9 AUXILIARY SYSTEMS

9.1 Fuel Storage and Handling System

9.1.1 New Fuel Storage

In SSER 22, the staff described administrative controls to which the applicant committed in order to control the spacing between new fuel assemblies in the spent fuel storage racks. On the basis of the "expanded checkerboard" array committed to by the applicant, the effective multiplication factor (K_{eff}) of an array of assemblies in the spent fuel pool is less than that in the new fuel storage racks under all credible accident conditions.

In a letter of October 23, 1989 (TU Electric letter TXX-89760 to NRC), the applicant agreed to impose administrative controls to ensure that within the fuel handling building, no more than two fuel assemblies shall be outside of an approved shipping container, fuel inspection station, storage rack, or the fuel transfer tube at any one time and a minimum 12-inch edge-to-edge distance shall be maintained between such assemblies. In a letter of January 3, 1990 (TU Electric letter TXX-89867 to NRC), the applicant stated that it would revise the FSAR in a future amendment to document its commitment. This was done in FSAR Amendment 78.

In a letter of December 18, 1992 (TU Electric letter TXX-92618 to NRC), the applicant requested an exemption from the monitoring requirements of Title 10 of the Code of Federal Regulations (CFR) Section 70.24 as provided for in 10 CFR 70.24(d). [This exemption request is identical to a Unit 1 request (letter of June 30, 1989, TXX-89438), which was addressed in SSER 22.] The basis for the exemption request is that storage facilities and procedures offer assurance that criticality cannot occur during receipt, inspection, or storage of new fuel. The reasons for the exemption are valid, and good cause exists for the exemption. The shipping containers and storage racks provide physical protection to ensure subcriticality. The procedural controls provide reasonable assurance that nuclear criticality will not occur during fuel handling, and monitoring is not needed. Even if the procedural controls were violated, optimum conditions of neutron moderation, physical spacing, and neutron reflection would be required for assemblies to be in a critical situation. The procedural controls, considering the limited activities and material handling methods, are deemed adequate to grant the exemption. This exemption is authorized by law, will not endanger life, property, or the common defense and security, and is otherwise in the public interest. The Commission has determined that the granting of this exemption will not significantly alter the environment. The environmental assessment and finding of no significant impact was published in the Federal Register on January 19, 1993 (58 FR 5035).

9.2 Water Systems

9.2.5 Ultimate Heat Sink

In the SER, the staff discussed the findings of the applicant's safe shutdown impoundment (SSI) thermal analysis presented in the FSAR. In this analysis, the applicant used onsite data selected from 30 years of airport meteorological data to determine maximum temperature and evaporation loss from the SSI under accident conditions. The original analysis included the use of 39 years of data from the Dallas-Fort Worth Airport and the selection of separate periods for maximum temperature and maximum evaporation. These reanalyses are discussed in more detail in Section 2.4.5 of this SSER.

The NRC staff still concludes that the SSI meets the guidelines of RG 1.27 and the requirements of GDC 44.

9.5 Other Auxiliary Systems

9.5.1 Fire Protection

Supplement 21 to the SER (SSER 21) which was issued in April of 1989 contained a review of the Comanche Peak fire protection program as documented in the FSAR through Amendment 71 and as described in Revision 1 to the Fire Protection Report.

This supplement documents a review of fire protection related changes and modifications made to the FSAR through Amendment 87 and through Revision 6 to the Fire Protection Report. Changes in these documents are primarily related to the inclusion of issues related to Unit 2. Although Units 1 and 2 are similar in design, the previously reviewed documents generally addressed only Unit 1. The purpose of this review is to ensure that the fire protection program for Unit 2 is in accordance with the guidance provided in Appendix A to Branch Technical Position (BTP) APCSB 9.5-1 as well as with Sections G, J, and O of Appendix R to 10 CFR 50. This review included a site visit on September 16-17, 1992.

9.5.1.1.b Fire Hazards Analysis

Revision 6 to the Fire Protection Report contained a number of additions to address Unit 2 fire areas. Revision 6 also identified a number of new deviations from the guidelines of Appendix A to BTP APCSB 9.5-1 and Appendix R to 10 CFR 50. The new deviations are as follows:

1b (2)	Unit 2 Chiller Units and Pumps
3a (2)	Room x-195/x-207, Removable Concrete Block
3a-1 (2)	Room 2-077A/2-088, Removable Concrete Block
3b (2)	Unit 2 Containment Penetration Seals
3d (2)	Unit 2 Water Tight Doors
3e (2)	Unit 2 Containment Air-Locks
3g (2)	Unit 2 Containment Mechanical Penetration Seals

3ha (2) Unit 2 Cable Spreading Room BR-PR Door (Door F-24)
3hb (2) Unit 2 Cable Spreading Room BR-PR (Door E23)
4a (2) Unit 2 Pressurizer Relief Valves
4a-1 (2) Unit 2 Containment Building RHR Valves
8c (2) Unit 2 Main Steam Isolation Valves

All of these deviations, with the exception of 1b (2), Unit 2 Chiller Units and Pumps, are equivalent to deviations previously reviewed and approved for Unit 1. These deviations were reviewed to ensure that the plant configuration and associated fire protection features were indeed equivalent to Unit 1. Based on this review, the above deviations were found to be acceptable and are therefore approved.

Deviation 1b (2), Unit 2 Essential Chiller Units is a deviation from Section III.g.2.b of 10 CFR 50 Appendix R for lack of separation between redundant components. Although, the physical configuration for the safety chiller room is the same for Units 1 and 2, the applicant is installing water curtains over each of the two partial walls. The applicant has protected the vital cables in Unit 2 as in Unit 1, however, the intervening cable trays containing non-vital cable are not enclosed in a 1-hour fire barrier material in Unit 2 as they are in Unit 1. The Unit 2 essential safety chiller room was walked down during the site visit. During this walkdown the partial height 1-hour fire barrier walls separating the Unit 2 essential chillers and pumps were verified to extend above and along the entire length of the chiller units and pumps. The applicant as part of their fire protection enhancements has also installed curbs from where the chiller pump partial wall terminates to the wall of the room. These curbs are installed to preclude a combustible liquid spill fire from impacting both chiller pumps. In addition, additional smoke detectors have been installed in this area to enhance their ability to rapidly detect a fire condition. In the overhead of this room, cable trays transverse the area. These trays are considered to be an intervening combustible hazard to redundant chillers and their associated pumps. In order to preclude fire propagation along these trays, caused by an electrically originated fire, the applicant has installed fire stops in the trays at the vertical extension plane of the partial height fire barrier walls which separate the chillers and the pumps. These fire stops will preclude fire extension along the tray so that a tray fire presents an exposure to only one chiller or pump. The chiller and pump area is protected by area wide sprinklers installed at the ceiling level. The applicant has installed a water curtain at the vertical extension plane of the partial height fire barrier walls. These water curtains consist of closely spaced fast response sprinklers designed to apply a discharge rate of 3 GPM/linear foot of curtain length.

The ceiling of the chiller room has deep beams running across the width of the room along the C-A and D-A column lines. These beams have created a beam pocket over the chiller pumps and two beam pockets over the chiller units. The significance of these beam pockets is that they will aid in the collection of heat at the ceiling area directly over the fire and will improve the response of the ceiling level area sprinklers and the water curtain fast response sprinklers.

For example, if a fire were to involve a chiller pump, a fire plume would develop and heat would spread across the ceiling and be collected within the beam pocket directly over the pumps. The fire barrier wall between the pumps would preclude direct fire exposure and propagation to the redundant chiller pump until the water curtain fast response and ceiling level area sprinklers could react to the fire condition. Based on the fast response sprinklers used for the water curtain, it is anticipated that they will respond to the fire condition prior to the actuation of the ceiling level sprinklers. The partial height fire barrier walls which separate the essential chillers and the chiller pumps in combination with the water curtain and the ceiling level sprinklers provide reasonable assurance that a fire, if one were to occur, would be mitigated and fire damage would be limited to one train of essential chillers. Based on the information provided in Revision 6 of the Fire Protection Report and the physical review of the Unit 2 essential chiller room, the staff determined that the lack of full height fire barriers to separate the Unit 2 essential chillers and pumps will not adversely affect the plant's ability to achieve post-fire safe shutdown and therefore, the applicant's deviation request can be granted. Based on information provided in Revision 6 of the Fire Protection Report and a physical review of the room in question, it is determined that the lack of complete separation of the safety chillers in Unit 2 does not adversely affect plant safety and a deviation can be granted.

Deviation 1a which deals with separation of redundant safety water pumps and associated components in the intake structure, was modified in Revision 6 to account for Unit 2 components. During the plant visit, the intake structure was walked down to verify that configurations did not differ from Unit 1 and that adequate fire protection features were present. Based on the review of information provided in Deviation 1a which was provided in Revision 6 to the Fire Protection Report and on the walkdown of the Safety Water Intake Structure, this deviation is found to be acceptable.

9.5.1.2 Administrative Controls

<u>System Operability and Surveillance Requirements</u>

The proposed operability and surveillance requirements for Unit 2 Fire Protection Features are equivalent to those provided for Unit 1 and consistent to NRC guidance provided in Generic Letters 86-10 and 88-12 with the exception of operability requirements for water curtains in the Unit 2 essential chiller room. The operability and surveillance requirements for the water curtain were reviewed as part of the deviation evaluation, discussed in this SER and were found acceptable.

9.5.1.3 Fire Brigade

The Fire Brigade for Unit 2 will be composed of the same brigade members that currently respond for Unit 1. The fire brigade staffing and training program was previously reviewed and found acceptable. However, the applicant has made one change in the brigade make-up from that which was originally reviewed. Three members of the brigade will continue to be from plant operations, however, the additional two members which were drawn from the plant security staff are now contract emergency response personnel. These personnel receive the same level of training as originally identified by the applicant and therefore the brigade make-up continues to be consistent with staff guidance.

9.5.1.5 General Plant Guidelines

Penetration Seals

The penetration seal program was reviewed during the site visit. The applicant has used the same contractor seal specification for Unit 2 as Unit 1, however, a different installation contractor was selected. The reviewer discussed with the applicant the impact that this would have on ensuring the penetration seal designs for Unit 2 were adequately qualified. During this discussion, the applicant presented the design detail drawings which cross referenced each of the details used in Unit 2 with vendor test reports. The applicant stated that each test report was assigned to a detail based on a review by the applicant. In addition, the applicant stated that any configurations within the plant which did not directly correspond to a design detail are reviewed by an engineer for disposition. The applicant stated that a report of any analyses of non-conformances, would be available for NRC review upon completion of the penetration seal installation program.

The applicant also included in Revision 6 to the Fire Protection Report, additional criteria for sealing inside of conduits. This criteria, which limits the sealing requirements for conduits based on size and percentage of fill, is based on criteria established in the "Conduit Fire Protection Research Program". This report, which documents the finding of fire tests on various conduit assemblies, was submitted to the NRC as a Topical Report by Wisconsin Electric Power Company. The report was reviewed by the staff and was subsequently accepted. Based on acceptance of this Topical Report, the use of the contained sealing criteria at Comanche Peak is considered acceptable.

Thermo-Lag

The applicant installed 1 hour fire rated Thermo-Lag barriers to separate one train of redundant safe shutdown components when both trains of a system required for hot standby are located in the same fire area and are not separated by more than 20 feet.

During a meeting with the Nuclear Management and Resources Council (NUMARC) on February 12, 1992, the Office of Nuclear Reactor Regulation (NRR) Special Review Team for the Review of Thermo-Lag Fire Barrier Performance expressed concerns regarding the Thermo-Lag 330-1 fire barrier system. In response to the concerns, the applicant conducted an assessment of test results and documentation, ampacity derating design basis, and installation and inspection specifications and procedures applicable to Thermo-Lag fire barrier configurations at CPSES. In letters of May 1, 1992 (TU Electric letter TXX-92219 to NRC), and May 6, 1992 (TU Electric letter TXX-92208 to NRC), the applicant informed the staff that it had initiated a comprehensive confirmatory test program to envelope the full range of protected conduit and cable tray configurations used at CPSES.

The staff audited the construction of fire endurance test specimens at the applicant's contract testing laboratory May 6 through 8, 1992, May 12 through 14, 1992, and September 29 through October 2, 1992. The staff observed the installation of cables, test instrumentation, and penetration seals, and the construction of the test specimen fire barriers. The staff also observed the test laboratory's and the applicant's quality control (QC) and quality assurance (QA) activities.

The staff observed fire endurance tests June 17 through 25, 1992, August 19 through 22, 1992, November 3 through 6, November 12, 13, 16 and 18, 1992, and December 1, 1992. The staff observed the test setups, the fire exposure and hose stream tests, thermocouple data collection, and the cable insulation resistance testing. The staff also observed the fire barrier condition and the cable condition after the fire and hose stream tests.

The staff met with the applicant to discuss the test program and fire test results on July 13, 1992, September 10, 1992, September 15, 1992, October 27, 1992, December 17, 1992, and January 21, 1993.

<u>Fire Endurance Test Acceptance Criteria</u>

During the early laboratory site visits and meetings, the staff expressed concerns about certain aspects of the applicant's fire test methodology and acceptance criteria including test specimen sizes and configurations, test methodology, and acceptance criteria. In a letter of September 8, 1992 (TU Electric letter TXX-92429 to NRC), the applicant provided an interim report entitled "Evaluation of Thermo-Lag Fire Barrier Systems," Revision 1, to describe the qualification of the Thermo-Lag barriers used at CPSES. During a telephone conference of September 22, 1992 to discuss the interim report, the staff requested additional information and clarifications from the applicant. The applicant provided additional information in a letter of September 24, 1992 (TU Electric letter TXX-92466 to NRC), and met with the staff on October 27, 1992 to discuss the fire test methodology and acceptance criteria. During the meeting, the applicant committed to supplement its acceptance criteria. In a letter of October 29, 1992, the staff stated that the applicant's proposed acceptance criteria were acceptable as supplemented by the conditions discussed during the meeting. In summary, the approved fire test acceptance criteria were:

1. External conduit, cable tray rail, and cable jacket temperatures should not exceed 250°F (121°C) plus ambient temperature (using thermocouple averaging) and no single thermocouple reading should exceed 30 percent above the specified average temperature rise.

2. The fire barrier should not burn through or develop any openings through which either the test specimen raceway or cables were visible.

3. If the temperature rise criteria were not satisfied, the cables should be inspected for visible cable damage. The following attributes constitute cable damage: jacket swelling, splitting, discoloration, hardening, blistering, cracking, or melting; conductor insulation exposed, degraded, or discolored; shield exposed; or bare copper conductor exposed.

4. If the fire barrier burned through during the fire exposure, or if a visual cable inspection revealed any of the damage attributes listed above, then the barrier was considered to have deviated from the acceptance criteria. Use of the fire test results to qualify a deviating fire barrier would require that cable functionality be demonstrated. Cable functionality test methodology and criteria were specified in the staff's letter.

In its letter of October 29, 1992, the staff concluded that the applicant's acceptance criteria, as supplemented by the conditions stated in the October 29, 1992 letter, ensured that adequate cable and barrier tests would be performed and that satisfactory results from these tests would constitute an acceptable basis for qualifying the CPSES Unit 2 fire barriers. The staff stated that its review of the applicant's evaluations of any test deviations, should they occur, would be included in its safety evaluation of the applicant's fire barrier test program.

<u>Fire Tests Used to Qualify the CPSES, Unit 2 Fire Barriers</u>

In a letter of December 23, 1992 (TU Electric letter TXX-92626 to NRC), the applicant provided Revision 2 of its interim engineering report entitled "Evaluation of Thermo-Lag Fire Barrier Systems." The report, ER-ME-067, documented the applicant's bases for the acceptance and continued use of 1 hour rated Thermo-Lag fire barriers at CPSES. It summarized the qualification of the Thermo-Lag fire barrier configurations used by the applicant for the protection of safe shutdown related components at CPSES, including the fire endurance test methodology and acceptance criteria. In the report, the applicant stated that it used the acceptance criteria included in the staff's letter of October 29, 1992.

ER-ME-067, Revision 2, identified 17 schemes that were tested by the applicant. By a letter of January 19, 1993 (TU Electric letter TXX-93023 to NRC), the applicant docketed the test reports for ten of the 17 fire test schemes. These were: Scheme 1-2, Schemes 9-1 and 9-3, Schemes 10-1 and 10-2, Scheme 11-1, Schemes 12-1 and 12-2, Scheme 13-1, and Scheme 14-1. The letter of January 19, 1993, stated that these ten reports supported the Thermo-Lag installations for CPSES Unit 2. The staff audited the test reports for the fire endurance tests of the nine test schemes identified in Table 1. Except for Scheme 1-2, the applicant used the test acceptance criteria specified in the staff's letter of October 29, 1992.

The staff's preliminary review of the test report for Scheme 9-3 found that the test deviated from the acceptance criteria approved by the staff in its letter of October 29, 1992. Specifically, the conduit surface temperatures were not known, cable temperatures exceeded allowable limits, the barrier burned through, and there was visible cable damage. On these bases, the staff concluded that the test specimen did not meet the acceptance criteria it had approved. The staff also found that the applicant did not provide evaluations of the test deviations. During a telephone conference of January 22, 1993, the staff informed the applicant that absent acceptable evaluations of the test deviations, Scheme 9-3 was not an acceptable basis for the installation of Thermo-Lag fire barriers in CPSES Unit 2. In a letter of January 28, 1993 (TU Electric letter TXX-93061 to NRC), the applicant informed the staff that it did not use Scheme 9-3 to qualify any of the Thermo-Lag fire barriers installed in Unit 2.

The staff was also concerned that the applicant issued ER-ME-067, Revision 2, before its test laboratory finalized the fire endurance test reports referenced throughout the report. In the letter of January 19, 1993, the applicant stated that it had reviewed the fire test reports and confirmed that they supported the conclusions provided in ER-ME-067, Revision 2. The applicant also stated that the report was no longer an interim report and that additional confirmation of the report was not required. This resolved the staff concern.

The staff reviewed and evaluated those portions of ER-ME-067, Revision 2, that applied to CPSES Unit 2. The staff also audited the nine fire test reports for the test schemes that the applicant used as the basis for qualifying the Thermo-Lag fire barriers installed in CPSES Unit 2. Table 1 identifies the nine test schemes and summarizes the test results and the staff's conclusions.

The staff noted errors and inconsistencies within the fire test reports and between the fire test reports and ER-ME-067, Revision 2. To the extent that the errors and inconsistencies did not affect the reports' conclusions or the staff's conclusions, the staff did not question the reports. The staff also observed that the applicant did not consistently address in the conclusions sections of the fire test reports how each test specimen satisfied the acceptance criteria approved in the staff's letter of October 29, 1992 or why deviations from the criteria were acceptable. In some cases, the staff reviewed the test reports to determine whether or not the criteria were satisfied. The staff also requested clarifications and additional information from the applicant during telephone conferences of January 22, 25, 26, and 27, 1993. The additional information was provided by letters dated January 25 (TU Electric letter TXX-93060 to NRC) and January 28, 1993. The following safety evaluation also documents independent evaluations performed by the staff where it disagreed with the applicant's conclusions.

Test Specimen Design, Configuration, and Construction

The applicant performed 1-hour fire endurance tests on test specimens of various sizes and configurations of cable trays and conduits, junction boxes, condulets, lateral bend boxes, and air drops. Each test specimen was constructed from raceway materials, cables, and fire barrier materials extracted from the applicant's CPSES stock material storage areas in accordance with the applicant's site procedures and were representative of materials installed at CPSES Unit 2.

The Thermo-Lag fire barriers were measured, cut, and installed to the test specimen raceways by the applicant's contract installers using applicant-approved CPSES drawings, procedures, and specifications. The installations were inspected by CPSES-certified quality control inspectors and the test laboratory's quality assurance manager.

The installers buttered each joint and seam with trowel-grade Thermo-Lag material before the individual panel sections and conduit preshapes were joined together. Except for straight runs of conduits larger than 2 inches in diameter, the fire barriers included applicant-designed upgrades. (The upgrades are not specified in the vendor's recommended installation procedures.) The upgrades, which were configuration dependent, were described in ER-ME-067, Revision 2, and the fire test reports. In summary, the upgrades consisted of overlays of additional Thermo-Lag material on small diameter conduits, reinforcement of certain seams and joints with stainless steel wire stitches, and reinforcement of certain seams and joints with stress skin and trowel-grade Thermo-Lag material.

In a letter of January 28, 1993, the applicant stated that the fire test specimens were conditioned in accordance with Section 11 of American Society for Testing and Materials (ASTM) Standard E 119-88, "Fire Tests of Building Construction and Materials."

The staff observed during its plant site visit of January 11 through 15, 1993, that the applicant's fire barrier installation specifications and procedures for CPSES Unit 2 included the tested fire barrier design upgrades.

<u>Bounding Configurations (Scheme 1-2)</u>

In its final report of April 21, 1992, the NRR Special Review Team for the Review of Thermo-Lag Fire Barriers indicated that fire tests of representative cable tray sizes and configurations should be conducted to determine the fire resistance ratings for the range of possible field configurations. The staff issued the report in NRC Information Notice 92-46, "Thermo-Lag Fire Barrier Material Special Review Team Findings, Current Fire Endurance Tests, and Ampacity Calculation Errors," June 23, 1992.

The staff was concerned that the fire endurance test used by the applicant as the basis for the widest cable tray fire barriers installed at CPSES Unit 2 (Scheme 1-2, 36-inch wide cable tray) was not performed in accordance with the test methodology and acceptance criteria approved by the staff in its letter of October 29, 1992 and, therefore, that the applicant had not adequately bounded the range of fire barrier configurations installed at CPSES Unit 2.

The staff discussed bounding configurations with the applicant on several occasions. During the meeting on September 15, 1992, the staff stated that the applicant's test configurations did not adequately address, or bound, previous test results or in-plant configurations. The staff informed the applicant during a followup telephone conference on September 22, 1992, that its concern would be resolved if TU Electric conducted a successful test of the widest cable tray installed in CPSES Unit 2. On September 23, 1992, the applicant informed the staff that the widest cable tray installed at CPSES Unit 2 was 30 inches. It also committed to test a 30-inch wide cable tray. This was done as Scheme 12-1, which was a satisfactory test.

Subsequently, in its letter of January 19, 1993, the applicant informed the staff that a 36-inch wide cable tray was installed at CPSES, Unit 2 and that it used the results of test Scheme 1-2 (36 inch wide cable tray) and Scheme 12-1 (30 inch wide cable tray) as the bases for qualifying the 36-inch wide cable tray fire barriers installed in CPSES Unit 2. In letters of January 25, 1993 and January 28, 1993, the applicant provided additional information to justify the use of these two fire tests as the licensing basis for installing the 36-inch wide cable tray fire barrier configuration in CPSES Unit 2.

The staff evaluated the information provided by the applicant and reviewed the fire test reports for Schemes 1-2, 12-1, and 14-1. The staff's acceptance of the 36-inch wide in-plant cable tray is based on satisfactory tests of two 30-inch cable tray configurations (Schemes 12-1 and 14-1). The 36-inch in-plant cable trays were constructed with similar upgrades as those employed on the 30-inch test schemes. The staff concluded that it has reasonable assurance that the 36-inch wide cable tray Thermo-Lag fire barrier installed in the plant will protect one train of safe shutdown capability from fire damage. However, the staff further discussed with the applicant concerns about the Scheme 1-2 test (e.g., test acceptance criteria, specific configuration concerns, and the lack of a bounding test conducted in accordance with the acceptance criteria approved by the staff). In a letter of February 1, 1993, (TU Electric letter TXX-93076 to NRC), the applicant committed to either perform a confirmatory test of a 36-inch cable tray, participate in an industry testing program to resolve concerns over a 36-inch wide barrier, or provide additional information which adequately addresses the staff's concerns. The applicant committed to perform one of these actions by the completion of the first refueling outage for Unit 2. Based on the staff's review, and the applicant's commitment for confirmatory actions, the staff finds the 36-inch wide in-plant cable tray acceptable.

Fire Endurance Test Results

The test laboratory exposed each test specimen to the 1 hour external fire exposure (standard time-temperature curve) specified in ASTM E 119-88. The laboratory controlled the furnace temperature during each test such that the area under the measured time-temperature curve was within 10 percent of the corresponding area under the standard time-temperature curve for the 1 hour test period.

Following the fire exposure, each test specimen was subjected to a hose stream test for at least 5 minutes. Each stream was delivered through a 1½ inch (3.8 cm) fog nozzle with a spray angle of 30°, a nozzle pressure of 75 psi (517 kPa), and a minimum flow of 75 gpm (284 lpm). The fog nozzle was located about 5 feet (1.5 m) from the test specimen during the test.

The laboratory identified several technical issues in the fire test reports. The staff's evaluations of the indeterminate conduit surface temperatures (Schemes 9-1, 10-1, and 10-2), conduit temperatures and cable jacket damage (Scheme 11-1), erratic temperature readings (Scheme 12-1), hose stream damage (Scheme 12-2), maximum single point temperature exceeded (Scheme 14-1), and cable stiffening are documented below. The staff concluded that the test laboratory satisfactorily addressed and resolved the other issues and problems that it documented in its fire test reports and that, except for Scheme 1-2, the problems did not affect the successful results of the CPSES Unit 2 fire tests.

Based on its audit review of the test reports, its audits of the fire test specimen construction, and its fire test observations, the staff concluded that except for Scheme 1-2, the applicant and its contract test laboratory conducted the fire tests identified in Table 1 in accordance with the test methodology discussed with the staff during its visits to the test laboratory, the meeting of October 27, 1992, and the staff's letter of October 29, 1992. The staff also concluded that except for Scheme 1-2, the test specimens satisfied the acceptance criteria specified in the staff's letter of October 29, 1992, with the deviations approved below, and were, therefore, adequate to establish the 1 hour fire resistance ratings of the tested configurations.

Fire Barrier Thickness

Some of the applicant's Thermo-Lag fire barrier upgrades consisted of overlapping or wrapping seams and joints with stress skin embedded in and covered with trowel grade Thermo-Lag 330-1 material. During visits to the test laboratory, the staff observed that the licensee's installation procedures included a combination of qualitative and quantitative instructions for applying the Thermo-Lag 330-1 trowel grade material, but did not specify a maximum allowable thickness of trowel grade material. The staff was concerned that absent a maximum allowable fire barrier thickness specification, the thickness of the installed fire barrier would not be known and the ampacity derating of enclosed power cables may not be adequate.

The staff inspected the thickness of the trowel grade material at a number of points on a 12-inch wide cable tray test specimen (Scheme 13-1). The troweled layer ranged from less than 1/16 inch (0.2 cm) thick to about ¼ inch (0.6 cm) thick. The thickness of the trowel grade material at any particular point appeared to be a function of its location on the test specimen. For example, the hardware used to fasten the ends of the stainless steel bands were about ¼ inch (0.6 cm) thick and protruded above the surface of the barrier. These fasteners were difficult to trowel around. Therefore, the troweled layer around the band fasteners tended to be smoothed off about even with the top of the fasteners. This was most evident at the inside bend radii of the 12-inch wide cable tray where a series of closely-spaced bands (1 to 2 inches apart) were installed to hold the scored Thermo-Lag panels to the radii. The band fasteners were located along the centerline of the inside radii between the edges of two pieces of stress skin that overlapped the cable tray side rails. The fire barrier installers were trained to completely cover the stress skin and to blend or feather the trowel layer across the panel surface adjacent to the edge of the stress skin. The edges of the stress skin in these areas were only 4 inches (10 cm) apart and had a series of protruding band fasteners between them. Feathering is difficult in these areas because of the protruding fasteners, the curve of the barrier, and the relatively small surface area available to feather into. Therefore, the inside bend radii were filled to the depth of the band fasteners with trowel-grade material. Conversely, the troweled layer on the outside of the radii, where there were no band fasteners, was only about 1/16 inch (0.2 cm) thick.

During the laboratory visit, the applicant informed the staff that the instructions and training provided to the applicant's contract fire barrier installers were consistent with the applicant's installation procedures and that the fire test specimens were constructed by the same installers used to construct the Thermo-Lag fire barriers at the CPSES Unit 2. Moreover, CPSES inspection procedures ensured that the barriers were inspected and that the installers followed the installation procedures. In the staff's judgement, nominal thickness variations are inherent in the Thermo-Lag fire barrier system, and the application of the trowel grade material with respect to thickness and quality of coverage could not be reasonably controlled better than that which was observed during the site visits. The applicant also informed the staff that the ampacity derating test specimens would be constructed using the same procedures and construction methods. Therefore, the ampacity derating factors derived from the tests will reflect typical barrier installations including the nominal thickness variations inherent in the system.

The staff concluded that the applicant's fire barrier installation and quality control procedures and specifications were adequate to ensure that the fire test specimens represented the materials, methods of assembly, dimensions, and configurations for which fire resistance ratings were desired.

Conduit Surface Temperatures (Schemes 9-1, 10-1, and 10-2)

The staff observed the fire endurance tests of Scheme 9-1 and Scheme 10-1 on November 3 and 5, 1992, respectively. During these tests the staff observed that temperatures reported by some of the thermocouples installed on the conduit surfaces between the conduit and the Thermo-Lag material rose faster and higher than expected. For example, after 31 minutes, a thermocouple on the 3-inch diameter conduit for Scheme 9-1 reported a temperature of 1480°F (804°C). The corresponding cable thermocouple temperatures were less than 200°F (93°C). By the end of the test, the temperature reported by this conduit surface thermocouple had dropped to 468°F (242°C). It was also noted that the thermocouple with the longest run of thermocouple wire had the highest temperature reading. During the post-fire inspection of the barrier, the staff observed that the fire barrier was intact and that virgin Thermo-Lag material remained between the char layer and the conduit surface thermocouples. When the laboratory disassembled the fire barrier, the staff observed that many of the thermocouple wires located between the outer conduit surface and the Thermo-Lag material were coated with a dark brown gummy substance and that the braided fiberglass thermocouple wire insulation was saturated with the substance in places. The foreign substance appeared to be a mixture of water and decomposed

Thermo-Lag material that had migrated into the enclosure under fire exposure and condensed on the cool conduit surfaces.

The morning after the fire test, the laboratory tested the operability of the Scheme 9-1 thermocouple that reported the highest temperature. It performed correctly. When the laboratory immersed a residue-saturated segment of the insulation in warm water, with the thermal junction exposed to ambient air, the thermocouple reported a temperature rise of about 10°F (12°C). The temperature reported by the thermocouple should not have changed. This demonstrated that the saturation of the thermocouple wire insulation affected the temperature reading.

The conduit surface temperatures for Schemes 10-1 and 10-2 were also irregular and inconsistent with visual observations. Following the tests of Schemes 9-1 and 10-1, the laboratory verbally informed the staff that it considered the conduit surface temperatures indeterminate. This declaration was not reflected in the fire test reports. However, the laboratory discussed the thermocouple readings as a problem in the fire test reports for Scheme 9-1, Schemes 10-1 and 10-2 and the applicant provided an evaluation of the thermocouple behavior in Revision 2 to ER-ME-067.

The test laboratory concluded that the high temperatures reported by the conduit surface thermocouples were caused by saturation of thermocouple wire insulation with a residue composed of water and Thermo-Lag off-gases which migrated through the Thermo-Lag material and condensed on the conduit surfaces. The saturation set up an ionic potential across the thermocouple wires which affected the thermocouple readings. The longer the thermocouple wire, the greater the potential, and the higher the temperature reported by the thermocouple. When the conduit surface reached 212°F (100°C), the water began to evaporate. This dried out the thermocouple wire insulation and reduced the potential, thereby lowering the thermocouple reading. The staff concurred with the laboratory's analysis and concluded that the conduit surface temperature measurements for Scheme 9-1, Schemes 10-1 and 10-2 were indeterminate. The staff also concluded, therefore, that these three test schemes deviated from the temperature acceptance criteria.

The fire test acceptance criteria specified that a fire test was successful if the barrier did not burn through and the cables did not have any visual fire damage even if the temperature criteria were exceeded. The staff concluded that the Scheme 9-1, and the Schemes 10-1 and 10-2 fire tests met the conditions of acceptance for post-fire barrier condition and post-fire cable condition; therefore the conduit surface temperatures were not needed to declare these three fire tests satisfactory. This was, therefore, an acceptable deviation from the temperature acceptance criteria.

