of the environmental protection activities required by Subsection 4.2 of this EPP for the report period, including a comparison with related preoperational studies, operational controls (as appropriate), and previous nonradiological environmental monitoring reports, and an assessment of the observed impacts of plant operation on the environment. If harmful effects or evidence of trends toward irreversible damage to the environment are observed, the licensee shall provide a detailed analysis of the data and a proposed course of mitigating action.

The Annual Environmental Operating Report shall also include:

(1) A list of EPP noncompliances and the corrective actions taken to remedy them.

(2) A list of all changes in station design or operation, tests, and experiments made in accordance with Subsection 3.1 which involved a potentially significant unreviewed environmental question.

(3) A list of nonroutine reports submitted in accordance with Subsection 5.4.2.

(4) A summary list of NPDES permit-related reports relative to matters identified in Subsection 2.1 which were sent to the U.S. Environmental Protection Agency Region VI during the report period.

In the event that some results are not available by the report due date, the report shall be submitted noting and explaining the missing results. The missing results shall be submitted as soon as possible in a supplementary report.

5.4.2 Nonroutine Reports

A written report shall be submitted to the NRC within 30 days of occurrence of a nonroutine event. The report shall (a) describe, analyze, and evaluate the event, including extent and magnitude of the impact and plant operating characteristics; (b) describe the probable cause of the event; (c) indicate the action taken to correct the reported event; (d) indicate the corrective action taken to preclude repetition of the event and to prevent similar occurrences involving similar components or systems; and (e) indicate the agencies notified and their preliminary responses.

Events reportable under this subsection which also require reports to other Federal, State or local agencies shall be reported in accordance with those reporting requirements in lieu of the requirements of this subsection. The NRC shall be provided with a copy of such a report at the same time it is submitted to the other agency.

APPENDIX C

TO

FACILITY OPERATING LICENSE NO. NPF-88

COMANCHE PEAK STEAM ELECTRIC STATION, UNIT 2

TEXAS UTILITIES ELECTRIC COMPANY

DOCKET NO. 50-446

ANTITRUST CONDITIONS*

LICENSE CONDITIONS FOR COMANCHE PEAK STEAM ELECTRIC STATION, UNIT NO. 2

*These are the Conformed Settlement License Conditions filed in December 1980 which were approved May 6, 1982 by the administrative law judge presiding over the consolidated antitrust proceedings for Comanche Peak Steam Electric Station. Although the text is identical, the sections have been renumbered for convenience.

A. The following definitions apply to paragraph B:

1. "Applicants" means severally and jointly Texas Utilities Generating Company, Dallas Power & Light Company, Texas Electric Service Company, Texas Power & Light Company, Texas Utilities Company, and each other subsidiary, affiliate, or successor company now or hereafter engaged in the generation, transmission, and/or the distribution of electric power in the State of Texas.

2. "North Texas Area" means the following Texas counties: Anderson, Andrews, Angelina, Archer, Bastrop, Baylor, Bell, Bordon, Bosque, Brown, Burnet, Cherokee, Clay, Coke, Collin, Comanche, Cooke, Coryell, Crane, Culberson, Dallas, Dawson, Delta, Denton, Eastland, Ector, Ellis, Erath, Falls, Fannin, Fisher, Freestone, Gaines, Glasscock, Grayson, Henderson, Hill, Hood, Hopkins, Houston, Howard, Hunt, Jack, Johnson, Kaufman, Kent, Lamar, Lampasas, Leon, Limestone, Loving, Lynn, Martin, McLennan, Midland, Milam, Mitchell, Montague, Nacogdoches, Navarro, Nolan, Palo Pinto, Parker, Pecos, Rains, Reagan, Red River, Reeves, Rockwall, Rusk, Scurry, Schackelford, Smith, Somervell, Stephens, Sterling, Tarrant, Terry, Tom Green, Travis, Upton, Van Zandt, Ward, Wichita, Wilbarger, Williamson, Winkler, Wise, Wood, and Young.

3. "Entity" means an electric utility which is a person, a private or public corporation, a governmental agency or authority, a municipality, a cooperative, or an association owning, operating or contractually controlling, or proposing in good faith to own, operate, or contractually control, facilities for generation of electric power and energy; provided, however, that as used in paragraphs B.1, B.2, B.7, B.9, B.10(a) and B.10(b), B.11, B.12, and B.13, "Entity" means an electric utility which is a person, a private or public corporation, a governmental agency or authority, a municipality, a cooperative, or an association owning or operating, or proposing in good faith to own or operate facilities for generation, transmission, and/or distribution of electric power and energy.

4. "Entity in the North Texas Area" means an Entity which owns or operates facilities for the generation, transmission, and/or distribution of electric power in any area within the North Texas Area.

5. "Bulk Power" means the electric power and/or electric energy supplied or made available at transmission or subtransmission voltages.

6. "Costs" means all appropriate operating and maintenance expenses and all ownership costs, where applicable.

7. The terms "connection" and "interconnection" are used interchangeably.

B. The "Applicants" defined in Paragraph A.1 are subject to the following antitrust conditions:

1. The Applicants shall afford an opportunity to participate in the Comanche Peak Steam Electric Station, Units 1 and 2, for the term of the instant license, or any extension or renewal thereof, to any Entity(ies) in the North Texas Area making a timely request therefor, through a reasonable ownership interest in such unit(s) on reasonable terms and conditions and on a basis that will fully compensate Applicants for their costs. It is understood that any request received prior to December 1, 1973, shall be deemed to be timely. In connection with such participation, the Applicants also will interconnect with and offer transmission service as may be required for delivery of such power to such Entity(ies) at a point or points on the Applicants' system on a basis that will fully compensate the Applicants for their costs, including a reasonable return on investment. Notwithstanding the December 1, 1973, date appearing hereinabove, the Applicants' offer of participation in Comanche Peak Steam Electric Station, Units 1 and 2, to Tex-La Electric Cooperative of Texas, Inc. shall not obligate the Applicants, by virtue of such offer, to offer an opportunity to participate in Comanche Peak Steam Electric Station, Units 1 and 2, to any other Entity.

2. The Applicants, as long as they are members of the Texas Interconnected Systems (TIS), shall support reasonable requests by Entities in the North Texas Area having generating capacity for membership in TIS. The Applicants shall also propose and actively support, as long as they are members thereof, the creation of one or more additional classifications of TIS membership based on non-discriminatory criteria to afford access to data, studies, and recommendations to all Entities in the North Texas Area for membership in any other electric utility planning or operating organization of which the Applicants are members (other than one involving only the Applicants). The Applicants shall share information with other Entities with respect to, and shall, with other such entities through any electric utility planning organizations (other than one involving only the Applicants) of which the Applicants are members, conduct and/or participate in joint studies and planning of future generation, transmission, and related facilities; provided, however, this condition shall not obligate the Applicants to conduct or participate in such joint studies or joint planning unless (1) the studies or planning are requested and conducted in good faith and are based on reasonably realistic and reasonably complete data or projections, (2) the studies or planning are reasonably justified on the basis of sound engineering principles, (3) appropriate protection is accorded proprietary or other confidential business and financial information, and (4) the costs for such studies or planning are allocated on a fair and equitable basis.

3. The Applicants will connect with, coordinate reserves, and sell, purchase or exchange emergency and/or scheduled maintenance bulk power with any Entity in the North Texas Area on terms that provide for the Applicants' costs, including a reasonable return on investment, in connection therewith and allow such Entity(ies) full access to the benefits of such reserve coordination.

4. Emergency service and/or scheduled maintenance service to be provided by each party shall be furnished to the fullest extent available from the supplying party and desired by the party in need. If requested, Applicants shall exchange maintenance schedules with any Entity in the North Texas Area. The Applicants and each such Entity(ies) shall provide to the other emergency service and/or scheduled maintenance service if and when available to the extent they can do so, without unreasonably impairing service to their customers including other electric systems to whom they have firm commitments. Any curtailment or refusal to provide such emergency and/or scheduled maintenance service shall be on a non-discriminatory basis.

5. The Applicants and the other party(ies) to a reserve sharing arrangement shall from time to time jointly establish the minimum reserves to be installed and/or provided under contractual arrangements as necessary to maintain in total a reserve margin sufficient to provide adequate reliability of power supply to the interconnected systems of the parties in accordance with good industry practice as developed in the area. Unless otherwise agreed upon, minimum reserve requirements shall be calculated as a percentage of each party's estimated net peak load demand (taking into account firm sales and firm purchases). No party to the arrangement shall be required to maintain greater reserves than the percentage which results from the aforesaid calculation. The reliability of power delivered into TIS-ERCOT over DC asynchronous connections shall not be treated differently by the Applicants, for purposes of spinning and installed reserve calculations and requirements, than would be the case if such power originated within TIS-ERCOT. Outages on DC asynchronous connections shall be treated by the Applicants the same as losses of generation within TIS-ERCOT. The Applicants agree to support the adoption of principles involving DC asynchronous connections contained in this paragraph within any TIS or ERCOT organization.

6. The parties to such a reserve sharing arrangement shall provide such amounts of spinning reserves as may be equitable and adequate to avoid the imposition of unreasonable demands on the other party(ies) in meeting the normal contingencies of operating its (their) system(s). However, in no circumstances shall such reserve requirement exceed the installed reserve requirement.

7. Interconnections with any Entity will not be limited to low voltages when higher voltages are requested and are available from the Applicants' installed facilities in the area where a connection is desired, when the proposed arrangement is found to be technically and economically feasible. Control and telemetering facilities shall be provided as required for safe and prudent operation of the interconnected systems.

8. Interconnection and coordination agreements shall not embody any restrictive provisions pertaining to intersystem coordination. Good industry practice, as developed in the area from time to time (if not unreasonably restrictive), will satisfy this provision.

9. The Applicants shall participate in and facilitate the exchange of bulk power by transmission over the Applicants' transmission facilities between or among two or more Entities in the North Texas Area with which the Applicants are connected, and between any such Entity(ies) and any Entity(ies) outside the North Texas Area between whose facilities the Applicants' transmission lines and other transmission lines, including any direct current (asynchronous) transmission lines, form a continuous electrical path; provided that (i) permission to utilize such other transmission lines has been requested by the proponent of the arrangement, (ii) the arrangements reasonably can be accommodated from a functional and technical standpoint, and (iii) any Entity(ies) requesting such transmission arrangements shall have given Applicants reasonable advance notice of its (their) schedule and requirements. Such transmission shall be on terms that fully compensate the Applicants for their costs including a reasonable return on investment; provided, however, that such transmission services and the rates to be charged therefor shall be subject to any regulatory agency(ies) having jurisdiction thereof. The Applicants shall not refuse to provide such transmission service merely because the rates to be charged therefor are the subject of dispute with such Entity. The Applicants shall not be required to enter into any arrangement which would unreasonably impair system reliability or emergency transmission capacity, it being recognized that while some transmission may be operated fully loaded, other transmission may be for emergency use and operated either unloaded or partially loaded. (The foregoing applies to any Entity(ies) to which the Applicants may be connected in the future as well as those to which they are now connected.)

10(a) The Applicants shall include in their planning and construction programs sufficient transmission capacity as required for the transactions referred to in paragraphs B.9 and B.11, provided any Entity(ies) in the North Texas Area gives the Applicants sufficient advance notice as may be necessary to accommodate its (their) requirements from a functional and technical standpoint and that such Entity(ies) fully compensates the Applicants for their costs including a reasonable return on investment. The Applicants shall not be required to construct transmission facilities if construction of such facilities is infeasible, or if such would unreasonably impair system reliability or emergency transmission capacity. In connection with the performance of their obligations above, the Applicants shall not be foreclosed from requiring a reasonable contribution in aid of construction or from making arrangements for coordinated construction of future transmission lines such that each of the parties to the transaction would own an interest in or a segment of the transmission addition in proportion to its share of the cost of the addition. Any such contribution made in aid of construction or ownership interest shall be properly credited in determining any wheeling charges. If the Applicants engage in joint ownership of transmission lines with any other Entity, they shall not refuse to engage in similar transactions in comparable circumstances with other Entities, subject to the provisions limiting the Applicants' obligations above.

10(b) Applicants shall provide other Entities with reasonable access to any future interstate interconnection facilities which Applicants may own, on terms and conditions comparable to the provisions of paragraph B.9 hereof and subparagraph 10(a).

11. The Applicants shall, upon reasonable advance notice, sell full and partial requirements bulk power to requesting Entities in the North Texas Area having, on the date of this license, non-aggregated generating capacity of less than 200 MW (including no generating capacity) under reasonable terms and conditions which shall provide for recovery of Applicants' costs, including a reasonable return on investment. The Applicants shall not be required to make any such sale if they do not have available sufficient bulk power or adequate transmission to provide the requested service or if the sale would impair their ability to render adequate and reliable service to their own customers or their ability to discharge prior commitments.

12(a) In connection with the performance of their obligations herein and subject to the provisions of this paragraph, the Applicants will not disconnect from or refuse to connect their then-existing or proposed facilities with the facilities of any Entity, used or proposed to be used for the transmission of electric energy in interstate commerce by reason of the interstate character of such facilities, and the Applicants will not prevent any Entity with which they maintain connection from establishing, maintaining, modifying, or utilizing a connection with facilities used or proposed to be used for the transmission of electric energy in interstate commerce by reason of the interstate character of such facilities, provided that, anything in these license conditions to the contrary notwithstanding (but subject to paragraph 12(b) and 12(d) below), any Entity seeking to establish, maintain, modify or utilize any connection which could affect the nonjurisdictional status of the Applicants under the Federal Power Act shall have filed an application with and used its best efforts to obtain an order from the Federal Energy Regulatory Commission, applicable to the Applicants under Sections 210, 211, and 212 of such Act, requiring the establishment, maintenance, modification or utilization of such connection. In the event that an Entity files an Application pursuant to this subparagraph, the Applicants agree that they will not unreasonably oppose any such application. In the event such application is denied by a valid order of the Federal Energy Regulatory Commission, any continuing refusal by the Applicants to establish, maintain, modify or utilize such connection with such Entity shall be subject to review by the NRC in accordance with the Atomic Energy Act of 1954, as amended, and the rules and regulations thereunder, to determine whether any such refusal would create or maintain a situation inconsistent with the antitrust laws or the policies thereunder in accordance with the standards set forth in Section 105 of such Act; provided that all factual determinations by the FERC on any cost or system reliability reason(s) for any such refusal shall not be subject to redetermination by the NRC. The burden of proof will be on the Applicants in such NRC proceeding.

12(b) Applicants shall not enter into or maintain any agreement or understanding with any other Entity(ies) to refuse to deal with another Entity(ies) with the purpose of maintaining a non-jurisdictional status under the Federal Power Act, and in the event that Applicants refuse to make an interconnection with, or choose to disconnect from any Entity(ies), such decision and/or action by the Applicants will be undertaken unilaterally, not jointly, and without consultation with any other Entity(ies), provided, however, that after Applicants decide to undertake such action, they may notify any affected Entity.

12(c) In the event that an Entity files an application pursuant to subparagraph 12(a) solely by reason of the Applicants' desire to maintain their non-jurisdictional status under the Federal Power Act, Applicants agree to pay such Entity's reasonable expenses in connection with such application and the ensuing proceeding,[1/] provided, however, that Applicants shall not be required to pay for any expenses of such Entity if that Entity's application is denied by FERC for reasons advocated by Applicants at FERC, and provided further, that Applicants shall not be required to pay for any expenses of such Entity which that Entity would have incurred had it not filed an application solely by reason of Applicants' desire to maintain their non-jurisdictional status under the Federal Power Act.

12(d) Nothing in these License Conditions shall impair the right of the Department of Justice or any other Entity, public or private, to file an antitrust action in any Federal Court in the event any Applicant refuses to establish, maintain, modify or utilize any connection with any Entity(ies), provided, that nothing herein shall preclude any Applicant from raising any legal or equitable defense that may be available to it.

1/ This obligation shall not apply to the expenses of the Central & South West Corporation or Houston Industries or any of their respective subsidiaries, including, but not limited to, the expenses of Central & South West Corporation and any of its subsidiaries incurred in FERC Docket EL79-8.

13. Applicants agree to use their best efforts to amend any agreements with all Entities to ensure that such agreements are not inconsistent with paragraphs B.12(a) and B.12(b).

14. The Applicants will, in accordance with applicable law, allow ownership participation in future nuclear generating facilities which they may construct, own, and operate in the State of Texas on conditions similar to these License Conditions.

15. Applicants shall use their best efforts to modify the Offer of Settlement filed in FERC Docket EL79-8 to include each of the undertakings set forth in the letter agreement among Applicants, Central & South West Corporation, Houston Lighting & Power Company and the FERC Staff dated September 11, 1980; Applicants shall thereafter use their best efforts to secure approval thereof by the FERC, and shall abide by any valid order(s) of the FERC issued pursuant to the Offer of Settlement. Nothing herein shall preclude the Department of Justice from instituting or intervening in any proceeding at FERC, including FERC Docket No. EL79-8, and from presenting such arguments and evidence that it deems appropriate.

16. The foregoing conditions shall be implemented i) in a manner consistent with applicable Federal, state and local statutes and regulations and ii) subject to any regulatory agency having jurisdiction. Nothing herein shall preclude the Applicants from seeking an exemption or other relief to which they may be entitled under applicable law or shall be construed as a waiver of their right to contest the applicability of the license conditions with respect to any factual situation.

7590-01

UNITED STATES NUCLEAR REGULATORY COMMISSION

DOCKET NO. 50-446

COMANCHE PEAK STEAM ELECTRIC STATION, UNIT 2

TEXAS UTILITIES ELECTRIC COMPANY

NOTICE OF ISSUANCE OF FACILITY OPERATING LICENSE

Notice is hereby given that the U.S. Nuclear Regulatory Commission (the Commission), has issued Facility Operating License No. NPF-88 (the license) to Texas Utilities Electric Company (the licensee). This license authorizes operation of the Comanche Peak Steam Electric Station, Unit 2 (the facility), by the licensee at reactor core power levels not in excess of 170 megawatts thermal in accordance with the provisions of the license, the Technical Specifications, and the Environmental Protection Plan.

Comanche Peak Steam Electric Station, Unit 2, is a pressurized water nuclear reactor located at the licensee's site in Somervell County, Texas, approximately 40 miles southwest of Fort Worth, Texas.

The application for the license, as amended, complies with the standards and requirements of the Atomic Energy Act of 1954, as amended (the Act), and the Commission's regulations. The Commission has made appropriate findings as required by the Act and the Commission's regulations in 10 CFR Chapter I, which are set forth in the license. Prior public notice of the overall action involving the proposed issuance of an operating license authorizing full power operation was published in the FEDERAL REGISTER on February 5, 1979 (44 FR 6995).

The Commission has determined that the issuance of this license will not result in any environmental impacts other than those evaluated in the Final Environmental Statement (NUREG-0775) since the activity authorized by the license is encompassed by the overall action evaluated in the Final Environmental Statement.

Pursuant to 10 CFR 51.52, the Commission has determined that the granting of relief and issuance of the exemptions included in this license will have no significant impact on the environment. These determinations were published in the FEDERAL REGISTER on January 19, 1993 (58 FR 5035 and 58 FR 5036).