<u>Conduit Temperatures and Cable Jacket Damage (Scheme 11-1)</u>

The staff noted several apparent inconsistencies and errors in the discussions and conclusions about conduit temperatures in the test report for Scheme 11-1. The report also indicated that the jackets of three cables in the 5-inch air drop were blistered and cracked and the filler material within the cables was slightly melted. The staff was concerned that the test results may not have been an acceptable basis for qualifying the fire barrier configurations. The staff discussed these issues with the applicant during telephone conferences on January 22 and 27, 1993. The applicant provided additional information in letters of January 25 and 28, 1993. The applicant also provided a letter of January 28, 1993, from its test laboratory that clarified the test report.

The staff found that the test laboratory corrected the reporting inconsistencies and errors. The staff did not, however, concur with the laboratory's conclusion that conduit surface thermocouples affected by moisture saturation could be used to conclude that the conduit temperatures remained within allowable limits. The staff concluded, therefore, that the surface temperatures of the 1-inch, 2-inch, and 3-inch diameter conduits were indeterminate. The staff found, however, that the surface temperatures of the 5-inch diameter conduit were not affected by moisture saturation and were within acceptable average and maximum temperature limits.

The staff reviewed the fire test report against the criteria specified in its letter of October 29, 1992. The staff concluded that, except for the 1-inch, 2-inch, and 3-inch conduit surfaces, all raceway and cable temperatures were within the allowable average and maximum temperature limits, that the barrier remained intact and did not burn through during the fire and hose stream tests, and that the results of the cable insulation resistance tests were satisfactory.

The cables in the 1-inch, 2-inch, and 3-inch diameter conduits and air drops and in the cable tray were not damaged. The cable damage was limited to the outside of the cable jackets of three of the cables installed in the 5-inch air drop. The inside surfaces of the cable jackets and the insulation of the individual cable conductors did not have any visual fire damage. In its letters, the applicant postulated that three of the cables in the 5-inch air drop were damaged because the cable installation techniques required to assemble the test specimen allowed the cable jackets to contact the inside Thermo-Lag surfaces.

As stated above, the staff concluded that the surface temperatures of the 5-inch diameter conduit were within allowable limits and the surface temperatures of the 1-inch, 2-inch, and 3-inch diameter conduits were indeterminate. The staff determined that two explanations for damage to the cables in the 5-inch air drop were possible (temperature related or improper installation technique). Assuming the temperatures in the three smaller diameter conduits exceeded allowable limits, the staff concluded that it is not credible that high temperatures in these areas could have caused the cable damage observed in the 5-inch air drop. Therefore, the staff concurred with the applicant's basis for the cause of the cable damage. In its letter of January 28, 1993, the applicant stated that CPSES cable installation practices preclude CPSES cable installations from experiencing the installation problems encountered with the test specimens. The staff concluded that the CPSES cable installation practices provided reasonable assurance that the cable damage observed in the fire test specimen will not occur in the event of a fire in the plant.

The staff concluded that the Scheme 11-1 fire endurance test was an acceptable basis for qualifying the tested fire barrier configurations.

Erratic Temperature Readings (Scheme 12-1)

The staff observed the fire endurance test of Scheme 12-1 on November 16, 1992. The test specimen temperatures rose slowly and fairly uniformly during the first 14 minutes of the fire exposure. Then, the thermocouples began to exhibit erratic behavior. After about 20 minutes, the staff observed that most of the thermocouples reported obviously erratic temperatures. Many read 0°F while others indicated negative temperatures. At this point, the test laboratory began to troubleshoot its data acquisition and control system. The laboratory project manager removed the multiplex system circuit boards from the signal processor, cleaned their contacts, and reinserted them. This appeared to correct the data acquisition problem. About 46 minutes into the fire test, the laboratory restarted the data acquisition system and recorded the test specimen thermocouple temperatures. The system behaved normally during the remainder of the test. The furnace thermocouples were connected to a separate data acquisition system and were not affected.

Following the test, the staff observed that the test laboratory project manager verified that the thermocouple calibration was within specifications (±2°C). The project manager concluded that the data acquisition breakdown was a signal processing problem that was caused by a poor multiplex system board connection. This problem was documented in the fire test report.

The fire test acceptance criteria specified that a fire test was successful if the barrier is intact and the cables do not have any visual fire damage after the fire and hose stream tests, even if the temperature rise criteria are exceeded. Heat transfer through the Scheme 12-1 barrier (as measured during the beginning and end of the fire exposure) did not raise the average temperature of the cable tray rails or the cable surfaces above either the allowable average temperature (321°F, 161°C) or the allowable maximum single point temperature (396°F, 202°C). Moreover, the test specimen met the conditions of acceptance for post-fire barrier and cable condition. The staff concluded that the loss of the test specimen temperature data during the middle portion of the test was not a concern. The staff also concluded that Scheme 12-1 met the conditions of acceptance for post-fire barrier and cable condition and, therefore, that the fire test was successful.

Hose Stream Damage (Scheme 12-2)

In its letter of October 29, 1992, the staff approved the use of a fog hose stream test in accordance with NUREG-0800, "Standard Review Plan." According to Branch Technical Position (BTP) CMEB 9.5-1, Section C.5.a.(3)(c) of NUREG-0800 the hose stream test was successful if the barrier remained intact and did not allow projection of water beyond the unexposed surface.

The test report for Scheme 12-2 stated that an opening was present in the tee section of the cable tray system and that an opening was present along the lower edge of the mouth of the cable tray tee section. The staff was concerned that the fire test report did not identify the cause of the opening and that the opening was an apparent test failure that was not evaluated by the applicant.

Revision 2 to ER-ME-067 indicated that the opening occurred during the hose stream test. However, because ER-ME-067 was based on the fire test report, which did not discuss the cause of the opening, and because ER-ME-067 was marked as an interim report, the staff also questioned the correctness of the information it contained on the fire barrier failure.

The applicant provided additional information in its letter of January 25, 1993. The applicant confirmed that the Thermo-Lag panel located below the fire stop in the tee section sagged leaving an opening between the panel and the fire stop during the hose stream test. The applicant attributed the failure to the absence of mechanical fasteners and failure of the trowel-grade Thermo-Lag to form an adequate mechanical bond at the joint between the penetration seal and the Thermo-Lag panel. The applicant also stated that it revised its fire barrier design to require mechanical attachment of bottom Thermo-Lag panels to fire stops. The applicant successfully tested the design change in Scheme 14-1, and implemented the design change into CPSES, Unit 2, through a design change authorization (which included upgrading previously installed configurations). The staff concluded that, based on the development and implementation of a corrective design change, failure of the hose stream test for Scheme 12-2 was an acceptable deviation from the fire test acceptance criteria specified in the staff's letter of October 29, 1992, and BTP CMEB 9.5-1, Section C.5.a.(3)(c).

Maximum Single Point Temperature Exceeded (Scheme 14-1)

The ambient temperature at the start of the test for Scheme 14-1 was 70 °F (21°C). Therefore, the maximum allowable individual temperature for Scheme 14-1 was 395°F (202°C). Thermocouple 91 (located on the horizontal centerline of the tray rail on the tee section, opposite the mouth of the tee) deviated from the maximum single point temperature limitation. It reached 395°F (202°C) at 59 minutes and 401°F (205°C) at 60 minutes. The Scheme 14-1 test report stated that the barrier did not burn through and there was no visible cable damage.

The fire test acceptance criteria specified that a fire test was successful if the barrier did not burn through and the cables did not have any visual fire damage even if the temperature criteria were exceeded. The staff concluded that Scheme 14-1 met the conditions of acceptance for post-fire barrier and cable condition and, therefore, that the fire test was successful.

Cable Stiffening

The laboratory removed the cables from each test specimen raceway and inspected them for visual damage after assessing the post-fire barrier condition. Except for Scheme 11-1, which was evaluated above, the applicant did not identify any of the cable damage attributes specified in the staff's letter of October 29, 1992.

The staff inspected the cables from Schemes 9-1 and 10-1 and concurred with the results of the visual cable inspections. However, the staff noted that when some of the cables that were exposed to the fire environment (heated cable) were flexed by hand, they felt stiffer than those that were not heated by the fire (unheated cable). Several cycles of flexing appeared to restore the flexibility of the cable segments that had been heated.

At the staff's request, the applicant dissected two sections of the instrumentation cable that was installed in a ¾-inch diameter conduit (Scheme 9-1). One section of the cable was located in a portion of the conduit that was heated during the fire exposure. The other section extended out of the conduit and, therefore, was not heated during the fire test. The staff's inspection of the heated cable section revealed that the cable jacket had not hardened, but the shielding material had constricted around the insulation of the individual conductors and the filler material located between the individual conductors had softened. These conditions caused the individual conductors to stick together and resulted in the heated cable being less flexible than the unheated cable. The cable jacket and the insulation of the individual conductors were free of visual fire damage. The shielding in the unheated section of the cable was not constricted and the filler material was not softened.

Cable stiffening was reported in each of the fire test reports audited by the staff. In ER-ME-067, Revision 2, the applicant stated that cable stiffening had no effect on cable performance. The individual test reports indicated that the post-fire cable insulation resistance test results were within acceptable specifications. Based on its observations of cable condition, including the condition of the cable jacket and the insulation of the individual conductors, and the satisfactory cable insulation resistance tests, the staff concluded that observed shrinkage of the shielding and softening of the cable filler material did not affect cable functionality.

<u>9-Inch Rule</u>

CPSES site specifications require that thermally conductive items that penetrate raceway fire barriers, including raceway supports, be covered with Thermo-Lag 330-1 material from the point of the penetration to a point 9 inches away from the point of the penetration. This is known as the 9-inch rule. With the exception of Scheme 1-2, the applicant applied the 9-inch rule to the raceway supports for the Unit 2 test specimens. The applicant's tests demonstrated that for the Unit 2 barrier configurations, covering heat conducting protruding items with Thermo-Lag for a distance of at least 9 inches from the barrier envelope is adequate to prevent excessive heat transfer into the barrier through the protruding item. The 9-inch rule is, therefore, acceptable for the Unit 2 Thermo-Lag fire barriers.

<u>Cable Types and Cable Fill</u>

During the meeting of October 27, 1992, the applicant informed the staff that CPSES procedures prohibited cabling from extending above the cable tray side rails, and that all CPSES Unit 2 power and instrument cable met IEEE Standard

383 and had thermosetting insulation. In its letter of October 29, 1992, the staff requested that the licensee confirm these facts in writing.
In ER-ME-067, Revision 2, the applicant stated that Thermo-Lag installation specifications, electrical installation specifications and quality control (QC) inspection procedures preclude the installation of Thermo-Lag panels if the cable fill results in cables extending above the tray side rails except where cables enter or exit the tray. Where a specific cable tray is found to be overfilled, the applicant stated that the height of the Thermo-Lag panel pieces installed along the cable tray side rails is increased. This increases the height of the Thermo-Lag fire barrier and prevents the cables from contacting the inside surface of the Thermo-Lag panel installed over the top of the tray. This resolved the staff's concern that cables in direct contact with Thermo-Lag panels could be damaged during a fire exposure.

In letters of January 19, 1993, and January 25, 1993, the licensee confirmed that all cables installed in raceways protected with Thermo-Lag fire barriers to satisfy fire safe shutdown requirements are IEEE-383 qualified and have thermosetting or mineral insulation. This satisfied the staff's request.

Thermo-Lag 350 Topcoat

In SSER 12, the staff concluded that the CPSES interior finishes were noncombustible or had a flame spread rating of 50 or less. The staff concluded that the interior finishes met the guidelines of BTP CMEB 9.5-1, Section C.5.a, and were, therefore, acceptable. Revision 2 to ER-ME-067 indicated that the applicant's Thermo-Lag fire barriers are finished with the vendor's top coating product (Thermo-Lag 350 Topcoat).

In ER-ME-067, Revision 2, the applicant stated that the flame spread rating for Thermo-Lag was 5. However, the report did not indicate whether or not this flame spread rating applied to Thermo-Lag 350 Topcoat. In a letter of January 19, 1993, the applicant informed the staff that Underwriters Laboratories, Incorporated (UL) determined that the flame spread rating for Thermo-Lag with topcoat was 5. During the meeting of January 21, 1993, the applicant confirmed that the UL test was performed in accordance with ASTM Standard E-84, "Standard Test Method for Surface Burning Characteristics of Building Materials." This flame spread rating meets the guidelines of BTP CMEB 9.5-1, Section C.5.a, and is, therefore, acceptable.

The staff was also concerned that the top coating product was never subjected to full-scale fire endurance testing. The 350 Topcoat was applied by the vendor as part of the manufacturing process to the Thermo-Lag 330-1 prefabricated panels and preshaped conduit sections used to construct the test specimens. Top coat was also applied to each of the applicant's test specimens after assembly in accordance with CPSES installation specifications and procedures. With the exception of Scheme 1-2, the Unit 2 test specimens with the topcoat met the test acceptance criteria approved by the staff in its October 29, 1992 letter. This resolves the staff's concern.

Combustibility of Thermo-Lag 330-1

To evaluate a staff concern that Thermo-Lag 330-1 material may be combustible, the staff's technical assistance contractor, the National Institute of Standards and Technology (NIST), subjected Thermo-Lag 330-1 material to the test methods specified in ASTM Standard E-136, "Standard Test Method for Behavior of Material in a Vertical Tube Furnace at 750°C," and ASTM Standard E-1354, "Standard Test Method for Heat and Visible Smoke Release Rates from Materials and Products Using an Oxygen Consumption Calorimeter." The staff evaluated the results of these tests and concluded that Thermo-Lag 330-1 material is combustible as defined in BTP CMEB 9.5-1. On December 15, 1992, the NRC issued Information Notice (IN) 92-82, "Results of Thermo-Lag 330-1 Combustibility Testing," to alert licensees and applicants of the results of the combustibility tests.

In letters of January 19, 1993, and January 25, 1993, the applicant described how it addressed the combustibility of Thermo-Lag 330-1 at CPSES, Unit 2. The applicant stated that there is no Thermo-Lag installed that could act as an intervening combustible between safe shutdown trains or as radiant energy shields inside containment structures. The applicant also stated that, based on its fire hazards analysis, it had provided adequate fire protection features, such as sprinkler systems, to address the combustible properties of Thermo-Lag. The applicant also stated that it is actively participating in the generic NUMARC effort to address Thermo-Lag combustibility. The staff did not agree with the applicant's assertion that ASTM E-136 is not an appropriate test to determine the combustibility of Thermo-Lag. The staff concluded, however, that the applicant's approach to addressing the combustibility issues identified in IN 92-82 was adequate pending completion of the NUMARC program.

Thermo-Lag Receipt Acceptance Criteria

In a telephone conversation of October 20, 1992, and a letter of November 7, 1992, the manufacturer of Thermo-Lag fire barrier materials (the vendor) informed the staff that some preshaped Thermo-Lag conduit sections received by the applicant showed signs of delamination and voids. The staff was concerned that the use of defective fire barrier materials could affect the applicant's fire test results and the fire performance of the Thermo-Lag fire barriers installed at CPSES Unit 2. The staff requested additional information from the applicant in a letter of November 25, 1992. The applicant responded in a letter of December 15, 1992.

In its letter, the applicant described the actions it had taken to ensure that the fire barrier materials used in its fire test program were representative of the materials installed in CPSES, described its quality controls and receipt inspection process, and described how it had addressed the delamination and void concerns. ER-ME-067, revision 2, also provided information on the applicant's receipt acceptance criteria for Thermo-Lag materials.

The staff evaluated the information provided by the applicant, observed the construction of several fire test specimens, and audited the applicant's fire barrier material procurement specifications, procedures, and documents during the CPSES, Unit 2 site visit of January 11 through 15, 1993. The staff concluded that the applicant's source inspections, including verification of the vendor's thickness and weight measurements, coupled with the applicant's receipt inspections provided reasonable assurance that the prefabricated and preshaped Thermo-Lag fire barrier materials used at CPSES Unit 2 are acceptable. The staff also concluded that the Thermo-Lag materials used to construct the fire test specimens were representative of the materials installed at CPSES, Unit 2, that the fire test program demonstrated that the nominal thickness variations and voids inherent in the prefabricated Thermo-Lag 330-1 fire barrier materials do not cause premature failure of the tested fire barrier configurations, and that the applicant had adequately addressed the delamination and void concerns that the vendor identified to the staff.

Generic Letter 92-08

On December 17, 1992, the NRC issued Generic Letter 92-08, "Thermo-Lag 330-1 Fire Barriers," to obtain additional information needed to verify that the Thermo-Lag 330-1 fire barrier system complies with the NRC's requirements. The generic letter required all addressees to submit a written report that addressed the use of Thermo-Lag fire barriers, fire endurance and ampacity derating testing, and the application of test results.

The applicant submitted the written report required by Generic Letter 92-08 in a letter of January 19, 1993 (TU Electric letter TXX-93038). The staff found the applicant's response acceptable for CPSES Unit 2 based on the satisfactory completion of the plant specific fire endurance test program, the applicant's use of the test results to design and construct the CPSES Unit 2 fire barriers, and its commitment to perform plant specific ampacity derating tests by the completion of the first CPSES Unit 2 refueling outage.

Fire Barrier Deviations and Special Configurations

By a letter of January 19, 1992, the applicant submitted its engineering report ER-ME-082, "Evaluation of Unit 2 Thermo-Lag Configurations," to the staff for review. The purpose of the applicant's evaluation was to establish the design basis for the Thermo-Lag fire barriers installed at CPSES Unit 2 that deviated from the tested configurations and to provide reasonable assurance that these Thermo-Lag fire barrier configurations will provide sufficient fire resistance to assure that at least one train of safe shutdown systems will remain free from fire damage.

The applicant's fire testing program established the technical and installation attributes for most of the Thermo-Lag fire barrier configurations installed in CPSES, Unit 2. The applicant documented about 180 cases where the application of Thermo-Lag fire barrier materials used to protect electrical raceways and structural steel deviated from the tested configurations. The staff recognized that there are actual field conditions that cause the application of fire barrier assemblies to deviate from the tested configurations. These cases may require the creation of a unique fire barrier design to address structural steel, other raceway, or mechanical equipment interferences. The staff also recognized that it was not feasible to qualify all aspects of the fire barrier deviations through configuration-specific fire endurance testing. In Generic Letter 86-10 the staff provided guidance for performing engineering evaluations of raceway fire barrier systems that deviated from the tested configurations. The applicant in its engineering evaluation used this guidance to establish its fire barrier evaluation criteria. The following summarizes the applicant's criteria: the continuity of the fire barrier material applied was consistent with the tested configuration; the effective thickness of the fire barrier material applied to the unique configuration was consistent with the thickness of the fire barrier material which was tested; the nature and effectiveness of the fire barrier support assembly was consistent with the tested configurations; and the application and end use of the fire barrier material was consistent with the tested configuration. The applicant included its evaluations of the following: unique fire barrier configurations; minor protected commodity deviations; protruding and interfering item coverage deviations; and structural steel deviations.

The staff, during its review of the applicant's engineering report, sampled those unique configurations where the fire barrier installations installed on safe shutdown raceways deviated from the conditions of its fire test program. The following is summary of the staff's review and evaluation of these unique configurations.

Auxiliary Building Elevation 810', Room X-207

<u>Configuration 1</u> - Three cable tray vertical stack assembly. This fire barrier configuration enclosed two 24-inch and one 30-inch cable tray in a box assembly. The fire barrier box assembly enclosed these trays for a straight run of approximately 6 feet. The box assembly was approximately 5 feet in height. Cable trays T230ACA75 and T230ACG75 are protected by Thermo-Lag as they enter and exit the fire barrier box assembly. One side of the fire barrier box assembly was attached to the concrete wall with Hilti bolts. Penetrating the concrete wall inside the fire barrier box assembly were 40 conduit sleeves which exit the cable spreading room and air drop its cables into the cable trays which are enclosed by the box assembly. The fire barrier box was constructed of ½ inch prefabricated Thermo-Lag 330-1 panels supported by a Unistrut frame. The joints and seams were stitched and reinforced with stress skin. The top and bottom sections of the box that extend from the tray to the wall use the score and fold method and are shaped accordingly. The bottom panel was tie wired to every other rung of the bottom tray and the sides were banded through the side of Thermo-Lag side panels to the trays.

The applicant's evaluation claimed that due to the large air volume and the thermal mass of the raceway and structural steel enclosed within the fire barrier assembly the thermal protection afforded to the protected raceways inside the enclosure was adequate. This conclusion was based on the fact that one side of this enclosure was a concrete wall, the methods of attaching the Thermo-Lag fire barrier panels to the raceway used conservative mechanical attachment techniques (for example, tie wire attachment of panels to tray bottom and to the Unistrut frame), and that the barrier joints were reinforced by stitching and stress skin.

The staff, from its review of this configuration, could not fully establish the applicant's basis for determining that this box configuration had similar construction attributes to fire tested box configurations, such as junction boxes (JBs). The staff noted that the mechanical methods of attaching the vertical Thermo-Lag panels with tie wire had not been qualified by fire testing. In addition, the applicant, in its qualification of JB barriers installed a second layer of Thermo-Lag fire barrier panel material.

The staff concluded that this and other box configurations using similar fire barrier construction techniques are not adequately justified by the applicant's engineering report and that these types of barrier systems may not provide the level of assurance required to assure that one train of safe shut down capability remain free from fire damage.

The staff discussed their findings with the applicant, stating that the applicant would be expected to implement compensatory measures in accordance with CPSES procedures until the barriers are qualified and operable. In a letter of January 28, 1993, the applicant committed to implement compensatory measures and to establish the qualification of the box enclosure barriers. The staff concluded that the applicant's commitments are acceptable and that the compensatory measures (discussed below) will provide an adequate level of fire protection until the barrier concerns are resolved.

Auxiliary Building Elevation 790, Room X-174

<u>Configuration 2</u> - This fire barrier assembly enclosed two parallel cable trays (T220ABC08 and T230ACA24), one 18 inch and one 12 inch, running horizontally down a corridor. This fire barrier enclosure was approximately 60 feet long. The enclosure was constructed in such a manner that the trays had a Thermo-Lag partition (except at the tray splice plates) separating the trays within the enclosure. The common enclosure top and bottom was fabricated using Thermo-Lag 330-1 panels with the bottom panels being secured to the rungs of the trays with tie wires. This tie wire attachment was applied to every other rung with at least two ties per rung. The seams of this configuration were provided with stress skin overlays and the butt joints were stitched and overlaid with stress skin.

The applicant's evaluation, found that the effective width of this configuration was similar to the 30 inch and the 36 inch tested tray configurations and that the upgrade techniques were used to secure the bottom fire barrier panels to the bottom of the cable trays.

The staff found, from its review, that this configuration was properly supported and the fire barrier material and its application were consistent with the construction and upgrade attributes established by the applicant's fire testing program for the 30-inch cable tray. The staff found this unique fire barrier configuration acceptable subject to the confirmatory resolution of staff concerns regarding the 36-inch wide cable tray fire barrier, discussed above - "Bounding Configurations (Scheme 1-2)".

Safeguards Building, Elevation 810', Room 2-083

Configuration 3 - This configuration consists of two vertical 24-inch wide cable trays which air drop its cables into conduit sleeves which penetrate the concrete wall interfacing with Room 2-082. The two cable trays are independently protected with Thermo-Lag to the point that they terminate and the cables air drop. At this point a Thermo-Lag box enclosure (5 feet x 7 feet x 10 inches) was constructed to enclose the air drop cables and the conduit sleeves. The box was secured to the wall with Hilti bolts and the joints and corners were upgraded with stress skin overlays.

The applicant's evaluation claimed that due to the large air volume and the thermal mass of the raceway and structural steel enclosed within the fire barrier assembly that the thermal protection afforded to the protected raceways inside the enclosure was adequate. This conclusion was based on the fact that one side of this enclosure was a concrete wall, the methods of attaching the Thermo-Lag fire barrier panels to the wall and raceway used conservative mechanical attachment techniques and that all joints were reinforced with stitching and stress skin.

The staff found this configuration to be similar to configuration 1, evaluated above. The staff's concerns with the configuration 1 barrier design also apply to this configuration. Accordingly, this is another example of a box enclosure barrier that the staff has determined necessitates compensatory measures until the barrier is qualified and operable. In a letter of January 28, 1993, the applicant committed to implement compensatory measures and to establish the qualification of the box enclosure barriers. The staff concluded that the applicant's commitments are acceptable and that the compensatory measures (discussed below) will provide an adequate level of fire protection until the barrier concerns are resolved.

Configuration 4 - This configuration consisted of two oversized JBs, installed against a concrete wall and boxed together. Between the JBs only a single layer of Thermo-Lag panel was installed. The remaining exposed sides of the JBs were protected with two layers of Thermo-Lag fire barrier panel material. The joints and seams were overlaid with stress skin and trowel grade material. The banding application could not be applied circumferentially around the JBs. Therefore, the applicant attached the bands to steel angles which were bolted to the wall above and below these JBs.

The applicant's evaluation of this configuration found it acceptable on the basis that one side of these JBs was attached to the wall which will act as a heat sink in the event of a fire in this area. The applicant's evaluation identified that the JBs in this configuration exceeded the sizes of the JBs tested as part of its testing program. The applicant found the fire barrier configuration acceptable due to the extra thermal mass created by the size of these JBs. In addition, the applicant found the alternative banding method to be equivalent to the tested method for banding the outer Thermo-Lag panels to the JBs.

The staff found, from its review, that this configuration, with the modified banding configuration, would assure that the outer Thermo-Lag panels would remain in place if a postulated fire were to occur in the area of this assembly. In addition, the staff found that the fire barrier material was applied to these oversized JBs using the same construction and upgrade attributes established by the applicant's fire testing program. Therefore, the staff found this unique fire barrier configuration acceptable and concluded that it will provide reasonable assurance that the shutdown functions being protected will be maintained free from fire damage.

Safeguards Building, Elevation 810', Room 2-082

<u>Configuration 5</u> - This configuration consists of cables air dropping out of several embedded wall conduit sleeves and entering three short run horizontal cable trays above the two service water lines running down the corridor. These cables exited these horizontal trays and air drop into a 30-inch tray which runs under the service water lines. The cables leaving the sleeves are protected with Flexiblanket 660 fire barrier material. When these cables enter the three horizontal trays installed above the service water piping they are protected in the trays by Thermo-Lag 330-1 fire prefabricated panel system. These trays were protected independently. As these cables exited the tray segments above the service water piping, they were protected by Flexiblanket 660 fire barrier material. The cables entered the 30-inch tray through the top of panel of the Thermo-Lag fire barrier system installed on this tray. To accommodate the air drop cables entering the 30-inch tray, a 12-inch wide by 43-inch long opening was cut into the top tray panel. A 6-inch high curb constructed out of Thermo-Lag 330-1 prefabricated panels was installed around the opening and this opening was filled with Thermo-Lag 660 trowel-grade material.

The applicant found this configuration an acceptable deviation on the basis that the air drop cable bundles that exceed the 6-inch diameter limit established in its testing program contain more thermal mass and therefore are less sensitive to thermal fire conditions. In addition, the air drop-cable tray fire barrier penetration configuration was upgraded with techniques confirmed by test.

The staff found this configuration acceptable on the basis that the continuity of the fire barrier was applied in a consistent manner to the protected raceway and was similar in configuration to various attributes which were qualified by the applicant's fire testing program.

Safeguards Building, Elevation 831', Room 2-088

<u>Configuration 6</u> - This configuration consisted of enclosing two JBs installed on a common support in one fire barrier enclosure. Each JB was enclosed in the first layer of Thermo-Lag 330 panel material separately and the second layer was applied using the score and fold method to enclose both JBs. The joints and seams were either overlaid with stress skin or were stitched.

The applicant's evaluation of this configuration found it acceptable on the basis that the common JB enclosure will be a greater heat sink than the JB fire barrier configurations the applicant tested as part of its fire test program.

The staff found, from its review of this configuration, that the fire barrier material was applied to this common JB enclosure using the same construction and upgrade attributes established by the applicant's fire testing program. Therefore, the staff found this unique fire barrier configuration acceptable and concluded that it will provide reasonable assurance that the shutdown functions being protected will be maintained free from fire damage.

From the sample of the fire barrier deviation conditions reviewed, the staff found that the construction and upgrade attributes used on these configurations is consistent with the design and installation requirements established by the applicant's design and installation specification and the installation procedure. The staff also found the continuity of material application, the thickness of the material applied and the upgrade techniques, except for the multi-conduit sleeve/cable tray box configurations, to follow the same design logic as those attributes applied to the fire test specimens. The remaining Thermo-Lag fire barrier deviation conditions documented by the applicant's engineering report ER-ME-082 and its adequacy to provide a reasonable assurance that they can maintain the protected safe shutdown component or raceway free from fire damage are subject to future NRC audit.

The fire barrier configurations tested by the applicant were plant specific to CPSES Unit 2, and bounded the range of fire barrier sizes and configurations installed in CPSES Unit 2.

<u>Compensatory Measures</u>

In a letter to the staff of October 5, 1991, the vendor stated that Thermo-Lag trowel-grade material takes about 30 days to reach its optimum properties. In its letter of January 19, 1993, the applicant stated that it considered its Thermo-Lag fire barriers to be functional (capable of performing their design function) immediately after completion of the barrier installation and inspection. The applicant did not provide a technical basis for its assertion. In its letter of January 25, 1993, the applicant provided additional information and a letter from the vendor. In its letter, the vendor stated that it had revised its curing recommendation. The staff found that neither the applicant nor the vendor provided a technical basis for the revised recommendation.

The applicant cured its fire test specimens for at least 30 days prior to conducting the fire endurance tests. The staff was concerned that Thermo-Lag fire barriers are not functional until they are either cured for 30 days in accordance with the vendor's original recommendation or the installed barriers reflect the tested conditions. In the case of the applicant's tests for CPSES, Unit 2, this would also be 30 days. During a telephone conference of January 22, 1993, the staff requested that the applicant submit a technical basis that supported its position that Thermo-Lag fire barriers are functional immediately after completion of the barrier installation and inspection notwithstanding the cure time.

In a letter of January 28, 1993, the applicant committed to provide fire watches as compensatory measures in accordance with the CPSES fire protection plan for the Thermo-Lag fire barriers installed in areas that contain fire-safe shutdown conduits or cable trays until the barriers have cured for 30 days, and where box enclosures are located until this issue is adequately resolved with the staff.

The use of fire watches is consistent with the compensatory measures implemented by the applicant for the CPSES Unit 1 Thermo-Lag fire barriers in response to NRC Bulletin 92-01, "Failure of Thermo-Lag 330 Fire Barrier System to Maintain Cabling in Wide Cable Trays and Small Conduits Free From Fire Damage," June 24, 1992. The staff concluded, therefore, that the applicant's commitment is acceptable and will ensure that an adequate level of fire protection will be provided at CPSES Unit 2 until the Thermo-Lag fire barriers are cured to reflect the condition of the fire test specimens and the box enclosure issue is resolved.

Conclusions

Based on its observations during test laboratory site visits, plant site audits and inspections, and safety evaluations, the staff concluded that except for Scheme 1-2, the applicant's fire endurance tests for CPSES Unit 2, were conducted in accordance with the methodology and acceptance criteria specified in the staff's letter of October 29, 1992. The staff also concluded that except for the deviating box configurations discussed above, the Thermo-Lag 330-1 fire barriers installed in CPSES Unit 2 were bounded by the plant specific fire test schemes as to materials, methods of assembly, dimensions, and configurations or provided an equivalent level of protection. Moreover, the staff concluded that except for the deviating box configurations discussed above, the CPSES Unit 2 Thermo-Lag fire barriers meet the guidelines of BTP CMEB 9.5-1, Section C.5 and are, therefore, acceptable. Additionally, the applicant committed to resolve the staff's concerns (as discussed above) regarding the 36-inch cable tray bounding issue.

The staff concluded that the applicant's Thermo-Lag fire barrier program for CPSES Unit 2, with approved deviations, compensatory measures, and confirmatory resolution of the 36-inch wide cable tray configuration, meets the staff fire protection guidelines of BTP CMEB 9.5-1 and is, therefore, acceptable.

Test Scheme Configuration Description	Average Raceway Temperature	Maximum Individual Raceway Temp.	Average Cable Temp.	Maximum Cable Temp.	Barrier Condition	Cable Condition	Staff conclusions
Scheme 1-2 36" wide cable tray w/Tee Upgraded barrier design	294 °F	377 °F	263 °F	314 °F	Damaged by hose stream.	Satisfactory	Test not conducted in accordance with staff letter of Oct. 29, 1992. Staff required confirmatory test of 36 inch wide cable tray fire barrier configuration.
Scheme 9-1 5", 3", & ¾" dia. conduits w/JB Upgraded barrier designs	Indeterminate	Indeterminate	156 °F 204 °F 244 °F	191 °F 309 °F 290 °F	Satisfactory	Satisfactory	Satisfactory test. Indeterminate temperature evaluation documented in SSER.
Scheme 10-1 Two 3" dia. conduits w/JBs Upgraded barrier design	Indeterminate	Indeterminate	166 °F 163 °F 172 °F 146 °F	233 °F 232 °F 186 °F 198 °F	Satisfactory	Satisfactory	Satisfactory test. Indeterminate temperature evaluation documented in SSER.
Scheme 10-2 Two 3" dia. conduits w/JBs Upgraded barrier design	Indeterminate	Indeterminate	186 °F 197 °F 280 °F 259 °F	324 °F 294 °F 366 °F 334 °F	Satisfactory	Satisfactory	Satisfactory test. Indeterminate temperature evaluation documented in SSER.
Scheme 11-1 24" wide cable tray w/air drops Upgraded barrier design	Conduits: Indeterminate. Tray rail: 242 °F	Conduits: Indeterminate. Tray rail: 301 °F	199 °F 195 °F 202 °F 201 °F	291 °F 291 °F 253 °F 240 °F	Satisfactory	Some jacket blistering and cracking	Satisfactory test. See evaluation of indeterminate conduit temperatures and cable functionality in SSER.
Scheme 12-1 30" wide cable tray w/o Tee Upgraded barrier design	272 °F	363 °F	255 °F	311 °F	Satisfactory	Satisfactory	Satisfactory test. No test deviations.
Scheme 12-2 24" wide cable tray w/Tee Upgraded barrier design	287 °F	353 °F	229 °F	280 °F	Minor hose stream damage	Satisfactory	Satisfactory test. See evaluation of hose stream test damage in SSER.
Scheme 13-1 12" wide cable tray w/o Tee Upgraded barrier design	285 °F	330 °F	270 °F	285 °F	Satisfactory	Satisfactory	Satisfactory test. No test deviations.
Scheme 14-1 30" wide cable tray w/Tee Upgraded barrier design	283 °F	401 °F	242 °F	336 °F	Satisfactory	Satisfactory	Satisfactory test. See evaluation of maximum individual raceway temperature in SSER.

Table 1. Fire Endurance Test Schemes Applied To CPSES, Unit 2

Ampacity

The applicant completed performance of the fire endurance testing in December 1992 and provided an interim Engineering Report ER-ME-067, "Evaluation of Thermo-Lag Fire Barrier Systems", Revision 2 for staff review. The applicant has committed to complete the required ampacity derating tests by the completion of the first refueling outage for CPSES Unit 2. The following evaluation reviews the technical basis of the ampacity derating factors assumed for CPSES Units 1 and 2 over the interim period until the applicant can complete the ampacity derating tests and associated analysis.

NRC Requirements and Guidance for Ampacity Derating

GDC 17 requires that onsite electric power systems be provided to permit the functioning of structures, systems, and components important to safety. The onsite electrical power system is required to have sufficient capacity and capability to ensure that vital functions are maintained. The Institute of Electrical and Electronics Engineers (IEEE) Standard 279, "Criteria for Protection Systems for Nuclear Power Generating Stations," and IEEE Standard 603, "Criteria for Safety Systems for Nuclear Power Generating Stations," include guidance on acceptable methods of satisfying GDC 17 and the single failure criterion. These IEEE standards state that the quality of protection system components and onsite power system shall be achieved by specifying requirements known to promote high quality, such as the requirements for the derating of components, and that the quality shall be consistent with minimum maintenance requirements and low failure rates. Furthermore, IEEE-279 and -603 state that type test data or reasonable engineering extrapolation based on test data shall be made available to verify that protection system equipment continually meets the performance requirements determined to be necessary for achieving the system requirements.

In Regulatory Guide (RG) 1.75, "Physical Independence of Electric Systems," the NRC staff gave guidance for complying with IEEE Standard 279 and GDC 17 for the physical independence of the circuits and electric equipment comprising or associated with the Class 1E power system. The applicant uses Thermo-Lag 330-1 barriers to achieve physical independence of Class 1E electrical systems in accordance with RG 1.75. The staff's concerns about ampacity derating apply to Thermo-Lag 330-1 barriers installed to achieve physical independence of electric systems and to those installed to protect safe shutdown capability from fire.

Ampacity Derating Tests and the Application of Ampacity Derating Test Results

Cables enclosed in electrical raceways protected with fire barrier materials are derated because of the insulating effect of the fire barrier material. Other factors that affect ampacity derating include cable fill, cable loading, cable type, raceway construction, and ambient temperature. The National Electrical Code, Insulated Cable Engineers Association (ICEA) publications, and other industry standards provide general ampacity derating factors for open air installations, but do not include derating factors for fire barrier systems. Although a national standard ampacity derating test method has not been established, ampacity derating factors for raceways enclosed with fire barrier material have been determined for specific installation configurations by testing.

The Thermo-Lag vendor has documented a wide range of ampacity derating factors that were determined by testing. For example, between 1981 and 1985, the vendor provided test reports to licensees that document ampacity derating factors for cable trays that range from 5.3 to 12.48 percent for 1-hour barriers and from 16.15 to 20.55 percent for 3-hour barriers. However, on October 2, 1986, the vendor informed the NRC and its customers by Mailgram that, while conducting a special services investigation in September 1986 at the Underwriters Laboratories, Incorporated (UL), it found that the ampacity derating factors for Thermo-Lag 330-1 barriers were greater than previous tests results (28.04 percent for 1-hour barriers and 31.15 percent for 3-hour barriers). However, the cable fill and tray configuration for each test differed from those tested previously. The NRC learned that UL performed duplicate cable tray baseline tests using a longer stabilization period (4 hours instead of 15 minutes) after the final current adjustment and obtained a higher baseline current, which yielded higher derating factors (36.1 percent for 1-hour barriers and 38.9 percent for 3-hour barriers). UL gave these test results to the vendor, but they were not submitted to the NRC or to licensees. While reviewing tests which had been conducted at Southwest Research Institute (SwRI) in 1986, the staff learned that the ampacity derating factor for another tested configuration was 37.4 percent for a 1-hour Thermo-Lag 330-1 barrier. The test procedures and test configurations tested at SwRI differed for each of the aforementioned tests. Therefore, the results from these different ampacity tests may not be directly comparable to each other.

The staff is concerned that the ampacity derating factors derived from the UL tests for similar Thermo-Lag 330-1 barrier designs are inconsistent with one another because of differing stabilization times, which calls into question the validity of the ampacity derating tests. While reviewing Industrial Testing Laboratories (ITL) test reports, the NRC staff noticed that ambient temperature and maximum cable temperature were allowed to vary widely for some tests (48°C instead of 40°C for ambient temperature and 94.4°C instead of 90°C for maximum cable temperature). ITL then used an ICEA procedure to calculate the ampacity derating factors by adjusting the tested current to 40°C ambient and 90°C cable temperature. Those tests may not be valid because the ambient and maximum cable temperatures were not maintained within specified limits in some tests. In IN 92-46, the NRC informed utilities that a licensee also discovered a mathematical error in the calculation of the ampacity derating factor as published in an ITL test report. A preliminary assessment of the use of lower-than-actual ampacity derating factors indicates that Thermo-Lag 330-1 barrier installations may allow cables to reach temperatures that exceed their ratings, which could accelerate cable aging.

The staff is also concerned that some licensees have not adequately reviewed the results of ampacity derating tests to determine if the tests are valid and if the test results apply to their plant designs. The staff ampacity derating concerns apply to the use of Thermo-Lag 330-1 on electrical raceways both as fire barriers to protect the safe shutdown capability and as barriers to create physical independence between electrical systems.

CPSES Fire Endurance Testing Results

As a result of the fire endurance testing conducted to date, the applicant has made the following conclusions:

1. Thermo-Lag material performs its design function if properly configured;

2. Thermo-Lag installations for conduit 2 inches diameter and smaller performs its design function when upgraded by addition of 1/4-inch thick overlay;

3. Thermo-Lag installations for cable trays perform their design function when unsupported bottom butt joints and vertical joints are reinforced with stitching and/or additional stress skin;

4. Thermo-Lag Box configuration for LBD boxes, JB boxes, etc. perform their design function when reinforced with additional stress skin;

5. Thermo-Lag 330-660 "flexi-blanket" installations on air drops perform their design function when properly configured.

A review of Engineering Report ER-ME-067 indicates that no deviations requiring cable functionality verification were identified by the applicant.

Interim Ampacity Derating Factors

The applicant selected the following cable ampacity derating factors for Thermo-Lag electrical raceways for CPSES Units 1 and 2:

1. 31 percent derating factor for single trays enclosed with Thermo-Lag material applied against ICEA P-534-440, "Cables in Random Filled Trays".

   Rationale:

   1 hour fire barrier derating factor taken based on 3 hour fire barrier test (1.0 inch thick Thermo-Lag product) as cited in the UL Report Project 86NK23826, File R6802. This determination is considered more conservative than the derating factor provided for the 1 hour fire barrier test (i.e., 28 percent).

2. 20 percent derating factor for single conduits enclosed with box design Thermo-Lag, applied against ICEA P-46-426, "Power Cable Ampacities ".

   Rationale:

   Derating factor has been determined by CPSES Calculation 16345/6-EE(B)-004.

3. 7.5 percent derating factor for single conduit enclosed with shell design Thermo-Lag, applied against ICEA P-46-426, "Power Cable Ampacities".

   Rationale:

   Derating factor was chosen based on the similarity of subject design to the TSI Report 111781 result for 1 inch conduit.

4. Other specific cable ampacity derating factors for free air wrapped cables.

   Rationale:

   Derating factors has been determined based on CPSES Calculation 16345-EE(B)-140.

Although the NRC Special Review Team recognized that in some extreme cases, nonconservative ampacity derating factors could induce premature cable jacket insulation failures over a period of time, the ampacity derating factor due to Thermo-Lag insulating properties represents but one variable to be used in determining the design ampacity for cable systems. For actual installations, the derating factors are typically applied to the ampacity values published in the ICEA Tables for each cable size. It should be noted that due to the conservative factors used, the ICEA ampacity values are lower than the base line values which have been typically determined by the ampacity derating tests. Cables are sized based on full load current times a factor of 1.25 in order to account for voltage and service factor requirements of the load. Upgrading of the cable size is another variable which may be required due to voltage drop consideration for long circuit lengths. Since most safety-related loads are operated intermittently, typically once a month during surveillance testing, the likelihood that cable related failures could be induced due to incorrect ampacity derating factors over the interim period has been judged by the staff to be improbable. The staff believes that the ampacity derating concern is an aging issue to be resolved over the long term. Therefore, the staff concludes that the use of interim ampacity derating factors is acceptable.

Additional Ampacity Derating Issues

In addition to the completion of the ampacity derating testing program, the following items were discussed with the applicant:

> Appendix C of the subject report references as the derating factor method "40% by Calculation/Testing ITL report 82-335-F-1" for cable trays. Although this report was not the report with the mathematical error identified in IN 92-46, the staff requested the applicant to clarify this reference.

The applicant responded by letter of January 25, 1993, stating that a cable derating factor of 31 percent was utilized using UL Report R6802. However, the applicant, in response to concerns raised by the NRC's Inspector General Report, performed a calculation to evaluate the acceptability of a 40 percent cable derating factor. The "40% derating by calculation" in Appendix C refers to this calculation. The applicant committed to revise the engineering report to reference the correct test report (UL 6802). The staff finds this acceptable.

The following issues were also discussed with the applicant, and will be reviewed further in conjunction with the staff's review of the applicant's ampacity derating test program:

1. The applicant states that ampacity derating based on ambient test environment of 40°C versus the normal plant ambient environment of 50°C (See Report Section 6.3) provides a more conservative parameter. The applicant discussed this issue further in their letter of January 25, 1993. The staff will review the applicable analysis which supports this assertion as part of the test program review.

2. The applicant states in the subject report that variations in configuration in the field that differ from the approved guidelines (for cable ampacity derating) are documented in the design change documents. The staff will review, in conjunction with the test program review, the engineering methodology used to determine that the ampacity derating was not impacted by the configuration variation.

3. Appendix C of the engineering report cites "various justification in DCA Engineering Basis" as the derating factor methodology for pull/junction boxes, electrical boxes in common enclosure, two conduits in common enclosure and two trays in common enclosure. The staff will review the technical basis for the acceptability of the derating factors assumed by TU Electric in conjunction with the test program review.

Conclusion

The applicant has committed in the engineering report (ER-ME-067, "Evaluation of Thermo-Lag Fire Barrier Systems"), to complete the required ampacity derating testing, and to identify corrective action, as required, by the completion of the first refueling outage for CPSES Unit 2. The staff will review the applicant's ampacity derating test program, which should be documented following the reporting requirements section of Generic Letter 92-08, "Thermo-Lag 330-1 Fire Barriers," specifically:

> State (1) whether or not the as-built Thermo-Lag 330-1 barrier configurations are consistent with the barrier configurations used during the ampacity derating tests relied upon by the licensee for the ampacity derating factors used for all raceways protected by Thermo-Lag 330-1 (for fire protection of safe shutdown capability or to achieve physical independence of electrical systems); (2) whether or not the ampacity derating test results relied upon by the licensee are correct and applicable to the plant design.

From the above, the staff concludes that there are no significant safety hazards due to ampacity derating concerns associated with the use of interim derating factors for cables enclosed by Thermo-Lag material for CPSES.

Seismic

As a result of the applicant's fire testing of the representative configurations of cable-trays, conduits, junction boxes and their supports with representative Thermo-Lag material, the applicant decided to upgrade certain configurations to ensure their satisfactory performance in the plant. The upgrade consisted of (1) adding ¼ in. Thermo-Lag overlays on the existing Thermo-Lag for conduits 2 in. diameter and smaller, (2) stitching and/or installing stress skin layers to the unsupported bottom butt joints and vertical joints, and (3) reinforcing the junction boxes, and box-out configurations of LBD boxes. This addition required the validation of the affected raceways and their supports. Also, the staff verified that the correct weights of the Thermo-Lag material were considered in the design of the electrical raceways and their supports.

This evaluation addresses the adequacy of the applicant's consideration of appropriate Thermo-Lag weights and seismic adequacy of the conduits, cable-trays and their supports. This evaluation also addresses seismic II over I considerations for Thermo-Lag material installed in the plant.

1. <u>Weight Consideration:</u>

   TU Electric letter of December 15, 1992 (TU Electric letter TXX-92589 to NRC), indicates that the applicant's quality assurance (QA) program for Thermo-Lag material required the verification of the weights of the prefabricated panels and conduit sections prior to shipment of the material (from the vendor) and at receipt inspection of the material at site. For example; the weight of a ½ in. (nominal) thick prefabricated panel was verified to be between 3.0 lbs/sq. ft. and 5.25 lbs/sq. ft., and that of a 3 ft. long half round section for 1 in. conduit to be between 2.6 lbs. and 4.5 lbs. The NRC staff verified the implementation of the QA requirement. Also, in TU Electric letter of December 23, 1992 (TU Electric letter TXX-92626 to NRC), Section 4.5.3, the applicant emphasized that the upper bound weights identified during the receipt inspection have been used in the seismic adequacy calculations. A review of TU Electric calculation No. 0218-CO-0429 confirmed the applicant's statement. A question, however, remained as to how the applicant assessed the weight of the trowelled Thermo-Lag material. For trowelled material, the applicant has used the material density of 84 lbs./cu. ft. However, depending on the density of the material, it could weigh up to a 120 lbs./cu. ft. In response to this concern, the applicant stated that the contribution of the trowelled material to the total Thermo-Lag weight was no more than 7%. Some difference from the assumed density would not affect the seismic analysis. The staff agrees with the applicant's assessment. Overall, the staff finds the applicant's consideration of Thermo-Lag weights in the seismic adequacy calculations reasonable and acceptable.

2. <u>Seismic Adequacy of Electrical Raceways and their Supports:</u>

   In Section 3.10B.3 of the FSAR, the applicant indicates that the full weights of the cable-trays and conduits (including the weight of the cables) have been used in the seismic analyses of the raceways and their supports. The FSAR does not explicitly indicate that the weights of the Thermo-Lag materials attached to the raceways have been considered in the analysis. However, Section 4.5.3 of TXX-92589 confirms that all Unit 2 electrical raceways and their supports have been qualified using the appropriate Thermo-Lag weights in accordance with the licensing basis documents. A review of sample calculations in TU Electric Calculation No. 0218-CO-0271 verifies the applicant's statement.

   One of the changes made in Section 3.10B.3 of Amendment 87 of the FSAR is related to the use of higher damping values (compared to the original FSAR commitment) when the Thermo-Lag upgrades are considered for the safety related conduit systems. The use of the proposed higher damping values requires case by case studies. However, the applicant informed the staff that for qualification of the Unit-2 safety related conduit systems, lower damping values (i.e., 2% for OBE, 3% for SSE) had been used even in the upgrade validation program. The applicant stated this by letter dated January 19, 1993 (TU Electric letter TXX-93088 to NRC).

Based on the review of the typical calculations provided in calculation 0271, and the seismic design criteria in the FSAR, the staff concludes that the Unit 2 safety related electrical raceways and their supports have been seismically qualified in accordance with the staff guidance in the Standard Review Plan (NUREG-0800) and are acceptable. However, as a result of the applicant's validation program, a number of corrective actions (additions and modifications of raceway supports) are identified. These corrective actions were completed, as documented in TU Electric letter of January 28, 1993.

3. <u>Seismic II over I Consideration for Thermo-Lag</u>

   The applicant classifies all fire-protection materials (including Thermo-Lag) as non-seismic. However, by provision C.2 of Regulatory Guide 1.29, "Seismic Design Classification", the failure of such material should not reduce the functioning of any Seismic Category I plant features. In Section 4.5.2 of TXX-92626, the applicant takes a position that the Thermo-Lag panels and sections are secured in place with extensive use of mechanical fasteners, staples, wire ties, additional stress skin, and steel bands, and would not fail in a gross manner (i.e., detachment of panels or sections from the raceways) to damage other Seismic Category I plant features. Based on the seismic analysis of the most commonly used panels and sections performed by the material supplier, and the tested material properties, the staff agrees with the applicant's assessment that in a maximum postulated seismic event at the plant, the Thermo-Lag material as attached to the raceways would not jeopardize the functioning of the essential plant features.

<u>Conclusion</u>

Based on the review of the applicant's submittals related to (1) Thermo-Lag weight consideration, (2) seismic adequacy of the safety related electrical raceways and their supports, and (3) II over I consideration for Thermo-Lag material; and audits of the implementation of the applicant's quality control procedure by the staff, the staff concludes:

1. The Thermo-Lag weights have been properly considered by the applicant in the seismic validation program.

2. The safety related cable-trays, conduits and their supports at CPSES Unit 2 affected by the additional weight of the Thermo-Lag material are able to withstand the postulated seismic loadings without exceeding the acceptance criteria commitments in the FSAR, and are acceptable. This conclusion is based on: (a) the higher damping values as proposed in Amendment 87 of the FSAR were not used for analyzing the Unit 2 conduit systems (as stated in

TU letter of January 19, 1993, and (b) the corrective actions as indicated by the validation program were implemented (as stated in TU letter of January 28, 1993).

3. The staff agrees with the applicant's assessment that the Thermo-Lag material as installed in the plant will not have damaging effects on other Seismic Category I features under the maximum postulated seismic event (i.e., SSE).

9.5.1.5.c Alternative or Dedicated Shutdown Capability

NRC Inspection Report 446/92-49 documents an onsite review of the applicant's safe shutdown capability. The inspection concentrated on specific circuits of concern, including those which have a physical separation that is less than that specified in Section III.G and have a connection to equipment whose spurious operation or maloperation could adversely affect the plant's safe shutdown capability. This concern is principally comprised of two items:

The maloperation of required equipment due to fire induced damage to associated cabling. Examples include false motor starts and stops, control signals, and instrument readings which may be initiated as a result of fire induced grounds, shorts, or open circuits.

The spurious operation of safety-related or nonsafety-related components that could prevent the accomplishment of a safe shutdown function.

The applicant has developed various methods to prevent and isolate spurious equipment operations that may occur as a result of fire. Specific examples noted include:

- administrative controls
- isolation/transfer switches which incorporate redundant fusing schemes
- fire wrap
- manual operator actions governed by written procedures

The applicant's post-fire safe shutdown analysis, for components having the potential to spuriously operate due to fire within a given fire area, such as flow path isolation or diversion valves, typically credits the use of manual operator actions. For interactions where reliance on manual operator actions is not feasible, other alternatives, such as fire wrapping of potentially affected cables have been implemented.

During a review (NRC Inspection Report 446/92-49) of plant schematic drawings and control circuit wiring diagrams, the staff noted that a postulated fire in the control room or cable spreading room could create a single hot short in the control circuitry of various motor operated valves (MOV), resulting in their spurious operation. The postulated fault could cause the position limit and torque switches to be bypassed. As a consequence, mechanical damage of the valve due to overtorque may occur. This condition could render the affected MOV inoperable (manually or automatically). This concern was previously described in detail by the NRC in Information Notice (IN) 92-18, "Potential for Loss of Remote Shutdown Capability During a Control Room Fire," dated February 28, 1992.

The applicant's assessment of this condition indicated the following:

CPSES MOV protection design is similar to the Washington Public Power Supply System Plant (WNP-2), i.e., all Class 1E thermal overload protection devices are bypassed for trip under all plant conditions

The concerns expressed in NRC IN 92-18, i.e., potential mechanical and/or electrical damage to MOVs sufficient to prevent operators from manually operating the valve, are valid for CPSES.

Approximately 55 MOVs are affected.

The control circuitry for the MOVs should be rewired internal to the motor control center (MCC) compartments so that the torque and limit switches in the valve operators are electrically connected downstream of the contacts located in the MCC.

The applicant's assessment of the Unit 2 modifications needed to correct the spurious operation condition indicated for those 55 MOV circuits which are vulnerable to failure that 41 MOV circuits potentially need to be modified and 14 require no modification.

In response to the NRC's concerns, the applicant committed in docketed correspondence dated December 23, 1992 (TU Electric letter TXX-92640 to NRC) to implement design changes in the control circuits of the affected MOVs, as required to assure that the torque and limit switches in the valve operators are electrically connected downstream of the contacts located in the MCC. The applicant committed to perform these alternative shutdown system design enhancements prior to startup from the first refueling outage for Unit 2 and prior to startup from the third refueling outage for Unit 1. These design enhancements will provide additional assurance, that a fire in either the control or cable spreading rooms, will not cause a spurious operation which will have an impact on alternative shutdown capability. The control and cable spreading rooms are equipped with fire detection and the cable spreading room contains automatic suppression. The control room is continually manned, and operators have been trained in manual fire fighting. The fire protection program in these areas meets Branch Technical Position 9.5.1, Appendix A. The staff finds the applicant's actions to address the concerns associated with IN 92-18 to be satisfactory and the planned corrective actions in conformance with their fire protection plan and therefore, acceptable.

9.5.1.5.e General Plant Guidelines

<u>Electrical Cable Construction, Cable Trays, and Cable Penetrations</u>

In SSER 12, the staff noted that there were small amounts of low-power service cable not qualified according to IEEE 383-1974 associated with radiation monitors and security systems located throughout the plant, and that they were all located in conduit, except for short connectors at the detectors. Further, the staff concluded that this was an acceptable deviation from Branch Technical Position (BTP) CMEB 9.5-1, Section C.5.e. In FSAR Amendment 87, the applicant noted that the same situation existed for the low-power service cabling for the Unit 2 secondary sampling system oxygen analyzer. The staff concludes that this additional small amount of cable not qualified to IEEE 383-1974, does not change the staff's evaluation and conclusions given in SSER 12, and is, therefore, also acceptable.

Fire Resistant Cables

By letters dated July 29, 1991 (TU Electric letter TXX-91248 to NRC), and April 1, 1992 (TU Electric letter TXX-92163 to NRC), the applicant proposed to use Rockbestos Fire Zone "R" cable in various safety-related safe shutdown systems as one-hour fire barriers.

Specifically, in the July 29, 1991, submittal, the applicant submitted information regarding the use of Rockbestos Fire Zone "R" cables in Class 1E and non-1E power and control fire safe shutdown circuits. The proposed cable 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. This cable is used in power and control circuits for the equipment required for fire safe shutdown systems outside the containment. During a site audit, the applicant identified that this cable is used specifically in the following applications: a circuit breaker for the train "B" diesel generator, turbine-driven auxiliary feedwater pump turbine trip and throttle valve, train "B" RHR pump room fan, train "B" RHR pump recirculation valve, a breaker in the 480-V ac switchgear train "B," and train "A" centrifugal charging pump room fan and recirculation valve.

In areas where one-hour fire-rated cables are used outside the containment, both detection and automatic suppression are provided, with the exception of three areas: in the laundry holdup area at auxiliary building elevation 790 ft., in valve room 66 at safeguards building elevation 790 ft., and the safeguards building stairwell areas. These areas were identified by the applicant by letter dated May, 13, 1992 (TU Electric letter TXX-92232 to NRC). Each of these areas was evaluated in the fire hazard analysis, which established administrative controls on the maximum permissible fire loadings. The proposed cable size is limited to No. 8 AWG. The voltage levels of the proposed cables will be between 125 V dc/120-V ac and 480-V ac.

The applicant also submitted for staff review Underwriters Laboratories, Inc., Report File R10925-1, "Report on Fire Resistant Cables," dated April 10, 1984. This describes the detailed description of the tests conducted on cables sizes ranging from No. 14 AWG to No. 6 AWG. The staff reviewed the Underwriters Laboratories, Inc. test data report, which was performed in accordance with ASTM E-119, and found that the test configuration was representative of the proposed cable configuration to be installed at CPSES Unit 2. In a letter of May 13, 1992 (TU Electric letter TXX-92232 to NRC), the applicant provided an analysis regarding the adequacy of the raceway supports for the fire zone "R" cable supports. The analysis identified that the raceway supports are able to retain their structural integrity in case of fire.

The test data and the analysis also indicated that the Rockbestos cable retained its ability to function when exposed to water suppression in postfire conditions in that these conditions did not create shorts or postfire mechanical forces that could affect the operability of the safe shutdown equipment.

On the basis of these reviews, the staff concluded that the proposed use of this cable in safe shutdown systems would not impair the ability of the plant to achieve and maintain safe shutdown in the event of a fire. Therefore, the use of Rockbestos Fire Zone "R" cables in the proposed applications is acceptable.

9.5.1.6 Fire Detection and Suppression

Fire Detection

The presence of fire detection systems was evaluated through review of the Fire Protection Report and by plant walkdown. Many of the partial installation issues which existed in Unit 1 and which required evaluations based on guidance in Generic Letter 86-10, do not exist for Unit 2 because full area detection was installed. Based on this review, which also included a comparison of the existing coverage for Unit 1, the detection for Unit 2 as described in Revision 6 to the Fire Protection Report is found to be acceptable.

Water Fire Suppression

The status of sprinkler system installation was reviewed during this evaluation. Although the number and type of systems are essentially the same for Unit 2 as exist in Unit 1, Unit 2 does not have the extent of partial coverage systems. In particular, the switchgear rooms in Unit 2 have been provided with complete coverage thereby eliminating the need for formal review of partial coverage configurations. At Comanche Peak Unit 2 automatic fixed water fire suppression systems are installed in safety related areas of the plant where a high fire hazard exists; where redundant safe shutdown equipment or cabling outside the containment building is located in the same fire area and is not separated by a three hour fire barrier; and where there is a congestion of cabling (e.g., tray stacks of four trays or more).

Several systems were walked down during the site visit including those in the switchgear rooms. The sprinkler installations and the selection of the thermal actuation setpoints of the ceiling level sprinklers follow the guidance of NFPA 13, "Standard for the Design of Automatic Sprinkler Systems." In addition to the ceiling level sprinklers, automatic fixed cable tray suppression systems in areas where cable congestion is present are installed. The cable tray suppression coverage is an extension of the sprinklers provided for area coverage. The current layout of these systems, for horizontal tray stacks, has the nozzles arranged in a "vertical stand-off" fashion, spaced 6-12 inches away from the tray side rails. The nozzles are on only one side of the tray stack and are offset 6-12 inches above the horizontal plane of the trays. In addition, the top of the tray is protected by nozzles positioned over the mid-line of the top tray. The individual cable tray water spray nozzles are provided with baffles. These baffles have a dual function, they prevent "cold solder" effects[1] and act as a heat collector to improve the nozzle actuation time. The applicant's design basis for these systems is to confine a fire to the congested tray array. The applicant has applied certain aspects of NFPA 15, "Water Spray Fixed Systems For Fire Protection," to the design of the cable tray suppression systems. These systems are designed to apply a water spray application density of 0.15 gpm per ft^2 of cable tray. The cable water spray nozzles have an actuation setpoint of 175°F. It is anticipated that these cable tray water spray systems would react to a flaming cable tray fire condition in the following manner: as the fire transitions from a smoldering to a flaming phase the heat generated by the fire plume would be collected by the water spray nozzle baffle; this baffle, acting as a heat collector, will collect the heat generated by the fire plume and direct the heat towards the water spray nozzle fusible actuation element; and, based on the design and layout of these cable tray water spray system, the upper level nozzles would be the first to react to the fire condition and would control and confine the fire to the affected cable tray array. The design concepts used by the applicant and the philosophy associated with the installation and the application of the Unit 2 automatic water fire suppression were found to be consistent with Unit 1 and the guidance of Branch Technical Position 9.5-1, Appendix A and therefore, are acceptable.

Halon Testing

The status of testing the Halon systems was discussed with the applicant. Unlike Unit 1, the applicant does not intend to perform Halon discharge tests as part of the system acceptance testing. Rather, the applicant intends to perform a system design review coupled with a room integrity test using the "door fan" technique. This practice is consistent with current guidance provided in NFPA 12A, "Standard on Halon 1301 Fire Extinguisher Systems" which has been changed to address the environmental concerns associated with Halon discharge to the atmosphere; therefore, the staff finds this acceptable.

9.5.1.7.b Fire Protection of Specific Plant Areas

Control Room

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

In Amendment 83 to the FSAR, the applicant indicated that in lieu of ASTM E-84, the control room carpet was purchased to comply with Class II, or higher, interior floor finish requirements of National Fire Protection

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[1] Cold Solder effects occur when an adjacent operating sprinkler sprays water directly onto the fusible operating element of an adjacent sprinkler. Without the use of a baffle to shield those sprinklers which are located within the zone influenced by the operating sprinkler, the water spray will create a significant delay on the operation of subsequent sprinklers in the area of the fire.

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

The staff had previously determined (NRC Inspection Report 50-445/91-42; 50-446/91-42) that the installed carpet is equivalent to requirements previously approved by the NRC and is, therefore, acceptable. However, SSER 25 contained a confirmatory item to track the applicant's revision of the FSAR to conform with the approved installation. The applicant submitted an advance FSAR change by letter of December 22, 1992 (TU Electric letter TXX-92637 to NRC) which committed to incorporate in FSAR Amendment 88 a statement that the carpet installed in the control room envelope complies with Class I interior floor finish requirements of NFPA 101, 1991 Edition. This commitment and the proposed FSAR revision is acceptable.

Conclusion

Based on the review of the FSAR through Amendment 87 and the Fire Protection Report through Revision 6, the fire protection program for Comanche Peak Steam Electric Station Unit 2 is found to be acceptable. The requirements of 10 CFR 50.48 are met.