For further details with respect to this action, see (1) Facility Operating License No. NPF-88, with Technical Specifications (NUREG-1468), Environmental Protection Plan, and Antitrust Conditions; (2) the report to the Advisory Committee on Reactor Safeguards dated November 17, 1981; (3) the Commission's Safety Evaluation Report (NUREG-0797) dated July 1981; Supplement No. 1 dated October 1981; Supplement No. 2 dated January 1982; Supplement No. 3 dated March 1983; Supplement No. 4 dated November 1983*; Supplement No. 6 dated November 1984; Supplement No. 7 dated January 1985; Supplement No. 8 dated February 1985; Supplement No. 9 dated March 1985; Supplement No. 10 dated dated April 1985; Supplement No. 11 dated May 1985; Supplement No. 12 dated October 1985; Supplement No. 13 dated May 1986; Supplement No. 14 dated March 1988; Supplement No. 15 dated July 1988; Supplement No. 16 dated July 1988; Supplement Nos. 17 through 20 dated November 1988; Supplement No. 21 dated April 1989; Supplement No. 22 dated January 1990; Supplement No. 23 dated February 1990; Supplement No. 24 dated April 1990, Supplement

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*Supplement No. 5 was never issued.

No. 25 dated September 1992; and Supplement No. 26 dated February 1993; (4) the Final Safety Analysis Report through Amendment No. 87 dated December 18, 1992; (5) the Environmental Report through Amendment No. 3 dated January 8, 1981; and (6) the Final Environmental Statement dated September 1981, supplemented October 1989.

These items are available for public inspection at the Commission's Public Document Room, the Gelman Building, 2120 L Street, N.W., Washington, D.C. 20555 and at the local public document room located at the University of Texas at Arlington Library, Government Publications/Maps, 701 South Cooper, P. O. Box 19497, Arlington, Texas 76019. A copy of Facility Operating License No. NPF-88 may be obtained upon request addressed to the U.S. Nuclear Regulatory Commission, Washington, D.C. 20555, Attention: Director, Division of Reactor Projects III/IV/V. Copies of the Safety Evaluation Report and its Supplements 1 through 26 (NUREG-0797) and the Technical Specifications (NUREG-1468) may be purchased by calling (202) 512-2249 or by writing to the Superintendent of Documents, U.S. Government Printing Office, Post Office Box 37082, Washington, D.C. 20013-7982.

Dated at Rockville, Maryland, this 2nd day of February 1993.

FOR THE NUCLEAR REGULATORY COMMISSION

Brian E. Holian, Senior Project Manager
Project Directorate IV-2
Division of Reactor Projects III/IV/V
Office of Nuclear Reactor Regulation

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

Docket Nos. 50-445
50-446

AMENDMENT TO INDEMNITY AGREEMENT NO. B-96
Amendment No. 10

Effective February 2, 1993, Indemnity Agreement No. B-96, between Texas Utilities Electric Company, Texas Municipal Power Agency and the Nuclear Regulatory Commission, dated February 14, 1983, as amended, is hereby further amended as follows:

Item 3 of the attachment to the indemnity agreement is deleted in its entirety and the following substituted therefor:

Item 3 - License number or numbers

SNM-1912 (From 12:01 a.m., February 14, 1983, to 12 midnight, February 7, 1990, inclusive)

SNM-1986 (From 12:01 a.m., September 27, 1989, to 12 midnight, February 1, 1993, inclusive)

NPF-28 (From 12:01 a.m., February 8, 1990, to 12 midnight, April 16, 1990, inclusive)

NPF-87 (From 12:01 a.m., April 17, 1990)

NPF-88 (From 12:01 a.m., February 2, 1993)

FOR THE U.S. NUCLEAR REGULATORY COMMISSION

Marylee M Slosson

Marylee Slosson, Acting Chief
Inspection and Licensing Policy Branch
Program Management, Policy Development
and Analysis Staff
Office of Nuclear Reactor Regulation

Accepted ________________, 1993

By ______________________
Texas Utilities Electric Company

Accepted ________________, 1993

By ______________________
Texas Municipal Power Agency

NUREG–0797
Supplement No. 26

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

February 1993

ABSTRACT

Supplement 26 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, 24, and 25 to that report were published. This supplement deals primarily with Unit 2 issues; however, it also references evaluations for several licensing issues that relate to Unit 1, which have been resolved since Supplement 25 was issued.

Supplement 5 was cancelled. 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.

This twenty-sixth supplement, which is in support of the low-power license for Unit 2, provides updated information on the issues that had been considered previously, as well as the evaluation of issues that have arisen since the twenty-fifth supplement was issued. This evaluation addresses all of the issues necessary to support the issuance of a low-power license for Unit 2.

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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.

- 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.

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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 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 for CPSES Unit 1. 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.

- Supplement 25 (SSER 25) was issued in September 1992. It updated 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. The staff review also addressed the translation of the Unit 1 and common area Corrective Action Program to Unit 2.

SSER 26 updates 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. This evaluation addresses all of the issues necessary to support the issuance of a low-power license for 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 25. 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 R contains information addressing inservice testing relief requests. Appendix S contains information addressing preservice inspection relief requests. Appendix FF contains a Technical Evaluation Report addressing relief and safety valves. No changes were made to SER Appendices F, G, H, I, J, K, L, M, N, O, P, Q, T, U, V, W, X, Y, Z, AA, BB, CC, DD, or EE 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 Publications/Maps, 701 South Cooper, P.O. Box 19447, Arlington, Texas 76019.

The NRC Project Manager for Comanche Peak Steam Electric Station, Unit 2, is Brian E. Holian. Mr. Holian may be contacted by calling (301) 504-1334 or by writing to the U.S. Nuclear Regulatory Commission, Washington, D.C. 20555.

1.7 Summary of Outstanding Issues

Section 1.7 of the SER, as supplemented, identified the following open issues at the time SSER 25 was issued. Those issues that were resolved in previous supplements were not listed in SSER 25. Listed in parentheses with each issue is the section of this SSER in which the issue is addressed.

(1) Cable Separation Criteria; review use of 1 inch and one barrier for power circuits rather than 1 inch and two barriers. (Section 8.4.4)

(2) Metal Clad and Rockbestos Cables; review use of copper sheath cable; review Rockbestos cable for proposed electrical separation usage. (Section 8.4.4)

(3) Combined Technical Specifications; complete review and certification. (Section 16)

(4) Optimized Fuel Assemblies; continue review of fuel assembly design and associated safety analyses. (Sections 4.2, 4.3, and 4.4)

(5) Mild Environmental Qualification Program; complete evaluation of changes to previously approved program. (Section 1.11, Items 22 and 23; Section 3.11)

(6) Station Blackout; complete assessment of dual-unit station blackout. (Section 8.4.10)

(7) Cable Tray Loading Criteria; review adequacy. (Section 8.4.11)

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

(8) Non-Class 1E Transformers in Cable Spreading Rooms; review use. (Section 8.4.6)

(9) Diesel Generator Post-24 Hour Load Test; review for compliance with Regulatory Guide (RG) 1.108. (Section 8.3.1)

(10) Initial Test Program; resolve exceptions to RG 1.68 and RG 1.108. (Section 14)

(11) Fire Protection Plan/Thermo-Lag; evaluate plan and implementation. (Section 9.5.1)

(12) Benbrook Second Circuit; verify that offsite modification is complete. (Section 8.2.1)

(13) Pipe Support Computer Codes; review Unit 2 applications (i.e., Code ME-215). (Section 1.11, Item 1; Section 3.7.2)

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

(15) RG 9.3 (Antitrust); complete "significant change" review. (Section 20)

(16) Leak Before Break on Reactor Coolant System (RCS) Branch Lines; complete review. (Section 3.6.1.2)

(17) Leak Before Break on Surge Line; complete review. (Section 3.6.1.2)

(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. (Section 15.3.8)

(20) Inservice Testing Program; assess revision to 1989 Code. (Section 3.9.6; Appendix R)

(21) High-Energy Line Break; review Unit 2 changes. (Section 3.6)

(22) Code Case Usage; review Unit 2 Code Cases used. (Section 3.9.3)

(23) Diesel Generator; perform design review/quality reverification (DR/QR) Phase II. (Section 9.5.9)

(24) Detailed Control Room Design Review and Safety Parameter Display/System; review Unit 2 submittal. (Section 22, Items I.D.1 and I.D.2)

(25) Boron Dilution Mitigation System; review Unit 2 submittal. (Section 4.6)

(26) Safe Shutdown Impoundment; review revised analyses. (Section 2.4.5; Section 9.2.5)

(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. (Section 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)

The NRC staff has completed its review of FSAR amendments through Amendment 87. As a result of the staff's continuing review of the CPSES Unit 2 applications (FSAR amendments, TU Electric letters to NRC), a number of outstanding issues were identified. These items are listed below; listed in parentheses with each issue is the section of this SSER in which the issue is addressed. Not relisted in this section are those items from Appendix C of this supplement, "NRC Generic Correspondence," which have been separately addressed in Appendix C.

(1) Feedwater Isolation Valve Impact Testing. (Section 10.3.3)

(2) Preservice Inspection Plan. (Sections 5.2.4.2 and 6.6.2; Appendix S)

(3) Steady State Reactor Physics. (Section 4.3.2.2)

(4) Post Accident Vital Area Access. (Section 22, Item II.B.2)

(5) Pre-operational Testing, Deferred Items. (Section 14)

(6) Reactor Coolant System Vents. (Section 22, Item II.B.1)

1.8 Confirmatory Issues

Section 1.8 of the SER, as supplemented, identified a total of seven confirmatory issues at the time SSER 25 was issued. These issues are listed below; listed in parentheses with each issue is the section of this SSER in which the issue is addressed.

(1) Performance of reactor relief and safety valves for Unit 2 (Section 22, Item II.D.1)

(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)

(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)

(6) Review diesel generator procedure upgrades/commitments. (Section 9.5.9)

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

1.9 License Conditions

In Section 1.9 of SSER 25, the staff listed three proposed license conditions. Those license conditions that were resolved in previous supplements were not listed in SSER 25.

License conditions discussed in previous SSERs that were included in the Unit 1 license, and are similarly included in the Unit 2 license, follow:

(1) The applicant 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 applicant 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 applicant 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 applicant 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 July 21, 1992; "Comanche Peak Steam Electric Station Security Training and Qualification Plan" with revisions submitted through June 10, 1991; and "Comanche Peak Steam Electric Station Safeguards Contingency Plan" with revisions submitted through December 1988.

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 50.55(e)) submitted to the NRC. The staff reviewed the Validation Efforts

Report and the applicable SSERs, and performed an onsite audit of the applicant programs and documentation describing the translation of the CAP to Unit 2. 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 staff identified and reviewed 25 differences between Unit 1 and Unit 2 CAP validation in SSER 25. Several items required further review and were left as open or confirmatory issues. Resolution of these issues is addressed below.

(1) A computer code (i.e., ME-215) used in the design validation of Unit 2 piping design is different from those used in Unit 1 (in SSER 14). This item is listed in Section 1.7, as Outstanding Issue 13. This issue is resolved in Section 3.7.2.

(2) Accepted in SSER 25

(3) In SSER 14, the staff described a concern related to pipe support modeling procedures of Stone & Webster Engineering Corporation (SWEC). The staff was concerned that piping system stresses and pipe support loads may be underpredicted in long straight runs of pipe with a series of adjacent, integrally welded, dual-trunnion-type supports (or single stanchion-trapeze type supports) modeled with moment restraining capability. Specifically, the staff stated that the SWEC modeling procedure, CPPP-7, will be unconservative at such supports interior to the series. The staff required that any such piping and pipe support configuration identified in CPSES design validations be subject to a case-by-case evaluation and that the resolution be submitted to the staff for review.

The applicant responded to the staff requirement in Calculation 2-NP-GENX-551 submitted by letter dated January 13, 1993 (TU Electric letter TXX-93024 to NRC). This calculation assesses the analytical modeling parameters which could conceivably affect piping stresses and support loads on long runs of pipe.

The first parameter assessed by the applicant was the general modeling of integrally welded, dual-trunnion-type supports or single stanchion trapeze-type supports. The staff was concerned that the applicant had modeled dual eccentric supports as single non-eccentric supports. The applicant stated that this modeling technique is no longer used and CPPP-7 models these types of supports, interior or end supports, so that they are modeled as dual eccentric supports to properly account for any rotational restraining effects.

The second parameter assessed was pipe support stiffness. The applicant confirmed that CPPP-7 requires actual modeling of stiffness for all pipe supports. The staff agrees that this method provides accurate results for both the supports at the end of long runs of pipe as well as any interior supports.

The third parameter assessed was the CPSES practice of not modeling pipe support gaps or end clearance effects for struts and snubbers. Pipe support gaps were evaluated in SSER 14, Appendix A, Section 13.4, and were acceptable. End clearance effects were evaluated for snubbers in SSER 14, Appendix A, Section 12.3, which concluded that the matching of snubber pairs for differential lost motion reasonably predicts snubber design loads. The staff concurs with the applicant's assessment that this conclusion for snubbers can be extrapolated for dual struts as their end clearances are similar to that of snubbers.

The above evaluations apply to large-bore piping. They generally apply to small-bore piping as well, with the exception of the applicability of support stiffness tolerances during final reconciliation. The applicant determined that final reconciliation of small bore piping is justified without the application of specific tolerances on support stiffness. The applicant stated that it is possible that on a long straight run of pipe involving a series of dual struts/snubbers, significant changes in support stiffness may occur and result in redistribution of loads within the series. However, significant changes in small-bore pipe support stiffness will likely result in insignificant effects on system response. In addition, occurrences of a series of three or more dual struts/snubbers on straight runs of small-bore piping are rarely expected. The staff, therefore, concurs with the applicant's assessment that small-bore piping systems are also acceptable without further case-by-case evaluation.

On the basis of this evaluation, the staff concludes that the current modeling methodology for single or dual eccentric supports utilized by CPSES for long runs of pipes is acceptable and no additional case-by-case evaluations are necessary.

(4) Accepted in SSER 25

(5) In SSER 16, the staff stated that walkdowns of Unit 1 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. The Validation Efforts Report stated that the extent of Unit 2 Thermo-Lag installation would be identified through use of the fire safe shutdown analysis (FSSA) in lieu of walkdowns. This information would then be used to determine the weight of Thermo-Lag installed on Unit 2 conduits for design validation of the conduit and support. In SSER 25, the staff stated that use of the FSSA to determine installed Thermo-Lag weight in lieu of walkdowns would be reviewed for proper implementation.

The staff conducted a site audit and conduit walkdown on December 10, 1992, to review completed conduit support calculation packages. The FSSA was used to generate M2-1700, "Unit 2 Thermo-Lag/RES Schedule," which defines the extent of Unit 2 Thermo-Lag installation. Fire Protection Installation Release (FPIR) forms are generated on the basis of the requirements of M2-1700. The FPIRs define the starting and ending points for Thermo-Lag installation. These FPIRs are used in conjunction with installation sketches of the conduit configurations to develop computer models that were reviewed for support validation calculations. The computer models that were reviewed accurately reflected as-built conditions. Inputs to the computer program were reviewed and found to have properly included the weight of the Thermo-Lag material. The staff determined that the applicant had adequately controlled the process of translating information from the FSSA to the design validation of conduit supports.

(6) In SSER 18, the staff stated that the seismic design validation of Unit 1 HVAC duct systems was performed using damping values of 2% and 4% for the operating basis earthquake (OBE) and the safe shutdown earthquake (SSE), respectively. In the Validation Efforts Report, the applicant stated that damping values of 4% for OBE and 7% for SSE were used for Unit 2 HVAC design validation. These damping values were higher than those which had previously been accepted by the staff in SSER 18. In SSER 25, the staff stated that the seismic damping values used for the validation of Unit 2 HVAC duct systems would be reviewed further.

In a letter dated August 30, 1989 (TU Electric letter TXX-89511 to NRC), the applicant stated that selection of damping values used in HVAC design validation would be based on the applicant's commitment to Regulatory Guide (RG) 1.61 "Damping Values for Seismic Design of Nuclear Power Plants." The applicant further stated that acceptable damping values would be selected and justified based on the HVAC design, and that RG 1.61 did not limit the possible values to 2% and 4%.

In a letter dated December 18, 1992, (TU Electric letter TXX-92630 to NRC), the applicant provided additional information in response to the issue stated in SSER 25. In the letter, the applicant submitted justification for using higher damping values in the seismic analysis of Unit 2 HVAC structures. The applicant had used 2% for OBE and 4% for SSE in the seismic analysis of Unit 1 HVAC systems. The applicant subsequently concluded that these values were very conservative, on the basis that the Unit 1 HVAC structures had been considered as welded structures, whereas in reality these structures should be considered as bolted structures. RG 1.61 recommends 2% for OBE and 4% for SSE for welded structures, and 4% for OBE and 7% for SSE for bolted structures. The applicant stated that for the CPSES HVAC structures there are a number of dissipative mechanisms, such as the connections between duct segments, the connections between the ducts and the supports, and the connections between the supports and the building structure, such that the HVAC duct systems should be considered as bolted structures.

The duct segments at CPSES are joined by bolted "companion-angle" (CA) or "hemmed flange" type connections with flexible gaskets, which are spaced along the duct at a maximum of four foot intervals. The ducts are either bolted, welded or shimmed to the supports which are spaced approximately every eight to ten feet. The supports are attached to the building concrete with one or more expansion anchors. The applicant stated that it is reasonable to conclude that the damping values may be even higher than those specified for typical bolted structures since HVAC structures contain additional damping mechanisms.

Although these arguments seem to be reasonable, the applicant did not provide specific data to support its position. No specific experimental tests or in-situ tests were performed to determine the structural damping which actually exists in the as-built HVAC configurations at CPSES.

Data on testing for damping values in Japanese PWR and BWR nuclear plants was reported in "An Evaluation of Damping Ratios for HVAC Duct Systems Using Vibration Test Data", in American Society of Mechanical Engineers, Pressure Vessel and Piping PVP-Volume 133 "Damping", 1988. These tests were performed in-situ on as-built HVAC structures consisting of rectangular and circular ducts, using a snap-back technique. The damping values reported in this reference ranged from 3% for low excitation to 8% for SSE type excitation, but the mean damping values for these conditions ranged from 4% to 5%. Furthermore, the damping values for circular ducts were lower than for rectangular ducts. Similar values were also obtained in laboratory tests on rectangular ducts reported in the Journal of Pressure Vessel Technology, November 1988. The HVAC structures described in these references also contained gasketed CA joints, as well as "Pittsburgh Lock" type joints along the corners. In Tennessee Valley Authority Report MA2-79-1, "Summary Report for HVAC Ducts Seismic Qualification and Verification/Improvement Program" dated June 16, 1979, TVA reported that damping values of 7% were measured in laboratory tests of rectangular HVAC duct segments with CA connections and welded corners, subjected to shake-table SSE excitation. Due to the support system used in these tests, the damping resulted almost entirely from the energy dissipation in the joints and none from the supports. However, in the ASME PVP-Volume 133 report, it was concluded that the energy dissipation between the ducts and the supports is the main contributor to the damping and that very little is contributed by the joints. This seems to contradict the TVA results. The actual damping values existing in as-built HVAC structures, as well as the sources of this damping, have not been clearly established.