9.5.9 Emergency Diesel Generator Reliability

In August 1983, a crankshaft failed in an emergency diesel generator (EDG) at the Shoreham plant. The EDG was manufactured by Transamerica DeLaval, Inc. (TDI)[2]. As a consequence of this failure the nuclear facilities that owned TDI EDGs formed a TDI Owners Group which, in conjunction with the staff, initiated an extensive review of the acceptability of the TDI diesel generators for use as emergency power sources at nuclear power plants. This review was conducted in two phases, and consisted of a review of the design and an inspection of a large number of engine components. Phase I involved a design review of 16 major engine components and an inspection of the installed components to validate the quality of their manufacture. Phase I concentrated on engine components with known problems. Phase II was identical to Phase I, but was performed at a different time and concentrated on other important engine components. The activities associated with Phase I and Phase II reviews and inspections are known as the Design Review/Quality Revalidation (DR/QR) program.

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

The TDI Owners Group DR/QR program was evaluated for the staff by Pacific Northwest Laboratory, Inc. (PNL). The findings of the PNL evaluation relative to DR/QR actions for Phase I components are documented in PNL-5600, "Review of Resolution of Known Problems in Engine Components for Transamerica Delaval Inc., Emergency Diesel Generators," dated December 1985. The staff endorsed PNL-5600, with minor exceptions, in NUREG-1216, "Safety Evaluation Report Related to the Operability and Reliability of Emergency Diesel Generators Manufactured by Transamerica Delaval, Inc.," dated August 1986. The results of the PNL evaluation relative to DR/QR actions for Phase II components are documented in PNL-5444, "Review of Design Review and Quality Revalidation Report for the Transamerica Delaval Inc., Diesel Generators at Comanche Peak Steam Electric Station Unit 1," dated October 1985. PNL concluded that the studies conducted on the individual Phase II engine components were generally adequate and sufficiently detailed to establish that the components in service will perform their intended function. The PNL conclusion is also endorsed in NUREG-1216.

The staff has reviewed the QR action associated with Phase I engine components for Comanche Peak Units 1 and 2. The findings of these reviews were documented in SSER 22 and SSER 25 for Units 1 and 2, respectively. On the basis of its review in SSER 25, the staff concluded that with the exception of the open issues pertaining to the engine block metallurgical examination and procedural upgrades/commitments, the applicant had satisfactorily demonstrated compliance with the recommendations and requirements of PNL-5600 and NUREG-1216 regarding the Unit 2 TDI diesel generator Phase I components. This supplement addresses the findings of the staff review of the actions associated with Units 1 and 2, Phase II engine components required to implement the quality revalidation (QR) recommendations of the DR/QR program. The staff findings are addressed below.

Phase II Engine Components QR Review

Phase II QR activities covered 155 individual components on each of four engines. For the majority of components, two or more separate actions were necessary to comply with the QR requirements. Consequently, there were approximately 450 independent QR actions per engine for the staff to audit, or a total of approximately 1800 QR actions for both Units 1 and 2.

Of these above 1800 QR actions, some 132 are associated with the seismic qualification of engine-mounted, small-bore piping and piping supports. The applicant's program for determining the seismic adequacy of these components was evaluated independently from the staff audit by Brookhaven National Laboratories (BNL). The findings of the BNL evaluation are documented in BNL Report L-1161, dated September 1989. BNL concluded that the seismic qualification of on-engine small-bore piping and supports is acceptable. The staff concurs with the BNL findings. These 132 components were, therefore, excluded from part of the staff review of Phase II components. For the remaining Phase II engine components, the staff reviewed various documents relative to the completion of the associated QR actions. These applicant documents included work orders, maintenance action requests, technical evaluation reports, design change requests, station operation plans, data recording sheets, and inspection procedures. The staff review covered all of the individual Phase II QR actions for the EDGs in both Units 1 and 2. In light of the number of QR actions and documents reviewed, however, this supplement will not include a written evaluation of each QR action. Rather, a generic conclusion is presented for each major area of review discussed below. In summary, the staff review revealed that more than 98 percent of the individual QR actions have been acceptably completed. In the few instances in which adequate documentation was not available at the time of the staff review, the applicant has implemented actions to complete them in a reasonable time. In a letter of December 18, 1992, the applicant committed to complete all open items for the Phase II DR/QR activities before the end of the first refueling outage of CPSES Unit 2. Therefore, on the basis of its review, the staff concludes that, with regard to Phase II components, the EDGs at Comanche Peak Units 1 and 2 are acceptable for nuclear service.

Confirmatory Issues from SSER 25

In SSER 25, the staff concluded that the applicant's actions relative to the Phase I components for the Unit 2 EDGs were acceptable with the exception of two confirmatory issues. The resolution of these issues, 5 and 6, is discussed below.

PNL-5600 contains a recommendation that the engine blocks be metallurgically examined to ensure that the microstructure is characteristic of typical gray cast iron of the grade specified for the block. The examination had not been conducted at the time of the staff Phase I review, and the staff concluded that the engine blocks would be acceptable on confirmation that the examinations had been successfully completed. The metallurgical examinations have now been completed and the results were documented in Failure Analysis Associated (FaAA) letters of October 26, 1992 (for Train A EDG), and August 18, 1992 (for Train B EDG). FaAA has concluded that the engine blocks can be classified as typical of ASTM A48 CL-40 gray cast iron that does not contain any evidence of Widmanstätten graphite. This conforms to the recommendation of PNL-5600, and the staff concludes that the engine blocks are acceptable. This resolves SSER 25 Confirmatory Issue 5.

PNL-5600 also contains a recommendation that crankshaft oil holes and fillets be non-destructively inspected at 5-year intervals. This recommendation is endorsed in NUREG-1216, but includes a 10-year interval corresponding to the major engine overhaul. The requirement to inspect crankshaft oil holes and fillets is included in the applicant inspection document REI-503, but there was confusion regarding the frequency of inspection. The staff concluded that the applicant's inspection program would be acceptable on confirmation that REI-503 was revised to accurately specify the proper inspection interval. On October 5, 1992, the applicant implemented the necessary changes in REI-503. The requirements now state that the first inspection would be conducted at the end of 5 years of operation and the subsequent inspections would be at 10-year intervals. The staff finds this consistent with the intent of NUREG 1216, and therefore, acceptable. This resolves SSER 25 Confirmatory Issue 6.

Outstanding Issues

Outstanding Issue 31 (from SSER 25) has two parts. The first part deals with revising the appropriate procedures at Comanche Peak to include actions to be taken in the event cracks occur in an EDG block. Specifically, in SSER 25, the staff stated that the applicant should revise plant procedures to include the requirement to declare an EDG inoperable in the event cracks appear in the block top or cylinder liner landing area. In addition, the procedure should include the requirement for the EDG to remain inoperable until the proposed disposition or corrective actions or both have been approved by the staff. The applicant has submitted copies of revised procedures STA-501 and MSM-PO-374, both of which include appropriate language to implement the above requirement. The staff finds this acceptable and concludes that the first part of Outstanding Issue 31 is resolved.

The second part of Outstanding Issue 31 involves the requirements to air roll the EDGs before starting. The purpose of the air roll is to detect water in the cylinders which could cause severe engine damage on starting. Performing the air roll, however, requires the EDG to be rendered inoperable for a period of time. If the plant was in an Action Statement of Technical Specification (TS) 3/4.8.1 which requires that the engine be able to start, performing the air roll would cause the affected EDG to be inoperable along with the other ac source(s) that is/are inoperable. The staff, therefore, concluded that the applicant should revise plant procedures to ensure the air roll is not conducted when starting an EDG in accordance with an Action Statement of TS 3/4.8.1. The applicant has submitted a copy of revised procedure SOP-609B which includes a caution not to perform the air roll when in an Action Statement, if doing so involves a potential loss of function, or when the turbine-driven auxiliary feedwater pump is inoperable. This caution is consistent with the plant TS, and fully addresses the staff's concern. This procedure revision adequately resolves the remaining part of Outstanding Issue 31.

Maintenance and Surveillance Program

The staff evaluations and conclusions detailed above and in SSER 22 and SSER 25 pertain to actions associated with Phase I and Phase II engine components.

These actions were necessary to establish the initial acceptability of TDI EDGs for nuclear service. In addition to Phase I and Phase II, however, NUREG-1216 includes a discussion of an acceptable maintenance and surveillance (M/S) program which contributes to satisfactory engine performance and facilitates the timely identification of potential problems. The staff has concluded that an acceptable M/S program should include the manufacturer recommendations, additional items required by the staff as indicated in Section 2.1.3 of NUREG-1216, and the recommendations found in Revision 2 of Appendix II of the Comanche Peak DR/QR Report. The applicant has committed to implement an M/S program at Comanche Peak which incorporates the above elements. The applicant commitments are stated in Enclosure 4 to TXX-6236, dated February 13, 1987, and in Enclosure 4 to TXX-91336, dated December 19, 1991. In NUREG-1216, the staff also concluded that any changes to the M/S program should be subject to a review in accordance with the provisions of 10 CFR 50.59. In Enclosure 4 to TXX-6236 and Enclosure 1 to TXX-91336, the applicant has made such a commitment. The staff finds these commitments acceptable.

The elements of the M/S program described above have been integrated into a single applicant document entitled, "Results Engineering Inspection Manual-503

(REI-503)." The staff reviewed this document as part of its Phase I and Phase II reviews. On the basis of its review, the staff concludes that REI-503 adequately reflects the requirements/recommendations of NUREG-1216, the TDI maintenance and instruction manual, and Revision 2 of the DR/QR Appendix II. The staff also concludes that REI-503 adequately implements the applicant's commitments regarding an M/S program described above.

REI-503 is the applicant's principal document for the Comanche Peak M/S program. To implement this program, the applicant has entered the data from REI-503 into the Managed Maintenance Computer Program (MMCP). The MMCP is designed to automatically generate maintenance-related work requirements at the appropriate time. The staff reviewed the MMCP against REI-503 and found that REI-503 maintenance and surveillance requirements are fully reflected in the MMCP data base. The staff, therefore, concludes that the M/S program for Comanche Peak is fully implemented.

Conclusion

On the basis of its review of Phase II engine components and the M/S program described above, the staff concludes that all actions required to show that TDI EDGs at Comanche Peak Units 1 and 2 are acceptable for nuclear service have been completed. This concludes the staff's activities relative to the Comanche Peak DR/QR program.

10 STEAM AND POWER CONVERSION SYSTEM

10.3 Main Steam Supply System

10.3.3 Steam and Feedwater Systems Materials

In Final Safety Analysis Report (FSAR) Section 10.3.6.1, the applicant stated that impact testing would be performed on containment ferritic pressure boundary materials. The feedwater isolation valve (FWIV) ferritic components of the containment pressure boundary consist of the bonnet, body, and neck. The FWIV procurement specification in ASME Boiler and Pressure Vessel Code, 1974 Edition, Winter 1974 Addenda (Code) did not require impact testing. The FWIV design specification did not require impact testing, making the impact requirement from Table NC-2331-1 optional.

The applicant submitted a request in a letter of October 28, 1991 (TU Electric letter TXX-91365 to NRC) to apply fracture mechanics analysis in lieu of actual impact testing for the bonnets used in the feedwater isolation valves. The applicant also asked to use the actual impact testing from two heats to represent a group of heats with similar chemistries and physical tests. The heats were used in the bodies and necks of the FWIVs.

In a letter of April 27, 1992 (TU Electric letter TXX-92211 to NRC), the applicant removed the fracture mechanics analysis request from the October 28, 1991 submittal. The applicant replaced the bonnets from FWIVs 2FW-0071, 2FW-0077, and 2FW-0089 with bonnets that were impact tested. The bonnet for FWIV 2FW-0083 had been replaced previously.

To satisfy the FSAR, the applicant supplied technical data in the submittal as an attachment: ER-DBE-ME-045, Revision 1. The staff concludes that the chemical, microstructural, and hardness data were similar for all heats and that the close grouping of impact test results (performed on the heats with highest and lowest ultimate tensile strength) adequately bounded all heats used for the bodies and necks of the FWIVs. The applicant included the appropriate information in Amendment 86 to the FSAR; therefore, the staff finds that the applicant has acceptably tested the FWIVs and has properly documented the results.

10.4 Other Features

10.4.5 Circulating Water System

In Section 10.4.5 of the SER, the staff identified various heat loads for the circulating water system (CWS). In FSAR Amendment 86, the applicant corrected the FSAR to include five non-safety related ventilation chiller condensers that are cooled by the CWS which were inadvertently omitted from Section 10.4.5 of the FSAR. This list of heat loads in the SER was for information only and did not affect the staff's conclusions in the SER or its supplements. Therefore, the staff is revising this section of the SER for clarification and completeness purposes and does not affect any of the staff's previous conclusions.

12 RADIATION PROTECTION

12.3 Design Features

In Amendment 87 to the FSAR, submitted by letter dated December 18, 1992 (TU Electric letter TXX-92569 to NRC), the applicant clarified its position regarding maintenance of engineered safety feature atmosphere cleanup system air filtration and absorption units. The change deleted the requirement to replace a charcoal absorber bed when the last test canister has been removed for laboratory testing. By letter dated January 15, 1993 (TU Electric letter TXX-93036 to NRC), the applicant revised the FSAR change to clarify the cases in which an absorber will be replaced. The staff finds that the change is in conformance with Regulatory Guide 1.140 and is therefore acceptable.

12.4 Dose Assessment

The applicant submitted an advance FSAR change by letter dated October 9, 1992, (TU Electric letter TXX-92495 to NRC) giving information on post-accident vital area mission routes and radiation doses in the form of revised FSAR pages. For those cases where the missions described in the applicant's submittal may have to be repeated, it was verified that the applicant has about 50 operators and about 15 chemistry technicians who have received the necessary training. The vital areas described in the submittal were determined as a result of a study done by the applicant in accordance with NUREG-0737. It was verified that radiation levels for pre-mission briefings and equipment use were determined and the calculated doses from these activities were included in the total dose figures given in FSAR Table II.B-2-4. Extremity doses were determined and were, in all but three cases, equal to the whole-body doses. In these three cases, the maximum extremity dose was determined to be 7.4 rem, considerably less than the 75 rem considered "equivalent" to the GDC 19 criterion of "5 rems whole-body or equivalent." Therefore, the calculated doses are acceptable.

13 CONDUCT OF OPERATIONS

13.1 Organizational Structure and Qualifications

13.1.1 Management and Technical Resources

Nuclear Engineering and Operations

The staff notes that the TU Electric corporate and Nuclear Engineering and Operations Group organizational structures are changing, in part resulting from the change to a two-unit operation. These changes were discussed with the applicant during a site audit on January 7, 1993. By letter dated January 22, 1993 (TU Electric letter TXX-93046 to NRC), the applicant stated that it remains in compliance with the CPSES Unit 1 and proposed dual unit Technical Specifications and described the reassignments of specific functions within the Technical Specifications. The applicant also committed to provide the organizational changes in a future FSAR amendment and to submit a license amendment request to revise the Technical Specifications to incorporate the administrative changes. The staff verified that all previously described responsibilities and duties have been reassigned to appropriate positions within the new organization structure. Therefore, this commitment is acceptable.

Health Physics

In Amendment 87 to the FSAR, the applicant eliminated the position of corporate health physics supervisor and delegated these responsibilities to the CPSES radiation protection manager and the director of nuclear overview. The applicant provided additional information regarding this change by letter dated January 20, 1993 (TU Electric letter TXX-93042 to NRC). Since this organizational change does not create an unreviewed safety question and is not inconsistent with regulatory requirements, the staff finds the change acceptable.

14 INITIAL TEST PROGRAM

The staff has reviewed the applicant's FSAR submittals for Comanche Peak Unit 2 through Amendment 87, in accordance with NUREG-0800, "Standard Review Plan" (SRP) for Section 14.2, "Initial Test Program." Additionally, the staff reviewed the proposed startup test program changes described in the applicant's letters of March 31, 1992, (TU Electric letter TXX-92146 to NRC) and July 10, 1992 (TU Electric letter TXX-92318 to NRC). The staff also reviewed a letter of October 23, 1992 (TU Electric letter TXX-92513 to NRC). This letter provided responses to the staff's request for additional information (RAI) dated September 25, 1992. This RAI was in regard to the applicant's FSAR Amendment 85 submittal and in response to a June 22, 1992, RAI.

Evaluation

The following evaluation presents the staff's position based upon its review of the Comanche Peak Unit 2 initial test program (ITP) as modified and clarified by the applicant's RAI responses of July 10, 1992 and October 23, 1992. The numbers in parentheses correspond to the numbering of the questions in the staff's RAI of September 25, 1992.

- (1) FSAR Appendix 1A(B), "Discussion of Regulatory Guides," page 1A(B)-70, conformance to Regulatory Guide (RG) 1.108, contains a "clarification" statement to RG 1.108, Regulatory Position C.2.d. This clarification, concerning the reliability of both diesel generators for a condition in which seven or more failures occur in the last 100 valid tests, does not conform to Regulatory Position C.3 (or to C.2.d) in that this position considers failures in the last 100 valid tests on a per-nuclear-unit basis, not on an individual-diesel-generator basis as described in the "clarification." This issue concerns the technical specifications for diesel generator operability, not the testing of the diesel generators in the Initial Test Plan. The staff verified that this FSAR "clarification" is consistent with the CPSES Technical Specifications and is therefore acceptable. This item is considered closed.

- (2 & 3) FSAR Appendix 1A(B), "Discussion of Regulatory Guides," page 1A(B)-70, conformance to RG 1.108, contains exceptions indicating that the 18-month interval periodic testing of the diesel generators will not demonstrate full-load-carrying capability at the continuous rating and will not demonstrate proper operation for design-accident-loading sequence to design-load requirements in accordance with Regulatory Positions C.2.a.(3) and C.2.a.(5), respectively. This issue concerns the technical specifications for diesel generator operability, not the testing of the diesel generators in the initial test plan. The staff verified that these exceptions are consistent with the technical specifications and are therefore acceptable. These items are considered closed.

- (4) FSAR Appendix 1A(B), "Discussion of Regulatory Guides," page 1A(B)-71, conformance to RG 1.108, contains an exception regarding minimum start and load tests of the diesel generators indicating that the applicant assumed a value other than two for the number of diesel generators in the equation in Regulatory Position C.2.a.(9).

  The applicant revised the FSAR in Amendment 87 to indicate that the reliability of the diesel generators would be demonstrated by performing no less than 35 starts and load tests per diesel generator. The staff finds this change is in conformance with RG 1.108 and is, therefore, acceptable.

- (5) The response to Q423.10 was revised to indicate deferral of the incore nuclear instrumentation test and the auxiliary startup instrumentation test until after fuel load. Deferral of these tests until after fuel load constitutes exceptions to RG 1.68, Appendix A, Subparagraphs 1.j(13) and 1.j(18).

  The applicant provided technical justification for deferral of these tests in Amendment 87 to the FSAR. The incore instrumentation will be installed after fuel load as the fuel assemblies provide structural support for the incore flux mapping thimbles. The auxiliary startup instrumentation will be tested prior to initial fuel load as the applicant has committed in the FSAR to complete the neutron response check within 8 hours of initial fuel loading. The staff finds that these changes are acceptable based on the justification provided.

- (6) FSAR Appendix 1A(B), "Discussion of Regulatory Guides," page 1A(B)-43, conformance to RG 1.68, Appendix A, Subparagraph 5.z, was modified in FSAR Amendment 86 regarding use of calibration of radiation monitors and detectors rather than performance of radiation checks to demonstrate their proper operation. The staff requested further technical justification for these revisions and the applicant submitted justification in Attachments 8 and 9 to the letter to the NRC dated October 23, 1992 (TU Electric letter TXX-92513 to NRC). The applicant stated that, during Unit 1 testing, it was found that testing of plant monitors during low-power and power ascension did not provide additional data over what was obtained during preoperational testing, as the majority of the systems remained at very low radiation concentrations. Therefore, the applicant proposed to perform instrument calibrations during preoperational testing in lieu of only performing radiation source checks. This technical justification is acceptable and this item is considered closed.

Pre-operational Test Deferral

The staff reviewed the applicant's pre-operational test program changes for Unit 2 described in the applicant's letters of December 23, 1992 (TU Electric letter TXX-92586 to NRC), January 8, 1993 (TU Electric letter TXX-93011 to NRC), and January 25, 1993 (TU Electric letter TXX-93051 to NRC). The applicant proposed to defer certain pre-operational and/or acceptance tests until after fuel load. The staff verified that the applicant's letters contain commitments for completion of the tests at the appropriate plant power levels or plant milestones. The schedule for performing the deferred testing and/or retesting ensures that systems required to prevent, limit, or mitigate the consequences of postulated accidents will be tested prior to the systems being required operable and ensures that the safety of the plant will not be dependent on the performance of untested systems, structures, and components. The applicant's justification for deferred testing and subsequent schedule for conducting the tests is acceptable.

Conclusions

The staff has reviewed the applicant's FSAR submittals through Amendment 87, in accordance with NUREG-0800, "Standard Review Plan," Section 14.2. The staff has concluded that the information in the Comanche Peak FSAR meets the acceptance criteria in SRP Section 14.2 and describes an acceptable initial test program for Unit 2, the successful completion of which will demonstrate the functional adequacy of plant structures, systems, and components.

15 ACCIDENT ANALYSIS

15.3 Infrequent Transients and Postulated Accidents

15.3.8 Loss-of-Coolant Accident

Small Break

By letter of October 2, 1992 (TU Electric letter TXX-92472 to NRC), the applicant submitted its final report under the provisions of 10 CFR 50.55(e) regarding a small-break loss of coolant accident (LOCA) during Mode 4 operation. This issue concerns the ability of the emergency core cooling system (ECCS) to perform its intended safety function when the low-pressure injection pumps are being used for residual heat removal (RHR). While in this condition, low-pressure injection with a pump that is operating as an RHR pump cannot be effected without manually realigning the suction to the refueling water storage tank.

In accordance with 10 CFR 50.55e, this issue was originally reported as a potential defect associated with a substantial safety hazard. The applicant has now completed its evaluation of this issue and has determined that it is not reportable as a defect and that no further action is necessary. These conclusions are based on a study by the Westinghouse Owners Group (WOG) documented in WCAP-12476, "Evaluation of LOCA During Mode 3 and Mode 4 Operation for Westinghouse NSSS." The report concludes that (1) the current ECCS design for Westinghouse NSSS is adequate for Mode 3 and Mode 4 operation, (2) loss-of-coolant accidents so severe as to require immediate injection are not credible at the relatively low operating pressure required in Mode 4, and (3) there is adequate operator action time to mitigate the consequences of a small-break LOCA during Mode 4 operation. The applicant also indicated that the Comanche Peak plant operating procedures are conservative with respect to operator actions and required action times assumed in the topical report.

The staff is presently reviewing the Westinghouse topical report cited on a generic basis. This is being done in anticipation that it will be referenced widely as a basis for future changes to technical specifications and abnormal operating procedures. However, as part of its evaluation of shutdown and low-power issues, the staff has considered the capability of the ECCS system in Westinghouse-designed operating plants as well as other pressurized water reactor (PWR) designs to mitigate LOCAs during non-power modes of operation. On the basis of that evaluation, the staff has concluded that the operational status of ECCS equipment during Mode 4 operation is not a defect associated with a substantial safety hazard. The applicant's final report on this issue per 10 CFR 50.55(e) is acceptable. This closes Significant Deficiency Analysis Report (SDAR) CP-86-41.

15.4 Radiological Consequences of Design-Basis Accidents

15.4.4 Steam Generator Tube Rupture Accident

The staff stated in SSER 23 that the reassessment of the radiological consequences due to a top break steam generator tube rupture (SGTR) would be treated as a confirmatory issue pending completion of a generic study sponsored by the Westinghouse Owners Group (WOG).

The WOG has submitted its evaluation of the offsite radiological consequences of a postulated top break SGTR. The staff is reviewing the WOG study. If the staff identifies any actions that it believes are necessary for addressing a top break SGTR, it will handle them on a generic basis. The staff has determined that the top break SGTR does not need to be tracked on a plant-specific basis, as required actions will be addressed generically; therefore, this is no longer an open issue.

16 TECHNICAL SPECIFICATIONS

At an April 12, 1991, meeting between the NRC and the applicant, TU Electric proposed, and the staff agreed, that the Technical Specifications (TSs) for Comanche Peak Unit 1 be revised to a combined Unit 1 and Unit 2 TSs. Subsequent to that meeting, on January 2, 1992, the applicant submitted a markup of the current Unit 1 TSs to show the changes necessary to make the Unit 1 TSs a combined Unit 1 and Unit 2 TSs. This markup served as the basis for numerous meetings between the staff and the applicant, additional applicant submittals, and various published drafts of the combined TSs.

The "Final Draft Combined Technical Specifications for Comanche Peak Unit 1 and Unit 2" was issued by the NRC to the applicant on September 9, 1992. The applicant certified on November 4, 1992 (TU Electric letter TXX-92536 to NRC), that the final draft accurately reflects the as-built plant and the Final Safety Analysis Report. The applicant also noted certain minor corrections. The staff discussed the corrections with the applicant and appropriate changes were made to the Final Draft TSs. The staff issued the Final Draft TSs to the applicant by letter dated January 22, 1993. Editorial corrections were discussed and the applicant recertified the TS by letter of January 30, 1993 (TU Electric letter TXX 93001 to NRC). Appendix A to the license is the resulting "Combined Comanche Peak Unit 1 and 2 Technical Specifications."

20 FINANCIAL QUALIFICATIONS

The Director of the Office of Nuclear Reactor Regulation has made a finding in accordance with Section 105c(2) of the Atomic Energy Act of 1954, as amended, that no significant (antitrust) changes in the applicant activities or proposed activities have occurred subsequent to the antitrust operating license review of Unit 1 of the Comanche Peak Steam Electric Station by the Attorney General and the Commission. The finding was published in the Federal Register on September 28, 1992 (57 FR 44595), as follows:

> Section 105c(2) of the Atomic Energy Act of 1954, as amended, provides for an antitrust review of an application for an operating license if the Commission determines that significant changes in the applicant activities or proposed activities have occurred subsequent to the previous construction permit review. The Commission has delegated the authority to make the "significant change" determination to the Director, Office of Nuclear Reactor Regulation. Based upon the examination of the events since the issuance of the Comanche Peak Steam Electric Station, Unit 1 (Comanche Peak 1) operating license, to TU Electric Company, the staffs of the Inspection and Licensing Policy Branch, Office of Nuclear Reactor Regulation and the Office of the General Counsel, hereafter referred to as "staff," have jointly concluded, after consultation with the Department of Justice, that the changes that have occurred since the operating license review of Comanche Peak 1 are not of the nature to require a second antitrust review at the operating license stage of the application for Comanche Peak 2.
>
> In reaching this conclusion, the staff considered the structure of the electric utility industry in northeastern and north central Texas, the events relevant to the Comanche Peak construction permit review, the antitrust settlement subsequent to the construction permit review and the Comanche Peak 1 operating license review.
>
> The conclusion of the staff analysis is as follows:
>
> In an effort to identify any changed activity on the part of the licensee, the staff requested updated Regulatory Guide 9.3 information in December 1991. Notice of receipt of this information was published in the Federal Register and the staff received comments from two electric power cooperatives, Cap Rock Electric Cooperative, Inc. and Cajun Electric Power Cooperative Inc.

The staff reviewed the comments from Cap Rock and Cajun and fully considered them in the context of the Commission's significant change review. The staff determined that the issues raised by Cap Rock addressed compliance or contractual matters, not licensing matters pertinent to the staff's §105c(2) operating license significant change review. Moreover, the issues of concern to Cap Rock were being litigated in a manner that ultimately should resolve the concerns raised by Cap Rock. The staff determined that the concerns raised by Cajun in its comments to Regulatory Guide 9.3 were issues that should be addressed by the FERC, not the NRC, and that there was an ongoing forum at the FERC in which Cajun could seek redress from its concerns pursuant to participation in the Texas DC intertie.

TU Electric experienced changes in its business since the Comanche Peak 1 operating license review; however, the changed activity was in large part due to the changing electric bulk power industry and the role of power generators within this industry. The staff did not identify any changes in TU Electric's activities that would require a remedy by the NRC in this licensing action. None of the changes identified meet all three of the Commission's Summer criteria.

Section 105c(2) requires a formal antitrust review at the operating license stage only in the event of significant changes in the applicant activities since the previous antitrust review. The NRC established criteria for identification of significant changes in its Summer decision and delegated the authority to make the significant change determination to the staff. The staff's analysis of the changes in the applicant activities has not identified any changed activity that could be remedied in the Commission's licensing process as envisioned in Summer. Consequently, the staff recommends that no affirmative significant change determination be made pursuant to the application for an operating license for Unit 2 of the Comanche Peak Steam Electric Station.

On the basis of its analysis, the staff concluded that there have been no "significant changes" in the applicant activities or proposed activities since the completion of the antitrust operating license review of Unit 1 of the Comanche Peak Steam Electric Station.

22 TMI-2 REQUIREMENTS

I.D.1 Control Room Design Review

In a letter of August 21, 1990, from J. H. Wilson, to W. J. Cahill, Jr., the staff asked the applicant to identify and evaluate any differences in design between the Unit 1 and Unit 2 control rooms to support the licensing of Comanche Peak Steam Electric Station (CPSES), Unit 2. In a letter of August 28, 1992 (TU Electric letter TXX-92401 to NRC), the applicant responded to this request by submitting Supplement No. 5 to the Human Factors Control Room Design Review Final Report. Findings of the environmental survey of the Unit 2 control room were sent to the staff in a letter of December 18, 1992 (TU Electric letter TXX-92568 to NRC).

The staff reviewed Supplement 5 to the applicant's Human Factors Control Room Design Review Final Report, dated August 28, 1992. Supplement 5 identified and evaluated those differences in design between Unit 1 and Unit 2 control rooms as it supported the licensing of CPSES Unit 2. The staff conducted an onsite audit of the control room on November 30, 1992.

Control Room Design Differences

Supplement 5 noted three differences in design between Unit 1 and Unit 2 control rooms. The applicant indicated that it did not intend to resolve these differences and presented its rationale in the report. The staff evaluated the differences and the applicant's rationale as to why the differences do not warrant further action. These are presented below.

(1) Color-Coded Operating Bands - The differences in location of the color bands for designating operating ranges for three specific system indicators were generated from actual system design differences. The band locations were determined on the basis of engineering data and will be subject to change as more operating data are acquired for Unit 2. Any such changes are controlled by formal operating instructions and procedures. Due to the actual system differences and the procedures in place for controlling changes to the operating bands, the staff finds these differences in system indicator color bands to be acceptable.

(2) Mirror Image Unit Differences - The mirror image configuration of equipment in the plant which affects the control room consists of two moisture separators and the four main steam lines. This affects only the descriptive labels of 12 valve position indicators. The staff's review of these labels in the control room revealed that the labels were very clear, legible, and unambiguous. In addition, a control board graphic operator aid was developed and installed to assist the operator in recognizing the differences. The staff, therefore, finds the applicant's resolutions in this area acceptable.

(3) Handswitch Module Deletion - During the validation of the Unit 2 design, the applicant determined that control of four isolation dampers was not needed and consequently removed the two handswitch controls for these dampers from the control room design. Although the switches were not installed in Unit 2, they remain installed in Unit 1. Since the handswitches for Unit 1 are located on a back panel which is normally not staffed, and operation of these switches has been determined to have a low risk potential, the applicant has decided not to remove the Unit 1 handswitches at this time. The staff finds the difference between Unit 1 and Unit 2 regarding these handswitches acceptable, but recommends that the Unit 1 switches be removed during some future outage.

Environmental Surveys

The applicant transmitted the results of its environmental survey of the Unit 2 control room in a letter of December 18, 1992. Four human engineering discrepancies (HEDs) were identified. The applicant provided a brief description of each HED and committed in their letter that all of the identified HEDs would be resolved before Unit 2 fuel load. The staff finds the applicant's schedule for resolution of these HEDs acceptable.