The applicant stated in discussions with the staff (subsequently documented by TU Electric letter TXX-93074 to the NRC dated January 29, 1993) that the HVAC structures at CPSES and Watts Bar are similar, and therefore since the 4% and 7% values have been accepted at Watts Bar these are also applicable at CPSES, Unit 2. However, the damping values at Watts Bar were based on the tests described in the TVA report noted above. The damping values determined in the TVA report were recently evaluated by the staff for application at the Browns Ferry Nuclear Plant, and reported in a safety evaluation (SE) dated July 16, 1992. In this evaluation the staff accepted a value of 7% for SSE only for rectangular ducts with CA or "pocket lock" joints. For welded rectangular ducts and circular ducts the staff accepted a value of 2%, which is lower than the SSE value which forms the licensing basis of CPSES, Unit 1.

By letter dated January 28, 1993 (TU Electric letter TXX-93068 to NRC), the applicant stated that Category I HVAC structures did not include any non-rectangular ducts; however, a number of non-Seismic Category I HVAC structures containing circular ducts were identified which could affect the structural integrity and operability of Seismic Category I systems under seismic loading. The applicant performed seismic reevaluations on bounding configurations of these non-Seismic Category I HVAC structures, using damping values acceptable to the staff for evaluation of non-rectangular ducts, and determined that the load and stress allowables accepted by the staff in SSER 18 would not be exceeded and that unacceptable interactions between these structures and Seismic Category I systems would not occur.

Based on review of the submittals by TU Electric, and of available data in the literature, the staff concludes the following:

1. Based on the available data, the damping values stated in Regulatory Guide 1.61 for bolted structures (4% for OBE and 7% for SSE) are acceptable for application to the seismic analysis of Seismic Category I HVAC systems consisting only of rectangular duct structures with "companion-angle" or "hemmed flange" bolted, gasketed joints, and therefore, are acceptable for use at CPSES, Unit 2.

2. For Seismic Category I HVAC systems consisting of non-rectangular duct structures or of combinations of rectangular and non-rectangular duct structures, and for similar non-Seismic Category I HVAC systems which may affect Seismic Category I systems, the acceptable damping values are those as currently stated in the licensing basis of CPSES, Unit 1 (2% for OBE and 4% for SSE). No data is available to support the acceptance of higher damping values for these structures.

3. The applicant's reevaluation of bounding non-Seismic Category I HVAC structures provides reasonable assurance that these structures will not affect the structural integrity and operability of Seismic Category I structures under seismic loading.

(7) In the Validation Efforts Report, the applicant stated that P-Delta STRUDL (a standard vendor program) was used in lieu of ANGLEWELD (a proprietary contractor program) for evaluation of Unit 2 HVAC structural member welds. In SSER 25, the staff stated that it would review the use of this program.

In a letter of December 18, 1992 (TU Electric letter TXX-92630 to NRC), the applicant sent additional information regarding this issue. The applicant stated that the P-Delta STRUDL program had been verified by the vendor's QA program, including execution of an extensive set of test problems. The applicant has audited the program's vendor, and the vendor is on the applicant's Approved Vendor List. The contractor responsible for design validation of the Unit 2 HVAC duct systems (ABB Impell) performed hand calculations to verify selected results generated by P-Delta STRUDL. These calculations confirmed the accuracy of the program's output for the selected cases.

The applicant previously used the P-Delta STRUDL program for validating the design of the Unit 1 HVAC duct systems; the applicant analyzed structural member welds using the ANGLEWELD program. The staff reviewed the applicant's design validation of Unit 1 HVAC duct systems, including use of the P-Delta STRUDL program, in SSER 18. The staff stated in SSER 18 that P-Delta STRUDL was an appropriate computer program for the analysis of HVAC duct systems and supports.

The applicant previously used the P-Delta STRUDL program for validating the design of HVAC duct systems. The program's accuracy has been extensively verified by the performance of test problems as well as hand calculations of selected program results. Therefore, the staff finds the use of P-Delta STRUDL in lieu of ANGLEWELD for evaluation of Unit 2 HVAC structural member welds acceptable.

(8) In SSER 25, the staff noted a concern regarding the allowable tensile stress and shear stress for seismic Category II HVAC conduit supports and

anchorages. The applicant stated that the normal tensile stress is limited to 1.0 Fy and shear stress to 0.577 Fy for member evaluations for seismic Category II supports. In SSER 16, the staff stated that verification for structural integrity was required to demonstrate qualification of Train C conduit supports, in addition to addressing their potential interactions with nearby seismic Category I systems, structures, or components. The acceptance criteria used by the applicant to show that the Train C conduit system maintains structural integrity are in the applicant's design-basis document DBD-CS-093, Revision 1, Section 5.1.2.1. It is indicated that, in all cases, stresses are limited to yield stress (1.0 Fy) for tension and shear yield stress for shear based on the AISC Manual of Steel Construction. The Commentary on the AISC Specification (11/1/78), Section 1.5.1.2 further states that 0.577 Fy is frequently taken as a shear yield stress. The staff considers these criteria for verifying structural integrity to be conservative for seismic Category II HVAC supports, and are therefore acceptable.

(9) Accepted in SSER 25

(10) SSER 18 stated that Hilti expansion anchor bolts used in seismic category I HVAC supports are designed with a factor of safety of four for safe shutdown earthquake (SSE) load conditions and a factor of safety of five for operating basis earthquake load conditions. However, SSER 18 did not address the factor of safety to be used in category II HVAC supports which are evaluated only for SSE load conditions. A factor of safety of three has been proposed for the evaluation of some equipment anchorages in the resolution of Unresolved Safety Issue A-46. 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 79-02 for Category I supports. In SSER 16, the staff stated that because the safety function of Category II conduit supports was to ensure only the structural integrity of the conduit system under the SSE loading, the staff found that the design considerations required for Category II conduit supports should accordingly be established commensurate with the importance of the safety function to be performed (i.e., ensuring structural integrity). On the basis of the findings of a series of dynamic and vibratory testings for concrete expansion anchor bolts, the staff concluded in SSER 16 that a probability-based factor of safety of three for wedge-type concrete expansion anchor bolts (e.g., Hilti Kwik-Bolts) when used in Category II (Train C) conduit supports was commensurate with the importance of the safety function to be performed. Therefore, a factor of safety of three is also acceptable for Hilti expansion anchor bolts used in Category II HVAC duct support evaluations.

(11) Accepted in SSER 25

(12) Accepted in SSER 25

(13) In SSER 17, the staff stated that the applicant would evaluate all Unit 1 and common area concrete embedments to identify any spacing violations and determine their effect on support attachment capacities. In a letter of June 23, 1989 (TU Electric letter TXX-89193 to NRC), the applicant stated that an engineering evaluation of a sample of concrete embedments had provided justification for accepting all of the Unit 1 and common

embedments. The staff reviewed this evaluation and found it acceptable, as documented in NRC Inspection Report 50-445/89-53; 50-446/89-53, of August 14, 1989. The staff review noted that the Unit 1 evaluation did not find a single case of overloaded hardware.

In the Validation Efforts Report, the applicant stated that the same approach was used to evaluate Unit 2 concrete embedments. In SSER 25, the staff stated that it would review the applicant's evaluation of Unit 2 concrete embedment spacing violations for proper implementation.

In response to staff questions, the applicant stated that the findings of the Unit 1 evaluation were determined to be applicable to Unit 2; therefore, additional evaluation of Unit 2 embedments would not be required. The applicant stated that this was due to the high confidence level attained by the Unit 1 evaluation (i.e., no overloaded hardware), and the fact that the design and installation of Unit 2 embedments used the same criteria as were used for Unit 1. The applicant stated in a letter of December 18, 1992 (TU Electric letter TXX-92630 to NRC), that it had performed an evaluation of a limited sample of Unit 2 embedments to ensure the validity of this conclusion.

The staff reviewed the applicant's summary report of the Unit 2 evaluation (calculation no. 0218-CS-0347) during a site audit on December 9, 1992. Engineering evaluations by the applicant did not identify any cases of overloaded hardware in the selected sample of Unit 2 concrete embedments. Based on the high confidence level achieved by the applicant's evaluation of concrete embedments, this item is closed.

(14) Accepted in SSER 25

(15) Accepted in SSER 25

(16) In SSER 17, the staff stated 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 1-hour fire-rated cable is being used. In SSER 25, the staff identified this as an as outstanding issue. This item is resolved in Section 8.4.4.3 of this SSER.

(17) In SSER 17, the staff 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 1 inch and one barrier. This item was listed in SSER 25 as an outstanding issue. The staff reviewed this item and found it acceptable, as noted in Section 8.4.4.1 of this SSER.

(18) Accepted in SSER 25

(19) Accepted in SSER 25

(20) Accepted in SSER 25

(21) Accepted in SSER 25

(22) In SSER 19, the staff described 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).

Equipment located in a mild environment will not experience environmental extremes that are more severe than its normal and abnormal operating environment and is, therefore, not subject to the same qualification requirements. This equipment is included on the EQ Master List and is maintained by the CPSES maintenance, surveillance, and trending programs which will monitor any abnormal occurrences that may be exhibited by any equipment located in mild environments. The staff has determined that these changes are acceptable.

(23) The applicant revised the environmental EQ program (as described in SSER 19) to insert 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." If the evaluation led to the conclusion that the performance of the equipment would not be degraded in an accident due to the high humidity, the equipment would be reclassified as being in a mild environment and the equipment will remain on the Master EQ list. The staff has reviewed these changes and found that they are consistent with the staff's position on environmental qualification of electrical equipment.

(24) In a letter of March 4, 1992 (TU Electric letter TXX-92063 to NRC), the applicant submitted an advance FSAR change to reclassify a portion of the steam generator blowdown (SGB) high-energy piping located in the turbine building from non-seismic to seismic Category II. By letter dated January 21, 1993 (TU Electric letter TXX-93037 to NRC), the applicant submitted a similar change which reclassified a portion of the heater drain line. This designation is used to satisfy Regulatory Guide 1.29, "Seismic Design Classification," Position C.2, regarding the seismic design of those portions of structures, systems or components whose continued function is not required but whose failure could reduce the safe shutdown capability of safety-related plant features to an unacceptable level, in response to a safe shutdown earthquake (SSE).

The SGB and heater drain lines are designed to maintain their structural integrity following a SSE. The applicant stated that the portion of these lines inside the non-seismic turbine building will retain their structural integrity during an SSE. During discussions with the applicant, the staff verified that (1) the piping, which is supported by a seismic Category I building wall, is seismically analyzed and qualified; (2) overhead and adjacent non-seismic sources (conduits and piping) have been evaluated and assessed to have no adverse effect on the lines based on established CPSES dynamic impact criteria or commodity clearance reviews; and (3) the turbine building has been seismically analyzed by the applicant to demonstrate its structural integrity, and therefore will not collapse on the SGB line or heater drain line during a SSE.

The staff's review concluded that the applicant's method of evaluation is adequate regarding the seismic qualification of the SGB line and the heater drain line within the non-seismic turbine building. In addition, the applicant stated in the advance FSAR submittals of March 4, 1992, and January 21, 1993, that all activities affecting the design and construction of the seismic Category II SGB and heater drain line piping are subject to the same quality assurance requirements of 10 CFR Part 50 Appendix B as for any Class 5, seismic Category II piping. Therefore, this change is acceptable.

(25) Accepted in SSER 25. (Appendix C discusses Bulletin 79-14 closure).

In summary, in SSER 25, the staff documented the translation of the CAP from Unit 1 and common systems to Unit 2 as being sufficiently comprehensive and effectively implemented. Additionally, 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.

2 SITE CHARACTERISTICS

2.4 Hydrologic Engineering

2.4.5 Ultimate Heat Sink

In the original SER (July 1981), the findings of the applicant's FSAR (Amendment 10) ultimate heat sink (UHS) thermal performance analysis are presented for the postulated shutdown and cooldown of one unit concurrent with the dissipation of post-design-basis-accident rejected heat in the other unit. This analysis was based on data collected on site between July 13 and August 23, 1974, and demonstrated to be the worst performance in 30 years (1948-1978) (analysis of meteorological data from Waco-Madison Cooper Airport and Dallas-Fort Worth Airport). The analysis determined a maximum return temperature of 113.2°F and a maximum component cooling water (CCW) heat exchanger outlet temperature of 129.7°F (maximum allowable temperature is 135°F). The applicant also calculated an evaporation loss from the pond of 80 ac-ft. over the 40-day period. Using the same meteorological record, but using its own independent model, the NRC staff calculated a maximum safe shutdown improvement (SSI) return temperature of 114°F occurring 255 hours after the accident. The staff also estimated a loss from evaporation of about 43 ac-ft or 15 percent of the SSI volume after sedimentation.

In Amendment 68 to the FSAR, the applicant updated the thermal analysis using increased post-accident heat loads and the same on-site meteorological data. This resulted in a maximum SSI return temperature of 115°F and a maximum component cooling water (CCW) temperature of 131°F. The CCW temperature was then increased to 135°F (Amendment 76) because of increased CCW heat loads and an adjustment for heat exchanger fouling. The first of these changes is reflected in SER Supplement 22, Section 2.4.5.

In Amendment 87 to the FSAR, the applicant reevaluated the SSI using 39 years (1953-1992) of data that were now available from the Dallas-Fort Worth Airport. A simulation of the SSI with these data and a comparison with measured temperatures in the SSI showed good agreement for the years 1990-1992. A review of these data also showed that the period from August 26 to September 25, 1990, resulted in higher SSI temperatures than the 1974 conditions. A re-analysis using further modified post-accident heat loads, a more complex SSI performance model, and the 1990 meteorological data still resulted in a maximum SSI return temperature of 115°F occurring about 7 days after the accident. The maximum CCW heat exchanger outlet temperature remained at 135°F. Evaporation was calculated using the same heat loads and the meteorological data from July 25 to September 2, 1980 (which was found to be the most critical period for SSI evaporation during the 39 years of Dallas-Fort Worth Airport data). The evaporation from this simulation was determined to be 92 ac-ft.

The model used by the applicant for this updated thermal analysis (Edinger Analysis, reviewed on site) is a three dimensional hydrodynamic heat transfer model and appears to be less conservative than the NRC model (an earlier staff version of the Edinger analysis) used for the staff's original independent evaluation given in the SER. However, the applicant's model accurately predicted temperatures observed in the SSI for three years of normal operation with a significant service water heat load during the severe meteorological conditions of summer (including 1990). This gives additional confidence in the results of the simulation for accident conditions. In addition, the use of the longer meteorological record further decreases the probability of the design meteorological condition, exceeding the requirements of Regulatory Guide 1.27 in regard to severe meteorology.

Also in Amendment 87, the applicant states that the only other uses of SSI water are as a source of emergency fill water for the fire protection system storage tanks and as a backup source for auxiliary feedwater. The fire protection storage tanks are designed to be adequate for the worst-case single plant fire and, therefore, are not expected to require refilling under design conditions for the SSI. Additionally, consumption of water by the auxiliary feedwater system for supply to the steam generators, should the condensate storage tank fail, is only 0.63 ac-ft.

The plant Technical Specifications also impose a limiting condition for operation (LCO) on the temperature of the SSI. This LCO limits SSI temperature to 102°F for the service water intake temperature. This temperature was the highest calculated normal operating temperature for the SSI from the long-term simulation (summer 1990), and was used as the starting temperature for the SSI for the accident condition simulation.

All of the modifications to the SSI thermal analysis described above are acceptable to the staff. The staff concludes that the SSI is designed in accordance with the guidelines of Regulatory Guide 1.27 and the requirements of General Design Criterion 44 (10 CFR Part 50).

3 DESIGN CRITERIA FOR STRUCTURES, SYSTEMS, AND COMPONENTS

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

FSAR Amendments 86 and 87 included changes which involved the pipe break (high energy line break - HELB) criteria. The changes primarily involved the addition of figures showing pipe break locations and the addition of references to the FSAR text. The SER and its supplements were reviewed in light of these changes, and no further update is necessary. Therefore, the changes are acceptable.

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 residual heat removal (RHR) piping, the pressurizer surge line, and the accumulator injection lines.

GDC 4 allows the use of 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 applicants with approved LBB analyses to remove pipe-whip restraints and jet impingement barriers. The acceptable technical procedures and criteria of the LBB evaluation are defined in NUREG-1061, Volume 3, "Report of the U.S. Nuclear Regulatory Commission Piping Review Committee, Evaluation of Potential for Pipe Breaks," November 1984, and summarized, in part, as follows:

(1) The materials data submitted should include types of materials and material specifications; stress-strain curves and J-R curves (not required if a limit load approach is used in the stability analysis); long-term effects such as thermal aging; and other limitations to materials data (e.g., J-maximum, and maximum crack growth). The piping materials must be free from brittle cleavage-type failure over the full range of the system operating temperature.

(2) The forces and moments of pressure, deadweight, thermal expansion, and earthquake associated with normal operation and SSE should be considered. The location(s) at which the highest stresses occur coincident with the poorest material properties for base metals, weldments, and safe ends should be identified.

(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 postulated leakage flaw should be shown to be stable under normal plus SSE loads for long periods of time; that is, crack growth is minimal during an earthquake. A flaw stability analysis should be done to show that the leakage flaw is 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 seismic loads are summed absolutely.

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

(6) Operating experience should be provided 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's evaluation of the applicant's analyses follows.

RHR Piping

The staff's evaluation of the RHR piping LBB analysis appeared in SSER 25. The staff concluded that 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.

Pressurizer Surge Line

The applicant's LBB analysis for the pressurizer surge line was given in WCAP-13100, which was submitted as an enclosure to the February 14, 1992, letter (TU Electric letter TXX-92076 to NRC). The applicant supplemented this analysis in letters of August 7, 1992 (TU Electric letter TXX-92350 to NRC) and December 4, 1992 (TU Electric letter TXX-92518 to NRC).

The applicant's request for use of the LBB analysis for the pressurizer surge line originates from its response to NRC Bulletin 88-11, "Pressurizer Surge Line Thermal Stratification." During certain modes of plant heatup and cooldown, a large temperature differential (as much as 320°F) between the pressurizer and hot leg coupled with a low flow rate (1 to 5 gpm) in the surge line cause the pipe to expand and to contact the pipe whip restraints. This contact may cause stresses to exceed the stresses allowed by the ASME Code, Section III. Bulletin 88-11 requested that the applicant take action to ensure the structural integrity of the surge line considering the occurrence of thermal stratification. To satisfy Bulletin 88-11, the applicant has performed a thermal stratification analysis for the Unit 2 pressurizer surge line and has documented this effort in WCAP-13210. Findings from this report show that the pressurizer surge line satisfies NRC Bulletin 88-11.

The staff has verified the applicant's leakage rate and flaw stability calculations on the Unit 2 pressurizer surge line and finds that this line complies with GDC 4 based on the following determinations:

(1) The CPSES Unit 2 pressurizer surge line has a nominal diameter of 14 inches with a minimum wall thickness of 1.250 inch. The piping material is austenitic wrought stainless steel SA-376.

The applicant provided material properties for the surge line based on the Certified Material Test Report. In the LBB calculations, the minimum material properties at average pipe section temperature were used for the flaw stability evaluations; the average material properties were used for the leakage rate calculations.

(2) The applicant used combined normal and faulted loadings in the flaw stability analysis to assess margins against pipe rupture at postulated faulted load conditions. The normal operating loads include pressure, deadweight, seismic, and thermal expansion; the faulted loads include stratification temperatures as high as 320 °F, the heatup/cooldown case, and the forced cooldown case. In the worst loading case for the stability analysis, all individual normal, faulted, and seismic loads were summed absolutely. The highest stress locations are at a gas tungsten arc weld (GTAW) close to the hot-leg nozzle.

(3) CPSES Unit 2 has RCS pressure boundary leak detection systems that satisfy the guidelines of Regulatory Guide 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 required sensitivity of the plant's leak detection systems. The staff determined that the margin is a factor of 10 on leakage and is consistent with NUREG-1061.

(4) The applicant showed that the postulated leakage flaw is stable under normal plus SSE loads. The safety margin in terms of applied loads was shown to exceed 1.0, which satisfies NUREG-1061.

The applicant's assessment of fatigue crack growth was based on the evaluation performed for CPSES Unit 1, which was approved by the staff on November 6, 1989. Because of the similarities between Unit 1 and Unit 2, and the ample margin associated with the calculated flaw depth of the Unit 1 surge line piping when compared to its wall thickness, the staff concludes that the projected fatigue crack growth for Unit 2 piping is acceptable.

(5) On the basis of the generic J-R curve of the surge line material supplied by the applicant (the actual test-generated J-R curve was not available), the staff determined that the margin between the leakage-size flaw and the critical-size flaw meets the minimum requirement of 2 for the worst load combination. The margin satisfies NUREG-1061.

(6) Since Unit 2 is not in operation, there is no plant operating history to illustrate that the pipe has not experienced stress corrosion cracking or water hammer. However, considering operating histories of other

Westinghouse plants, the staff concludes that stress corrosion and water hammer are not issues for Unit 2.

Independent Staff Calculations

The staff conducted independent leak rate and flaw stability calculations using the PICEP computer code for loading case B/G and found that there was a discrepancy of 38% between the reported leakage crack size (3.7 inches) and that calculated by the staff (5.0 inches). Application of LBB to the surge line is still acceptable because the critical crack size of 10.4 inches obtained by the applicant's use of an alternative J-integral/tearing (J/T) approach in the stability analysis provides adequate margin even for the larger leakage crack size calculated by the staff.

Conclusion

The staff concludes that the applicant's LBB analysis is consistent with the criteria in NUREG-1061, Volume 3. Thus, the probability of large pipe breaks occurring in the surge line is sufficiently low that dynamic effects associated with postulated pipe breaks need not be considered in the design basis. The applicant may eliminate pressurizer surge line rupture from the structural design basis for CPSES Unit 2.

Revisiting the approved pressurizer surge line LBB submittal from CPSES Unit 1 indicates that Unit 1 should also have a discrepancy of about 38% between the reported leakage crack size and that calculated by using PICEP for loading case B/G. Again, application of LBB to the CPSES Unit 1 surge line is acceptable because the applicant is able to demonstrate adequate margin for the Unit 2 surge line by using an alternative J-integral/tearing (J/T) approach in the stability analysis. Due to the structural similarities between Unit 1 and Unit 2, evidenced by the almost identical leakage and critical flaw sizes reported in the submittals for both units, the J/T analysis performed for CPSES Unit 2 is applicable to CPSES Unit 1, and the conclusions made here for Unit 2 are applicable to Unit 1.

Accumulator Lines

The applicant's LBB analysis for the accumulator injection lines appeared in WCAP-13167, "Technical Justification for Eliminating 10 Inch Accumulator Lines Rupture as the Structural Design Basis for the Comanche Peak Nuclear Plant Unit 2," which was submitted as an enclosure to the February 14, 1992, letter. The applicant supplemented this analysis in letters of June 5, 1992 (TU Electric letter TXX-92252 to NRC) and December 4, 1992 (TU Electric letter TXX-92581 to NRC).

The staff has checked the licensee's leakage rate and flaw stability calculation on the Unit 2 accumulator lines and finds that these lines comply with GDC 4 based on the following determinations:

(1) The Unit 2 accumulator injection lines have a nominal diameter of 10.75 inches with a minimum wall thickness of 0.875 inch. The piping material is austenitic wrought stainless steel A376/TP316, A403/TP316, and A403/WP304.

The injection nozzle material is SA351-CF8A, a cast stainless steel product.

The applicant submitted material properties for the accumulator lines based on the certified materials test report. In the LBB calculations, the minimum material properties at average pipe section temperature were used for the flaw stability evaluations; the average material properties were used for the leakage rate calculations.

Since only the accumulator injection nozzle is made of cast stainless steel, the nozzle is the only place where the effect of thermal aging degradation at 550°F has to be considered. On the basis of the J/T analysis performed by the applicant on the injection nozzle, the staff concludes that the result is acceptable because material toughness parameters J and T (2200 in.-lb/in.^{2} and 60) are larger than the calculated J_{app} and T_{app} values (2060 in.-lb/in.^{2} and 23).

(2) The applicant used combined normal and faulted loadings in the flaw stability analysis to assess margins against pipe rupture at postulated faulted load conditions. The normal operating loads include pressure, deadweight, and thermal expansion; the faulted loads include the loads caused by SSE. In the worst loading case for the stability analysis, all individual normal and faulted loads were summed absolutely. The highest stress location is close to the cold leg for loop 2 and loop 3 lines and is about in the middle for loop 4 line. All these governing locations are welds of the submerged arc weld (SAW) type. There were no critical locations identified in the loop 1 line.

(3) CPSES Unit 2 has RCS pressure boundary leak detection systems that satisfy the guidelines of Regulatory Guide 1.45 so that a leakage of 1 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 staff determined that the margin is a factor of 10 on leakage and is consistent with NUREG-1061.

(4) The applicant showed that the postulated leakage flaw is stable under normal plus SSE loads. The safety margin in terms of applied loads was shown to be 1.0, which is appropriate since all applied loads were added absolutely according to NUREG-1061.

(5) The staff determined that the margin between the leakage-size flaw and the critical-size flaw exceeds 2 for the load combination for each accumulator line. The margin satisfies NUREG-1061.

(6) From comparing major geometric and operational parameters of Unit 2 to those assumed for a generic fatigue analysis, Westinghouse concluded that the fatigue crack growth analysis for the generic case can be applied to Unit 2. The generic fatigue analysis showed that the fatigue usage factors are within the ASME Code allowable value of 1.0. Although Unit 2 is not in operation and does not have records showing no stress corrosion cracking or water hammer problems in the accumulator line, good operating histories of other Westinghouse plants help the staff to conclude that stress corrosion and water hammer are not issues for Unit 2.

On the basis of the technical procedures and criteria of the LBB evaluation defined in NUREG-1061 and the ASME Code (Section XI, Appendix C), the staff concludes that eliminating accumulator injection line rupture as the structural design basis is acceptable. The loop 1 line is adequate because no governing (critical) locations can be identified in that line; the loop 2 and loop 4 lines are adequate because ample safety margins exist based on limit load analysis; and the loop 3 line is adequate based on a tearing instability analysis.

Independent Staff Calculations

The staff performed independent leakage rate and flaw stability calculations to evaluate the applicant's LBB analyses of the accumulator lines. The applicant's leakage flaw size calculated for the loop 3 line is close to the staff's value, but the applicant's critical flaw size is larger than the staff's due to a difference in calculating the "Z" factor. The applicant used the actual outer diameter of the piping (10 inches) in the Z-factor formula instead of the value of 24 inches required by the ASME Code. If the Code was followed exactly, the margin would be 1.85 instead of 2.1.

Staff discussions with the applicant (documented by the applicant's December 4, 1992 letter) identified that the applicant had performed a flaw stability calculation in WCAP-13167 for the loop 3 cast stainless steel injection nozzle using a J/T analysis. This analysis showed that unstable crack propagation would not occur with a postulated critical size flaw of 2 times the calculated leakage flaw. The applicant stated that the J/T analysis used greater stresses than would be applied in a similar analysis of the loop 3 piping; therefore, the applicant stated that the J/T analysis of the nozzle bounds the loop 3 piping. The staff reviewed the WCAP-13167 analysis and the information provided in the applicant's December 4, 1992, letter, and determined that the margin provided by the J/T analysis on the cast stainless steel injection nozzle bounds the wrought stainless steel piping. Therefore, the staff's concern regarding the discrepancy between the staff's and the applicant's limit-load analyses (using differing Z-factors) was resolved.

Conclusion

The staff concludes that the applicant's LBB analysis is consistent with the criteria in NUREG-1061, Volume 3. Thus, the probability of large pipe breaks occurring in the accumulator injection lines is sufficiently low that dynamic effects associated with postulated pipe breaks need not be considered in the design basis. The applicant may eliminate accumulator injection line rupture from the structural design basis for CPSES Unit 2.

3.6.2 Outside Containment

In Section 3.6.2 of SSER 6, the staff referenced the applicant's letter of January 5, 1984, (TU Electric letter TXX-4092 to NRC) and in part, based some of its conclusions on information in that letter. In FSAR Amendment 87, the applicant provided updates and clarifications which revised some of the information that the staff reviewed in the January 5, 1984, letter. The change provides as-built clarifications and corrections and updates the high-energy-line seismic criteria discussed in the January 5, 1984, letter. The staff has reviewed the additional information and concludes that it does not change the conclusions reached in Section 3.6.2 of SSER 6.

3.7 Seismic Design

3.7.2 Seismic Structural System and Subsystem Analysis

Computer Programs Used in Dynamic and Static Analyses

In a letter of February 28, 1992 (TU Electric letter TXX-92082 to NRC), the applicant submitted Amendment 84 to the Comanche Peak Steam Electric Station (CPSES) Final Safety Analysis Report (FSAR). The applicant stated that it used the computer program SAPCAS (ME-215) for performing local stress analysis of ASME Section III piping integral welded attachments (IWAs) at CPSES Unit 2. The staff had not previously reviewed and approved this code for use. The applicant had previously employed computer program ME-214 in the IWA analysis. ME-215 was used in lieu of ME-214 for cases in which ME-214 results exceeded the allowable limits. Therefore, the applicant was asked to provide verification and validation documentation of ME-215 computer program.

On June 23, 1992, based on the staff's preliminary review of ME-215 documents at Bechtel Corporation, Gaithersburg, Md; the staff requested additional information since the complete documentation of ME-215 was not available for review at that time. In letters of August 12, 1992, (TU Electric letter TXX-92353 to NRC), and October 7, 1992 (TU Electric letter TXX-92473 to NRC), the applicant responded to the staff's request for additional information and provided verification documentation of ME-215. The applicant's submittal included: (1) ME-215 User and Theory Manual, "Stress Analysis for Pipe Component and Pipe Support Using Finite Element Method (SAPCAS)," Revision 0, April 1991; (2) Comanche Peak Unit 2 Calculation No. 2-NP-GENX-544, "Reconciliation of Local Stress Evaluation Using ME-215 Analysis"; (3) Bechtel ME-215 Validation Manual, Revision 0, April 1991 with microfiche of the benchmark problems computer output; and (4) the applicant's responses to the staff's concerns.

Evaluation

The staff has reviewed the applicant's response to the staff's request for additional information, and verification documentation of computer program ME-215 submitted by letter of August 12, 1992 (TU Electric letter TXX-92353 to NRC). The review focused on the method of validation of the program and results of analyses associated with the benchmark test problems.

The applicant stated that computer program ME-215 was developed based on the widely known SAP program using linear finite element methods. ME-215 is a special purpose program for computing local piping stresses at pipes, pads, attachments, and welds. The limitations and input instructions are given in detail in the users manual.

In the Validation Manual, the applicant verified the program for four piping attachment configurations: (1) circular pipe attachment welded to a circular run pipe or elbow with or without a pad (VER-E1, VER-E2, VER-E5 and VER-E7), (2) rectangular tube attachment welded to a circular run pipe with a pad (VER-E3),

(3) rectangular solid attachment welded to a circular elbow with no pad (VER-E4), and (4) square tube attachment welded to a square run tube with no pad (VER-E6). The verification was performed for 14 problems and a total of 71 load cases. The applicant compared the ME-215 results with (1) results obtained by using the ANSYS Version 4.4 program, (2) results obtained by using ME-214, and (3) theoretical and experimental results of ASME publications.

Comparison of ANSYS Results

The staff's review indicated that ME-215 maximum stresses vary in comparison to ANSYS results from +14% to -11% for the benchmark problems VER-1 to VER-7. In summary, the staff finds that the maximum stresses obtained by ME-215 using default mesh generation are in most cases conservative. However, for some cases, ME-215 produced nonconservative results. The applicant performed an audit on ME-215 and concluded that the default mesh generation is adequate at welds, attachments, pads, and piping near attachments, but may not be adequate at the pipe near a pad. In response to this concern, the applicant developed calculation 2-NP-GENX-544 which presented a method of reconciliation of ME-215 results. The reconciliation was performed based on the comparison of ME-215 and ANSYS results using a rectangular tube attachment welded to a circular run pipe with a pad of two different weld sizes (1/4 inch and 3/16 inch), one greater than the pipe thickness (0.216 inch) and the other smaller. Two basic models using 3D solid isoparametric elements were employed in the ANSYS analysis. The ME-215 analysis consisted of five model configurations: three for 1/4 inch pad weld with 1, 2 and 3 layers and two for 3/16 inch weld with 1 and 2 layers. A modification factor was derived from maximum stress ratios of ANSYS to ME-215 results. The applicant applied the modification factor to 22 anchor analyses. The staff reviewed the results and concluded that ME-215 yielded conservative results after applying the modification factor. Based on its review, the staff finds the methodology of reconciliation regarding the scaling-up of under-estimated results based on ANSYS results to be acceptable. Therefore, the staff concludes that the use of ME-215 is acceptable provided that the final results are reconciled in accordance with the proposed method in calculation 2-NP-GENX-544 for the conditions specified in the calculation.

Comparison of ME-214 Results

Section 3.2 of the Validation Manual compares the primary plus bending stress intensity calculated by ME-214 and ME-215 for five of the seven main geometry configurations available in ME-215. The results show that the ME-214 calculated stresses are higher than ME-215 results by a factor from 1.23 to 2.50 for eight selected problems. The deviations between ME-215 and ME-214 results mentioned above were discussed with the applicant. The staff concurred that ME-214, which was coded according to Welding Research Council (WRC) Bulletin No. 107, is conservative because the WRC methodology was intended to be conservative for use by design analysts as a "cook book." Based on the eight sample problems, the staff agreed that ME-215 results using finite element method are bounded by ME-214 results.

Comparison of ASME and ORNL Results

On the basis of the staff's review, the maximum stresses obtained using ME-215 agree with results of theoretical finite element results (Problem VER-A1) and experimental results (Problem VER-A2) of ASME publication, "1972 Computer Programs Verification," and the experimental ORNL results supplied by the applicant. However, the results of Problem VER-A2 with a pad are lower by 80 percent with an applied force and by 40 percent with an applied moment than the ASME results given in ASME Publication No. PVP-169, "Stress Indices for Hollow Circular Trunnions Locally Reinforced with Pads." The method of reconciliation of membrane plus bending stress described in 2-NP-GENX-544 addresses this concern. In summary, the staff finds that ME-215 results are acceptable for cases in which the IWA has no pad or has a pad not thicker than the pipe. For cases in which the pad is thicker than the pipe wall, the staff concludes that the use of ME-215 is acceptable subject to the reconciliation proposed in calculation 2-NP-GENX-544 as discussed above.

Adequacy of Default Automatic Mesh Generation

The staff compared stress profiles generated by ME-215 which used the same model but varied the mesh size. On the basis of this review, the staff finds that the default automatic mesh generation is acceptable based on (1) the stress profiles nearly coincide with those utilizing finer meshes and (2) the maximum stresses at the edge of the attachment juncture where the actual weak link is located, are within an acceptable range in comparison with the results of a finer mesh.

Conclusion

The staff concludes that computer program ME-215, Revision 0, is acceptable for use in piping local stress analyses at CPSES Unit 2 subject to the conditions that (1) results from ME-215 analyses are reconciled in accordance with Section 5 of 2-NP-GENX-544 and (2) users adhere to those conditions specified in the program users manual.

3.7.3 Seismic Subsystem Analysis

In Amendment 87 to FSAR Section 3.10B, the applicant identified its use of damping values of 4% and 7% for Thermo-Lag upgraded safety-related conduits, in lieu of the 2% and 3% design basis damping values for OBE and SSE respectively, for electrical conduit support systems at CPSES that were found to be acceptable in the SER. In accordance with Regulatory Guide (RG) 1.61, "Damping Values For Seismic Design of Nuclear Power Plants," Regulatory Position C.2, damping values higher than the ones delineated in Table 1 of RG 1.61 may be used in a dynamic seismic analysis if documented test data are provided to support higher values. The staff reviewed an attachment to the licensing document change request (LDCR-SA-92-822), which initiated the change to the FSAR, which provided additional information supporting use of the higher damping values. However, the staff found that the information provided in the LDCR attachment was not conclusive regarding the use of higher damping values for safety-related conduits at CPSES.

By letter dated January 19, 1993 (TU Electric letter TXX-93038 to NRC), the applicant indicated that only design basis damping values of 2% and 3% were used for safety related conduit systems at CPSES Unit 2. Therefore, the staff concludes that the FSAR changes on damping values do not impact the structural integrity of electrical conduit systems at CPSES Unit 2. The staff is continuing its evaluation of the applicant's FSAR change for application to Unit 1 and future modifications on Unit 2, and will provide resolution of this issue by separate correspondence.

3.9 Mechanical Systems and Components

3.9.1 Special Topics for Mechanical Components

3.9.1.1 NRC Bulletin 88-08

In a letter of October 20, 1992 (TU Electric letter TXX-92500 to NRC), the applicant updated its response to NRC Bulletin 88-08, "Thermal Stresses in Piping Connected to Reactor Coolant Systems." Action 3 of Bulletin 88-08 requested that licensees offer continuing assurance that unisolable sections of piping connected to the reactor coolant system will not be subjected to thermal cycling from valve leakage that could cause fatigue failure during the life of the plant. The bulletin presented three options for providing this assurance: (1) redesigning and modifying these sections of piping to meet the ASME Section III Code requirement, (2) instrumenting this piping to detect adverse temperature distributions, or (3) providing means for ensuring that pressure upstream from block valves does not exceed RCS pressure. The NRC provided guidelines for implementing Action 3 in Appendix EE to SSER 25.

The applicant stated in the October 20, 1992, letter that it had implemented a program utilizing the second option given above. The applicant submitted descriptions of the program, based on monitoring guidelines developed by Westinghouse, in letters of August 9, 1989 (TU Electric letter TXX-89566 to NRC), September 18, 1989 (TU Electric letter TXX-89710 to NRC), and March 27, 1990 (TU Electric letter TXX-90113 to NRC). The response included a Westinghouse study, WCAP-12258, Supplement 2, "Evaluation of Thermal Stratification for Comanche Peak Unit 1 Residual Heat Removal Lines." The applicant had installed resistance temperature detectors (RTSs) on Unit 1 piping and declared the data acquisition system operational on March 10, 1990. During the first fuel cycle, the applicant collected temperature data for a baseline temperature history. Westinghouse Electric Corporation reviewed these data and concluded that there was no evidence of cyclic valve leakage in the unisolable piping. By letter dated January 20, 1993 (TXX-93026), the applicant stated that it had completed installation of the temperature detectors, data acquisition system, and interconnecting wiring in Unit 2. The applicant stated that it will monitor temperatures using the guidelines for data collection and evaluation given in SSER 25.

The staff has reviewed the applicant's submittals and finds that the methodology used to provide assurance that unisolable sections of piping will not experience abnormal thermal cycling is consistent with the guidelines given in SSER 25. Accordingly, the staff concludes that the applicant has satisfied the provisions of Action 3 of Bulletin 88-08.