I.D.2 Safety Parameter Display System

On October 31, 1980, the staff issued NUREG-0737 which provided guidance for implementing TMI Action Plan items, including Item I.D.2, Safety Parameter Display System (SPDS). The staff had evaluated implementation of the SPDS at 57 units and, upon finding that a large percentage of designs did not fulfill the requirements, issued Generic Letter 89-06 which included a checklist to help licensees determine the status of their SPDSs with respect to NRC requirements.

In a letter of November 2, 1992 (TU Electric letter TXX-92525 to NRC), the applicant responded to Generic Letter 89-06, "Task Action Plan Item I.D.2 - Safety Parameter Display System - 10 CFR 50.54(f)" for CPSES Unit 2. The applicant did not submit adequate information for some of the devices that are used to maintain electrical isolation between the Class 1E input signals and non-Class 1E safety parameter display system (SPDS). The applicant sent additional information regarding the testing of these isolation devices. The staff verified this information during a control room audit on November 30, 1992.

The applicant identified six devices that produce the electrical isolation between the Class 1E inputs and the non-Class 1E SPDS. These are

- Gammametrics Isolator 200626-1
- Action Pak Isolator Model 4300-107
- core cooling monitor
- heater junction thermocouple system
- Westinghouse 7300 System
- Computer Products, Inc. RTP bus isolator

The Gammametrics isolator was tested using a voltage of 120-V ac which was applied directly across the output (non-Class 1E) of the device to simulate the postulated maximum credible fault. The output was disabled by the fault; however, there was no perturbation of the input (Class 1E). Therefore, the device maintained the required electrical isolation and is acceptable for this application.

The Action Pak isolator was tested using a voltage of 120-V ac which was applied directly across the output (non-Class 1E) of the device to simulate the postulated maximum credible fault. The output was disabled by the fault; however, there was no perturbation of the input (Class 1E). Therefore, the device maintained the required electrical isolation and is acceptable for this application.

The core cooling monitor was previously reviewed and approved in WCAP-10621, "Westinghouse Thermocouple/Core Cooling Monitor System Test", July 1984. This isolation device is acceptable for this application.

The heater junction thermocouple system is isolated by optical fiber cable. Fiberoptic cable provides inherent electrical isolation and, therefore, is acceptable to the staff without additional fault testing.

The Westinghouse 7300 system was previously reviewed and approved in WCAP-8892A, "Westinghouse 7300 Series Process Control System Noise Test", June 1977. This isolation device is acceptable for this application.

The Computer Products, Inc. RTP bus isolator provides isolation for both analog and digital Class 1E inputs to the non-Class 1E outputs. The acceptance criteria for the Class 1E input parameters are defined as $\pm$ 1 percent for the analog inputs, and no change in status of the digital inputs when the fault is applied to the non-Class 1E output terminals. The device was tested and met these acceptance criteria and is, therefore, acceptable.

On the basis of its review of the information provided, the staff concludes that the isolation devices are acceptable for interfacing the SPDS with the Class-1E input signals.

II.B.1 Reactor Coolant System Vents

The staff stated in SSER 6 that the reactor vessel head is vented through a line containing a 3/4-inch orifice and two 1-inch valves in series. The SSER also indicated that the pressurizer vapor space is vented in the same manner.

In a letter of December 9, 1992 (TU Electric letter TXX-92587 to NRC), the applicant stated that review of project documents indicated that the reactor vessel head vent has a 3/8-inch orifice in lieu of a 3/4-inch orifice. The pressurizer vent remains similar to the reactor head vent in that both lines have two 1-inch valves in series with an upstream flow-restricting device. However, the pressurizer vent utilizes a length of 3/4-inch pipe in lieu of an orifice to provide flow restriction.

The corrections submitted by the applicant do not affect the staff's previous conclusions regarding the RCS vents. If the two valves in a vent line were left open, the flow out of either vent line would be less than that of a small-break LOCA and would be within the capacity of the reactor makeup system. Therefore, the staff finds these corrections to be acceptable.

II.B.2 Plant Shielding To Provide Access to Vital Areas and Protect Safety Equipment for Postaccident Operation

The applicant submitted an advance FSAR change in a letter of October 9, 1992 (TU Electric letter TXX-92495 to NRC), giving information on postaccident vital area mission routes and radiation doses in the form of revised FSAR pages. For those cases where the missions described in the applicant's submittal may have to be repeated, it was verified that the applicant has an adequate number of operators and technicians who have received the necessary training. The vital areas described in the submittal were determined by a study done by the applicant in accordance with NUREG-0737. It was verified that radiation levels for pre-mission briefings and equipment use were determined and the calculated doses from these activities were included in the total dose figures given in Table II.B.2-4. Extremity doses were determined and were, in all but three cases, equal to the whole-body doses. In the three exceptions, the maximum extremity dose was determined to be 7.4 rem, considerably less than the 75 rems considered "equivalent" to the GDC 19 criterion of "5 rems whole-body or equivalent." The applicant was asked to document additional information regarding the above items. These items were included in FSAR Amendment 87 and are acceptable.

II.D.1 Relief and Safety Valve Testing

NUREG-0578 and NUREG-0737 recommended that licensees develop programs that examined the functional performance capabilities of pressurized water reactor primary system safety, relief, and block valves, and verified the integrity of the pressurizer safety and relief valve piping systems for normal, transient, and accident conditions. The applicant submitted its Unit 2 evaluation of valve performance testing in four parts dated March 31, 1982 (TU Electric letter TXX-3503 to NRC); May 18, 1992 (TU Electric letter TXX-92246 to NRC); November 12, 1992 (TU Electric letter TXX-92548 to NRC); and December 18, 1992 (TU Electric letter TXX-92628 to NRC). The NRC staff has reviewed the responses and finds that the applicant has met the requirements of NUREG-0578 and NUREG-0737, Item II.D.1 for Unit 2. The Safety Evaluation Report is located in Appendix FF of this supplement.

APPENDIX A

CONTINUATION OF CHRONOLOGICAL LIST OF CORRESPONDENCE

This appendix continues the chronological listing of routine licensing correspondence, regarding Unit 2 and Unit 1/Unit 2 common issues, between the U.S. Nuclear Regulatory Commission (NRC) staff and the applicant (Texas Utilities Electric Company) since Supplement 25 was issued.

August 7, 1992	Letter from applicant advising that utility initiated comprehensive confirmatory test program to envelope full range of protected conduit and cable tray configurations to provide further assurance of overall adequacy of Thermo-Lag fire barriers.
August 13, 1992	Letter from applicant forwarding response to NRC request regarding Thermo-Lag.
August 26, 1992	Letter to applicant transmitting relief request to use helical coil threaded inserts.
August 27, 1992	Summary of July 23, 1992, meeting with applicant concerning status of station blackout submittal.
August 28, 1992	Letter from applicant forwarding Supplement 5 to "Human Factors Control Room Design Review of Comanche Peak Steam Electric Station."
August 28, 1992	Letter from applicant forwarding individual plant exam for Comanche Peak Steam Electric Station, Volume 1: Front End Analysis.
September 4, 1992	Letter from applicant forwarding Amendment 86 to FSAR.
September 8, 1992	Letter from applicant forwarding Revision 1 to Interim Engineering Report ER-ME-067, "Evaluation of Thermo-Lag Fire Barrier System."
September 9, 1992	Letter to applicant concerning final draft version of combined Technical Specifications.
September 9, 1992	Letter from applicant forwarding major milestone schedule and portions of Part 21 open items list of issues currently under review.
September 11, 1992	Memorandum and Order setting pleading schedule.

September 15, 1992	Letter from applicant forwarding final response to NRC Bulletin 88-01 regarding defects in Westinghouse circuit breakers.
September 15, 1992	Letter to applicant requesting documents to support staff review of 2.206 petition.
September 17, 1992	Letter to applicant transmitting Supplement 25 to NUREG-0797.
September 17, 1992	Letter from applicant forwarding Revision 4 to physical security plan.
September 18, 1992	Letter from applicant forwarding Comanche Peak Steam Electric Station 1992 field exercise scenario.
September 18, 1992	Letter from applicant forwarding response to NRC Bulletin 92-01, Supplement 1, regarding failure of Thermo-Lag fire barrier system.
September 21, 1992	Letter from applicant forwarding documents regarding agreements with Tex-La Electric Cooperative of Texas and with Brazos Electric Power Cooperative.
September 24, 1992	Letter from applicant forwarding information regarding methodology of upcoming Thermo-Lag barrier fire endurance testing.
September 24, 1992	Letter from applicant forwarding supplemental response to NRC Bulletin 88-05, Supplements 1 and 2, regarding nonconforming materials.
September 25, 1992	Letter to applicant requesting additional information concerning initial test program.
September 28, 1992	Letter to applicant requesting additional information concerning Comanche Peak FSAR, Chapter 8, Amendments 79 through 84.
October 1, 1992	Letter to applicant regarding applicant's response to Generic Letter 88-20, Supplement 4.
October 2, 1992	Letter to applicant regarding applicant's response to NRC Bulletin 92-01, Supplement 1.
October 6, 1992	Order finding that administrative hearing process would better be served by shortening prescribed time for answering motions contained in 10 CFR 2.730(c).
October 7, 1992	Letter from applicant forwarding major milestone schedule and portions of Part 21 open items list of issues currently under review.

October 9, 1992	Letter from applicant forwarding advance FSAR submittal regarding vital area mission routes and radiation doses.
October 12, 1992	Letter from applicant forwarding response to NRC request for additional information regarding RXE-91-002, "Reactivity Anomaly Events Methodology."
October 13, 1992	Summary of September 15, 1992, meeting with applicant concerning Thermo-Lag test results.
October 19, 1992	Memorandum and Order regarding ruling on Dow Motion for Extension of Time and Setting a Further Schedule.
October 20, 1992	Letter from applicant forwarding interim response regarding NRC Bulletin 88-08, "Thermal Stresses in Piping Connected to Reactor Coolant System."
October 23, 1992	Letter from applicant forwarding response to NRC staff request for additional information regarding Unit 2 initial test program per Regulatory Guide 1.108 and Generic Letter 84-15.
October 23, 1992	Letter from applicant forwarding advance FSAR submittal regarding electrical lineup for Unit 2 preoperational testing.
October 23, 1992	Letter from applicant forwarding advance FSAR submittal regarding ASME Code Case usage.
October 27, 1992	Letter from applicant forwarding response to NRC request for additional information regarding FSAR Chapter 8, Amendments 79 through 84.
October 29, 1992	Letter from applicant correcting error in applicant's 10/16/92 response to 2.206 petition on Tex-La settlement agreement.
October 29, 1992	Letter to applicant informing of results of staff review of Thermo-Lag acceptance methodology.
October 30, 1992	Letter from applicant forwarding preservice inspection relief requests B-1 through B-14 and C-1 through C-5 from preservice exam requirements for Class 1 and 2 components.
November 2, 1992	Letter from applicant forwarding response to Generic Letter 89-06.
November 3, 1992	Letter from applicant forwarding response to NRC Bulletin 88-04.
November 3, 1992	Letter from applicant forwarding response to NRC letter regarding long-term resolution actions taken to prevent potential for dead-heating of safety-related pumps.

November 3, 1992	Letter from applicant forwarding major milestone schedule and portions of Part 21 open items list of issuance that are currently under review.
November 4, 1992	Letter from applicant forwarding final draft combined Units 1 and 2 Technical Specifications.
November 6, 1992	Letter from applicant forwarding advance draft FSAR regarding cooling pond hydrothermal analysis.
November 13, 1992	Letter from applicant forwarding supplemental response to NRC request for additional information regarding NUREG-0737, Item II.D.1, "Performance Testing of Relief and Safety Valves."
November 16, 1992	Letter from applicant forwarding advance FSAR submittal regarding deleting inputs to steam generator water hammer circuit.
November 18, 1992	Letter from applicant forwarding clarification to Reference 1 in applicant's November 2, 1992, letter regarding final draft combined Technical Specifications.
November 25, 1992	Letter to applicant requesting additional information concerning Thermo-Lag fire barrier testing acceptance criteria.
December 2, 1992	Letter from applicant forwarding revised FSAR pages of reflecting revised analysis for releases through containment pressure relief line during a loss-of-coolant accident.
December 2, 1992	Summary of October 27, 1992, meeting with applicant concerning fire barrier acceptance criteria.
December 3, 1992	Letter from applicant forwarding revised FSAR pages of reactor coolant system (RCS) cooldown time after residual heat removal (RHR) initiation.
December 4, 1992	Letter from applicant forwarding major milestone schedule and portion of Part 21 open items list of issues current under review.
December 4, 1992	Letter from applicant forwarding response to NRC request regarding leak-before-break analysis of pressurizer surge line and accumulator line.
December 8, 1992	Letter from eight utilities having Enterprise emergency diesel generators (EDGs) for emergency standby ac power forwarding "NRC Licensing Submittal Review of Licensing Conditions Imposed by NUREG-1216."
December 9, 1992	Letter from applicant requesting NRC review of information regarding RCS vents.

December 11, 1992	Letter from applicant forwarding revised FSAR pages regarding Section 3.9B and Table 3.9B-10, "Manual Active Valves."
December 11, 1992	Letter from applicant forwarding response to NRC request regarding FSAR Section 3.11 concerning environmental qualification program.
December 11, 1992	Letter from applicant forwarding FSAR submittal regarding Section 3.6B, "Reference Deletion Regarding Environmental Flow Models."
December 14, 1992	Letter from applicant forwarding FSAR submittal regarding revised RCS hot-leg recirculation switchover time.
December 14, 1992	Letter from applicant forwarding FSAR submittal regarding Section 3.8, "Loadings and Stresses in Category I Structures."
December 15, 1992	Memorandum and Order Ruling on Intervention Petitions and Terminating Proceedings.
December 15, 1992	Letter from applicant forwarding response to NRC request regarding testing of Thermo-Lag fire barrier materials and report entitled, "Receipt, Dispensing, Quality and Inspection Requirements for Thermo-Lag Fire Barrier Materials."
December 17, 1992	Letter from applicant regarding early implementation of 10 CFR 20.
December 17, 1992	Letter from applicant forwarding FSAR submittal regarding Section 3.10B, "Cranes."
December 17, 1992	Letter from applicant forwarding FSAR submittal regarding essential equipment classification and break postulation criteria.
December 17, 1992	Letter from applicant forwarding FSAR submittal regarding identification of additional active valves.
December 18, 1992	Letter from applicant forwarding reactor containment building integrated leakage rate test Unit 2 final report.
December 18, 1992	Letter from applicant forwarding Revision 9 to "Technical Requirements Manual."
December 18, 1992	Letter from applicant forwarding Supplement 6 to Human Factors Control Room Design Review.

December 18, 1992	Letter from applicant forwarding request for exemption from 10 CFR 70.24(a) to maintain criticality alarm system in each area in which special nuclear material is handled, used, or stored.
December 18, 1992	Letter from applicant forwarding Amendment 87 to FSAR.
December 18, 1992	Letter from applicant forwarding FSAR submittal regarding Thermo-Lag upgrade to safety-related components.
December 18, 1992	Letter from applicant forwarding status of diesel generator action items.
December 18, 1992	Letter from applicant forwarding revised data point sheets that incorporate correct engineering units.
December 18, 1992	Letter from applicant forwarding response to NRC request regarding HVAC (heating, ventilation, and air conditioning) design validation and concrete embedments.
December 18, 1992	Letter from applicant forwarding response to NRC request regarding NUREG-0737. Item II.D.1, "Performance Testing of Relief and Safety Valves."
December 21, 1992	Letter from applicant forwarding errata to Revision 9 to Technical Requirements Manual.
December 21, 1992	Letter from applicant forwarding supplemental response to Generic Letter 88-14.
December 21, 1992	Letter from applicant forwarding Revision 1 to inservice inspection relief request.
December 22, 1992	Letter from applicant forwarding advance FSAR submittal regarding control room carpet requirements to limit flame spread.
December 22, 1992	Letter from applicant forwarding additional information requested by NRC Bulletin 88-05, Supplements 1 and 2.
December 23, 1992	Letter from applicant forwarding comitment to implementing hardware modifications to address potential for loss of shutdown capability.
December 23, 1992	Letter from applicant forwarding list of preoperational acceptance testing items to be deferred past fuel load.
December 23, 1992	Letter from applicant forwarding Revision 2 to ER-ME-067, "Evaluation of Thermo-Lag Fire Barrier System" describing qualification of fire barriers.
December 30, 1992	Letter from applicant forwarding "Preservice Inspection Summary Report" addressing exams and tests of Code Class 1 and 2 systems completed to date.

January 6, 1993	Summary of December 17, 1992, meeting with applicant concerning fire protection issues.
January 7, 1993	Letter from applicant forwarding major milestone schedule and portion of Part 21 open items list of issues current under review.
January 8, 1993	Letter from applicant forwarding preoperational and acceptance testing to be deferred past fuel load.
January 8, 1993	Letter from applicant forwarding supplemental response to NRC Bulletin 88-05.
January 13, 1993	Letter from applicant forwarding response to Bulletin 90-01, Supplement 1.
January 13, 1993	Letter from applicant forwarding WCAP-13571, "Pressurizer Surge Line Leak-Before-Break for Comanche Peak Unit 2."
January 13, 1993	Letter from applicant forwarding Calculation 2-NP-GENX-551 regarding interior supports in long piping runs.
January 13, 1993	Letter from applicant forwarding additional clarification regarding Topical Report RXE-89-002, "VIPRE-01 Core Thermal-Hydraulic Analysis Methods."
January 14, 1993	Letter from applicant forwarding Revision 15 to Comanche Peak physical security plan.
January 15, 1993	Letter from applicant forwarding additional information regarding charcoal absorber testing and replacement.
January 15, 1993	Letter from applicant forwarding commitment to listed actions in response to fire protection inspection.
January 19, 1993	Letter from applicant forwarding Thermo-Lag laboratory test results and response to request for information.
January 19, 1993	Letter from applicant forwarding response to Generic Letter 92-08.
January 20, 1993	Letter from applicant forwarding response to Bulletin 88-08.
January 20, 1993	Letter from applicant forwarding information regarding FSAR Chapter 12.5, "Radiation Protection."
January 21, 1993	Letter from applicant forwarding information regarding seismic Category II piping and supports located in a non-category I building.
January 21, 1993	Letter from applicant forwarding information regarding ASME inservice test program and IST relief request V-5.

January 22, 1993	Letter from applicant forwarding organizational changes.
January 25, 1993	Letter from applicant forwarding information regarding deferral of pre-operationl testing.
January 25, 1993	Letter from applicant forwarding information regarding Thermo-Lag.
January 26, 1993	Letter from applicant forwarding Revision 10 to Technical Requirements Manual.
January 28, 1993	Letter from applicant forwarding information regarding Thermo-Lag conduit support modifications and test schemes.
January 28, 1993	Letter from applicant forwarding information regarding the design of HVAC system utilizing circular cross-section duct.
January 29, 1993	Letter from applicant forwarding information regarding outstanding issue 18 (HVAC) of SSER 25.
January 30, 1993	Letter from applicant forwarding request for issuance of operating license for Unit 2.
February 1, 1993	Letter from applicant forwarding information regarding Thermo-Lag.

APPENDIX B

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See Appendix C.

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See Appendix C.

NRC Letters

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NUREG-0630, "Cladding, Swelling and Rupture Models for LOCA Analysis," April 1980.

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APPENDIX C

NUCLEAR REGULATORY COMMISSION GENERIC CORRESPONDENCE

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OVERVIEW

In this appendix, the staff has summarized the status of Generic Letters and Bulletins issued since SSER 24 was published. Generic Letters and Bulletins for which Comanche Peak Steam Electric Station (CPSES) Unit 2 verification of action is necessary are also included. This appendix was included in SSER 25, and is updated in this SSER.

ISSUES: Nuclear Regulatory Commission Bulletins (NRCB)

NRCB 79-14 Seismic Analysis for As-Built Safety Related Piping Systems

Bulletin 79-14, issued August 15, 1979, requested that licensees take certain actions in regard to verifying that seismic analyses were applicable to as-built plants. In SSER 14, the staff reviewed the Post-Construction Hardware Validation Program and applicable plant procedures and concluded that the applicant had developed an adequate program to ensure that the as-built verification of safety-related piping systems is in accordance with the requirements of the bulletin. Completion of this program was inspected in December 1992 (Inspection Report 50-445/92-48; 50-446/92-48). The inspectors verified that walkdown inspection discrepancies were documented for resolution and that proper corrective actions were completed. Based on this inspection, all requirements of Bulletin 79-14 were adequately addressed. This item is closed.

NRCB 88-01 Defects in Westinghouse Circuit Breakers

Bulletin 88-01, issued February 5, 1988, requested licensees to perform and document inspections on welds on the pole shafts of Westinghouse DS series circuit breakers used in Class 1E applications. By letter dated September 15, 1992, TU Electric documented completion of the actions requested by the bulletin for Comanche Peak Unit 2. The applicant determined that 46 Westinghouse type DS-416 breakers were installed in Unit 2 Class 1E applications. The pole shafts on these breakers and spares were replaced. The replacement pole shafts were receipt inspected and accepted per the inspections requirements contained in the bulletin. These actions meet the requirements of the bulletin and this issue is closed.

NRCB 88-04 Potential Safety-Related Pump Loss

Bulletin 88-04 requested licensees to investigate and correct as applicable two miniflow design concerns. Licensees were required to determine the potential for dead-heading of one or more pumps in safety-related systems with a common miniflow line and to evaluate the adequacy of the recirculation flow available to ensure continuous operation in the miniflow mode.

The applicant's revised response of May 26, 1989, concluded that the current Chemical and Volume Control System configuration at CPSES has the potential for dead-heading the boric acid transfer pumps when both Units 1 and 2 are operating and the centrifugal charging pumps when operating in the miniflow mode. The applicant described two modifications to eliminate pump-to-pump interaction in letters of September 20, 1989 and April 30, 1992. By letter of November 3, 1992, TU Electric stated that all modifications associated with

Bulletin 88-04 had been completed. The applicant revised the applicable portions of the FSAR to reflect the modifications in Amendment 86 dated September 4, 1992. The applicant will maintain a documented evaluation of these actions for a minimum of two years in accordance with the bulletin. Accordingly, the staff concludes that the applicant's responses have addressed the issues in the bulletin. Further NRC review, if any, will be by future inspections or audits. This issue is closed.

NRCB 88-05 Nonconforming Material Supplied by Piping Supplies, Inc. at Folsom, New Jersey and West Jersey Manufacturing Company at Williamstown, New Jersey

The NRC issued Bulletin 88-05 in May 1988 regarding alleged falsification of Certified Material Test Reports (CMTR) by West Jersey Manufacturing Co. (WJM) and Piping Supplies, Inc. (PSI). Bulletin 88-05 requested licensees to identify, locate, and replace material manufactured by WJM or PSI or perform testing to assure that this material meets applicable ASME Code and specification requirements. Supplements 1 and 2 issued in June and August of 1988 revised the reporting requirements and added a third manufacturer, Chews Landing Metal Manufacturers Inc. (CLM).

The applicant provided the Unit 2 response to the bulletin by letters of September 24, 1992, December 22, 1992, and January 8, 1992. The staff concluded that the applicant had adequately qualified all nonconforming parts in Unit 2 as being suitable for their intended service. Therefore, this issue is closed. This item is also discussed in Section 3.9.3 of this supplement.

NRCB 88-08 Thermal Stresses in Piping Connected to Reactor Coolant Systems

The NRC issued Bulletin 88-08 on June 22, 1988 that requested licensees to take the following actions: (1) review their reactor coolant systems (RCS) to identify any connected unisolable piping that could be subjected to temperature distributions that could result in unacceptable thermal stresses, (2) examine unisolable piping sections for existing flaws, and (3) implement a program to provide continuing assurance that unisolable sections will not be subject to stresses that could cause fatigue failure.

By letter of January 20, 1993 (TU Elecric letter TXX-93026 of NRC), the applicant submitted its final response to the bulletin. The letter stated that TU Electric had satisfied Action 3 of the bulletin by installing resistance temperature detectors on the Unit 2 RCS piping to detect adverse temperature distributions. The staff reviewed the methodology used and determined that it is consistent with the guidelines provided by the bulletin. By letter of January 28, 1993 (TU Electric letter TXX-93071 of NRC), the applicant updated its response to Action 2 stating that, based on preservice inspections of Unit 2, a crack would not be initiated during the relatively short time that Unit 2 was at elevated temperature. Therefore, this issue is closed. This item is discussed in Section 3.9.1.1 of this supplement.

NRCB 89-03 Potential Loss of Shutdown Margin During Refueling

On November 21, 1989, the staff issued NRC Bulletin 89-03, "Potential Loss of Required Shutdown Margin During Refueling Operations", to all holders of operating licenses or construction permits for PWRs. The bulletin was issued to alert addressees to the potential loss of required shutdown margin during the movement and placement of highly reactive fuel during refueling operations. Recipients were requested to take three actions to ensure that adequate shutdown margin is maintained during all refueling operations.

In a letter of January 5, 1990, the applicant responded to the bulletin by addressing the three recommendations. The applicant has incorporated the fuel vendor guidelines for assuring a minimum shutdown margin of 5% into the applicable CPSES refueling procedures. The procedures have been revised to require that changes in planned fuel shuffles resulting in new intermediate fuel assembly configurations will be evaluated against the vendor guidelines to assure that shutdown margin requirements are maintained. The applicant committed to train refueling organizations personnel on these procedures and on the consequences of violating these procedures. These actions and commitments satisfy the recommendations of Bulletin 89-03. This issue is closed.

NRCB 90-01, Supplement 1 Loss of Fill-Oil in Transmitters Manufactured by Rosemount

On December 22, 1992, the NRC issued Bulletin 90-01, Supplement 1. The bulletin requested plants under construction to identify any Rosemount transmitters series 1153 B, 1153 D, or 1154 in the plant that were manufactured before July 11, 1989, and to evaluate the enhanced surveillance program used to monitor these transmitters. These actions must be completed prior to fuel load. The applicant responded by letter dated January 13, 1993. The applicant stated that all Unit 2 transmitters currently installed and spares are either post July 11, 1989, manufacture or are refurbished with new sensing elements. This response fulfills the requirements of the bulletin. This issue is closed.

NRCB 92-01 Failure of Thermo-Lag 330 Fire Barrier System to Maintain Cabling in Wide Cable Trays and Small Conduits Free from Fire Damage

On June 24, 1992, the NRC issued Bulletin 92-01 which requested licensees to identify the plant areas where Thermo-Lag 330 fire barrier is used and to implement appropriate compensatory measures where inoperable fire barriers are located. The applicant responded by letter of July 9, 1992, stating that fire watches had been included in the fire protection programs for Units 1 and 2 as a compensatory measure. By letter of September 22, 1992, the NRC staff found this response acceptable. On August 28, 1992, the NRC issued Supplement 1 to NRCB 92-01 to extend the scope of the original bulletin to include verification of safe shutdown capability. The applicant responded to the supplement by letter of September 18, 1992, stating that all actions had been satisfied. The applicant had implemented compensatory actions and provided a description of long-term corrective actions. As documented in a letter of October 2, 1992, the NRC staff found the applicant's response to Supplement 1 acceptable. This issue is closed.

Generic Letters (GL):

GL 88-14 Instrument Air Supply Problems Affecting Safety-Related Equipment

Generic Letter 88-14 requested licensees to review NUREG-1275, Volume 2 and perform a design and operations verification of the instrument air system. The recommendations consisted of (1) testing instrument air quality, (2) reviewing procedures to be used on loss of instrument air, and (3) verifying that the system is designed in accordance with its intended function. The applicant responded to the generic letter by letters of February 6 ,1989, May 11, 1989, July 31, 1989, and August 9, 1989. These letters documented TU Electric's plans and schedule for completing the recommendations. By letter of December 21, 1992, the applicant stated that it had completed implementation of all requirements of GL 88-14 for Unit 2. This issue is closed.

GL 89-06 Task Action Plan Item I.D.2 - Safety Parameter Display System

By letter of November 2, 1992, the applicant responded to GL 89-06 for Unit 2. In response to questions from the staff, the applicant provided additional information which identified 6 devices which are used to provide the electrical isolation between the Class 1E inputs and the non-Class 1E SPDS. The staff reviewed the testing of these isolation devices and concluded that they are acceptable for interfacing the SPDS with the Class 1E input signals. Therefore, this issue is closed. The staff's evaluation is located in Section 22 of this supplement.

GL 92-08 Thermo-Lag 330-1 Fire Barriers

Generic Letter 92-08, dated December 17, 1992, requested licensees to confirm that the Thermo-Lag 330-1 barrier systems have been qualified by fire endurance tests, that the ampacity derating factors have been derived by valid tests, and that these qualified barriers have been installed in compliance with NRC requirements. The applicant submitted a response for Unit 2 by letter of January 19, 1993 (TU Electric letter TXX-93038 to NRC). The response stated that the Thermo-Lag systems have been qualified by fire endurance tests and untested configurations were evaluated. These test results and evaluation were submitted to the NRC on December 23, 1992 (TU Electric letter TXX-92626 to NRC), and January 19, 1993 (TU Electric letter TXX-93023 to NRC). The December 23, 1992, letter also documented the applicant's evaluation of ampacity derating factors which was based on the conservative application of several ampacity test results. The applicant stated that, although installation of the Thermo-Lag barrier system was not complete at the time of the response, appropriate procedures and quality controls are in place to ensure that they comply with NRC requirements.

The staff found the applicant's response acceptable for CPSES Unit 2 based on the satisfactory completion of the plant specific fire endurance test program, the applicant's use of the test results to design and construct the CPSES, Unit 2 fire barriers, and its commitment to perform plant specific ampacity derating tests by the completion of the first refueling outage. Therefore, this issue is closed. This issue is also discussed in Section 9.5.1.5 of this supplement.

GENERIC LETTERS

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

Table 1: Generic Letters

Generic Letter	Description	Applies/ Action Required	Licensee Response	Date of Response	Status
88-05 03/17/88	Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components In PWR Plants	Yes/Yes	TXX-88481 TXX-90110	06/24/88 03/23/90	Closed in SSER 25.
88-14 08/08/88	Instrument Air Supply Problems Affecting Safety-Related Equipment	Yes/Yes	TXX-89052 TXX-89191 TXX-89461 TXX-89561 TXX-90062 TXX-92621	02/06/89 05/11/89 07/31/89 08/09/89 02/09/90 12/21/92	Closed in SSER 26.
88-20 12/01/88 88-20, S1 8/29/89 88-20, S2 04/04/90 88-20, S3 07/06/90	Individual Plant Examination for Severe Accident Vulnerabilities	Yes/Yes	TXX-92387 TXX-89782 TXX-92490	8/28/92 10/30/89 10/30/92	NRC reviewing. Closure not required for license issuance.
88-20, S4 06/08/91	Individual Plant Examination of External Events	Yes/Yes	TXX-91640	12/20/91	TU to submit by 6/95.
89-06 04/12/89	Task Action Plan Item I.D.2 - Safety Parameter Display System - 10 CFR 50.54(f)	Yes/Yes	TXX-89445 TXX-92525	07/11/89 11/2/92	Closed in SSER 26.

Generic Letter	Description	Applies/ Action Required	Licensee Response	Date of Response	Status
89-10 6/28/89 89-10, S1 6/13/90 89-10, S2 8/3/90 89-10, S3 10/25/90 89-10, S4 2/12/92	Safety-Related Moter-Operated Valve Testing and Surveillance	Yes/Yes	TXX-89817	12/21/89	Complete actions by 6/28/94. Within 30 days of completing notify NRC.
89-13 07/18/89 89-13, S1 04/04/90	Service Water System Problems Affecting Safety-Related Equipment	Yes/Yes	TXX-90031 TXX-90186 TXX-90347 TXX-91004 TXX-92268	01/26/90 05/21/90 09/21/90 01/07/91 06/19/92	Closed in SSER 25.
90-01 01/18/90	Request for Voluntary Participation in NRC Regulatory Impact Survey	Yes/Yes	TXX-90082 TXX-90154	03/01/90 05/03/90	Closure Not Required.
90-02 02/01/90 90-02, S1 07/31/92	Alternative Requirements for Fuel Assemblies in the Design Features Section of Technical Specifications	Yes/No	---	---	Closure Not Required.
90-03 03/20/90 90-03, S1 05/14/90	Relaxation of Staff Position in Generic Letter 83-28, Item 2.2 Part 2 "Vendor Interface for Safety-Related Components"	Yes/Yes	TXX-90353 TXX-901046	09/27/90 12/10/90	Closed by NRC letter of 02/01/91.