Action 2 of Bulletin 88-08 required licensees to examine nondestructively sections of piping that may have been subjected to excessive thermal stresses.

These examinations are designed to provide assurance that no flaws exist. The applicant updated its response to Action 2 by letter dated January 28, 1993 (TU Electric letter TXX-93071 to NRC). The applicant stated that it had performed preservice inspections on CPSES Units 1 and 2 and inservice inspections on Unit 1. The inservice inspections did not identify any flaws. Based on the preservice and inservice inspections, the applicant and Westinghouse concluded that a crack would not be initiated by thermal fatigue during the relatively short time that Unit 2 has been at elevated temperature. Therefore, the staff agrees that nondestructive examination is not required for CPSES Unit 2.

Accordingly, the staff concludes that all actions of Bulletin 88-08 have been satisfied for Unit 2.

3.9.3 ASME Code Class 1, 2, and 3 Component and Component Supports

ASME Code Cases

In a letter of October 23, 1992 (TU Electric letter TXX-92499 to NRC), the applicant proposed a revision to FSAR Sections 3.7B and 3.9N.3.1.1, and Table 3.9B.1F to use American Society of Mechanical Engineers, Boiler and Pressure Vessel Code (ASME Code), Code Cases N-411 and N-318, for Unit 2 application.

ASME Code Case N-411 gives alternative damping values in lieu of the damping values specified in Regulatory Guide (RG) 1.61, "Damping Values for Seismic Design of Nuclear Power Plants," for response spectra analysis of ASME III Class 1, 2, and 3 piping. This code case was determined to be suitable for NRC staff use in RG 1.84, "Design and Code Case Acceptability, ASME Section III, Division 1," as referenced by 10 CFR 50.55a. The use of the code case for CPSES is acceptable provided the conditions in the regulatory guide are satisfied. The applicant used Code Case N-411 for the stress analysis of safety-related piping at CPSES Unit 1. The NRC approved the use of Code Case N-411 at CPSES in SSER 21 on the basis of commitments the applicant made which were in conformance with Regulatory Guide 1.84. On the basis of its review, the staff finds that the use of Code Case N-411 is acceptable for CPSES Unit 2 ASME Class 1, 2, and 3 piping analyses.

ASME Code Case N-318 provides procedures for evaluating the design of rectangular cross-section attachments on ASME III Class 2 and 3 piping. This code case is also referenced in RG 1.84 an is acceptable for CPSES subject to the conditions specified in the regulatory guide. The applicant noted the location of each pipe support to which the code case is applied and the method of attachment in Table 3.9B-1F of the FSAR. This satisfies the conditions specified in RG 1.84 for approval of Code Case N-318. The staff concludes that the use of Code Case N-318 is acceptable for CPSES Unit 2 ASME Class 2 and 3 rectangular piping attachments.

Bulletin 88-05

NRC Bulletin 88-05 and its supplements requested holders of construction permits and operating licenses to (1) submit information regarding materials purchased from Piping Supplies, Incorporated (PSI) at Folsom, New Jersey; West Jersey Manufacturing Company (WJM) at Williamstown, New Jersey; and Chews Landing Metal Manufacturers (CLM), (2) take actions to ensure that the materials comply with the American Society of Mechanical Engineers (ASME) Code and design specification requirements or are suitable for their intended service, or (3) replace such materials. The NRC action was precipitated by the discovery that certified material test reports (CMTRs) for material supplied by WJM, PSI, and CLM contained false information. A number of CMTRs were apparently used to certify that commercial-grade steel met the requirements of ASME Code Section III, Subarticle NCA-3800.

The applicant responded to Bulletin 88-05 for CPSES Unit 1, on October 10, 1988 (TU Electric Engineering Report ER-ME-18, Rev. 0), January 11, 1989 (TU Electric letter TXX-89005 to NRC), and March 31, 1989 (TU Electric letter TXX-89163 to NRC). In response to a request for additional information from the staff, the applicant submitted additional clarifying information on January 26, 1990 (TU Electric letter TXX-90039 to NRC), February 2, 1990, (TU Electric letter TXX-90059 to NRC), and March 2, 1990 (TU Electric letter TXX-90088 to NRC), enabling the staff to complete its review for Unit 1. The applicant stated that CPSES had transmitted all required information in response to Bulletin 88-05 for Comanche Peak Unit 1, and that additional information based on the results of the location, identification and testing of WJM/PSI flanges for Unit 2 would be provided before Unit 2 fuel load. The staff completed and issued an evaluation of Bulletin 88-05 response for Comanche Peak Unit 1 in SSER 24.

The applicant responded to the requirements of Bulletin 88-05 for CPSES Unit 2 on September 24, 1992 (TU Electric letter TXX-92450 to NRC). The staff reviewed the applicant's submittal and found that the information was insufficient to fully evaluate the structural adequacy of the nonconforming flanges. In response to requests from the staff, the applicant submitted additional clarifying information in submittals of December 22, 1992 (TU Electric letter TXX-92631 to NRC), and January 8, 1993 (TU Electric letter TXX-93016 to NRC), enabling the staff to complete its review. The staff's review and evaluation of the applicant's response to Bulletin 88-05 for CPSES Unit 2 follows.

OVERVIEW SUMMARY

The staff has reviewed the applicant's responses to NRC Bulletin 88-05 which describe the applicant's activities with respect to identifying, locating, and testing nonconforming flanges and fittings supplied by PSI, WJM, and CLM and evaluating their adequacy and suitability for their intended service.

The applicant conducted a comprehensive program to identify and locate materials supplied by PSI, WJM, and CLM. Initially, the applicant conducted an in-depth document review and field inspection. Comanche Peak had received a total of 466 flanges from WJM and PSI; no items were supplied by CLM.

Of the 466 WJM and PSI flanges received at CPSES, 138 were found in site warehouses, 102 were verified to be installed in Unit 1 safety-related systems, 84 were verified to be installed in Unit 2 safety-related systems, and 142 were either scrapped or installed in non-safety-related systems. The document review and field inspection of Unit 2 also revealed that no WJM or PSI material was installed in any ASME Code Class 1 piping system.

The 84 WJM and PSI flanges installed in Unit 2 safety-related systems were hardness tested and the findings were as follows:

- Low hardness . . . . 22 flanges
- High hardness . . . . 8 flanges
- Satisfactory hardness . . . . 51 flanges
- Scrapped . . . . 3 flanges

Stress analyses were performed for each of the 22 safety-related items in Unit 2 that had tensile strengths below the minimum required tensile strengths given in the ASME Code Section III (66 ksi (137 BHN) for ASME SA-105 material and 70 ksi (147 BHN) for SA-350 LF2 material). The 22 items consist of:

- 14 carbon steel SA105 flanges
- 8 carbon steel SA350 LF2 flanges

Structural evaluation of the nonconforming flanges was based on the assumption that the reduced flange capacity is linearly dependent on the yield strength of the material. Details of the evaluations are contained in the applicant's report of January 8, 1993 (TU Electric letter TXX-93016 to NRC), which is based on the qualification procedure described in the Bechtel generic analysis report.

On the basis of its review of the submittals, the staff finds that the applicant was responsive to the action and reporting requirements of Bulletin 88-05, and that the applicant has qualified all nonconforming parts in CPSES Unit 2 as being suitable for their intended service. The staff concludes that the identification program and the results of the tests and analytical procedures used by the applicant to qualify the nonconforming parts provide an adequate basis for resolving the concerns expressed in Bulletin 88-05 with respect to demonstrating adequacy for service.

<u>DESCRIPTION AND EVALUATION OF APPLICANT'S RESPONSE</u>

<u>Evaluation of Applicant's Identification Efforts</u>

In response to Bulletin 88-05 and its supplements, the applicant identified the safety-related materials that were purchased from WJM and PSI for CPSES. No material was supplied by CLM.

The identification activities conducted by Comanche Peak Engineering (CPE) were not limited to any specific time frame or to any specific list of suppliers, vendors, fabricators, or manufacturers. In the March 2, 1990, submittal, the applicant verified that, in addition to ASME Code Class 2 and 3 material records, Code Class 1 material records were also reviewed. Approximately 2655 documents were reviewed during this effort to identify the material.

The following records were reviewed to identify and locate any PSI, WJM, and CLM material:

- Purchase Orders
- Material Receiving Reports
- Manufacturer Record Sheets
- Receipt Inspection Reports
- Piping Subassembly Reports
- N-Stamped Component Records
- Records for NPT Stamped Items
- Heat Card Files
- N-5 Code Data Reports
- Line Designation Lists
- Flow Diagrams
- Piping Isometric Drawings
- Nuclear Network Reports
- Warehouse Issue Reports

• Material Heat Logs

To complete the location phase, the following computer programs/printouts were also utilized during this review:

• Plant Information Management System (PIMS)
• Line List System
• Warehouse Issue Report
• N5M Master Report

The review identified the following:

(1) Only WJM and PSI flanges were received at CPSES; no CLM material or other product forms were received at CPSES.

(2) Three different materials (SA-105, SA-350 LF2, SA-182 F304) were received at CPSES.

(3) Material was received from 9 different suppliers (Tyler-Dawson, ITT Grinnell, Gulf Alloy, Guyon Alloys, Capitol DuBose, A&G Engr., Joseph Oat Corp., P. X. Engr. (TDI), Hub and Rockwell).

(4) Flange sizes ranged from 1/2 inch to 24 inches and pressure ratings from 150 lb to 2500 lb.

(5) Four hundred sixty-six (466) WJM/PSI flanges were identified. Of this total flange population, 138 were found in site warehouses and were disposed of as follows: 106 flanges were placed on hold in site warehouses, 27 warehoused flanges were shipped off site for testing, and 5 warehoused flanges were donated to Bechtel to support a generic laboratory test program. One-hundred two (102) flanges are installed in Unit 1 safety-related systems, 84 in Unit 2 safety-related systems, and 142 are either scrapped or installed in non-safety-related systems.

(6) The 84 flanges installed in Unit 2 safety-related systems were identified and located by using the N-5 data packages and the Unit 2 material takeoff database. These flanges are SA-105 and SA-350 LF2 materials from 21 heats, and did not include stainless steel material.

Material was identified by using the Brown and Root N5M master report (heat no. log) and heat card file. Brown and Root discontinued this report in October 1984, but continued to maintain the heat card file.

In addition, heat numbers for WJM, PSI and CLM material that were reported over the nuclear network were checked against the heat card file to determine if that heat number had been received at CPSES.

For identification of material which was incorporated into NPT stamped piping subassemblies from ITT Grinnell and Southwest Fabricators (ITT Grinnell and Southwest Fabricators supplied all of the CPSES ASME Code Class 2 and 3 piping subassemblies), a large bore line number takeoff was made using the line list system report.

A mark number takeoff was made from the flow diagrams to identify material which was incorporated into other NPT stamped items, N-stamped components, and skid-mounted equipment.

On the basis of its review of the applicant's responses, the staff finds that the applicant conducted a thorough and comprehensive search to identify and locate nonconforming flanges and fittings supplied by PSI, WJM, and CLM in response to the requirements of Bulletin 88-05 and Supplements 1 and 2. The staff also finds that the applicant was responsive to the action and reporting requirements of Bulletin 88-05 and Supplements 1 and 2, and that there is a high probability that all nonconforming flanges and fittings have been identified.

The staff concludes that the applicant's identification efforts provide an adequate basis to resolve the nonconforming material identification concerns described in Bulletin 88-05 and are acceptable.

Evaluation of Applicant's Test Program

Bulletin 88-05 required the applicant to provide assurance that materials supplied by PSI, WJM, and CLM meet the proper specification requirements. The applicant responded by developing and conducting a test program to

- Develop a specific in situ testing program in accordance with guidelines developed by NUMARC.
- Conduct hardness testing on safety-related, installed components.
- Conduct chemical testing on representative material samples from heat numbers of installed components.
- For comparison purposes, conduct independent testing on 27 flanges common to the NUMARC program.

The NUMARC program included comprehensive laboratory testing of PSI, WJM, and CLM items contributed by the utilities and in situ testing of installed items. The applicant contributed 5 stock flanges for the NUMARC laboratory testing. For comparison purposes, the applicant conducted hardness, tensile, and chemical tests on 27 flanges common to the NUMARC Laboratory Test Program.

For ferritic steels, the principal attribute is strength, which can be evaluated by hardness testing. Thus, by demonstrating an appropriate tensile strength through hardness testing, an item satisfactorily tested and inspected after welded installation would be considered acceptable. The applicant performed field hardness tests on each of the 84 WJM and PSI flanges installed in Unit 2 safety-related systems. In addition, the applicant developed an Equotip to tensile strength conversion table. Each flange was categorized as having low or high hardness based on the results of the in situ hardness tests. Each of the 22 flanges that were found to have low hardness values was further evaluated on a case-by-case basis to determine acceptability.

The acceptance criterion used by the applicant for WJM and PSI material is based on existing hardness to tensile conversion tables in ASTM A370 (i.e., 137 to 187 Brinell Hardness Number (BHN) for SA-105 and maximum 197 BHN for SA-350 LF2). A conservative value of 147 BHN was used as the low value criterion for SA-350 LF2. This value is not delineated in the applicable Code or specification, but correlates to the minimum required ultimate tensile strength of 70 ksi.

The results of the Equotip hardness testing performed on the 84 WJM and PSI carbon steel flanges installed in Unit 2 safety-related systems are summarized as follows:

- Low hardness . . . . 22 flanges
- High hardness . . . . 8 flanges
- Satisfactory hardness . . . . 51 flanges
- Scrapped . . . . 3 flanges

All of the 22 flanges with low readings were deemed to be acceptable after an analytical engineering evaluation utilizing the methodology developed in the "Report on Generic Analysis and Evaluation of Suspect Material Identified in NRC Bulletin 88-05," prepared for NUMARC/EPRI by Bechtel, dated July 21, 1988. All of the 8 flanges with high hardness values were accepted after the applicant evaluated the weldability and brittle fracture properties of the flanges and found them acceptable. The high hardnesses measured were below that which is normally associated with brittle material. Also, there were five heats of material (DD, J69D, T1404G, 86861, and B3281) with erratic hardness results. Flanges initially identified with the lowest hardness value from each heat were retested for chemical analysis and hardness values and were found acceptable. The hardness retests resulted in higher hardness values and less variation within their respective heats.

Chemical analyses were performed for the six heats of material representing the 22 low hardness flanges. This testing, together with the testing performed earlier for the NUMARC program, is sufficient to resolve the concerns regarding nonconforming chemistry for the material installed in safety-related systems. The results of these laboratory chemical analyses indicate that the material is within the required ASME specifications. A review of the hardness variations within the individual heats indicates that the chemistry values adequately represent the installed items and that the heats are not mixed with fraudulent steel flanges.

The various test programs were performed to confirm that the installed materials met required specifications and to identify any items that may need to be replaced. The methods selected for in situ testing were intended to screen out nonconforming materials and verify that the specified materials were furnished.

The staff reviewed the test program and findings contained in the applicant's report and concludes that the testing was well planned and that the findings provide assurance that all suspect safety-related items have been identified.

Evaluation of Applicant's Structural Analyses of Nonconforming Parts

Table 1 of the January 8, 1993, submittal summarizes the engineering evaluations of the 22 low hardness flanges installed in safety-related systems of Unit 2. The 22 flanges have the following characteristics:

HEAT NO.	SYSTEM	SIZE	MATERIAL	INITIAL TEST BHN*	FIRST RETEST BHN*	SECOND RETEST BHN*
86861	FEEDWATER	4"-150#	SA-105	125.5	137	132
86861	AFW	4"-150#	SA-105	128.5		
86861	AFW	4"-150#	SA-105	130.5		
B32861	FEEDWATER	3"-1500#	SA-350 LF2	117	137	148
B32861	FEEDWATER	3"-1500#	SA-350 LF2	126		
B32861	FEEDWATER	3"-1500#	SA-350 LF2	130		
B32861	FEEDWATER	3"-1500#	SA-350 LF2	130		
B32861	FEEDWATER	3"-1500#	SA-350 LF2	130		
B32861	FEEDWATER	3"-1500#	SA-350 LF2	138		
B32861	FEEDWATER	3"-1500#	SA-350 LF2	142		
B32861	FEEDWATER	3"-1500#	SA-350 LF2	144		
DD	SER. WTR.	10"-150#	SA-105	127	153.5	141
DD	SER. WTR.	10"-150#	SA-105	130.5		
J69D	EDG AIR	1"-150#	SA-105	128	187	199
M551701	FUEL OIL	1.5"-300#	SA-105	126		
M551701	EDG AIR	1.5"-300#	SA-105	126		
M551701	FUEL OIL	1.5"-300#	SA-105	127		
M551701	EDG AIR	1.5"-300#	SA-105	136		
T1404G	SER. WTR.	10"-150#	SA-105	121	147.5	145
T1404G	SER. WTR.	10"-150#	SA-105	127		
T1404G	SER. WTR.	10"-150#	SA-105	133		
T1404G	SER. WTR.	10"-150#	SA-105	134		

*Average of three Equotip values converted to BHN

The stress analysis and evaluation methodology for the 22 low hardness flanges are based on the generic analysis methods contained in the NUMARC/Bechtel generic report. The actual analyzed stresses in the flanges for the normal, upset, and faulted conditions was compared to the reduced allowable stresses based on the hardness measurements and were found to be acceptable.

Each flange was vibro-etched with a statement that the flange is to be used only in the specific application in which it is currently installed. The respective drawing was revised with the same statement for each flange.

Table 2 of the December 22, 1992 submittal lists 8 flanges that were found to have high hardness values. By comparison, in Unit 1, there were 20 flanges with high hardness. High hardness values in Unit 2 ranged from 191 to 238 BHN. Weldability and brittle fracture are the principal concerns affected by high hardness. Weldability of the high hardness flanges has been shown to be acceptable based on visual and/or nondestructive examination of the installed weld and an acceptable hydrostatic test. Also, these hardness values do not indicate phase transformations in the flanges. In addition, the flanges were able to sustain the loads resulting from installation of the bolts.

Conclusion

On the basis of its review of the applicant's submittals, the staff finds that the applicant conducted adequate material property tests and structural analyses of the nonconforming flanges using acceptable analytical methods and evaluation criteria. The staff also finds that the applicant was responsive to the action and reporting requirements of Bulletin 88-05, Supplements 1 and 2, and that the applicant has qualified all nonconforming parts as being suitable for the intended service.

The staff concludes that the analytical procedures used by the applicant to qualify the nonconforming parts and the results of the analyses serve as an adequate basis for resolving the concerns with respect to demonstrating adequacy for service. The staff does not consider the nonconforming parts to be ASME Code material. However, the staff finds that the use of this material is an acceptable alternative in accordance with 10 CFR 50.55a(a)(3)(ii) because full compliance with all specified requirements would result in hardship or unusual difficulties without a compensating increase in the level of quality or safety.

3.9.6 Inservice Testing of Pumps and Valves

In a letter of July 2, 1992 (TU Electric letter TXX-92302 to NRC), the applicant submitted the first 10-year interval IST program for pumps and valves. The IST program included in this submittal supersedes all previous revisions of the program and was given the designation Revision 0. Therefore, the evaluations below relate to Revision 0 of the new IST program and all relief request numbers correspond to the Revision 0 designation.

Revision 0 of the IST program identified one pump relief request and seven valve relief requests which apply to Unit 2. The NRC staff has determined with respect to six of the relief requests listed in the safety evaluation that the proposed alternatives are acceptable for implementation and authorized pursuant to 10 CFR 50.55a(a)(3)(i). In one relief request (V-5) that was denied, the proposed alternative testing does not appear to be consistent with single failure assumptions in the SAR. By letter dated January 21, 1992 (TU Electric letter TXX-93029 to NRC), the applicant committed to address this issue by July 1, 1993, either by submitting a revised relief request or withdrawing the request. The proposed testing should continue until the applicant determines the appropriate actions necessary to address this issue.

The safety evaluation for these relief requests is given in Appendix R of this supplement. The staff review of Revision 0 did not include verification that all pumps and valves within the scope of 10 CFR 50.55a and Section XI are contained in the IST program. Additionally, for the components included in the IST program, not all applicable testing requirements were verified.

3.11 <u>Environmental Qualification of Mechanical and Electrical Equipment</u>

<u>Definition of a Harsh Environment</u>

In the CPSES FSAR, part of the definition of a harsh environment is that the equipment is subject to a relative humidity value of 100 percent. Amendment 82 adds a note to the FSAR stating that if humidity is the only parameter that causes a component to be classified as being in a harsh environment, then the applicant would perform an evaluation to determine whether the equipment can perform its safety-related function when exposed to the postulated relative humidity environment. If the evaluation resulted in the conclusion that the performance of the equipment would not be degraded in an accident due to the high humidity, the equipment would be reclassified as being in a mild environment. As stated by the applicant in a letter of December 11, 1992

(TU Electric letter TXX-92572 to NRC), a record of this evaluation will be maintained through the life of the plant as is required by 10 CFR 50.49(j). The equipment will remain on the Master EQ List.

The staff has reviewed these changes to the FSAR and to the Environmental Qualification Program and finds that these changes are consistent with the staff's position on environmental qualification of electrical equipment as stated in Standard Review Plan Section 3.11.2 and are acceptable.

3.11.3 Staff Evaluation

3.11.3.3 Service Conditions

3.11.3.3.7 Mild Environment/Potentially Harsh Environment

The FSAR has been revised to exclude Class IE electrical equipment located in a mild environment from the Environmental Qualification Program. The FSAR and Environmental Qualification Program text were changed to emphasize that the Environmental Qualification Program applies to equipment located in a potentially harsh environment. Equipment located in a mild environment, by definition, will not experience environmental extremes that are worse than its normal and abnormal operating environment and is, therefore, not subject to the same qualification requirements. This equipment is included on the Master EQ List. The equipment located in mild environments is maintained by the CPSES maintenance, surveillance, and trending programs which will monitor any abnormal occurrences that may be exhibited by any equipment located in mild environments. Procurement documents are used to specify the aging requirements for equipment located in a mild environment.

The staff has reviewed these changes to the FSAR and to the Environmental Qualification Program. These changes will reduce the documentation requirements for equipment located in a mild environment. However, the revised program is consistent with Standard Review Plan Section 3.11.2, which describes the staff's position on equipment located in a mild environment. Therefore, the proposed changes are acceptable.

4 REACTOR

By letters of July 15, 1991 (TU Electric letter TXX-91241 to NRC), and February 28, 1992 (TU Electric letter TXX-92083 to NRC), the applicant proposed Amendment 84 to the CPSES FSAR to reflect the use of the optimized fuel assembly (OFA) and the removal of the boron dilution mitigation system from the Technical Specifications for CPSES Unit 2. This review also includes the applicant's response of August 19, 1992, to the staff's request for additional information (TU Electric letter TXX-92397 to NRC).

4.2 Mechanical Design

4.2.1 Fuel System Design

The Unit 2 fuel assembly design, described in the FSAR, is a 17x17 array of fuel rods, each having an outer diameter of 0.360 inch. This design is the so-called optimized fuel assembly and has been generically described in Topical Report WCAP-9500, "Reference Core Report 17x17 Optimized Fuel Assembly." This topical report was reviewed and approved as a generic reference (NRC letter of May 22, 1981). The applicant has used WCAP-9500 as a reference for the Unit 2 fuel assembly design; the fuel assembly design is, therefore, generically acceptable. Thus, the applicant need only satisfy the plant-specific information required by the WCAP-9500 SER.

Information supplied by the applicant in the FSAR relevant to the required plant-specific information is evaluated below.

Control Material Leaching

In FSAR Section 4.2.1.6 and in Table 4.1-1B, the applicant has specifically identified Ag-In-Cd as the absorber material to be used in Unit 2 control rods. Therefore, the concern with control material leaching from boron-containing control rods is not applicable to Unit 2.

Cladding Collapse

Using approved methods (WCAP-8377, "Revised Clad Flattening Model"), as stated in FSAR Section 4.2.3.1, the applicant has determined that cladding will not collapse within the anticipated fuel lifetime. Therefore, the applicant has satisfactorily demonstrated conformance to the collapse criteria.

Supplemental ECCS Calculations

The applicant has performed large-break loss-of-coolant accident (LOCA) analysis utilizing the 1981 version of the Westinghouse ECCS evaluation model (WCAP-9200-P-A, Revision 1) as stated in FSAR Section 15.6.5. The LOCA clad model issues, including the rupture temperature model, the flow blockage model, and clad ballooning, have been resolved by the 1981 version and meet the guidelines of NUREG-0630, "Cladding, Swelling, and Rupture Models for LOCA Analysis."

Structural Damage From External Forces

In FSAR Sections 4.2.3.4 and 4.2.3.5.2, the applicant has stated that the applied seismic and LOCA forces considered in the approved WCAP-9401 ("Verification Testing and Analyses of the 17x17 Optimized Fuel Assembly") are applicable to Unit 2 and that the fuel assemblies will maintain a coolable geometry during the combined seismic and double-ended LOCA conditions. Therefore, the response to this issue is acceptable.

Online Fuel System Monitoring

The applicant has described the online fuel failure detection system as discussed in FSAR Section 11.5.2.7.11 and in the response to NRC Question Q231.6 of January 31, 1979. The detector will continuously monitor the reactor coolant flow in the nuclear sampling system and will have a preset limit with a control room alarm that will activate if the limit is exceeded. The staff concludes that the fuel rod detection system and monitoring plan meet the SRP criteria and are acceptable.

Postirradiation Surveillance

The applicant has committed to visual surveillance of a sample of fuel assemblies that will be performed during refuelings in response to NRC Question Q231.6 of January 31, 1979. Additional inspections will be performed if significant anomalies are encountered. The staff finds that these commitments meet the SRP criteria and are acceptable.

The staff concludes that the fuel system design in FSAR Section 4.2, for Unit 2, is acceptable since use of OFA fuel has previously been generically approved and the applicant has responded satisfactorily to the plant-specific requirements.

4.3 Nuclear Design

Comanche Peak Unit 2 has a reactor based on the optimized fuel assembly design of WCAP-9500, which the staff has reviewed and approved generically. Based on the information contained in WCAP-9500, the Comanche Peak FSAR, amendments and the referenced topical reports, the staff conducted its review in accordance with guidelines in SRP Section 4.3. Compared to the Unit 1 17x17 low parasite (LOPAR) assemblies, the OFAs have a more optimum hydrogen to uranium moderation ratio and a decreased neutron parasite capture, which results in more efficient fuel usage. For Unit 2, the burnable absorber rods used are the wet-annular type instead of the pyrex glass type. The design methods for the nuclear analysis of the core use both TURTLE and PALADON for multi-dimensional analyses of Unit 2. Design bases are presented which comply with the applicable GDC.

4.3.2 Design Description

In the FSAR, the applicant describes the first-cycle fuel loading which consists of three different enrichments and has a first-cycle length of approximately one year, accumulating approximately 11,000 MWD/MTU per year. This FSAR section addresses power distribution, reactivity coefficients, control requirements, control rod patterns and reactivity worth, criticality of the reactor during refueling, and criticality of fuel assemblies, stability, and vessel irradiation. The staff reviewed the nuclear design of the Comanche Peak reactors in Section 4.3.2 of the SER (NUREG-0797). The applicant's use of OFA fuel in Unit 2 does not affect the staff's previous conclusions regarding the nuclear design of the Unit 2 reactor; therefore, its use is acceptable.

4.3.2.1 Power Distribution

In a letter of July 31, 1989, the applicant submitted Topical Report RXE-89-003-P, "Steady State Reactor Physics Methodology." The applicant developed this methodology to perform the steady-state reactor physics analyses required for design, licensing, startup, and operation of the Comanche Peak Steam Electric Station Units 1 and 2. In response to questions from the staff, the applicant submitted a letter on May 20, 1991 (TU Electric letter TXX-91198 to NRC), which stated that the analyses of Unit 1 and Unit 2 Cycle 1 cores would be performed in parallel with Westinghouse. The staff approved the methodology for Unit 1 for reload analyses only. In a letter of May 29, 1992 (TU Electric letter TXX-92238 to NRC), the applicant described changes to the FSAR, including a revision to reflect the use of this methodology for Unit 2 initial startup and reload cycles.

The staff approved the methodology for Unit 1 reload licensing analyses in a safety evaluation transmitted to the applicant by letter dated July 25, 1991. The staff focused its review on benchmarking against critical experiments and operational data from Catawba 1 Cycle 1 and 2 and Prairie Island 1 Cycle 5-10 cores. TU Electric has indicated that this operating reactor data base is typical of the expected Unit 2 core loadings. The calculational methods and procedures used in the benchmarking calculations are identical to those used in TU Electric licensing analyses. The reliability factors determined by the benchmarking comparisons may, therefore, be applied to the licensing calculation. On the basis of the conclusions of the staff's safety evaluation, the applicant's steady-state physics methodology is acceptable for Unit 2 licensing analyses for cores loaded with fuel similar to the fuel types included in the RXE-89-003-P data base.

4.3.3 Analytical Methods

The applicant has described the computer programs and calculational techniques used to obtain the nuclear characteristics of the reactor core. The Cycle 1 core design calculation consists of three distinct types performed in sequence: determination of effective fuel temperatures, generation of macroscopic few-group parameters, and space-dependent few-group diffusion calculations. The programs used for the Cycle 1 design have been applied as part of the applications for most earlier Westinghouse-designed nuclear plant facilities. Testing and operations support methodology has also been described. This methodology is employed to predict core characteristics required for physics testing and reactor operations. The predicted results using the described core design methodology and operation support methodology have been compared with measured core characteristics. The findings of these comparisons have validated the ability of these methods to predict experimental results. The staff, therefore, concludes that these methods are acceptable for use in calculating the nuclear characteristics of Unit 2.

4.4 Thermal-Hydraulic Design

The staff reviewed the thermal-hydraulic design of the OFA core for Unit 2. The review included the safety criteria, the design basis, and steady-state analysis of the core thermal-hydraulic performance. The review concentrated on the difference between the proposed design and the designs that have been found acceptable by the staff in the past. The applicant's thermal-hydraulic analyses were performed using the WRB-1 CHF correlation with the improved thermal design procedure (ITDP). The analytical methods and correlations used have been previously approved by the staff in a safety evaluation dated April 19, 1978.

The thermal-hydraulic design parameters for Unit 2 are compared with those of the Byron plants in Table 4.4-1B of the FSAR. The Unit 2 thermal-hydraulic design is almost identical to that of Byron, which has been previously reviewed and approved by the staff.

On the basis of its review, the staff concludes that the thermal-hydraulic design of the Unit 2 reactor initial core conforms to the guidance contained in Regulatory Guide 1.68, SRP Section 4.4, and the requirements of GDC 10, and is, therefore, acceptable.

4.6 Reactivity Control

Boron Dilution Mitigation System

In a letter of February 28, 1992 (TU Electric letter TXX-92116 to NRC), the applicant requested an amendment to the Unit 1 operating license (NPF-87) which would remove the boron dilution mitigation system (BDMS) setpoints from the Technical Specifications (TSs). The BDMS was developed to detect and mitigate a boron dilution event in Modes 3, 4, and 5 before a complete loss of shutdown margin. The system detects a boron dilution event by monitoring the output of the source range neutron flux detectors to determine if the neutron flux has increased by a specified multiplication factor over a prescribed time period. When a dilution event is detected, the BDMS isolates known dilution paths to the reactor coolant system and realigns the reactor makeup water system to the refueling water storage tank so that any additional makeup will result in boration of the reactor coolant.

For Units 1 and 2, TS 3.3.1, Table 3.3-1, Functional Unit 6.b, "Boron Dilution Flux Doubling," requires that this function be operable in Modes 3, 4, and 5. If not operable when required, Action 5 applies. The action requires, in part, that the reactor trip breakers be open, that all operations involving positive reactivity changes be suspended, and that the sources of possible dilution be isolated. Since changing the plant temperature is an operation that could add positive reactivity, this Action Statement could require that plant cooldown or heatup be suspended.

In response to a recent review of the analyses for the licensing basis boron dilution event for Unit 1, the applicant identified certain nonconservatisms related to the input assumptions and boundary conditions used by Westinghouse in the original design of the system. Specifically, the inverse count rate ratio (ICRR) and flux multiplication setpoint used in the analyses are not bounding. As a result, the licensing basis boron dilution event analysis which shows that the BDMS response will prevent a return to critical may not be applicable to either unit of Comanche Peak. Because of this, the applicant has declared the boron dilution flux doubling channels inoperable. The current TSs and Action Statement described above could prevent a plant restart following entry into Mode 3, 4, or 5. Therefore, the applicant proposed revised TSs for Units 1 and 2 which would remove the boron dilution flux doubling requirements.

On March 23, 1992, a meeting was held at NRC Headquarters and was attended by representatives from the NRC, TU Electric, and Westinghouse. According to the applicant, a potential long-term solution would be to relocate the source assemblies in the core. (NOTE: The Unit 1 sources were moved during their second refueling outage, and data were taken on Unit 1's startup, but the applicant's evaluation continues).

The staff did not feel that it was appropriate to approve the proposed amendment as a permanent change because of the contradiction with the staff position that requires positive actions to prevent an unplanned criticality due to boron dilution events. However, the staff did recognize that temporary relief was necessary for CPSES until the issue could be researched further and an acceptable long-term solution could be identified with more certainty. Therefore, the staff asked the applicant to propose a time limitation for the revised TSs and to discuss the compensatory actions that the applicant would take during this time period. The applicant submitted a letter on April 6, 1992 (TU Electric letter TXX-92169 to NRC) responding to this request.

The applicant has requested that the TS revisions proposed in the letter of April 6, 1992, remain in effect for Unit 1 until six months after criticality following the second refueling outage and for Unit 2 until six months following initial criticality. After this time interval, the boron dilution flux doubling requirements would again become effective. These durations are expected to allow sufficient time to research the issue, perform testing, propose a permanent resolution, and for the staff to review the proposed permanent resolution; therefore, the staff concurs with the proposed time limits. The revision to the Unit 1 TS was issued by the NRC on June 8, 1992, as an amendment to the Unit 1 license (this revision will be incorporated in the combined TS upon license issuance).

The applicant has proposed the following actions for the duration of the temporary revision to the CPSES TS:

(1) Within 4 hours of entry into Modes 3, 4, or 5 from Modes 1, 2, or 6 (and once every 14 days thereafter while in Modes 3, 4, or 5), the applicant will verify (unless startup is in progress) that either valve CS-8455 or valves CS-8560, FCV-111B, CS-8439, CS-8441, and CS-8453 are closed and secured in position; or

(2) Within 4 hours of entering Mode 5, the applicant will ensure that only one reactor makeup water pump (dilution source) is aligned to the supply header. Following entry into Modes 3, 4, or 5 from Modes 1, 2, or 6, each crew of the control room staff will receive a briefing to discuss the type of reactivity changes that could occur during a dilution event; the indications of a dilution event; and the actions required to stop a dilution, commence immediate boration, and establish the required

shutdown margin. For extended shutdowns, this briefing will be repeated for each crew before it resumes control room duties following an off-duty period that exceeds seven days. During time periods when this option is used, the source range will be monitored every 15 minutes for indication of unexplained increasing counts and inadvertent boron dilution.

These administrative actions will serve to isolate dilution flow paths by locking out valves from dilution sources or will restrict the maximum dilution flow rate by ensuring that no more than one reactor makeup water pump can supply water to the RCS during Mode 5 operation. The staff concurs that these administrative controls will reduce the probability of an inadvertent boron dilution event during the proposed temporary time interval for the revised TS.

In addition, the staff believes that the proposed interim actions will provide appropriate operator vigilance to reduce the probability of an inadvertent boron dilution in all three shutdown modes during the proposed time interval for the revised TS.

Westinghouse has performed new analyses for Units 1 and 2 with no credit for the BDMS which show at least 15 minutes exists from the initiation of an inadvertent boron dilution while operating in Modes 3, 4, or 5 before shutdown margin is lost. These are documented in the letters from J. L. Vota (W) to W. J. Cahill, Jr. (TU), WPT-14386 dated February 25, 1992, and D. R. Woodlan (TU) to NRC, dated August 19, 1992. These analyses offer reasonable confidence that the reactor operators have sufficient time during performance of their routine duties to identify and mitigate an inadvertent boron dilution event.

Even though credit is not taken for the BDMS, its use during operation provides additional assurance that an inadvertent dilution event will be detected and mitigated before a return to critical. In addition, other alarms and indications (as provided in Section 15.4.6.1 of the FSAR) are available to the operator which allow for the detection of an inadvertent boron dilution.

In view of these alarms and indications, together with the procedures, training, and activities previously mentioned, the NRC believes that reasonable assurance has been provided to minimize the likelihood of an inadvertent boron dilution event during the time interval proposed for the temporary TS revisions. Should such an event occur, these actions offer reasonable assurance of timely detection and mitigation.

5 REACTOR COOLANT SYSTEM

5.2 Integrity of Reactor Coolant Pressure Boundary

5.2.4 Reactor Coolant Pressure Boundary Inservice Inspection and Testing

5.2.4.2 Evaluation of Compliance With 10 CFR 50.55a(g) for Unit 2*

This evaluation supplements conclusions in Section 5.2.4.2 of the original Safety Evaluation Report and its supplements that addressed the definition of examination requirements and the evaluation of compliance with 10 CFR 50.55a(g). Section 50.55a(g) of 10 CFR Part 50 defines the detailed requirements for the preservice and inservice inspection programs for components of light-water-cooled nuclear power facilities. On the basis of the construction permit date of December 19, 1974, this section of the regulations requires the following: Components classified as ASME Code Class 1 and 2 must (1) be designed and have access to enable the performance of inservice examination and (2) meet the preservice examination requirements of the ASME Boiler and Pressure Vessel Code, Section XI, and addenda applied to the construction of the particular component. The components (including supports) may meet the requirements in subsequent editions and addenda of this Code that are incorporated by reference in 10 CFR 50.55a(b), subject to the limitations and modifications listed therein.

The basic preservice inspection (PSI) program for Unit 2 complies with the requirements of the 1983 Edition of Section XI of the ASME Code with the following exceptions:

(1) Among areas within the Unit 2 PSI boundary that were examined before the 1983 Code was adopted were the reactor vessel and 37 Class 1 piping welds in the reactor coolant and safety injection systems. These areas were examined in accordance with the 1980 Code.

    A review of the two editions of the Code reveals that such similarities exist that baseline documentation gathered under the 1980 Edition is acceptable under the rules in the 1983 Edition.

(2) To provide baseline examination that is consistent with the latest published edition of the Code, the applicant has elected to adopt ASME Code Case N-408, "Alternative Rules for Examination of Class 2 Piping,

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*This section was prepared with the technical assistance of Department of Energy (DOE) contractors from the Idaho National Engineering Laboratory.