Generic Letter	Description	Applies/ Action Required	Licensee Response	Date of Response	Status
90-04 04/25/90	Request for Information on the Status of Licensee Implementation of Generic Safety Issues Resolved with Imposition of Requirements or Corrective Actions	Yes/Yes	TXX-90217	06/26/90	Closure not required.
90-05 06/15/90	Guidance for Performing Temporary Non-Code Repair of ASME Code Class 1, 2, and 3 piping	Yes/No	---	---	Closure not required.
90-06 06/28/90	Resolution of Generic Issue 70, "Power-Operated Relief Valve and Block Valve Reliability," and GSI 94, "Additional Low-Temperature Overpressure Protection for Light-Water Reactors," Pursuant to 10 CFR 50.54(f)	Yes/Yes	TXX-901053 TXX-91427 TXX-92255	12/21/90 11/27/91 05/27/92	Closed in SSER 25.
90-07 08/10/90	Operator Licensing National Examination Schedule	Yes/Yes	TXX-90329	09/14/90	Closure not required.
90-08 08/10/90	Simulation Facility Exemptions	Yes/No	---	---	Closure not required.

Generic Letter	Description	Applies/ Action Required	Licensee Response	Date of Response	Status
90-09 12/11/90	Alternative Requirements for Snubber Visual Inspection Intervals and Corrective Actions	Yes/No	TXX-91323	09/06/91	Closure not required.
91-01 01/04/91	Removal of the Schedule for the Withdrawal of Reactor Vessel Material Specimens from Technical Specifications	Yes/No	---	---	Closure not required.
91-02 12/28/90	Reporting Mishaps Involving Low-Level Waste (LLW) Forms Prepared for Disposal	Yes/Yes	---	---	Closure not required.
91-03 03/06/91	Reporting of Safeguards Events	Yes/No	---	---	Closure not required.
91-04 04/02/91	Changes in Technical Specification Surveillance Intervals to Accommodate a 24-Month Fuel Cycle	Yes/No	---	---	Closure not required.
91-05 04/09/91	Licensee Commercial Grade Procurement and Dedication Programs	Yes/No	---	---	Closure not required.
91-06 04/29/91	Resolution of Generic Issue A-30, "Adequacy of Safety-Related DC Power Supplies," Pursuant to 10 CFR 50.54(f)	Yes/Yes	TXX-91390	10/28/91	Closed by NRC letter of 07/02/92.

Generic Letter	Description	Applies/ Action Required	Licensee Response	Date of Response	Status
91-07 05/02/91	Generic Issue-23 "Reactor Coolant Pump Seal Failures" and Its Potential Impact on Station Blackout	Yes/No	TXX-91363	10/01/91	Closure not required.
91-08 05/06/91	Removal of Component Lists from Technical Specifications	Yes/No	---	---	Closure not required.
91-09 06/27/91	Modification of Surveillance Interval for the Electrical Protective Assemblies in Power Supplies for the Reactor Protection System	No/No	---	---	Closure not required.
91-10 07/08/91	Explosives Searches at Protected Area Portals	No/No	---	---	Closure not required.
91-11 07/18/91	Resolution of Generic Issues 48, "LCOs for Class 1E Vital Instrument Buses," and 49, "Interlocks and LCOs for Class 1E Tie Breakers," Pursuant to 10 CFR 50.54(f)	Yes/Yes	TXX-92055	02/03/92	Closed by NRC letter of 04/02/92.
91-12 08/27/91	Operator Licensing National Examination Schedule	Yes/Yes	TXX-91374	10/14/91	Closure not required.

Generic Letter	Description	Applies/ Action Required	Licensee Response	Date of Response	Status
91-13 09/19/91	Request for Information Related to the Resolution of Generic Issue 130, "Essential Service Water System Failures at Multi-Unit Sites," Pursuant to 10 CFR 50.54(f)	Yes/Yes	TXX-92120 TXX-92260 TXX-92410	03/16/92 06/05/92 08/31/92	Closed in SSER 25.
91-14 09/23/91	Emergency Telecommunications	Yes/Yes	---	---	Closure not required.
91-15 09/23/91	Operating Experience Feedback Report, Solenoid-Operated Valve Problems at U.S. Reactors	Yes/No	---	---	Closure not required.
91-16 10/03/91	Licensed Operators' and Other Nuclear facility Personnel Fitness for Duty	Yes/No	---	---	Closure not required.
91-17 10/17/91	Generic Safety Issue 29, "Bolting Degradation or Failure in Nuclear Power Plants"	Yes/No	---	---	Closure not required.
91-18 11/07/91	Information to Licensees Regarding Two NRC Inspection Manual Sections on Resolution of Degraded and Nonconforming Conditions and on Operability	Yes/No	---	---	Closure not required.

Generic Letter	Description	Applies/ Action Required	Licensee Response	Date of Response	Status
91-19 12/19/91	Information to Addressees Regarding New Telephone Numbers for NRC Offices Located in One White Flint North	Yes/No	---	---	Closure not required.
92-01 03/06/92	Reactor Vessel Structural Integrity 10 CFR 50.54(f) Rev. 1	Yes/Yes	TXX-92319	07/02/92	NRC reviewing. Closure not required for license issuance.
92-02 03/06/92	Resolution of Generic Issue 79, "Unanalyzed Reactor Vessel (PWR) Thermal Stress During Natural Convection Cooldown"	No/No	---	---	Closure not required.
92-03 03/19/92	Compilation of Current Licensing Basis: Request for Voluntary Participation in Pilot Program	Yes/No	---	---	Closure not required.
92-04 08/19/82	Resolution of the Issues Related to Reactor Vessel Water Level Instrumentation in BWRs Pursuant to 10 CFR 50.54(f)	No/No	---	---	Closure not required.
92-05 9/4/92	NRC Workshop on SALP	Yes/No	---	---	Closure not required

Generic Letter	Description	Applies/ Action Required	Licensee Response	Date of Response	Status
92-06 9/16/92	Operator Licensing National Examination Schedule	Yes/No	TXX-92531	10/29/92	Closure not required.
92-07 10/15/92	NRR Reorganization	Yes/No	---	---	Closure not required.
92-08 12/17/92	Thermo-Lag 330-1 Fire Barriers	Yes/Yes	TXX-93038	01/19/93	Closed in SSER 26.

NRC BULLETINS

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

Table 2: NRC Bulletins

NRC Bulletin	Description	Applies/ Action Required	Licensee Response	Date of Response	Status
79-14 07/02/79 79-14, R1 07/18/79 79-14, S1 08/15/79 79-14, S2 09/07/79	Seismic Analysis for As-Built Safety Related Piping Systems	Yes/Yes	TXX-3062 TXX-3597 TXX-4729	10/25/79 12/03/82 04/03/86	Closed in SSER 26 and inspection report 92-48.
88-01 02/05/88	Defects in Westinghouse Circuit Breakers	Yes/Yes	TXX-88377 TXX-89080 TXX-92432	04/08/88 02/17/89 09/15/92	Closed in SSER 26.
88-04 05/05/88	Potential Safety-Related Pump Loss	Yes/Yes	TXX-88556 TXX-88766 TXX-88817 TXX-89140 TXX-89251 TXX-89708 TXX-92197 TXX-92539	07/08/88 10/31/88 11/30/88 03/13/89 05/26/89 09/20/89 04/30/92 11/03/92	Closed in SSER 26.
88-05 05/06/88 88-05,S1 06/15/88 88-05,S2 08/03/88	Non-Conforming Materials Supplied by Piping Supplies, Inc. at Folsom, New Jersey and West Jersey Manufacturing Company at Williamstown, New Jersey.	Yes/Yes	TXX-89005 TXX-89163 TXX-90039 TXX-90059 TXX-90088 TXX-92450 TXX-92631 TXX-93016	01/11/89 03/31/89 01/26/90 02/02/90 03/02/90 09/24/92 12/22/92 01/08/93	Closed in SSER 26.

NRC Bulletin	Description	Applies/ Action Required	Licensee Response	Date of Response	Status
88-08 06/22/88 88-08, S1 06/24/88 88-08, S2 08/04/88 88-08, S3 04/11/89	Thermal Stresses in Piping Connected to Reactor Coolant Systems	Yes/Yes	TXX-88740 TXX-88766 TXX-89246 TXX-89566 TXX-89710 TXX-89805 TXX-90113 TXX-92010 TXX-92009 TXX-92500 TXX-93026 TXX-93071	10/21/88 10/31/88 05/09/89 08/09/89 09/18/89 11/17/89 03/27/90 02/07/92 03/23/92 10/20/92 01/20/93 01/28/93	Closed in SSER 26.
88-10 11/22/88 88-10, S1 08/03/89	Nonconforming Molded-Case Circuit Breakers	Yes/Yes	TXX-89160 TXX-89640	03/31/89 09/08/89	Closed in SSER 24. Addressed in 50-446/ 89-84 and 50-446/ 89-37.
88-11 12/20/88	Pressurizer Surge Line Thermal Stratification	Yes/Yes	TXX-91389 TXX-92076 TXX-92077	11/25/91 2/14/92 2/24/92	Closed in SSER 25. Addressed in 50-446/ 89-37.
89-02 07/19/89	Stress Corrosion Cracking of High-Hardness Type 410 Stainless Steel Internal Preloaded Bolting in Anchor Darling Model S350W Swing Check Valves or Valves of Similar Design	Yes/Yes	TXX-89677 TXX-91434	10/12/89 11/26/91	Closed in SSER 25. Addressed in 50-446/ 91-66.
89-03 11/21/89	Potential Loss of Required Shutdown Margin During Refueling Operations	Yes/Yes	TXX-89873	01/05/90	Closed in SSER 26.

NRC Bulletin	Description	Applies/ Action Required	Licensee Response	Date of Response	Status
90-01 03/09/90	Loss of Fill-Oil in Transmitters Manufactured by Rosemount	Yes/Yes	TXX-90238 TXX-92300	07/18/90 07/08/92	Closed in SSER 25.
90-01, S1 12/22/92		Yes/Yes	TXX-93015	01/13/93	Closed in SSER 26.
90-02 03/20/90	Loss of Thermal Margin Caused by Channel Box Bow	No/No	—		Closure not required.
91-01 10/18/91	Reporting Loss of Criticality Safety Controls	No/No	—	—	Closure not required.
92-01 06/24/92 92-01, S1 08/28/92	Failure of Thermo-Lag 330 Fire Barrier System to Maintain Cabling in Wide Cable Trays and Small Conduits Free from Fire Damage	Yes/Yes	TXX-92331 TXX-92446	07/09/92 09/18/92	Closed in SSER 26.

APPENDIX D

LIST OF PRINCIPAL CONTRIBUTORS

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APPENDIX R

INSERVICE TESTING PROGRAM RELIEF REQUESTS

COMANCHE PEAK STEAM ELECTRIC STATION, UNIT 2

The Code of Federal Regulations, 10 CFR 50.55a, requires that certain ASME Code Class 1, 2, and 3 pumps and valves be tested in service in accordance with Section XI of the ASME Boiler and Pressure Vessel Code and applicable addenda, except where relief has been granted or the Commission has authorized proposed alternatives pursuant to 50.55a(f)(5)(iii), (a)(3)(i), or (a)(3)(ii). In requesting relief or proposing an alternative, the applicant must demonstrate that (1) conformance is impractical for its facility, (2) the proposed alternative offers an acceptable level of quality and safety, or (3) compliance would result in a hardship or unusual difficulty without a compensating increase in the level of quality and safety. NRC guidance in Generic Letter (GL) 89-04, "Guidance on Developing Acceptable Inservice Testing Programs," lists alternatives to the Code requirements determined to be acceptable to the staff and authorized the use of the alternatives in Positions 1, 2, 6, 7, 9, and 10 if the applicant adheres to the guidance given in the applicable position. When an alternative is proposed that is in accordance with GL 89-04 guidance and is documented in the IST program, no further evaluation is required; however, implementation of the alternative is subject to NRC inspection.

In a letter of July 2, 1992, the applicant submitted an IST program that superseded all previous revisions to the program. Therefore, the evaluations that follow relate to Revision 0 (dated July 2, 1992) of the new IST program, and all relief request numbers correspond to the Revision 0 designation. Additionally, the staff has augmented the proposed IST for certain chemical and volume control system valves.

Test Intervals

The IST program relief requests addressed in this safety evaluation (SE) apply to the first 10-year interval for both units. Section 1.3 of the Comanche Peak IST program indicates that both units "will be subject to the same inservice testing requirements as regards Code edition and schedule for future periodic updates pending NRC staff approval." The staff has determined that for facilities that include two similar units, it is advantageous to implement an inservice testing program consistent between units by using the same Code edition for developing the program and for scheduling 10-year updates. The applicant proposes to use the Unit 2 commercial operation date for establishing the 120-month interval for both units. Therefore, for a period of time, the Unit 1 program will not be in accordance with the regulation requiring an update to a later edition of the Code and an exemption from the regulation is required to be submitted prior to 120 months from the date Unit 1 began commercial operation.

Code Edition

Revision 0 was developed utilizing the 1989 Edition of ASME Section XI was approved by rulemaking effective September 8, 1992, to 10 CFR 50.55a (57 FR 34666, August 6, 1992). The applicant requested NRC approval per § 50.55a (f)(4)(iv), to use this edition of the Code. This SE issues the requisite approval to meet the requirements stated in the 1989 Edition subject to the limitations and modifications listed in § 50.55a(b), related to containment isolation valve leakage testing, with the scope of the inservice testing program as defined by § 50.55a. The 1989 Edition of ASME Section XI references Operations and Maintenance (OM) Standards, Parts 6 and 10, 1988 Addenda, for the rules of inservice testing of pumps and valves. Additionally, when using OM-10 for inservice testing requirements, OM-1-1987 must be used for safety and relief valve testing (not OM-1-1981). The scope of the safety and relief valves includes Class 1, 2, or 3 valves which provide a specific function in shutting down the reactor or mitigating the consequences of an accident, as first stipulated in the 1986 Edition of ASME Section XI. Revision 0 incorporates these requirements.

RELIEF REQUEST P-1

The applicant has requested relief for the diesel generator fuel oil transfer pumps, four per unit, from the requirements of OM-6, Section 6.1, "Acceptance Criteria," and Table 3b, "Ranges for Test Parameters."

Applicant's Basis for Relief

The applicant stated:

> Unlike earlier editions of ASME Section XI, OM Part 6 emphasizes the use of bearing vibration measurements as the primary indicator of pump degradation and places less emphasis on hydraulic measurements. Further, OM Part 6 introduces the classification of pumps by type. According to References 1 and 2 [1. John Zudans, "Introduction to ASME/ANSI OMa-1988, Part 6: Inservice Testing of Pumps in Light-Water Reactor Power Plants and Technical Differences Between Part 6 and ASME Section XI, Subsection IWP," in Proceedings of the Symposium on Inservice Testing of Pumps and Valves, NUREG/CP-0111 at 25-58 (1989). 2. Lawrence Sage, "Introduction to ASME/ANSI OMa-1988, Part 6: Basis of the New Vibration Measurement Criteria and Requirements of Part 6, Id at 59-74.], pump classification is introduced in recognition of the fact that the quality of vibration measurements varies among pump types. By classifying pumps, different test requirements and acceptance criteria can be specified depending on type. For example, vertical line shaft pump bearings are generally inaccessible for vibration monitoring. So, to compensate, OM Part 6 imposes more stringent hydraulic acceptance criteria for these pumps and additionally requires that vibrations be monitored on the driver bearings.
>
> Another pump type that incurs a "penalty" in hydraulic acceptance criteria in OM Part 6 is reciprocating, positive-displacement pumps. Reciprocating pumps are characterized by pulsating flow

and high oscillating inertia forces due to the back and forth motion of the pressure-producing members. Therefore, diagnosing the mechanical condition of reciprocating pumps using vibration measurements is somewhat difficult and to compensate, OM Part 6 specifies a reduced range of hydraulic acceptance criteria for these pumps.

Throughout OM Part 6, the terms "positive displacement pump" and "reciprocating pump" are used interchangeably. However, from Reference 2 it is clear that the pump type being addressed is the reciprocating *variety* of positive displacement pumps. Unfortunately, OM Part 6 ignores the other kind of positive displacement pumps, rotary positive displacement pumps. The fuel oil transfer pumps are rotary positive displacement pumps that do not share the inherent difficulties and limitations of bearing vibration diagnostics that reciprocating pumps experience. On the contrary, these low-inertia, untimed multiple-rotor screw pumps are characterized by low mechanical vibration, pulsation-free axial flow, and bearing loadings that do not vary through the pumping cycle. The bearings are quite accessible as the pump bores themselves effectively form continuous hydrodynamic fluid film bearings along the entire length of the rotors. The mechanical condition of screw pumps can be well understood through vibration monitoring.

Reference 2 discusses the pump classification methodology used by the O&M Task Group on Vibration Monitoring in preparing OM Part 6. That task group drew heavily on guidance from Reference 3 [3. International Standards Organization (ISO) Standard, "Mechanical Vibration of Machines With Operating Speeds From 10 to 200 Revolutions per Second - Basis for Specifying Evaluation Standards" ISO 2372, 1st ed., 1974-11-01.], in classifying pump types. Of the six classes of pumps recognized in the ISO standard, the group determined that most pumps in nuclear power plant applications belonged to one of two ISO categories: Class III or Class V. The primary difference between these classes is that Class III comprises rotating machines and Class V comprises reciprocating machines. These ISO classifications were translated into OM Part 6 as two major pump types: centrifugal and reciprocating positive displacement. (Note that vertical line shaft pumps are a special case of centrifugal pumps.) The subject screw-type pumps were not specifically considered for classification by the task group. Nonetheless, they are inadvertently classified with reciprocating pumps in OM Part 6 because the general term "positive displacement" issued the fuel oil transfer pumps are most closely ISO Class III pumps and should, therefore, be subject to the applicable requirements and criteria for centrifugal pumps in OM Part 6.

Alternative Testing

The applicant proposed:

> For the purpose of determining the acceptable range, alert range, and required action range for fuel oil transfer pump flow rate (Q), the ranges specified in OM Part 6, Table 3b, for centrifugal pump flow rate shall be used.
>
> For the purpose of determining the acceptable range, alert range and required action range for fuel oil transfer pump discharge pressure (P), the ranges specified in OM Part 6, Table 3b, for centrifugal pump differential pressure shall be used.
>
> For the purpose of determining the acceptable range, alert range and required action range for fuel oil transfer pump vibration (V), the ranges specified in OM Part 6, Table 3a, for centrifugal pump vibration shall be used.
>
> For the purpose of making fuel oil transfer pump vibration measurements, the requirements of OM Part 6, paragraph 4.6.4(a), shall apply.

Evaluation

ISO 2372 addresses vibration for rotating equipment as discussed in the applicant's basis for relief. Annex A of the standard gives guidance for classifying machinery and assigning ranges of "quality judgment" for each of these classes that relate to vibration severity levels. Class III is appropriate for "[l]arge prime movers and other large machines with rotating masses mounted on rigid and heavy foundations which are relatively stiff in the direction of vibration measurement." Class V is appropriate for "[m]achines and mechanical drive systems with unbalanceable inertia efforts (due to reciprocating parts), mounted on foundations which are relatively stiff in the direction of vibration measurement." In a phone conference on October 7, 1992, the applicant verified that the diesel fuel oil transfer pumps are rigidly mounted on a "relatively stiff" foundation. This assessment is supported by information that rotary screw pumps with right- and left-hand helices have a balanced load, and that for double-screw pumps, flow is practically continuous. See Theodore Baumeister and Lionel S. Marks, Standard Handbook for Mechanical Engineers, 7th ed. at 14-16, 17 (1967). Additionally, the applicant notes that the rotation of the pumps does not create an unbalanced inertia force as would be created by a reciprocating pump. Therefore, it appears that these pumps would be more similar to centrifugal pumps in the context of OM-6.

Considering the pumps as subject to the limits for centrifugal pumps rather than positive displacement pumps for OM-6 acceptance criteria effectively eliminates an alert range and changes the hydraulic required action limit for flow from 0.93 of the reference to 0.90 of the reference value. The vibration limits will not effectively change except by classifying these as centrifugal pumps; an absolute alert limit and required action limit are required in addition to the limits applied as multipliers of reference values. Depending on the current reference values for vibration, derived from initial tests, the applicant's alternative will be at least as conservative as the limits for reciprocating pumps. Therefore, the applicant has determined that classifying the fuel oil pumps as centifugal pumps is conservative. Based on the above, the staff determined that the alternative offers an acceptable level of quality and safety based on the type of pumps and the service application.

Conclusion

The applicant's proposal to apply the limits of OM-6 for centrifugal pumps rather than positive displacement pumps for the rotary diesel fuel oil transfer pumps as an alternative is authorized pursuant to 10 CFR 50.55a (a)(3)(i), because the alternative offers an acceptable level of quality and safety.

VALVE INSERVICE TESTING RELIEF REQUESTS

The valves subject to IST are listed in the valve table in the program document. The table identifies the actuator type, design features, safety functions, and applicable testing requirements for each valve. The applicant has identified seven instances in which relief from the code is requested. The relief requests are discussed below. A review of these justifications indicates that the basis for deferral of testing are adequate.

RELIEF REQUEST V-1

This relief request relates to setpoint testing the pressurizer relief and main steam safety valves in accordance with OM-1 requirements for an *in situ* test preceding the startup of Comanche Peak Steam Electric Station, Unit 2. It is a revision of the request submitted on February 3, 1992. The revision does not change the technical basis or the alternative testing. The staff approved Relief Request V-1 in NUREG-0797, Safety Evaluation Report Related to Operation of Comanche Peak Steam Electric Station, Unit 2, Supplement 25, Section 3.9.6, September 1992. Because the approval is not affected by the revision, no further evaluation is required.

RELIEF REQUEST V-2

The request includes a number of pairs of Category A/C or Category C, Class 3, series check valves that form the boundary between the non-safety-related instrument air or nitrogen supply systems and the safety-related accumulator and receiver tanks for certain safety-related components. The check valves are required to close upon failure of the air or nitrogen supply system to contain the compressed gas in the tanks. Relief is requested from the requirements of OM-10, Section 4.3.2, "Exercising Tests for Check Valves."

Applicant's Basis for Relief

The applicant stated:

> Each valve listed is one of two check valves in series at the inlet to a safety-grade accumulator or receiver tank. In each case, only one check valve is required in order to meet the safety class interface criteria of ANSI N18.2a-1975. However, two check valves are provided for added reliability, not for redundancy.

The safety-related components served by the accumulator and receiver tanks are redundant to other similar components which have their own dedicated safety-grade air supplies. As long as one of the check valves in the pair is capable of closure, then the safety analysis assumptions for the check valves are met. Some of the check valve pairs do not have provisions for testing each valve individually. However, the closure capability of each pair of check valves can be verified.

Alternative Testing

The applicant proposed:

> Each pair of series check valves will be exercise tested at the required frequency by some positive means to verify the closure capability of at least one of the valves. No additional exercise testing will be performed unless there is an indication that the closure capability of the pair of valves is questionable. In that case, both valves will be declared inoperable and not returned to service until they are either repaired or replaced.

Evaluation

The relief request relates to the exercising of these series check valves, not to leakage testing. The Code requires periodic verification of a check valve's capability to function to its safety position to ensure that the plant operates within its safety analyses. For series check valves, when only one of a pair is required to meet safety analysis assumptions, the staff has determined that the intent of Code requirements is met and that it is acceptable to test the pair of valves as a single valve with the following provisions: (1) both valves must be subject to comparable quality assurance requirements, (2) acceptance criteria for the pair of valves must be established appropriate to the verification method, and (3) if the acceptance criteria are not met, both valves shall be declared inoperable and corrective actions shall be initiated for both valves, including a retest, before returning the pair of valves to service. The relief request includes these stipulations. The alternative is acceptable because the tests verify the requirements of the plant's safety analysis for the valves and meet the intent of the Code requirements. Additional justification is based on the corrective actions required for both valves when acceptance criteria are not met to ensure that at least one of the two valves continues to function to meet safety analysis assumptions. Therefore, the proposed alternative offers an acceptable level of quality and safety.

Conclusion

The applicant's proposed alternative is authorized pursuant to 10 CFR 50.55a (a)(3)(i), because the alternative offers an acceptable level of quality and safety.

RELIEF REQUEST V-3

The Category A/C valves included in Relief Request V-2 (above) are the subject of this relief request. These series check valves require leakage testing in addition to exercising. Relief from the requirements of OM-10, Section 4.2.2, "Valve Seat Leakage Rate Test," is requested.

Applicant's Basis for Relief

The applicant stated:

> Each valve listed is one of two check valves in series at the inlet to a safety-grade accumulator or receiver tank. In each case, only one check valve is required in order to meet the safety class interface criteria of ANSI N18.2a-1975. However, two check valves are provided for added reliability, not for redundancy. The safety-related components served by the accumulator and receiver tanks are redundant to other similar components which have their own dedicated safety-grade air supplies. As long as one of the check valves in the pair is capable of meeting its leakage rate criteria, then the safety analysis assumptions for the pair of check valves are met. Some of the check valve pairs do not have provisions for testing each valve individually. However, the leakage rate of each pair of check valves can be verified.

Alternative Testing

The applicant proposed:

> Each pair of series check valves will be leakage rate tested at the required frequency to verify acceptable seat leak-tightness of at least one of the valves. No additional leakage rate testing will be performed unless there is an indication that the seat leak-tightness of the pair of valves is questionable. In that case, both valves will be declared inoperable and not returned to service until they are either repaired or replaced.

Evaluation

The relief relates to the leakage testing of these series check valves. The Code requires periodic verification of a check valve's leak-tight capability to ensure that the plant operates within its safety analyses. For series check valves when only one of a pair is required to meet safety analysis assumptions, the staff has determined that it is acceptable to leak test the pair as a single valve with the following provisions: (1) both valves must be subject to comparable quality assurance requirements, (2) acceptance criteria for the leakage of the pair of valves must be established, and (3) if the acceptance criteria are not met, both valves shall be declared inoperable and corrective actions shall be initiated for both valves, including a retest before returning the pair of valves to service. The relief request includes these stipulations. The alternative is acceptable because the leakage tests verify the requirements of the plant's safety analysis for the valves and meet the intent of the Code requirements. Additional justification is based on the corrective actions required for both valves when acceptance criteria are not met to ensure that at least one of the two valves continues to function to meet safety analysis assumptions. Therefore, the proposed alternative offers an acceptable level of quality and safety.

Conclusion

The applicant's proposed alternative is authorized pursuant to 10 CFR 50.55a (a)(3)(i), because the alternative offers an acceptable level of quality and safety.

RELIEF REQUEST V-4

The applicant has requested relief from the requirements of OM-10, Section 4.3.2.4(c) to disassemble check valves every refueling outage to verify operability of the containment spray header and pump suction check valves. Alternatively, the applicant proposes to implement Position 2 of GL 89-04 which allows only a sample of the check valves to be disassembled at each refueling outage. The staff has reviewed the alternatve testing and found that it follows the guidance given in Position 2 of the generic letter. Because the staff has approved this alternative in GL 89-04, no additional evaluation is necessary. The implementation of the disassembly and inspection in accordance with Position 2 is subject to NRC inspection.

REFLIEF REQUEST V-5

The applicant has requested relief from the requirements of OM-10, Section 4.3.2, "Exercising Tests for Check Valves," for the reactor coolant pump seal injection and charging pressure boundary isolation check valves.

Applicant Basis for Relief

The applicant stated:

> Each pair of valves listed constitutes two check valves in series at a CVCS/RCS [chemical and volume control system/reactor coolant system] interface. Two Safety Class 1 check valves are provided in accordance with the safety class interface criteria of ANSI N18.2A-1975 in order to isolate the interfacing Class 2 system. Either of the check valves provided can perform this function. The system design, however, does not include the test connections necessary to close exercise test each of the series check valves individually. The system design does include sufficient test connections to verify the check function of each pair of valves (i.e., verification that at least one of the valves will close).
>
> Offsetting the inability to separately test each series check valve are the following design features:
>
> (1) Both of the Class 1 check valves at each interface lie within the secondary shield wall inside containment and thus are afforded protection from dynamic events and missiles generated elsewhere in containment.

(2) The interfacing portions of the CVCS redundant system are designed and constructed as Safety Class 2 and are seismically qualified.

(3) The interfacing portions of the CVCS redundant system are designed for pressures greater than or equal to RCS pressure.

(4) Upstream of each of the subject check valve pairs, the interfacing CVCS lines contain a separate containment isolation check valve and power operated valve which are close exercise tested individually.

Alternative Testing

The applicant proposed:

> Each pair of series check valves will be exercise tested at the required frequency by some positive means to verify the closure capability of at least one of the valves. No additional exercise testing will be performed unless there is an indication that the closure capability of the pair of valves is questionable. In that case, both valves will be declared inoperable and not returned to service until they are either repaired or replaced.

Evaluation

The chemical and volume control system (CVCS) maintains the water level in the pressurizer, therefore maintaining reactor coolant system (RCS) water inventory. It also supplies seal injection to reactor coolant pump seals, controls chemistry of the RCS, cools the core in the event of an emergency involving a loss-of-coolant accident (LOCA), and allows a means for filling, draining, and pressure testing the RCS during shutdown conditions. The subject valves serve as the reactor coolant pressure boundary between the reactor coolant system and the CVCS. These valves are not listed in Technical Specification Table 3.4-1 as pressure isolation valves. Pressure isolation valves are defined in Generic Letter 87-06, Periodic Verification of Leak Tight Integrity of Pressure Isolation Valves, as any two valves in series within the reactor coolant pressure boundary that separate the high-pressure RCS from an attached low-pressure system. The CVCS is a high-pressure system at the interface. Therefore, the pair of series check valves could be considered as a single valve, with another valve, such as the containment isolation check valve, sering as the second high-to-low pressure interface. The relief request indicates that the containment isolation valve (CIV) check valve is exercise tested periodically.

In FSAR Section 3.6B.1.2.2, "LOCA Break Propagation Criteria," the applicant states that:

> [A] loss of reactor coolant accident is assumed to occur for a branch line break . . . down to and including the second check valve (Case III in FSAR Figure 3.6B-10) on incoming lines normally with flow. A pipe break beyond the restraint or

second check valve will not result in an uncontrolled loss of reactor coolant if either of the two valves in the line closes.

On the basis of the information in FSAR Section 3.6B.1.2.2, it appears that both valves are credited for single-failure assumptions at each of the subject RCS/CVCS interfaces. While verifying that at least one of the two valves is closed would be acceptable if only one valve were required, the applicant needs to develop an additional method to verify that both valves close. A nonintrusive method that may prove to be effective for these 2- and 3-inch valves is radiography. If no nonintrusive method is available, a periodic disassembly and inspection is an acceptable alternative if performed in accordance with the guidance in Generic Letter 89-04, Position 2. Because this relief does not raise a significant safety concern, resolution may be delayed to the end of the first refueling outage. Additionally, if the applicant has information that gives further insight for the single-failure assumptions, the relief request should be revised and resubmitted.

NOTE: Figure 3.6B-10, Case III, depicts a single test connection upstream of the two series check valves. However, the isometric drawings that depict these six sets per unit of series valves show the test connections downstream (flow into RCS). Therefore, it appears that a leakage test of the pair of valves using a downstream test connection in the lines that each contain a third check valve and a power-operated valve that function as containment isolation valves (CIVs), and a manual valve between the second check valve and the CIV check valve, may not verify that the series check valves are closed. The applicant should review this issue and ensure that the testing performed for these valves is adequate to verify closure.

Conclusion

The proposed alternative testing is not consistent with statements in the FSAR; therefore, the proposal cannot be authorized. The applicant should develop a method for verifying that each of the valves functions closed before startup from the first refueling outage for Unit 2 or submit a revised relief request that addresses FSAR Section 3.6B.1.2.2 and describes the adequacy of the test method. By letter dated January 21, 1993 (TXX-93029), the applicant committed to address this issue by July 1, 1993, either by submittal of a revised relief request or withdrawal of the request. Because the licensee has committed to address this issue prior to the first refueling outage, it is likely that this issue will be resolved before the tests are scheduled to be performed. In addition, because this issue is not a significant safety concern, the proposed alternative is acceptable until an appropriate resolution is determined.

RELIEF REQUEST V-6

The applicant has requested relief from the requirements of OM-10, Section 4.3.2, "Exercising Tests for Check Valves," for Category C, Class 3 check valves that form the boundary between the nonsafety demineralized water system or waste-processing system and the safety-grade reactor makeup water storage tank (RMWST) to preclude draining the RMWST upon failure of the nonsafety systems (four valves each unit).

Applicant Basis for Relief

The applicant stated:

> Each pair of valves listed constitutes two check valves in series at a Class 3/nonsafety piping interface. Two Safety Class 3 check valves are provided in accordance with the safety class interface criteria of ANSI N18.2-1975 in order to isolate the interfacing nonsafety system. Either of the check valves provided can perform this function. The system design, however, does not include the test connections necessary to close exercise test each of the series check valves individually. The system design does include sufficient test connections to verify the check function of each pair of valves (i.e., verification that at least one of the valves will close).
>
> Offsetting the inability to separately test each series check valve is the availability of the other unit's RMWST. Each unit's RMWST normally provides inventory for makeup to various safety-related systems in that unit via the reactor makeup water pumps. The two units' reactor makeup water pumps, however, are cross-connected (but normally isolated) at their suction, discharge and miniflow lines such that either the Unit 1 RMWST or the Unit 2 RMWST can be aligned to supply any of the reactor makeup water pumps users in either unit. In the unlikely event that one unit's tank contents are lost through a makeup line failure in combination with the failure of both makeup line check valves to close, the other unit's tank would be unaffected.

Alternative Testing

The applicant proposed:

> Each pair of series check valves will be exercise tested at the required frequency by some positive means to verify the closure capability of at least one of the valves. No additional exercise testing will be performed unless there is an indication that the closure capability of the pair of valves is questionable. In that case, both valves will be declared inoperable and not returned to service until they are either repaired or replaced.

Evaluation

The relief request relates to the exercising of these series check valves to verify closure. The Code requires periodic verification of a check valve's capability to function to its safety position to ensure that the plant operates within its safety analyses. For series check valves when only one of a pair is required to meet safety analysis assumptions, the staff has determined that it is acceptable to test the pair as a single valve with the following provisions: (1) both valves must be subject to comparable quality assurance requirements, (2) acceptance criteria for the pair of valves must be established appropriate to the verification method, and (3) if the acceptance criteria are not met, both valves shall be declared inoperable and corrective actions shall be initiated for both valves, including a retest, before returning the pair of valves to service. The relief request includes these stipulations. The relief request does not specifically state that the safety analysis does not credit both valves for single-failure assumptions; however, a review of the applicable sections did not identify any statements stipulating that both valves are required. Therefore, the alternative is acceptable because the tests verify the safety requirements for the pair of valves. Additional justification is based on the corrective actions required for both valves when acceptance criteria are not met to ensure that at least one of the two valves continues to function to meet safety analysis assumptions. Therefore, the proposed alternative will result in an acceptable level of quality and safety.

Conclusion

The alternative proposed by the applicant is authorized pursuant to 10 CFR 50.55a(a)(3)(i), because it offers an acceptable level of quality and safety.

RELIEF REQUEST V-7

The applicant has determined that exercising the safety injection accumulator check valves quarterly or during cold shutdowns is impractical. That determination is included in Note 8 of Table 13, "Safety Injection System," of the IST program. The applicant has requested relief from the requirements of OM-10, Section 4.3.2.4(c), which requires disassembly of check valves every refueling outage to verify operability of the safety injection accumulators to RCS/RCS pressure isolations isolation valves. Alternatively, the applicant proposes to implement the sampling program allowed in Generic Letter 89-04, Position 2 which allows only a sample of the valves to be disassembled at each refueling outage. The staff reviewed the licensee's alternative testing and determined that it follows the guidance in the generic letter. Because the staff has already approved the alternative in Generic Letter 89-04, no additional evaluation is necessary. The implementation of the disassembly and inspection in accordance with Position 2 is subject to NRC inspection. The use of disassembly and inspection for these valves is for exercising requirements only and does not verify leak-tightness for their pressure isolation function. Leakage testing is performed according to the schedule and requirements of Technical Specification 4.4.5.2.2, which meets the Code requirements.

AUGMENTATION OF THE IST PROGRAM

Chemical volume control system valves 8510A and 8510B have been categorized as relief valves by the licensee and as such are proposed to be set pressure tested at a nominal ten-year testing frequency in accordance with the 1989 Edition of Section XI of the ASME Code. However, the staff has determined that these valves perform the safety functions of opening to assure adequate flow in the alternate minimum flow (AMF) lines and of closing to assure integrity of the high head safety injection (HHSI) system. Specifically, the valves open to prevent the HHSI pumps from deadheading following a safety injection signal and close to assure HHSI flow for emergency core cooling. The staff has determined that in order to properly assure these safety functions for these valves, the testing must be performed more frequently than would be required for relief valves whose function is that of system overpressure protection. By letter dated January 18, 1993 (TU Electric letter TXX-93031 to NRC), the applicant committed to implement the following augmented inservice testing on these valves prior to the first refueling outage.

(1) A minimum of one of the valves shall be set pressure tested each fuel cycle. Both valves shall be tested within two fuel cycles.

(2) If one valve fails a set pressure test, the other valve shall be tested.

(3) Both valves shall be set pressure tested, inspected and refurbished as necessary following any system actuation requiring valve discharge. This testing, inspection, and refurbishment shall be performed at the next cold shutdown of sufficient duration to perform these activities.

ACTIONS

The reviews performed for this SE 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, all applicable testing requirements were not verified. Therefore, the applicant is asked to submit to the NRC a description of the process used in developing the IST program. The submittal should include, as a minimum, details of the documents used, the method for determining if a component requires inservice testing, the basis for the testing required, the basis for categorizing valves, and the method of for process used for maintaining the program current with design modifications or other activities performed under 10 CFR 50.59. By letter dated January 21, 1993 (TXX-93029), the applicant has committed to send this report by July 1, 1993.

APPENDIX S

PRESERVICE INSPECTION RELIEF REQUESTS
COMANCHE PEAK STEAM ELECTRIC STATION, UNIT 2

1 INTRODUCTION

This section was prepared with the technical assistance of U.S. Department of Energy contractors from the Idaho National Engineering Laboratory.

For nuclear power facilities with construction permits issued on or after July 1, 1974, 10 CFR 50.55a(g)(3) states that components (including supports) that are classified as ASME Code Class 1, 2, or 3 must be designed with access for the performance of inservice examination and must meet the preservice examination requirements in editions and addenda of Section XI of the ASME Code applied to the construction of the particular component.
10 CFR 50.55a(g)(3) also states that 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 staff has reviewed the applicant's submittal of June 2, 1988, transmitting the Preservice Inspection (PSI) Program, Revision 0. Evaluations of the relief requests contained in this report are based on the October 30, 1992, submittal, except for Relief Request B-11 (Revision 1), which was submitted in a letter of December 21, 1992, and Relief Request D-1, which was contained in the June 2, 1988, submittal. The relief requests were supported by information pursuant to 10 CFR 50.55a(a)(3). Therefore, the staff evaluation consisted of reviewing the applicant's submittal to the requirements of the applicable Code and determining if the applicant has demonstrated that the proposed alternatives would offer an acceptable level of quality and safety, or that compliance with the specified requirements would result in hardship or unusual difficulties without a compensating increase in the level of quality and safety.

2 TECHNICAL REVIEW CONSIDERATIONS

The construction permit for Comanche Peak Steam Electric Station, Unit 2, was issued on December 19, 1974. The PSI program is based on the 1983 Edition (no Addenda) of Section XI of the ASME Code, with the exceptions discussed in Sections 5.2.4.2 and 6.6.2 of this SER supplement (SSER 26).

Verification of the as-built structural integrity of the primary pressure boundary is not dependent on the Section XI preservice examination. The applicable construction codes to which the primary pressure boundary was fabricated contain examination and testing requirements that, by themselves, contain the necessary assurance that the pressure boundary components are capable of performing safely under all operating conditions reviewed in the FSAR and described in the plant design specifications. As a part of these examinations, all of the primary pressure boundary full-penetration welds received both surface and volumetric (radiographic) examinations, and the system was subjected to hydrostatic pressure tests.

The intent of a preservice examination is to establish a reference or baseline before the initial operation of the facility. Then, the results of subsequent inservice examinations can be compared with the original condition to determine if changes have occurred because of inservice degradation. If review of the inservice examination findings shows no change from the original condition, no action is required. If baseline data are not available, all flaws must be treated as new flaws generated during service and must be evaluated in accordance with Section XI of the Code.

Another benefit of the preservice examination is that it calls for redundant or alternative volumetric examination of the primary pressure boundary using a test method different from that employed during fabrication. Successful performance of preservice examination also demonstrates that the welds so examined are capable of subsequent inservice examination using that volumetric test method.

In the case of Comanche Peak Steam Electric Station (CPSES), Unit 2, a large portion of the preservice examination required by the ASME Code was performed. Those portions not performed are addressed by the requests for relief examined in this report. Failure to perform a 100 percent preservice examination of the welds identified below will not significantly affect the assurance of the initial structural integrity of that component.

In some instances where the required preservice examinations were not performed to the full extent specified by the applicable ASME Code, the staff may require that these examinations or supplemental examinations be conducted as a part of the inservice inspection program. Requiring that supplemental examinations be performed before plant startup would cause hardships or unusual difficulties without producing a compensating increase in the level of quality or safety. The performance of such supplemental examinations as surface examinations in areas in which volumetric inspection is difficult will be more meaningful after a period of operation. Acceptable preoperational integrity has already been established by similar ASME Code, Section III, fabrication examinations.

In cases in which portions of the required examination cannot be performed because of a combination of component design and current examination technique limitations (e.g., branch connection welds), the development of new or improved examination techniques will continue to be evaluated. As improvements are made in these areas, the staff will require that these new techniques be incorporated into the inservice examination program for the components or welds that received only a limited preservice examination.

Several of the preservice inspection (PSI) relief requests involve limitations to the examination of the required volume of a specified weld. The inservice inspection (ISI) program is based on the examination of a representative sample of welds to detect generic degradation. If the welds identified in the PSI relief requests must be examined again, the possibility of augmented ISI will be evaluated when the staff reviews the applicant's initial 10-year ISI program. An augmented program may include increased extent or increased frequency, or both, of inspection of accessible welds.

3 EVALUATION OF RELIEF REQUESTS

The applicant requested relief from the ASME Code, Section XI, requirements that it considered not practical in letters of June 2, 1988; October 30, 1992; and December 21, 1992. The staff evaluated those relief requests on the basis of (1) these letters and (2) a meeting with the applicant on December 8, 1992. On the basis of this information and review of the design, geometry, and materials of construction of the components, certain preservice requirements of ASME Code, Section XI, have been determined to be impractical. Imposing these requirements would result in hardships or unusual difficulties without producing a compensating increase in the level of quality and safety. Therefore, pursuant to 10 CFR 50.55a(a)(3), conclusions that these preservice requirements are impractical are justified. Unless otherwise stated, references to the Code refer to the ASME Code, Section XI, 1983 Edition with no addenda.

A. <u>Relief Request B-1, Examination Category B-A, Item B1.11, Reactor Pressure Vessel (RPV) Circumferential Head-to-Shell Weld TCX-1-1100-4</u>

<u>Code Requirement</u>: Section XI, Table IWB-2500-1, Examination Category B-A, Item B1.11, requires a 100% volumetric examination of RPV circumferential shell welds as defined by Figure IWB-2500-1.

<u>Applicant's Code Relief Request</u>: Relief is requested from performing the volumetric examination of RPV Head-to-Shell Weld TCX-1-1100-4 to the extent required by the Code.

<u>Applicant's Proposed Alternative</u>: None. However, the manufacturer performed volumetric examinations during fabrication and the resulting records are available in permanent plant files to supplement the partial preservice examination.

<u>Applicant's Basis for Requesting Relief</u>: The applicant states that six core support lugs limit access to the RPV lower head-to-shell weld and preclude ultrasonic examination of 20% of the volume described in Figure IWB-2500-1. This weld was examined to the maximum extent practical using automated immersion techniques from the inside surface. An examination from the outside surface is prevented by the surrounding support structure.

Staff Evaluation: The applicant has stated that preservice examinations were performed using automated immersion inspection techniques to examine the RPV from the vessel interior to the extent practical. Similar examinations will be conducted during future inservice inspections to minimize radiation exposure to personnel. Portions of Weld TCX-1-1100-4 cannot be examined from the vessel interior because six adjacent core support lugs limit access to the weld. In order to perform the volumetric examination to the extent required by the Code, the core support lugs would have to be redesigned and replaced to allow access for weld examination. Compliance with the Code requirement would result in hardship without a compensating increase in quality and safety.

Considering that a significant portion of the weld (80%) was examined, and considering the potential burden on the applicant if the Code requirement was imposed, it is concluded that, pursuant to 10 CFR 50.55a(a)(3)(ii), relief is authorized. The partial examination from the vessel interior, supplemented by the manufacturer's fabrication volumetric examination, provides reasonable assurance of the structural integrity of the subject RPV shell-to-head weld.

B. Relief Request B-2, Examination Category B-A, Item B1.21, RPV Lower Head Dome Weld TCX-1-1100-5

Code Requirement: Section XI, Table IWB-2500-1, Examination Category B-A, Item B1.21, requires a 100% volumetric examination of the lower head circumferential welds as defined by Figure IWB-2500-3.

Applicant's Code Relief Request: Relief is requested from the volumetric examination of RPV Lower Head Dome Weld TCX-1-1100-5 to the extent required by the Code.

Applicant's Proposed Alternative: None. However, volumetric examinations were performed by the manufacturer during fabrication and the resulting records are available in permanent plant files to supplement the partial preservice examination.

Applicant's Basis for Requesting Relief: The applicant states that the protrusion of 58 reactor bottom-mounted-instrumentation tubes through the lower head dome renders automated ultrasonic examination of this weld from the inside surface impractical. Approximately 20% of the volume described in Figure IWB-2500-3 of Section XI, as applied to this weld, could not be examined due to the component geometry. This weld was examined to the maximum extent practical from the outside surface using manual ultrasonic techniques.

Staff Evaluation: The Code requires a 100% volumetric examination of the subject lower head weld. Because of accessibility and radiation hazards encountered during ISI, this examination is typically performed by automated immersion testing from the vessel interior for both ISI and the PSI baseline examinations. However, the applicant states that automated examination of this weld from the interior was not possible due to instrument nozzle penetrations that restrict access for the ultrasonic testing equipment inspection head. Therefore, the examination was performed to the extent practical from the outside using manual ultrasonic inspection methods. Approximately 20% of the manual examination of the weld could not be completed due to component geometry. In order to complete the Code-required examination, the RPV would have to be modified to provide access for weld examination. Imposition of the requirement on the applicant would cause a burden that would not be compensated by the increase in safety above that provided by the limited examination.

Considering that a significant portion of the weld (80%) was examined, and considering the potential burden on the applicant if the Code requirement was imposed, it is concluded that, pursuant to 10 CFR 50.55a(a)(3)(ii), relief is authorized. The partial manual examination from the vessel exterior, supplemented by the manufacturer's fabrication volumetric examination, provides reasonable assurance of the structural integrity of the subject RPV lower head dome weld. However, the applicant should continue to monitor the industry for improvements in inspection technology that would allow this weld to be examined from the vessel interior using automated inspection techniques.

C. <u>Relief Request B-3, Examination Category B-A, Item B1.40, RPV Closure Head-to-Flange Weld TCX-1-1300-1</u>

<u>Code Requirement</u>: Section XI, Table IWB-2500-1, Examination Category B-A, Item B1.40, requires 100% volumetric and surface examinations of RPV head-to-flange welds as defined by Figure IWB-2500-5.

<u>Applicant's Code Relief Request</u>: Relief is requested from performing the volumetric examination, to the extent required by the Code, of RPV Closure Head-to-Flange Weld TCX-1-1300-1.

<u>Applicant's Proposed Alternative</u>: None. However, the manufacturer performed volumetric examinations during fabrication and the resulting records are available in permanent plant files to supplement the partial preservice examination.

<u>Applicant's Basis for Requesting Relief</u>: Interference from the reactor vessel head flange and three head lifting lugs preclude ultrasonic examination of 38% of the volume described in Figure IWB-2500-5 of the Code. The applicant completed the required surface examinations.

<u>Staff Evaluation</u>: The Code requires a volumetric examination of 100% of the subject weld. However, ultrasonic examination of certain portions of the weld is obstructed by the flange below the weld and lifting lugs above the weld. In order to perform the volumetric examination to the extent required by the Code, the RPV head would have to be modified to

allow access for examination of the subject weld. Compliance with the Code requirement would result in hardship without a compensating increase in quality and safety.

Considering that a significant portion (62%) of the Code-required weld volume was examined, and considering the potential burden on the applicant if the Code requirement was imposed, the staff concludes that, pursuant to 10 CFR 50.55a(a)(3)(ii), relief is authorized. The partial ultrasonic examination, supplemented by the manufacturer's volumetric examination, will provide reasonable assurance of the structural integrity of the subject welds.

D. <u>Relief Request B-4, Examination Category B-K-1, Item B10.10, Class 1 Integrally Welded Attachment TCX-1-4505-H1</u>

<u>Code Requirement</u>: Section XI, Table IWB-2500-1, Examination Category B-K-1, Item B10.10, requires a 100% surface or volumetric examination, as applicable, for integrally welded attachments to piping as defined by Figures IWB-2500-13, -14, and -15. Examinations include welded attachments of piping required to be examined by Examination Category B-J and associated pumps and valves integral to such piping.

<u>Applicant's Code Relief Request</u>: Relief is requested from performing 100% of the Code-required surface examination for Integrally Welded Piping Attachment TCX-1-4505-H1.

<u>Applicant's Proposed Alternative</u>: The applicant performed surface examinations during construction and the resulting records are available in permanent plant files to supplement the partial preservice examination.

<u>Applicant's Basis for Requesting Relief</u>: The component support configuration, which consists of an integrally welded plate on each side of an integrally welded trunnion, does not provide access for complete surface examination. The applicant examined approximately 70% of the required weld length.

<u>Staff Evaluation</u>: The Code requires a 100% surface examination of those integrally welded attachments selected for examination. In the case of Integrally Welded Attachment TCX-1-4505-H1, the weld is obstructed by welded plates on either side that limit access for the required surface examination.

Considering that a significant portion (70%) of the Code-required examination was completed, the staff has determined that the partial surface exams, supplemented by the construction surface examination, constitute an examination equivalent to the PSI examination required by ASME Code, Section XI, and provide an acceptable level of quality and safety. Therefore, pursuant to 10 CFR 50.55a(a)(3)(i), relief is authorized.

E. <u>Relief Request B-5, Examination Category B-A, Item B1.12, RPV Upper Shell Longitudinal Welds</u>

<u>Code Requirement</u>: Section XI, Table IWB-2500-1, Examination Category B-A, Item B1.12, requires a 100% volumetric examination of all RPV longitudinal shell welds as defined by Figure IWB-2500-2.

<u>Applicant's Code Relief Request</u>: Relief is requested from performing the volumetric examination of RPV Upper Shell Longitudinal Welds TCX-1-1100-6, TCX-1-1100-7, and TCX-1-1100-8 to the extent required by the Code.

<u>Applicant's Proposed Alternative</u>: None. However, the manufacturer performed volumetric examinations during fabrication and the resulting records are available in permanent plant files to supplement the partial preservice examination.

<u>Applicant's Basis for Requesting Relief</u>: Interference from the main reactor coolant loop nozzles limits the automated ultrasonic examination of the three RPV upper shell longitudinal welds. This is due to the lack of surface distance available when examining the welds for reflectors parallel to the weld seam. Manual ultrasonic examinations are not practical because of limited accessibility to the affected areas. Approximately 10% of Welds TCX-1-1100-6 and TCX-1-1100-8 was not examined in all four directions. For Weld TCX-1-1100-7, approximately 50% of the weld volume was examined in four directions; the remaining 50% was only examined in three directions.

<u>Staff Evaluation</u>: The automated ultrasonic examination of the subject welds is performed to provide a baseline examination to which future inservice examinations can be compared. Automated examinations of the RPV are performed during ISI to minimize radiation exposure to personnel. Portions of the subject longitudinal welds are inaccessible for automated inspection due to nozzle obstructions that limit the scan path perpendicular to the weld. In order to perform the volumetric examination to the extent required by the Code, the RPV would have to be modified to allow access for examination of the subject welds. Compliance with the Code requirement would result in hardship without a compensating increase in quality and safety.

Considering that a significant portion (>50%) of the subject welds was examined, and considering the potential burden on the applicant if the Code requirement was imposed, the staff concludes that pursuant to 10 CFR 50.55a(a)(3)(ii), relief is authorized. The partial examinations, along with the manufacturer's fabrication volumetric examinations provide reasonable assurance of the structural integrity of the RPV longitudinal welds.

F. <u>Relief Request B-6, Examination Category B-B, Item B2.11, Pressurizer Lower Head-to-Shell Weld TCX-1-2100-1</u>

<u>Code Requirement</u>: Section XI, Table IWB-2500-1, Examination Category B-B, Item B2.11, requires a volumetric examination of pressurizer circumferential shell-to-head welds as defined by Figure IWB-2500-1.

<u>Applicant's Code Relief Request</u>: Relief is requested from performing the volumetric examination of Pressurizer Shell-to-Head Weld TCX-1-2100 to the extent required by the Code.

<u>Applicant's Proposed Alternative</u>: None. However, the manufacturer performed volumetric examinations during fabrication and the resulting records are available in permanent plant files to supplement the partial preservice examination.

<u>Applicant's Basis for Requesting Relief</u>: Interference from welded pads, instrumentation lines, and the pressurizer support skirt preclude a complete ultrasonic examination. Approximately 16% of the required volume (per Figure IWB-2500-1) could not be examined.

<u>Staff Evaluation</u>: The required volumetric examination is limited by adjacent physical obstructions that prevent access to a portion of the weld volume. To perform the volumetric examination to the extent required by the Code, design modifications to allow access for examination of the pressurizer shell-to-head weld must be made. Compliance with the Code requirement would result in hardship without a compensating increase in quality and safety.

Considering that a significant portion of the weld (>80%) was examined, and considering the potential burden on the applicant if the Code requirement was imposed, the staff concludes that pursuant to 10 CFR 50.55a(a)(3)(ii), relief is authorized. The partial examination, along with the manufacturer's fabrication volumetric examination, provides reasonable assurance of the structural integrity of the pressurizer shell-to-head weld.

G. <u>Relief Request B-7, Examination Category B-B, Item B2.40, Steam Generator Tubesheet-to-Head Welds (4 Welds)</u>

<u>Code Requirement</u>: Section XI, Table IWB-2500-1, Examination Category B-B, Item B2.40, requires a 100% volumetric examination of steam generator tubesheet-to-head welds as defined by Figure IWB-2500-6.

<u>Applicant's Code Relief Request</u>: Relief is requested from performing the volumetric examination of Steam Generator Tubesheet-to-Head Welds TCX-3100-1-1, TCX-1-3100-2-1, TCX-1-3100-3-1, and TCX-1-3100-4-1 to the extent required by the Code.

Applicant's Proposed Alternative: None. However, the manufacturer performed volumetric examinations during fabrication and the resulting records are available in permanent plant files to supplement the partial preservice examination.

Applicant's Basis for Requesting Relief: Interference from 21 welded pads and an integral support collar preclude ultrasonic examination of 35% of the volume described in Figure IWB-2500-6 of the Code. The same limitation applies to all four steam generators.

Staff Evaluation: The Code requires a 100% volumetric examination of the subject steam generator welds. However, the required examination volume is obstructed by 21 welded pads and an integral support collar. To perform the volumetric examination to the extent required by the Code, design modifications to allow access for examination of the subject tubesheet-to-head welds are necessary. Compliance with the Code requirement would result in hardship without a compensating increase in quality and safety.

Considering the portion of the examination that was completed (65%), and considering the potential burden on the applicant if the Code requirements were imposed, the staff concludes that pursuant to 10 CFR 50.55a(a)(3)(ii), relief is authorized. The partial examinations, along with the manufacturer's fabrication volumetric examinations provide reasonable assurance of the structural integrity of the subject steam generator tubesheet-to-head welds.

H. Relief Request B-8, Examination Category B-D, Item B3.110, Pressurizer Nozzle-to-Vessel Welds (6 Welds)

Code Requirement: Section XI, Table IWB-2500-1, Examination Category B-D, Item B3.110, requires a 100% volumetric examination of all pressurizer nozzle-to-vessel welds as defined by Figure IWB-2500-7.

Applicant's Code Relief Request: Relief is requested from performing the volumetric examination, to the extent required by the Code, of the following pressurizer nozzle-to-vessel welds:

TCX-1-2100-11 (Surge)
TCX-1-2100-12 (Spray)
TCX-1-2100-13 (Safety A)
TCX-1-2100-14 (Relief)
TCX-1-2100-15 (Safety C)
TCX-1-2100-16 (Safety B)

Applicant's Proposed Alternative: None. However, the manufacturer performed volumetric examinations during fabrication and the resulting records are available in permanent plant files to supplement the partial preservice examination.

Applicant's Basis for Requesting Relief: The proximity of the nozzle-to-vessel weld to the pressurizer shell and the location of heater penetrations near the pressurizer surge line limit the ultrasonic examination of the volume designated in Figure IWB-2500-7(b). The applicant examined these nozzles to the maximum extent possible using 0°, 45°, and 60° beam angles. Approximately 50% of the required volume did not receive all required beam angle directions for each pressurizer nozzle, excluding the surge line nozzle. The heater penetrations increased the limitation associated with the surge line nozzle to 65%.

Staff Evaluation: The pressurizer nozzle-to-vessel welds require a 100% volumetric examination. However, examination of the subject welds is limited by component geometry, or in the case of the surge line nozzle, by heater penetrations. To examine the nozzle-to-vessel welds to the extent required by the Code, the pressurizer would have to be modified to allow access for inspection. Imposition of the requirement on the applicant would cause a burden that would not be compensated by an increase in safety above that provided by the limited examination.

Considering the portion of the examination that was completed, that the subject welds received volumetric examinations during fabrication, and considering the burden on the applicant if the Code requirement was imposed, it is concluded that, pursuant to 10 CFR 50.55a(a)(3)(ii), relief is authorized. The partial examinations, supplemented by the volumetric examinations performed during fabrication, provide reasonable assurance of the structural integrity of the subject pressurizer welds.

I. Relief Request B-9, Examination Category B-D, Items B3.40 and B3.60, Pressurizer and Steam Generator Nozzle Inner Radii

Code Requirement: Examination Category B-D, Items B3.40 and B3.60, require 100% volumetric examination of the pressurizer and steam generator nozzle inner radius sections as defined by Figure IWB-2500-7(a) through (d).

Applicant's Code Relief Request: Relief is requested from performing the Code-required preservice examination of the following nozzle inner radius sections:

Pressurizer	Steam Generator
--	TCX-1-3100-1A
--	TCX-1-3100-1B
TCX-1-2100-11IR	TCX-1-3100-2A
TCX-1-2100-12IR	TCX-1-3100-2B
TCX-1-2100-13IR	TCX-1-3100-3A
TCX-1-2100-14IR	TCX-1-3100-3B
TCX-1-2100-15IR	TCX-1-3100-4A
TCX-1-2100-16IR	TCX-1-3100-4B

Applicant's Proposed Alternative: None. The applicant will examine the inner radius of the pressurizer spray nozzle in the first period of the first inservice inspection interval.

Applicant's Basis for Requesting Relief: The applicant states that specialized techniques and nozzle-specific calibration blocks are required to ensure meaningful results for volumetric examination of the referenced inside radius sections. To determine which nozzles warrant use of these enhanced techniques, each nozzle was evaluated. In this evaluation, the nozzle designs, the nozzle stress and usage factors, and the potential for thermal shock were considered. Of the referenced nozzles, only the pressurizer surge and spray nozzles exhibit a potential for thermal shock. Only the spray nozzle contains stresses close to the allowable limits and associated usage factors that will approach allowable limits over the life of the facility. A specific calibration block for the pressurizer spray nozzle has not been fabricated for PSI. The applicant stated in their October 30, 1992, submittal that this calibration block will be fabricated and available for use during ISI. For PSI, a best effort examination has been performed on the pressurizer spray nozzle inner radius by directing ultrasound tangentially toward the inner radius of the nozzle from the pressurizer head surface. The applicant stated in their October 30, 1992, submittal that the inner radius of the pressurizer spray nozzle will be examined during the first period of the first ISI interval using enhanced ultrasonic techniques and a specificallydesigned calibration block to maximize coverage. Since this nozzle is not subjected to significant stresses related to usage before initial operation, there is adequate assurance that the structural integrity of the inner radius section will be maintained until the enhanced examination is performed.

Limited access due to the close proximity of the pressurizer heater connections and the fact that the nozzle stresses do not approach the allowable limits, indicate that the effort required for enhanced examination methodology is not warranted for the inner radius of the pressurizer surge line nozzle. For the inner radius sections of the remaining pressurizer nozzles (relief and safeties), as well as the integrally cast primary side steam generator nozzles, the effort associated with volumetric examination does not produce a corresponding increase in reliability or safety based on the expected service conditions, which do not include potential for thermal shock or stresses that approach allowable limits.

Staff Evaluation: The Code requires that pressurizer and steam generator nozzle inner radius sections receive 100% volumetric examination during PSI and ISI. However, the applicant states that examination of the subject sections requires specialized ultrasonic techniques and nozzle calibration blocks for a meaningful examination.

The manufacturer's fabrication surface examinations provide reasonable assurance of the structural integrity of the pressurizer and inner radius sections of the steam generator nozzle. Requiring the applicant to fabricate special calibration blocks for the sole purpose of performing PSI would result in hardship without a compensating increase in quality and safety. Therefore, pursuant to 10 CFR 50.55a(a)(3)(ii), the staff concludes that relief is authorized for the subject inner radius sections. However, examination of these inner radius sections will be required during ISI. The lack of calibration blocks and meaningful inspection techniques is not an adequate reason for not performing the ISI examinations. The applicant should develop calibration blocks and techniques before the required inservice inspections are performed.

J. Relief Request B-10, Examination Category B-F, Items B5.40 and B5.70, Pressurizer and Steam Generator Dissimilar Metal Nozzle-to-Safe End Welds

Code Requirement: Examination Category B-F, Items B5.40 and B5.70, require 100% surface and volumetric examinations of all pressurizer and steam generator dissimilar metal nozzle-to-safe end welds as defined by Figure IWB-2500-8.

Applicant's Code Relief Request: Relief is requested from the volumetric examination, to the extent required by the Code, of the following dissimilar metal welds:

Pressurizer	Steam Generator
TCX-1-4500-6	TCX-1-4100-4
	TCX-1-4300-4
	TCX-1-4400-4
	TCX-1-4100-5
	TCX-1-4100-5
	TCX-1-4400-5

Applicant's Proposed Alternative: None. However, the manufacturer performed volumetric examinations during fabrication and the resulting records are available in permanent plant files to supplement the partial preservice examination.

Applicant's Basis for Requesting Relief: The physical configuration of each of the nozzle-to-safe ends (inlet and outlet) on Steam Generators 1, 3, and 4, and the nozzle configuration of four welded lugs on the pressurizer surge line nozzle-to-safe end weld, preclude complete ultrasonic examination of the volume described in the Code. In each case, approximately 15% of the required volume did not receive all required beam scan directions.

Staff Evaluation: The Code requirement for the subject welds is 100% volumetric and surface examinations. However, the volumetric examinations are limited by nozzle configuration or, in the case of the pressurizer surge line, welded lugs. In order to perform the volumetric examination to the extent required by the Code, the steam generator nozzle-to-safe end welds would have to be modified to allow access for the complete examination of the subject welds. Compliance with the Code requirement would result in hardship without a compensating increase in quality and safety.