Section XI, Division 1," for determining components subject to examination and for establishing examination requirements for Class 2 piping. The NRC approved Code Case N-408 by reference in Regulatory Guide 1.147, "Inservice Inspection Code Case Acceptability ASME Section XI Division 1."

The reactor pressure vessel welds requiring preservice inspection have been examined in accordance with the examination techniques of ASME Section V, Article 4, and were supplemented by additional requirements to address the intent of Regulatory Guide 1.150. The program for examination of the reactor vessel was submitted in a letter dated June 13, 1983 (TU Electric letter TXX-3686 to NRC) and was addressed in SER Supplement 4.

The staff evaluated "Comanche Peak Steam Electric Station, Unit 2, ASME Section XI Preservice Inspection Plan," Revision 0, as submitted on June 2, 1988, for (1) compliance with the appropriate edition/addenda of Section XI, (2) acceptability of examination sample, and (3) correctness of the application of system or component examination exclusion criteria. The staff requested additional information in order to complete the review. In a response of October 30, 1992 (TU Electric letter TXX-92540 to NRC), the applicant submitted a list of the welds and components receiving preservice examinations, isometric drawings, and the PSI requests for relief from the ASME Code Section XI requirements that the applicant has determined are not practical.

Evaluations of the relief requests contained herein (Appendix S) are all based on the October 30, 1992 submittal, except for Relief Request D-1, which was submitted on June 2, 1988. All of the relief requests were supported by information pursuant to 10 CFR 50.55a(a)(3). The staff evaluated these requests for relief and concluded that the applicant has demonstrated that either: (1) the proposed alternatives would provide an acceptable level of quality and safety, (2) compliance with the specific requirements of Section XI would result in hardships or unusual difficulties without a compensating increase in the level of quality and safety, or (3) no relief was required.

Having reviewed the applicant's submittals and having authorized relief from these preservice examination requirements, the staff concludes that the Preservice Inspection Program for the reactor coolant pressure boundary at CPSES Unit 2 is acceptable and in compliance with 10 CFR 50.55a(g)(2). The detailed evaluation supporting this conclusion regarding relief requests appears in Appendix S to this report.

The applicant has not submitted the initial ISI program. NRC regulations require that this plan be submitted within six months of the date of issuance of the operating license. The staff will evaluate the ISI program plan at that time based on 10 CFR 50.55a(g)(4), which requires that the initial 120-month inspection interval comply with the requirements in the latest edition and addenda of Section XI of the Code incorporated by reference in 10 CFR 50.55a(b) on the date 12 months preceding the date of issuance of the operating license.

6 ENGINEERED SAFETY FEATURES

6.2 Containment Systems

6.2.1 Containment Functional Design

In FSAR Amendment 87, the applicant added new information regarding LOCA and MSLB analysis results for Unit 2, and clarified unit applicability of existing related information. Unit 2 uses new mass and energy release rates provided by Westinghouse (Reference 17 in FSAR Section 6.2.1) which differs from the mass and energy release rates for Unit 1. Reanalysis for Unit 2 was performed as a result of the fuel design change using updated computer code LOFTRAN, which has substantially improved capabilities over the Marvel Code (used for Unit 1) for calculating mass and energy release data. For LOCA cases, Unit 2 also uses slightly different component cooling water (CCW) system flow rates (affecting the Residual Heat Removal and the Containment Spray System [CSS] heat exchangers) and 0.8 second longer CSS actuation delay time due to a larger CSS volume, which results in an increased system fill rate. The applicant indicated that due to the above differences, the containment peak pressure and temperature analyses for LOCAs and main steamline breaks were performed to provide Unit 2 specific results. The re-analyses were performed using the Stone and Webster LOCTIC code and assumptions described in SSER 22, Section 6.2.1 (accounting for the difference noted above).

For LOCA, the applicant considered a spectrum of pipe break locations and sizes similar to that in the previous analysis. For Unit 2, the peak containment pressure of 47.8 psig was calculated (compared to the previous result of 48.2 psig for Unit 1) for the same limiting break (i.e., the double-ended pipe rupture at the pump suction of the reactor coolant system). The above peak calculated value is within the containment-design pressure of 50 psig and is, therefore, acceptable.

For MSLBs, the applicant considered a spectrum of breaks at four power levels (102 percent, 70 percent, 30 percent and hot shutdown) similar to that in the previous analysis. For the various steam line breaks analyzed, the 0.942-ft^2 split rupture at 30-percent power resulted in the maximum containment-pressure and temperature of 41.9 psig and 345°F for Unit 2 (compared to the previous result of 42.4 psig, and 345°F for 0.908-ft^2 rupture at 70-percent power level for Unit 1). The maximum containment-pressure during MSLB remains lower than the design basis LOCA and the containment-design pressure of 50 psig. Also, the newly calculated Unit 2 pressure and temperature curves for LOCA and MSLB cases remain enveloped by the curves used for equipment calculations.

Based on the above, the staff concludes that the updated LOCA and MSLB analysis results specific for Unit 2 are acceptable as the peak values for pressure and temperature remain enveloped by the previous evaluated values using the codes and assumptions described in SSER 22.

6.2.5 Containment Leakage Testing Program

6.2.5.1 Relaxation of Airlock Leakage Testing From Technical Specification Requirement (Section III.D.2(b)(ii) of Appendix J to 10 CFR Part 50)

In Section 6.2.5.1 of SSER 12, the staff withdrew its acceptance of the applicant's request to relax the containment airlock leakage testing requirements [10 CFR Part 50 Appendix J, Section III.D.2(b)(ii)] because the regulatory procedures mandated for the issuance of an exemption to the regulations (10 CFR 50.12) had not been fulfilled. By letter of January 20, 1986, the applicant submitted additional justification to address the requirements in 10 CFR 50.12 in support of the exemption request. This issue was resolved in SSER 22 for Unit 1. The following applies to Unit 2.

The applicant has identified the special circumstances for granting this exemption pursuant to 10 CFR 50.12. The purpose of Appendix J to 10 CFR Part 50 is to ensure that containment leaktight integrity can be verified periodically throughout the plant service lifetime so as to maintain containment leakage within the limits specified in the plant Technical Specifications. In lieu of the requirements of Appendix J, Section III.D.2(b)(ii), the applicant proposed an alternative test method in Technical Specification 4.6.1.3.b.2, which requires that an overall airlock leakage test be conducted at pressure P_a before establishing containment integrity if maintenance has been performed on the airlock that could affect the airlock's sealing capability. The proposed alternative test method is sufficient to achieve the purpose of Appendix J in that it provides adequate assurance of continued leaktight integrity of the airlock. Because of this, the staff has previously granted comparable exemptions to other plants. Consequently, the special circumstances described by 10 CFR 50.12(a)(2)(ii) exist in that the regulation need not be applied in these particular circumstances to achieve the underlying purpose of the rule since the applicant has proposed an acceptable alternative test method that accomplishes the intent of the regulation.

On this basis, the staff concludes that the requested exemption is justified since the alternative test method proposed by the applicant is consistent with the guidelines of NUREG-0452, "Standard Technical Specifications for Westinghouse Pressurized Water Reactors" (Revision 4). Further, the staff finds that, in accordance with the requirements of 10 CFR 50.12(a)(2), the requested exemption represents special circumstances, as discussed above, and is consistent with the intent of Appendix J to 10 CFR Part 50 and is, therefore, acceptable. The Commission has determined that the granting of this exemption will not result in any significant environmental impact. The environmental assessment and finding of no significant impact were published in the Federal Register on January 19, 1993 (58 FR 5036).

6.5 Engineered-Safety-Feature Atmosphere Cleanup System

6.5.2 Containment Spray System

In FSAR Amendment 87, the applicant added information to clarify the similarities and differences in the containment-spray nozzle arrangements of Units 1 and 2. The applicant also updated the average spray drop distance (from 130 feet to 126 feet) and sprayed volumes and percentages (from a total sprayed percentage of containment free volume of 56.7% to 56.3%) due to HVAC obstructions which prevent the full development of some spray cones. The applicant summarized its calculation, stating that reducing the average spray drop fall height and sprayed volumes and percentages due to those nozzle obstructions will have no impact on the containment spray system's capability to perform its safety functions. These obstructed nozzles have only been removed from the analysis of the sprayed volumes and volume percentage. The nozzles have not been removed from service and will spray water into the containment building upon containment spray actuation. Based on the above, the staff concludes that the proposed change is acceptable as the containment spray effectiveness for heat removal, as stated in SSER 23, is still valid.

6.6 <u>Inservice Inspection of Class 2 and 3 Components</u>

6.6.2 Evaluation of Compliance With 10 CFR 50.55a(g) for Unit 2*

This evaluation supplements conclusions in Section 6.6.2 of the original SER and its supplements that addressed the definition of examination requirements and the evaluation of compliance with 10 CFR 50.55a(g). Section 50.55a(g) of 10 CFR Part 50 defines the detailed requirements for the preservice and inservice programs for components of light-water-cooled nuclear power facilities. On the basis of the construction permit date of December 19, 1974, this section of the regulations requires that the following: Components classified as ASME Code Class 1 and 2 must (1) be designed and have access to enable the performance of inservice examination and (2) meet the preservice examination requirements of the ASME Boiler and Pressure Vessel Code, Section XI, and addenda applied to the construction of the particular component. The components (including supports) may meet the requirements in subsequent editions and addenda of this Code that are incorporated by reference in 10 CFR 50.55a(b), subject to the limitations and modifications listed therein.

The "Comanche Peak Steam Electric Station, Unit 2, ASME Section XI Preservice Inspection Plan," Revision 0, as submitted on June 2, 1988, (TU Electric letter TXX-88464 to NRC) was evaluated for (1) compliance with the appropriate edition/addenda of Section XI, (2) acceptability of examination sample, and (3) correctness of the application of system or component examination exclusion criteria. The staff needed additional information to complete the review. In a response of October 30, 1992 (TU Electric letter TXX-92540 to NRC), the applicant sent a list of the welds and components receiving preservice examinations, isometric drawings, and the PSI requests for relief from the ASME Code Section XI requirements that the applicant has determined are not practical.

The basic PSI program for Unit 2 complies with the requirements of the 1983 Edition of Section XI of the ASME Code with the following exception: To provide baseline examination that is consistent with the latest published edition of the Code, the applicant has elected to adopt ASME Code Case N-408, "Alternative Rules for Examination of Class 2 Piping, Section XI, Division 1," for

*This section was prepared with the technical assistance of Department of Energy (DOE) contractors from the Idaho National Engineering Laboratory.

determining components subject to examination and for establishing examination requirements for Class 2 piping. The NRC approved Code Case N-408 by reference in Regulatory Guide 1.147, "Inservice Inspection Code Case Acceptability ASME Section XI Division 1."

All examinations that were applied to components within the Class 2 piping boundary as determined by IWC-1220 and Examination Category C-F of the 1983 Code were applied to the piping selected in accordance with N-408 (e.g., integral attachments, bolting, valve supports).

The Unit 2 PSI plan stated that it was the applicant's intent to examine twice the minimum number of Class 2 piping welds required by Code Case N-408 in order to provide a buffer should inservice conditions dictate selection of Class 2 welds outside the required baseline scope. Review of the program showed that the PSI examinations of the Class 2 piping systems easily exceeded the 7.5 percent minimum as required by Code Case N-408. However, comparison of the listing of the welds receiving PSI examinations and the isometric drawings provided in the October 30, 1992, submittal shows that some safety-significant Class 2 welds are not receiving examinations based on the wall thicknesses. The following are the staff's areas of concern:

(1) The residual heat removal (RHR) system piping on the discharge side of RHR pumps 1 and 2 contains a total of approximately 250 welds on 8-inch and 10-inch NPS Schedule 40 piping with wall thicknesses of 0.322 inch and 0.365 inch, respectively. The PSI examinations performed by the applicant were on the suction side of the RHR pumps where the 12-inch and 16-inch NPS pipe wall thicknesses are equal to or greater than 0.375 inch. When developing the inservice inspection plan, the applicant should consider redistributing the 7.5 percent sample to include volumetric examination of welds on the discharge side of the RHR pumps.

(2) The containment spray (CT) system piping on the discharge side of the four CT pumps contains approximately 77 welds (15-25 each loop) that are 10-inch NPS Schedule 40 with a wall thickness of 0.365 inch. As discussed above, when developing the inservice inspection plan, the applicant should consider redistributing the 7.5 percent sample to include volumetric examination of welds on the discharge side of the CT pumps.

Evaluations of the relief requests contained in this report (Appendix S) are all based on the October 30, 1992, submittal, except for Relief Request D-1, which was submitted on June 2, 1988. All of the relief requests were supported by information pursuant to 10 CFR 50.55a(a)(3). The staff evaluated these requests for relief and concluded that the applicant has demonstrated that either: (1) the proposed alternatives would provide an acceptable level of quality and safety, (2) compliance with the specific requirements of Section XI would result in hardships or unusual difficulties without a compensating increase in the level of quality and safety, or (3) no relief was required.

Having reviewed the applicant's submittals and having authorized relief from these preservice examination requirements, the staff concludes that the preservice inspection program for Comanche Peak Steam Electric Station, Unit 2, is acceptable and in compliance with 10 CFR 50.55a(g)(2). The detailed evaluation supporting this conclusion regarding the requests for relief appears in Appendix S to this report.

The applicant has not submitted the initial ISI program. NRC regulations require that this plan be submitted within six months of the date of issuance of the operating license. The staff will evaluate the ISI program plan at that time based on 10 CFR 50.55a(g)(4), which requires that the initial 120-month inspection interval comply with the requirements in the latest edition and addenda of Section XI of the Code incorporated by reference in 10 CFR 50.55a(b) on the date 12 months preceding the date of issuance of the operating license.

7 INSTRUMENTATION AND CONTROLS

7.1 General

Staff review of Amendment 79 to the FSAR revealed that the applicant proposed to eliminate GDC 54 applicability to the auxiliary feedwater instrumentation. The applicant committed to withdraw those proposed FSAR changes by letter of May 21, 1992 (TU Electric letter TXX-92249 to NRC). FSAR Amendment 86 was reviewed and verified that GDC applicability was reinstated to the appropriate instrumentation in Tables 7.1-2.3 and 7.1-2.4.

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. FSAR Amendment 87 was reviewed and verified that the table now lists the instrumentation with appropriate remarks. Table 7.3-4 was made consistent with Table 7.2-1.

Both of the above items were confirmatory items from SSER 25. The staff has reviewed the updates to the FSAR and finds them acceptable.

8 ELECTRIC POWER SYSTEMS

8.2 Offsite Power System

8.2.1 General Description

The SER and SSER 22 describe five 345-kV transmission lines from the offsite transmission network connected to the 345-kV switchyard. Four of these lines were connected before Unit 1 commenced operation. The applicant committed to connect the Benbrook line when Unit 2 goes into service. The installation of the Benbrook circuit has been completed. The FSAR was revised (Amendment 87) to reflect that the commitment that the circuit be installed before Unit 2 startup has been satisfied. Therefore, this item is acceptable.

8.3 Onsite Emergency Power Systems

8.3.1 AC Power Systems

Diesel Generator Post-24-Hour Load Testing

The FSAR text incorrectly described the post-24-hour load test for the diesel generators. As described, the post-24-hour load test involved simulating a loss of offsite power (LOOP) in conjunction with a safety injection actuation signal (SIAS). Information in FSAR Amendment 85 corrected this discrepancy by clearly indicating that the post-24-hour test only involved simulating a LOOP. Regulatory Guide (RG) 1.108, which is the basis for the diesel generator surveillance, recommends simulating a LOOP in conjunction with a SIAS to demonstrate that a diesel generator is capable of auto-starting, achieving rated voltage and frequency within a specified time frame, and demonstrating the shutdown load sequence for shutdown load requirements. For CPSES, as illustrated in FSAR Table 8.3-2, a LOOP is the most limiting diesel generator loading event in that it results in a load of approximately 6280 KW. While simulation of a LOOP in conjunction with a SIAS following the 24-hour load test would be consistent with the Standard Technical Specifications, Unit 1 was licensed with the more load-limiting simulation of a LOOP only.

Base on the above, the staff concludes that the post-24-hour load test for the diesel generators is consistent with that provided for Unit 1 and conforms to the intent of RG 1.108 in that it results in the most limiting diesel generator loading event and, as such, is acceptable.

8.4 Other Electrical Features and Requirements for Safety

8.4.4 Physical Identification and Independence of Redundant Safety-Related Electrical Systems

8.4.4.1 Minimum Physical Separation Criterion for Electrical Power Cable Circuits

Amendment 79 to the FSAR contained information that revised the minimum physical separation criterion for electrical power circuits. The previous minimum physical separation criterion for power circuits required a physical separation distance of 1 inch and two physical barriers. The revised minimum criterion requires 1 inch and one physical barrier for power cable circuits requiring separation. To support the revised minimum criterion, the amendment contained information documenting that testing and analyses information is available in laboratory test reports which demonstrates that the revised criterion is adequate.

In a letter of September 28, 1992, the NRC staff asked the applicant to submit a detailed description of how the cables and cable configurations at CPSES compared to those used in the test documentation. Comparative information was requested on cable materials, construction, sizes, protective wraps, cable configuration arrangements. The applicant's response of October 27, 1992 (TU Electric letter TXX-92502 to NRC), documented that cables used at Comanche Peak have the same manufacturers, materials, and construction as those tested. It was also noted that cable configuration arrangements during testing were such that target cable or conduit configurations were closer than one-quarter inch to fault cables or conduits containing fault cables with the results being no functional damage for target cables. For these reasons, a cable configuration with the minimum physical separation distance of 1 inch and one physical barrier as required by the revised criterion is viewed as adequate and conservative.

On this basis, the staff concludes that the revised minimum physical separation criterion for power cable circuits is supported technically by information contained in documentation addressing testing and analyses. These means are permitted by IEEE Standard 384-1974, "Criteria for Separation of Class IE Equipment and Circuits," and Regulatory Guide 1.75, "Physical Independence of Electric Systems," as ways to establish separation distances for electrical cable circuits. Therefore, the staff considers the revised criterion acceptable.

8.4.4.2 Copper-Sheathed Cable

Amendment 82 to the FSAR contained information supporting the use of copper-sheathed (CS) cable at CPSES. As described, this cable is used in lighting circuits that are located inside the Comanche Peak containment buildings. Information contained in this amendment indicated that technical justification for use of this type of cable was provided in Wyle Laboratory Test Report Number 53575. This report contains information relating to testing of CS cable for use at the South Texas Project Electric Generating Station. The intent of this testing was to establish that a physical separation distance of 1 inch is adequate to protect Class 1E cables from a fault in a CS cable. This minimum physical separation distance shall apply to CS cable installations at CPSES.

The staff questioned whether the testing performed for the CS cable was representative of the most limiting condition existing at CPSES and requested a discussion containing technical details that would further support the use of this cable. In response to this request, it was documented that the CS cable used at CPSES is enclosed in 16-mil-thick corrugated copper tube which provides mechanical integrity (crush resistance) comparable to the 6-mil-thick 3/4-inch BOA flex conduit tested per Wyle Test Report Number 48037-02. In addition, the CS cable insulation is flame retardant and the seamless copper tube containing the CS cable conductors will contain any cable ignition that could result from an electrical fault. Further, a maximum of four No. 10 AWG conductors make up the cable assembly, and the annulus between the conductors and the tube is tightly packed with flame-retardant filler material that will inhibit flame propagation because there is no free air surrounding the conductors.

As indicated above, CS cable is used for lighting circuits located in the CPSES containment buildings. Test Number 2E per Wyle Laboratory Test Report Number 48037-02 for CPSES indicated a single conductor No. 12 AWG fault cable contained in 3/4-inch BOA flex conduit was subjected to a 135-ampere fault current for approximately 27 minutes until it open circuited. The maximum upstream protective device for CPSES containment lighting circuits is a 150A panel main circuit breaker. Therefore, the fault current in a CS cable can be assumed to be limited to 150 amperes for a worst case fault with primary protective device failure. Further, other information contained in Test Report Number 48037-02 clearly indicated that 6-mil-thick BOA flex conduit offers adequate protection for a substantial fault current magnitude over a long duration even if the target cable is in contact with the conduit.

The minimum separation required at CPSES between CS cable and Class 1E cable/raceways is 1 inch. From the analysis, the No. 10 AWG CS cable should provide a barrier at least as effective as the 3/4-inch BOA flex conduit. Thus, the CS cable used at CPSES can be considered the same as cable inside conduit for electrical separation purposes. Further, testing per Wyle Laboratory Test Report Number 53575 that was conducted for the South Texas Project demonstrates the ability of CS cable to perform as well as cable in conduit for separation purposes at higher fault levels over shorter time periods.

On this basis, the staff concludes that the electrical separation criterion proposed for CS cable installation is adequately supported by testing and analyses, conforms to regulatory requirements, and, as such, is acceptable.

8.4.4.3 One-Hour Fire-Rated Cable

Information contained in FSAR Amendment 82 expanded the scope of 1-hour fire rated materials to include 1-hour fire-rated cable. This amendment documented that this cable meets the requirements of ASTM E-119-1971 for fire resistance and, therefore, is considered equivalent to conventional cable enclosed within a 1-hour fire barrier. Further, it was concluded that 1-hour fire-rated cables are considered acceptable barriers for electrical separation and are considered equivalent to metal-enclosed raceways with respect to protection from electrical failures. Regarding these concluding statements, the staff requested a description including technical bases that explain why meeting the ASTM E-119 requirements makes this cable equivalent to metal enclosed raceways. The bases were to include a discussion addressing the protection of power and control circuits used in fire safe shutdown system applications.

In response to this request, it was documented that 1-hour fire-rated cable (Firezone "R") is constructed of a continuously welded, corrugated, 12-mil-thick stainless steel sheath with high-temperature nickel-clad copper conductors, glass braid cable jacket, and silicone rubber insulation. The 1-hour fire-rated cable resistance to fire damage, as evidenced by ASTM E-119 testing, demonstrates its ability to withstand the effects caused by a severe fault on adjacent cables for the durations typically encountered during testing for electrical separation as endorsed by Regulatory Guide 1.75, "Physical Separation of Electrical Systems."

Further, at CPSES, the only size of Firezone "R" cable used for fire safe shutdown equipment is No. 8 AWG. In this application, the No. 8 AWG cable will be substituted for No. 10 AWG and smaller field cable sizes. The worst-case postulated fault condition for Firezone "R" cable is a locked rotor condition of a motor with failure of the primary protective device to trip. This is deemed worst case because in control applications, upstream protective devices should clear a fault of much smaller magnitude than a motor with locked rotor. In addition, the worst case safe shutdown selected component fed by No. 10 AWG cable where 1-hour fire-rated cable could be substituted is 59.70 amperes. The normal free-air ampacity for No. 8 AWG Firezone "R" cable is 58 amperes. The worst-case locked rotor current as noted above of 59.70 amperes is approximately equal to the normal free-air ampacity of No. 8 AWG Firezone "R" cable. Thus, even under extended locked rotor conditions, the temperature rise in the No. 8 AWG Firezone "R" cable would be negligible.

On the basis of the above analysis, the staff concludes that Firezone "R" cable can be considered equivalent to a regular qualified cable enclosed in a metallic raceway for the purpose of conforming to Regulatory Guide 1.75. This being the case, the staff also concludes that the use of this cable with the existing electrical separation criteria is acceptable.

8.4.6 Fire Protection

Non-Class 1E Transformers Located in the Cable Spreading Rooms

Amendment 83 to the CPSES FSAR contained a correction to the description of the power circuits inside the cable spreading room. The correction was needed because of the addition of low-energy non-Class 1E transformers to the Unit 2 cable spreading room. The staff asked the applicant to provide the technical bases used to determine that the non-Class 1E transformers located in the cable spreading room are low energy. The staff concern was based on IEEE Standard 384-1974, which clearly notes that the cable spreading area shall not contain high-energy equipment. In addition, a fire resulting from one of the transformers may preclude the safe shutdown of the station.

The applicant stated that the transformers located in the cable spreading room supply power to the emergency response facility (ERF) computers. Each transformer is a 10-KVA 120/208-V ac, single-phase, dry-type transformer and is fully enclosed in sheet metal. The associated cabling is completely contained in dedicated conduit between the transformers and panels. The low voltage and loading level in conjunction with total enclosure of the dry-type transformers and connecting cables conforms to the intent of the requirements for nonhazard areas, as failure is limited to within the equipment or cables. Additionally, fire safe shut down analyses demonstrate that CPSES can be safely shut down in the event of a fire that damages all essential circuits in either cable spreading room.

Because the power supply for the plant computer has been reconfigured to replace the ERF computer, these transformers have been de-energized in CPSES Unit 2 and will be removed from the cable spreading room before fuel load. A similar modification is planned for Unit 1 during the third refueling outage. The Unit 1 transformers will be disconnected and removed from the cable spreading room at that time. The staff concludes that these actions adequately address the concern, conform to the applicable requirements in Standard 384-1974, and are, therefore, acceptable.

8.4.10 Station Blackout

The staff's safety evaluation (SE) pertaining to the applicant's responses to the Station Blackout (SBO) Rule, 10 CFR 50.63, for Comanche Peak Unit 1 was transmitted to the applicant in a letter of February 27, 1992. The staff found the applicant's proposed method of coping with an SBO to be incomplete. In a letter of March 31, 1992 (TU Electric letter TXX-92157 to NRC), the applicant advised the NRC that design modifications for Unit 1 might not be necessary once the dual-unit analysis was completed. Therefore, the staff postponed further technical review of Unit 1 pending receipt of the dual-unit SBO response from the applicant. However, in a letter of July 28, 1992, the staff advised the applicant that the 2-year clock for Unit 1 implementation of the SBO Rule, in accordance with 10 CFR 50.63(c)(4), would begin upon the applicant's receipt of the July 28, 1992, letter.

In a letter of October 1, 1992 (TU Electric letter TXX-92447 to NRC), the applicant submitted its dual-unit response for coping with an SBO. The applicant stated that this response would apply to each unit individually unless otherwise indicated. Also, the applicant highlighted (in boldface) those portions of the submittal that had changed from the original Unit 1 submittal. Thus, the following evaluation applies to both units and is based on the October 1, 1992, response. However, the staff's February 27, 1992, safety evaluation of the CPSES, Unit 1, SBO submittal remains effective to the extent indicated in the evaluation that follows.

<u>EVALUATION</u>

The items that follow are discussed in the same order as they were addressed in the staff's February 27, 1992, Safety Evaluation.

<u>Station Blackout Duration</u>

In its February 27, 1992, SE (Section 2.1), the staff accepted an SBO duration of 4 hours, based on a plant ac power design characteristic Group P1, an emergency ac (EAC) power configuration Group C, and a target EDG reliability of 0.95. These plant-specific characteristics and the required 4-hour coping duration are not affected by the applicant's dual-unit submittal.

Station Blackout Coping Capability

(1) Condensate Inventory For Decay Heat Removal

In its February 27, 1992, SE (Section 2.2.1) for Comanche Peak Unit 1, the staff concluded that the technical specification (TS) which required a minimum permissible condensate storage tank level of 282,540 gallons of water would constitute sufficient condensate inventory to cope with a 4-hour SBO event. In the October 1, 1992, dual-unit submittal, the applicant revised this by stating that the TS requires 262,000 gallons of water per unit and that a site-specific calculation indicated that 187,200 gallons of water per unit are required to cool down the reactor coolant system, remove decay heat for 4 hours, and restore water levels in the steam generator. Accordingly, the applicant concluded that no modification is necessary to ensure adequate condensate inventory for an SBO event.

On the basis of its review, the staff agrees with the applicant's conclusion that no modification is needed and that there will be sufficient condensate inventory to cope with a 4-hour SBO event for either unit at the Comanche Peak plant.

(2) Class 1E Battery Capacity

The staff's February 27, 1992, SE (Section 2.2.2) found the Unit 1 Class 1E battery capacity to be adequate. The applicant's dual-unit response stated that the battery sizing calculations were performed in accordance with the methodology and assumptions in IEEE-485-1978. The calculations used an aging factor of 1.25, a temperature correction factor of 1.08 (based on a 65°F minimum temperature), and resulted in a design margin of 25 to 35 percent. The staff finds this margin acceptable; therefore, the staff finds that the conclusion regarding Class 1E battery capacity for Unit 1 is also applicable to Unit 2.

(3) Compressed Air

In its February 27, 1992, SE (Section 2.2.3) for Comanche Peak Unit 1, the staff concluded that the applicant had provided adequate assurance that air operated valves relied upon to cope with an SBO event of 4-hours' duration either had sufficient backup sources or could be operated manually.

On the basis of its review of the applicant's October 1, 1992, dual-unit submittal, the staff finds that the conclusion regarding compressed air for Unit 1 is also applicable to Unit 2.

(4) Effects of Loss of Ventilation

In its February 27, 1992, SE (Section 2.2.4.1) for Comanche Peak Unit 1, the staff recommended that the applicant provide (for staff review) all the input parameters (i.e., equipment heat loads, personnel heat loads, thermal conductivity for structures, room free air volumes, initial temperatures, etc.) used in the temperature transient analyses for the control room, electrical equipment areas, valve rooms, main steam penetration platform, main steam penetration area, and turbine-driven AFW pump room and provide the justification for each of these input parameters. In addition, the staff recommended

(February 27, 1992, SE Section 2.2.4.2) that the applicant reevaluate the temperature rise calculations for the uninterruptible power supply (UPS) and distribution rooms taking into account the installation of dc-powered fans and verify that the maximum temperatures expected during a 4-hour SBO event were lower than the temperature limit for the operability of the inverters. In a letter of March 31, 1992 (TU Electric letter TXX-92157 to NRC), the applicant responded to these staff recommendations. Also, in its October 1, 1992, dual-unit submittal, the applicant sent additional information on the effects of loss of ventilation during an SBO event at either unit. The staff's evaluation of the response regarding the effects of loss of ventilation in the above cited areas at both units follow:

(a) Control Room

In its October 1, 1992, submittal, the applicant indicated that the control rooms for Units 1 and 2 are in a common area and are served by a common ventilation system. The common ventilation system has four 50- percent capacity air conditioning units, two of which are normally operating. At least one of these air conditioning units will be available during an SBO event. Because of the greatly reduced heat load following an SBO event, one air conditioning unit is sufficient to prevent a significant rise in room temperature. Therefore, the operator actions and the operability of control room equipment and instrumentation will not be affected. On the basis of its review, the staff finds that the applicant's response regarding the effects of degraded ventilation in the control rooms during an SBO event at either unit is acceptable.

(b) Electrical Equipment Areas and Turbine-Driven AFW Pump Room

In its October 1, 1992, dual-unit submittal, the applicant noted that the calculated peak temperatures for the electrical equipment areas and turbine-driven AFW pump rooms are 120.7°F and 131.1°F, respectively. The applicant also indicated that the operability of the equipment in these areas required during an SBO event had been assessed in accordance with vendor data or NUMARC 87-00 guidelines and concluded that no modifications or associated procedure changes would be required to provide reasonable assurance of equipment operability in these areas.

On the basis of its review of similar designs for Westinghouse reactors and subject to future audit, the staff finds this response regarding the effects of loss of ventilation in the electrical equipment areas and turbine-driven auxiliary feedwater (AFW) pump rooms at either unit acceptable.

(c) Valve Rooms, Main Steam Penetration Area, and Main Steam Penetration Platform

In its October 1, 1992, dual-unit submittal, the applicant indicated that all equipment required for coping with an SBO event in these areas had been evaluated for operability in a harsh environment resulting from a main steamline break accident, which would bound the environment due to an SBO event.

On the basis of its review of similar designs for Westinghouse reactors and subject to future audit, the staff finds the applicant's response regarding the effects of loss of ventilation in the valve rooms, main steam penetration area, and main steam penetration platform at either unit acceptable.

(d) UPS and Distribution Rooms

In its October 1, 1992, submittal, the applicant indicated that the UPS room ventilation system consists of two 100-percent-capacity air conditioning units, each of which is powered by common electrical distribution equipment. Each unit is supplied with condenser cooling water from either the Unit 1 or Unit 2 train of component cooling water (CCW). During normal operation, only one condenser cooling water path is open in each unit. During an SBO, the condenser cooling water to the operating UPS room cooler may be lost. However, fans on the cooler will continuously circulate air throughout the UPS rooms with or without condenser cooling water. Using an initial temperature of 95°F and the methodology described in NUMARC 87-00 in conjunction with the assumption that the doors to the UPS room will be opened within 30 minutes after an SBO event, a maximum steady-state temperature of 121.8°F was calculated. The applicant further indicated that administrative controls will be provided to monitor the UPS room temperature on a per-shift basis so as to ensure that the initial room temperature will remain at or below that used in the temperature calculation for an SBO event.

On the basis of its review and the applicant's commitment to revise procedures to open doors to the UPS room within 30 minutes after initiation of an SBO event, the staff finds the effects of degraded ventilation in the UPS rooms during an SBO event at either unit of the Comanche Peak plant acceptable.

With regard to the effects of loss of ventilation in the containment, the staff, in its February 27, 1992, SE (Section 2.2.4.3) for Comanche Peak Unit 1, concluded that the LOCA/MSLB temperature profile will bound the temperature profile resulting from a 4-hour SBO event. On the basis of its review of the applicant's October 1, 1992, dual-unit submittal, the staff finds that the conclusion for Unit 1 regarding the effects of loss of ventilation in the containment is also applicable to Unit 2.

(5) Containment Isolation

In its February 27, 1992, SE (Section 2.2.5) for Comanche Peak Unit 1, the staff concluded that the containment isolation valve design and operation at the Comanche Peak plant had met the intent of the guidance described in RG 1.155 and were, therefore, acceptable.

On the basis of its review of the applicant's October 1, 1992, dual-unit submittal, the staff finds that the conclusion regarding containment isolation for Unit 1 is also applicable to Unit 2.

(6) Reactor Coolant Inventory

In its February 27, 1992, SE (Section 2.2.6), the staff found reasonable assurance that the reactor coolant system (RCS) inventory would be sufficient.

The applicant's October 1, 1992, dual-unit response states that Unit 1 and Unit 2 plant-specific analyses of reactor coolant system inventory assumed that the reactor coolant pump leakage is initially 25 gpm per pump and decreases with decreasing RCS pressure.

The analyses show that the expected rates of reactor coolant inventory loss under SBO conditions do not result in core uncovery during the 4- hour SBO event. The staff accepts the applicant's reconfirmation that the core will remain covered.

Procedures and Training

The staff's February 27, 1992, SE (Section 2.3) reviewed the applicant's response with respect to the procedures that had been or were to be implemented. The applicant's October 1, 1992, dual-unit response notes that several of the procedure changes and additions for Unit 1 have been completed. The applicant has also committed to implement the procedural changes and additions (as applicable) for Unit 2. The applicant's dual-unit response notes that the dc-powered ventilation fans initially considered for the UPS rooms will not be required for dual-unit operation. However, the applicant committed in their October 1, 1992, submittal to revise procedures to direct operators to open the UPS distribution room doors within 30 minutes of a station blackout if the UPS air conditioning units are not operating (i.e., single failure of the associated train on the unit that is not blacked out). Implementation and maintenance of the appropriate procedures (including training) may be reviewed by the staff in a future inspection.

Proposed Modifications

The applicant stated in their Unit 1 SBO submittal that they planned addition of dc-powered ventilation fans (and possibly additional battery capacity) to provide cooling for the UPS rooms during station blackout. The applicant's dual-unit response states that no hardware modifications are required to cope with a SBO.

As noted in Item (4)(d), "UPS and Distribution Rooms," under Station Blackout Coping Capability in this SER section, the applicant performed an analysis of heatup in the UPS rooms which indicates a maximum steady-state temperature of 121.8°F in the UPS rooms during an SBO event. The applicant's assessment determined that no hardware modifications were necessary to provide reasonable assurance of continued equipment operability in the UPS rooms; therefore, the applicant's statement that no hardware modifications are necessary is acceptable to the staff.

Quality Assurance and Technical Specifications

The applicant's October 1, 1992, dual-unit response states that most of the equipment required to cope with an SBO event is safety related and included in the plant's QA program. The turbine stop valves, feedwater control and bypass valves, and their associated power and control components are not Class 1E components. Operability of these valves and components is assured through surveillance testing in accordance with the Technical Specifications and slave relay testing, respectively. The required instrumentation and control room indications are enveloped by accident monitoring or FSAR Chapter 15 accident analyses requirements, and the indications are routinely monitored to ensure operability. On this basis, the staff concludes that the QA programs for the SBO equipment meet the intent of RG 1.155, Appendix A.

EDG Reliability Program

The applicant's October 1, 1992, dual-unit response states that the current EDG reliability program meets the minimum guidance of RG 1.155, Section 1.2. The staff finds this to be acceptable pending the resolution of Generic Issue B-56, "Diesel Generator Reliability."

Implementation Schedule

The applicant's October 1, 1992, dual-unit response notes that many of the procedure changes for Unit 1 have been completed. The applicant states that it plans to complete the operating procedures and equipment list associated with dual-unit operation once the NRC has reviewed and approved the October 1, 1992, submittal. Full implementation, including training, is to be completed as soon as practical and well within the mandatory 2-year period.

CONCLUSION

On the basis of its review, the staff finds the applicant's March 31, 1992, response to the SE for Unit 1 and the October 1, 1992, submittal for both units acceptable. The applicant has stated that full implementation of 10 CFR 50.63, including training, is to be completed as soon as practical and well within the mandatory 2-year period. The applicant should maintain the SBO supporting documentation for possible NRC audit.

8.4.11 Cable Tray Loading

Amendment 79 to the CPSES FSAR also contained information about loading cable trays above the side rails. The staff questioned how the applicant would handle a situation in which the cables extend above the cable tray side rails but do not exceed the cable tray fill limits. More explicitly, the NRC asked the applicant to submit any evaluation criteria and bases to be used for such a situation and to describe in detail why such a cable installation should be considered satisfactory and technically adequate.

The applicant indicated that the cable tray fill limits are controlled by design and cable sizing taking into account cable tray fill limits. However, due to the way the cables lay in a tray, cables may extend above a tray side rail even though the tray fill limit is not exceeded. In such cases, when the cables

extend above the cable tray side rails, the CPSES criteria require these cables to be treated as cables in air for the purpose of separation.
On this basis, the staff concludes that the applicant has adequately addressed cables that extend above cable tray side rails; the additional information added to the FSAR addressing this issue is acceptable.