Considering that a significant portion (85%) of the Code-required volume was examined, and considering the potential burden on the applicant if the Code requirements were imposed, it is concluded that, pursuant to 10 CFR 50.55a(a)(3)(ii), relief is authorized. The partial preservice examinations, supplemented by the manufacturer's fabrication examinations, provide an adequate assurance of the structural integrity of the subject nozzle-to-safe end welds.

K. Relief Request B-11 (Revision 1), Examination Category B-J, Items B9.11 and B9.31, Class 1 Piping Welds

Code Requirement: Examination Category B-J, Items B9.11 and B9.31, require 100% surface and volumetric examinations of circumferential welds and branch connection welds greater than four inches NPS as defined by Figures IWB-2500-8, -9, -10, or -11. Preservice examinations are to be extended to include essentially 100% of the pressure-retaining welds in all Class 1 components not exempted by IWB-1220(a), (b), or (c).

Applicant's Code Relief Request: Relief is requested from performing the volumetric examination to the extent required by the Code for the following welds:

Weld No.	Description	Completed	Restriction
TCX-1-4100-2	29" RC safe end-to-pipe	80%	RPV insulation support
TCX-1-4100-13	27.5" RC pipe-to-safe-end	80%	RPV insulation support
TCX-1-4100-15	12" RC branch connection	80%	Nozzle configuration
TCX-1-4100-20	10" RC branch connection	80%	Nozzle configuration and instrumentation line
TCX-1-4103-1	6" SI valve-to-pipe	60%	Adjacent valve and weld

Weld No.	Description	Completed	Restriction
TCS-1-4103-2	6" SI pipe-to-pipe	89%	Adjacent welds
TCX-1-4200-2	29" RC safe end-to-pipe	80%	RPV insulation support
TCX-1-4200-13	27.5" RC pipe-to-safe end	80%	RPV insulation support
TCX-1-4200-15	6" RC branch connection	80%	Nozzle configuration
TCX-1-4300-2	29" RC safe end-to-pipe	80%	RPV insulation support
TCX-1-4300-13	27.5" RC pipe-to-safe end	80%	RPV insulation support
TCX-1-4300-15	6" branch connection	80%	Nozzle configuration
TCX-1-4300-18	10" RC branch connection	80%	Nozzle configuration
TCX-1-4400-2	29" RC safe end-to-pipe	80%	RPV insulation support
TCX-1-4400-13	27.5" RC pipe-to-safe end	80%	RPV insulation support
TCX-1-4400-16	10" RC branch connection	80%	Nozzle configuration and instrumentation line
TCX-1-4400-21	14" RC branch connection	80%	Nozzle configuration
TCX-1-4400-22	12" RC branch connection	80%	Nozzle configuration

Applicant's Proposed Alternative: None. However, volumetric examinations were performed by the manufacturer during fabrication and the resulting records are available in permanent plant files to supplement the partial preservice examination.

Applicant's Basis for Requesting Relief: The applicant states that the presence of certain physical restrictions and/or examination area geometries preclude the complete ultrasonic examination of the volumes required in Figures IWB-2500-8, -9, and -11. The specific restrictions are listed above. The Code-required surface examinations have been completed with acceptable results.

Staff Evaluation: The Code requires a 100% volumetric examination of those Class 1 circumferential welds and branch connection welds selected for examination. However, examination of the subject welds is restricted as listed above. To perform the volumetric examinations to the extent required by the Code, design modifications to allow access for examination of the welds are necessary. Compliance with the Code requirements would result in hardship without a compensating increase in quality and safety.

Considering that a significant portion (at least 60%) of the Code-required examination has been completed for each of the subject welds, and considering the potential burden on the applicant if the Code requirements were imposed, the staff concludes that pursuant to 10 CFR 50.55a(a)(3)(ii), relief is authorized. The partial examinations, supplemented by fabrication volumetric examinations, provide adequate assurance of the structural integrity of the subject welds.

L. Relief Request B-12, Examination Category B-J, Item B9.31, Class 1 Piping Branch Connection Welds

Code Requirement: Examination Category B-J, Item B9.31, requires surface and volumetric examinations of selected branch connection welds four inches NPS and larger as defined by Figures IWB-2500-9, -10, and -11. Preservice examinations are to be extended to include essentially 100% of the pressure-retaining welds in all Class 1 components not exempted by IWB-1220(a), (b), or (c).

Applicant's Code Relief Request: Relief is requested from performing the volumetric examinations of Branch Connection Welds TCX-1-4100-18, TCX-1-4104-1, TCX-1-4400-18, and TCX-1-4404-1 to the extent required by the Code.

Applicant's Proposed Alternative: None. However, the applicant has performed the acceptable surface examinations required by ASME Section XI, and radiographic examinations required by ASME Section III, and the records are available in permanent plant files.

Applicant's Basis for Requesting Relief: The two 4-inch pressurizer spray-to-reactor coolant main loop branch connections and the two 6-inch safety injection (SI) to residual heat removal (RHR) branch connections are of a configuration similar to that in Figure IWB-2500-10. The configuration of this joint type presents significant difficulties for ultrasonic examination. These four connections present additional difficulties due to limited surface area for scanning on the branch connection side. The pressurizer spray connection has the additional hindrance of cast stainless steel material in the main coolant loop.

The effort associated with examination of these four nozzles would entail development of a specific calibration for each type of branch connection. It is anticipated that with the specific calibration blocks, no more than 5% of the pressurizer spray connection and no more than 15% of the SI connection would receive all required angle beam directions. The effort associated with these examinations would not produce a corresponding increase in the level of quality and safety.

Staff Evaluation: The Code requires that all non-exempt welds on Class 1 piping branch connections receive a preservice volumetric examination. However, examination of the four branch connection welds included in this relief request is limited by the configuration of their weld joints, which severely restricts the required examination volume. Examination of the pressurizer spray connection is further restricted by the cast stainless steel material used in the main coolant loop. To perform the volumetric examinations to the extent required by the Code, the design must be modified to allow access for examination of the welds. Compliance with this Code requirement would result in hardship without a compensating increase in quality and safety.

The Code requires a volumetric examination of all Item B9.31 branch connection welds during preservice examination. Therefore, the subject welds are only a small portion of the total welds required to be examined. Considering that other, similar welds have received complete volumetric examination and considering the burden on the applicant if the Code requirement was imposed, the staff concludes that pursuant to 10 CFR 50.55a(a)(3)(ii), relief is authorized. The surface examinations and the construction volumetric examinations provide adequate assurance of the structural integrity of the subject welds.

M. Relief Request B-13, Examination Category B-G-1, Item B6.30, RPV Closure Studs

Code Requirement: Examination Category B-G-1, Item B6.30, requires surface and volumetric examinations of RPV closure studs, when removed, as defined by Figure IWB-2500-12.

Applicant's Code Relief Request: Relief is requested from performing the Code-required volumetric examination from the top surface of RPV Closure Studs TCX-1-1400-1 through -54, S1, and S2.

Applicant's Proposed Alternative: The applicant examined the subject studs ultrasonically from the bottom surface of the stud.

Applicant's Basis for Requesting Relief: The physical configuration of the RPV studs includes a cone-shape cut out from the inside diameter of the upper stud section. This configuration precludes ultrasonic examination from the top surface of the stud. Ultrasonic examinations from the bottom surface of each stud, along with 100% surface examinations, have been completed with acceptable results.

Staff Evaluation: The Code requires a volumetric examination of the full length of RPV studs. The examination volume is the same for studs in place and for studs removed. It appears that the applicant is requesting relief from performing the required examination from the top end of the stud, and has performed the volumetric examination from the bottom end with the stud removed. Since the Code does not specify which surface the examination is to be conducted from, relief is not required.

Code Case N-307-1, which has been approved by the NRC for general use by reference in Regulatory Guide 1.147, provides alternative inspection requirements for studs with center-drilled holes and could be used for examination of the majority of the Code-required volume if an in place examination becomes necessary.

N. Relief Request B-14, Examination Category B-J, Item B9.40, Piping Socket Weld TCX-1-4404-18A

Code Requirement: Examination Category B-J, Item B9.40, requires a 100% surface examination of selected Class 1 piping socket welds, as defined by Figure IWB-2500-8.

Applicant's Code Relief Request: Relief is requested from performing the surface examination on Socket Weld TCX-1-4404-18A to the extent required by the Code.

Applicant's Proposed Alternative: The applicant examined construction surfaces and the resulting records are available in permanent plant files to supplement the partial preservice examination.

Applicant's Basis for Requesting Relief: The configuration of a pipe support located adjacent to the subject weld does not provide access for a complete surface examination. Approximately 77% of the Code-required weld surface was examined during PSI.

Staff Evaluation: The Code requires a 100% surface examination of the Class 1 socket welds selected for examination. However, the subject weld is obstructed by an adjacent pipe support that limits access to a portion of the examination area. To supplement the partial PSI examination, surface examinations have also been performed during construction.

Considering that a significant portion (77%) of the Code-required examination was performed, the staff concludes that, pursuant to 10 CFR 50.55a(a)(3)(i), relief is authorized. The partial examination, supplemented by the surface examination performed during construction, constitutes an examination equivalent to the Code PSI requirements and provides an acceptable level of quality and safety.

O. <u>Relief Request C-1, Examination Category C-A, Items C1.10, C1.20, and C1.30, Class 2 Pressure Vessel Welds</u>

<u>Code Requirement</u>: Examination Category C-A, Item C1.10, requires a 100% volumetric examination of circumferential welds in vessels at structural discontinuities as defined by Figure IWC-2500-1. Items C1.20 and C1.30 require volumetric examination of 100% of head-to-shell welds and tubesheet-to-shell welds as defined by Figures IWC-2500-1 and IWC-2500-2.

<u>Applicant's Code Relief Request</u>: Relief is requested from performing the Code-required volumetric examinations of the following Class 2 pressure vessel welds:

Weld No.	Description	Completed	Restriction
TCX-2-1110-1	Excess letdown HX head-to-flange	50%	Inlet, outlet and instrumentation nozzles and flange taper configuration
TCX-1120-1	RHR HX head-to shell	79%	Head configuration, welded supports
TCX-2-1120-2	RHR HX shell-to-tubesheet	58%	Inlet and outlet nozzles, flange
TCX-2-1150-5	Regenerative HX shell-to-flange	90%	Drain lines and joint configuration (reducer)
TCX-2-1150-6	Regenerative HX shell-to-tubesheet	90%	Drain lines and joint configuration (reducer)
TCX-2-1180-2	Containment spray HX shell-to-flange	86%	Welded supports, flange

<u>Applicant's Proposed Alternative</u>: None. However, the manufacturer performed volumetric examinations during fabrication and the resulting records are available in permanent plant files to supplement the partial preservice examination.

<u>Applicant's Basis for Requesting Relief</u>: The presence of certain physical restrictions and/or examination area geometries precludes the complete examination of the volumes required in Figures IWC-2500-1 and -2 in the Code.

<u>Staff Evaluation</u>: The Code requires that certain Class 2 vessel welds receive 100% volumetric examination. However, due to physical restrictions and/or examination area geometry, portions of the subject vessel welds could not be examined to the extent required by the Code.

To complete the Code-required volumetric examinations, design modifications to allow access for examination are necessary. Compliance with the Code requirement would result in hardship without a compensating increase in quality and safety.

Considering that a significant portion (≥50%) of each weld did receive the Code-required volumetric examination, and considering the burden on the applicant if the Code requirements were imposed, the staff concludes that pursuant to 10 CFR 50.55a(a)(3)(ii), relief is authorized. The partial examinations, supplemented by manufacturer's fabrication examinations, provide adequate assurance of the structural integrity of the subject welds.

P. <u>Relief Request C-2, Examination Category C-B, Item C2.22, Steam Generator, RHR Heat Exchanger, and CT Heat Exchanger Nozzle Inner Radii (IR)</u>

<u>Code Requirement</u>: Examination Category C-B, Item C2.22, requires a volumetric examination of nozzle IR sections, as defined by Figures IWC-2500-4(a) or (b), for nozzles without reinforcing plates in Class 2 vessels with nominal wall thickness greater than 1/2 inch.

<u>Applicant's Code Relief Request</u>: Relief is requested from performing the Code-required volumetric examinations of Steam Generator IR Sections TCX-2-1100-9IR and TCX-1-1100-11IR, RHR Heat Exchanger IR Sections TCX-2-1120-3IR and TCX-2-1120-4IR, and CT Heat Exchanger Nozzle IR Section TCX-2-1180-3IR.

<u>Applicant's Proposed Alternative</u>: None. The applicant will examine the steam generator main inner radius of the feedwater nozzle during the first period of the first ISI interval.

<u>Applicant's Basis for Requesting Relief</u>: The applicant states that specialized techniques and nozzle-specific calibration blocks are required to ensure meaningful results for volumetric examination of the referenced inside radius of the nozzle. To determine which nozzles warrant use of these enhanced techniques, each nozzle was evaluated. In this evaluation, the nozzle stress and usage factors, as well as the potential for thermal shock, were considered. Of the referenced nozzles, only the main feedwater nozzles on the steam generators exhibit a potential for thermal shock and have stresses close to the allowable limits and associated usage factors that will approach allowable limits over the life of the facility. A specific calibration block for the main feedwater nozzle has not been fabricated for PSI. This calibration block will be fabricated and available for ISI. For PSI, a best effort examination has been performed in the inner radius of the steam generator's main feedwater nozzle by directing ultrasound tangentially toward the inner radius of the nozzle from the surface of the steam generator shell. The applicant will examine the inner radius of the main feedwater nozzle during the first period of the first ISI interval

using enhanced ultrasonic techniques and a calibration block specifically designed to maximize coverage. Since this nozzle is not subjected to significant stresses related to usage before initial operation, there is adequate assurance that the structural integrity of the inner radius section will be maintained until the enhanced examination is performed.

The designs of the RHR and CT heat exchanger nozzles include a reinforcing pad welded to the internal vessel wall. This configuration minimizes stresses in the inner radius of the nozzle. Therefore, the effort associated with volumetric examination of these areas does not produce a corresponding increase in reliability or safety.

Staff Evaluation: The Code requires that Class 2 steam generator and heat exchanger nozzle inner radius sections receive 100% volumetric examination during PSI and ISI. However, the applicant states that in order to perform a meaningful examination, specialized ultrasonic techniques and nozzle calibration blocks are needed. Requiring the applicant to fabricate special calibration blocks for the sole purpose of performing PSI would result in hardship without a compensating increase in quality and safety. In addition, drawings reviewed during the December 8, 1992, meeting revealed that the design of the RHR and CT nozzles is not conducive to ultrasonic examination. The reinforcing pad on the vessel interior essentially eliminates the nozzle inner radius and makes the effectiveness of ultrasonic examination questionable.

On the basis of this evaluation and pursuant to 10 CFR 50.55a(a)(3)(ii), the staff concludes that relief is authorized as requested from the preservice examination requirements for the subject inner radius sections.

Q. Relief Request C-3, Examination Category C-B, Item C2.21, Containment Spray (CT) and Residual Heat Removal (RHR) Heat Exchanger Nozzle-to-Shell Welds

Code Requirement: Examination Category C-B, Item C2.21, requires a 100% surface and volumetric examinations, as defined by Figures IWC-2500-4(a) or (b), for nozzle-to-shell welds without reinforcing plates in vessels with nominal wall thickness greater than 1/2 inch.

Applicant's Code Relief Request: Relief is requested from performing 100% of the Code-required volumetric examination for Nozzle-to-Shell Welds TCX-2-1120-3, TCX-2-1120-4, and TCX-2-1180-3.

Applicant's Proposed Alternative: None. However, the manufacturer performed volumetric examinations during fabrication and the resulting records are available in permanent plant files to supplement the partial preservice examination.

Applicant's Basis for Requesting Relief: The applicant states that the outlet and inlet nozzles of the containment spray and RHR heat exchangers are of a double-bevel corner joint design. Examination for reflectors parallel to the weld was completed without limitation on the containment spray nozzle and with a limitation of 2% of the required volume described in Figure IWC-2500-4(b) on the RHR nozzles. Examination for reflectors perpendicular to the weld was subject to a limitation of 25% of the required volume for each of the nozzles. These limitations are the result of the weld joint design. The Code-required surface examinations were completed with acceptable results.

Staff Evaluation: The Code requires a 100% volumetric examination of the CT and RHR heat exchanger nozzle-to-vessel welds. However, examination of the subject welds is limited by weld joint design that restricts portions of the required weld volume. In order to perform the volumetric examination to the extent required by the Code, the subject nozzle-to-shell welds would require design modifications to allow access for examination of the weld. Compliance with the Code requirement would result in hardship without a compensating increase in quality and safety.

Considering that a significant portion (~75%) of each weld did receive the Code-required volumetric examination, and considering the burden on the applicant if the Code requirements were imposed at this time, the staff concludes that pursuant to 10 CFR 50.55a(a)(3)(ii), relief is authorized. The partial examinations, supplemented by manufacturer's fabrication examinations and the Code-required surface examinations provide adequate assurance of the structural integrity of the subject welds.

R. Relief Request C-4, Examination Category C-F-2, Item C5.51, Class 2 Branch Connection-to-Flange Welds

Code Requirement: Code Case N-408, Examination Category C-F-2, Item C5.51, requires surface and volumetric examinations for welds in piping greater than 4-inch NPS and nominal wall thickness of 3/8 inch and greater. Welds to be inspected are examined as defined by Figure IWC-2500-7.

Applicant's Code Relief Request: Relief is requested from examining 100% of the Code-required volume of Welds TCX-2-2100-37, TCX-2-2200-36, and TCX-2-2300-41.

Applicant's Proposed Alternative: None. However, the manufacturer performed volumetric examinations during fabrication and the resulting records are available in permanent plant files to supplement the partial preservice examination.

Applicant's Basis for Requesting Relief: The applicant states that the physical configuration of the main steam header branch connection to safety valve inlet flange weld precludes ultrasonic examination of 88% of the required examination volume. The required surface examinations were completed with acceptable results. The partial ultrasonic examinations, supplemented by the required surface examination and the fabrication volumetric examinations, provide adequate assurance of the subject welds' structural integrity.

Staff Evaluation: The Code requires a 100% volumetric examination of the subject welds during preservice inspection. However, examination of the welds is limited by the physical configuration of the branch connection and flange. To perform the examination to the extent required by the Code, the subject components would have to be modified. Imposition of the requirement on the applicant would cause a burden that would not be compensated by an increase in safety above that provided by the limited examination.

On this basis, the staff concludes that pursuant to 10 CFR 50.55a(a)(ii), relief is authorized. The partial preservice examinations, supplemented by the volumetric examinations performed during fabrication, provide reasonable assurance of the structural integrity of the subject branch connection welds.

S. Relief Request C-5, Examination Category C-C, Items C3.20 and C3.30, Class 2 Integrally Welded Attachments to Piping and Pumps

Code Requirement: Examination Category C-C Items C3.20 and C3.30 require surface examination of integrally welded attachments to piping and pumps as defined by Figure IWC-2500-5.

Applicant's Code Relief Request: Relief is requested from performing the surface examinations, to the extent required by the Code, for Integrally Welded Attachments TCX-2-3-110-3WS, TCX-2-3-110-4WS, and TCX-2-2301-H1.

Applicant's Proposed Alternative: The applicant examined construction surfaces and the examination records are available in the permanent plant records to supplement the partial preservice surface examinations.

Applicant's Basis for Requesting Relief: The applicant states that for Integral Attachment Welds TCX-2-3110-3WS and 4WS, the pump configuration and housing seal do not provide access for complete surface examination of approximately 23% of the weld surface area. For Weld TCX-2-2301-H1, the component support configuration, which consists of eight integrally welded lugs located between the pipe, slotted plates, and the building wall, does not provide access for complete surface examination of approximately 55% of the required weld surface area.

Staff Evaluation: The Code requires a 100% surface examination of the subject welds. However, examination of the welds is restricted by component configuration and the pump housing (Welds TCX-2-3110-3WS and -4WS). To supplement the partial PSI examination, surface examinations have also been performed during construction.

The staff concludes that the partial preservice examinations, supplemented by the construction surface examinations, constitute an examination equivalent to that required by the Code for PSI and provides an acceptable level of quality and safety. Therefore, pursuant to 10 CFR 50.55a(a)(3)(i), relief is authorized.

T. Relief Request D-1, Examination Categories D-A, D-B, and D-C, Class 3 Integral Attachments

Code Requirement: Table IWD-2500-1, Examination Categories D-A, D-B, and D-C, all items except Item D1.10 (Pressure Retaining Components), require VT-3 visual examination of integral attachments as defined by Figure IWD-2500-1.

Applicant's Code Relief Request: Relief is requested from performing the VT-3 visual examinations required by Table IWD-2500-1.

Applicant's Proposed Alternative: None.

Applicant's Basis for Requesting Relief: The applicant states that visual examinations conducted during construction ensure that conditions qualifying as unacceptable under a VT-3 examination do not exist. Personnel performing these examinations are trained and certified under a program that meets the requirements of ANSI N45.2.6 as endorsed and supplemented by Regulatory Guide 1.58, Revision 1. These examinations are documented and the records maintained as permanent plant records. Additionally, Table IWD-2500-1 allows for the examination of only one of the multiple components within a system of similar design, function, and service, whereas the visual examinations performed during construction are conducted on all Class 3 integral attachments.

Staff Evaluation: The Code requires a VT-3 visual examination of Class 3 integrally welded attachments during preservice examination. In general, personnel performing nondestructive examinations shall be qualified with a written procedure prepared in accordance with SNT-TC-1A with exceptions as noted in IWA-2300. Paragraph IWA-2300(b) states that personnel performing nondestructive examinations utilizing methods not covered by IWA-2300(a) (i.e., VT-3 visual examinations) shall be trained and qualified to comparable levels of competency by subjection to comparable examinations on the particular method involved. Paragraph IWA-2300(c) states that personnel performing visual examinations VT-2, VT-3, and VT-4 of IWA-2212, IWA-2213, and IWA-2214, respectively, shall be qualified by the owner or the owner's agent in accordance with comparable levels of competency as defined in ANSI N45.2.6-1973. Since the applicant examined all of the Class 3 integral attachments by personnel trained and certified under a program that meets the requirements of ANSI N45.2.6, the applicant has met the intent of the Code and relief is not required.

4 CONCLUSIONS

This evaluation has not come up with any practical method by which the applicant can meet all the specific PSI requirements of Section XI of the ASME Code for the existing CPSES, Unit 2, facility. Compliance with all the exact Section XI required inspections would delay the startup of the plant in order to redesign a significant number of plant systems, obtain sufficient replacement components, install the new components, and repeat the preservice examination of these components. Even after the redesign efforts, all the preservice examination requirements probably could not be completely satisfied. However, the as-built structural integrity of the existing facility has already been established by the construction code fabrication examinations.

On the basis of its review and evaluation, the staff concludes that the public interest will not be served by imposing certain provisions of Section XI of the ASME Code when the proposed alternative would produce an acceptable level of quality and safety, or when compliance would result in hardship or unusual difficulty without a compensating increase in the level of quality and safety. Therefore, pursuant to 10 CFR 50.55a(a)(3), relief from these requirements is authorized for the reasons discussed in this appendix with the exception of Requests for Relief B-13 and D-1, for which the staff determined that relief was not required.

APPENDIX FF

PERFORMANCE TESTING OF RELIEF AND SAFETY VALVES

APPENDIX FF

SAFETY EVALUATION REPORT
TMI ACTION--NUREG-0737 (II.D.1)
PERFORMANCE TESTING OF RELIEF AND SAFETY VALVES
COMANCHE PEAK, UNIT 2
DOCKET NO. 50-446

1. INTRODUCTION

1.1 Background

In the past, safety and relief valves installed in the primary coolant system of light water reactors have performed improperly. There were instances of valves opening below set pressure, valves opening above set pressure, and valves failing to open or reseat. From the past instances of improper valve performance, it is not known whether they occurred because of limited valve qualification or because of a basic unreliability in the valve design. It is known that the failure of a power-operated relief valve (PORV) to reseat was a significant contributor to the Three Mile Island sequence of events. These facts led the task force which prepared NUREG-0578 (Reference 1) and, subsequently, NUREG-0737 (Reference 2) to recommend the establishment of programs to accomplish the following two objectives: first, reevaluate the functional performance capabilities of pressurized water reactor (PWR) primary system safety, relief, and block valves; and second, verify the integrity of the pressurizer safety and relief valve piping systems for normal, transient, and accident conditions. The task force deemed this necessary to reconfirm that Licensees and Applicants satisfied General Design Criteria 14, 15, and 30 of 10 CFR 50, Appendix A, for the subject equipment.

1.2 General Design Criteria and NUREG Requirements

General Design Criteria 14, 15, and 30 require: (a) the reactor primary coolant pressure boundary be designed, fabricated, and tested so as to have an extremely low probability of abnormal leakage; (b) the reactor coolant system and associated auxiliary, control, and protection systems be designed with sufficient margin to assure that the design conditions are not exceeded during normal operation or anticipated operational occurrences; and (c) the components, which are part of the reactor coolant pressure boundary, be constructed to the highest quality standards practical.

To confirm the integrity of overpressure protection systems and thereby assure compliance to the General Design Criteria, the Division of Licensing, Office of Nuclear Reactor Regulation, issued the NUREG-0578 position as a requirement in a letter dated September 13, 1979, to all operating nuclear power plants. The NRC incorporated this requirement as Item II.D.1 of NUREG-0737, Clarification of TMI Action Plan Requirements, which they issued for implementation on October 31, 1980. As stated in the NUREG reports, each PWR Licensee or Applicant shall:

1. Conduct testing to qualify reactor coolant system relief and safety valves under expected operating conditions for design basis transients and accidents.

2. Determine valve expected operating conditions through the use of analyses of accidents and anticipated operational occurrences referenced in Regulatory Guide 1.70, Rev. 2.

3. Choose the single failures such that the dynamic forces on the safety and relief valves are maximized.

4. Use the highest test pressures predicted by conventional safety analysis procedures.

5. Include in the relief and safety valve qualification program the qualification of the associated control circuitry.

6. Provide test data for NRC staff review and evaluation, including criteria for success or failure of valves tested.

7. Submit a correlation, or other evidence, to substantiate the valves tested in a generic test program demonstrate the functionability of as-installed primary relief and safety valves. This correlation must show the test conditions used are equivalent to expected operating and accident conditions as prescribed in the Final Safety Analysis Report (FSAR). The effect of as-built relief and safety valve discharge piping on valve operability must also be considered.

8. Qualify the plant specific safety and relief valve piping and supports by comparing to test data and/or performing appropriate analyses.

2. PWR OWNER'S GROUP RELIEF AND SAFETY VALVE PROGRAM

In response to the NUREG requirements previously listed, a group of utilities with PWRs requested the assistance of the Electric Power Research Institute (EPRI) in developing and implementing a generic test program. The test program covered pressurizer PORV block valves, PORVs, safety valves, and associated piping systems. Texas Utilities Electric Company (TUEC), the owner of Comanche Peak, Unit 2, was one of the utilities sponsoring the EPRI Safety and Relief Valve Test Program. In Reference 3, the participating utilities transmitted to the NRC the series of reports containing the results of the program. This section discusses the applicability of those reports below.

In Reference 4, EPRI developed a plan for testing PWR safety and relief valves under conditions which bound actual plant operating conditions. Through the valve manufacturers, EPRI identified the valves used in the overpressure protection systems of the participating utilities. They then selected representative valves for testing. The valves selected included enough of the variable characteristics so that their testing would adequately demonstrate the performance of the valves used by utilities (Reference 5). Through the nuclear steam supply system vendors, EPRI evaluated the FSARs of the participating utilities. They then developed a test matrix which bounded the inlet conditions for the plant transients that require overpressure protection (Reference 6).

The utilities participating in the EPRI Safety and Relief Valve Test Program also tested PORV block valves (Reference 7). The Electric Power Research Institute developed a list of valves used or intended for use in participating PWR plants. They selected seven block valves to represent the block valves used in PWR plants. Westinghouse Electro-Mechanical Division (WEMD) performed additional tests on valve models they manufacture (Reference 8).

Westinghouse, under contract to EPRI, produced a report on pressurizer safety and relief valve inlet conditions in Westinghouse designed plants (Reference 9). Because Comanche Peak, Unit 2, is a Westinghouse designed plant, that report is applicable to this evaluation.

The Electric Power Research Institute sponsored several test series. They tested PORVs and block valves at the Duke Power Company Marshall Steam Station located in Terrell, North Carolina. Only steam tests were conducted at the Marshall Station. Therefore, EPRI tested block valves at Marshall only for full flow, full pressure steam conditions. Westinghouse (WEMD) performed water flow tests on four valve models they manufacture. The Electric Power Research Institute conducted additional PORV tests at the Wyle Laboratories Test Facility located in Norco, California. They tested safety valves at the Combustion Engineering Company Kressinger Development Laboratory located in Windsor, Connecticut. In Reference 10, EPRI reported the results of the relief and safety valve tests. They reported the results of the block valve tests in References 7 and 8.

The EPRI test program's primary objective was to test each of the various types of primary system safety valves used in PWRs for the full range of expected inlet fluid conditions. The test program limited the conditions selected for test (based on analyses) to steam, subcooled water, and steam to water transition. Additional objectives were to: (a) obtain valve capacity data, (b) assess hydraulic and structural effects of associated piping on valve operability, and (c) obtain piping response data for verifying analytical piping models.

The EPRI test program did not provide information on valve reliability. The EPRI program plan (Reference 4) states, "During the course of the specified tests, each valve will be subjected to a number of operational cycles. However, it should be noted that the test program, to be completed by July, 1981, is not intended to provide valve lifetime, cyclic fatigue or statistical reliability data."

Reference 11 contains NRC staff approval of the EPRI test program. The staff concluded the EPRI program produced enough generic valve performance information for utilities to meet the plant specific information requirements in NUREG-0737, Item II.D.1. Transmittal of the test results meets Item 6 (provide test data to the NRC) of Section 1.2 in this report.

3. PLANT SPECIFIC SUBMITTAL

Texas Utilities Electric Company submitted their Comanche Peak, Unit 2, evaluation report for NUREG-0737, Item II.D.1, in four parts. The submittal dates were, March 31, 1982 (Reference 12), May 18, 1992 (Reference 13), November 13, 1992 (Reference 14), and December 18, 1992 (Reference 15).

4. REVIEW AND EVALUATION

4.1 Valves Tested

Comanche Peak, Unit 2, uses three safety valves, two PORVs, and two PORV block valves in the overpressure protection system. The safety valves are Crosby Model HB-BP-86 6M6 valves with loop seal internals. The PORVs are 3-inch Copes-Vulcan Model D-100-160 air-operated globe valves with 316 SS stellited plugs and 17-4 PH cages. The safety valves have hot loop seals and the PORVs have cold water seals upstream of the valves. The block valves are Westinghouse Model 3GM88 motor operated gate valves with Limitorque SB-00-15 motor operators.

The Electric Power Research Institute tested the safety valve model used at Comanche Peak, Unit 2, the Crosby Model HB-BP-86 6M6 valve. At Comanche Peak, Unit 2, the applicant mounted the safety valves on loop seal piping with a hot loop seal upstream of the valve. The valve internals are for loop seal service. The test valve also had loop seal internals, and EPRI tested it on loop seal piping with a hot loop seal. In Reference 13, the applicant stated the Crosby 6M6 valves at Comanche Peak, Unit 2, use factory set ring settings. Therefore, the applicant can use the results from the EPRI tests with factory ring settings to demonstrate operability of the plant safety valves.

The PORVs at Comanche Peak, Unit 2, are the same design as one tested by EPRI. They tested the valve with a cold loop seal. Because there is no difference between the test and plant valves, the test results are directly applicable to Comanche Peak, Unit 2.

The block valves used at Comanche Peak, Unit 2, are the same design as one of the EPRI test valves, the Westinghouse 3GM88 block valve. The Electric Power Research Institute tested the valve in a horizontal configuration. Texas Utilities Electric Company installed the plant valve in the same configuration (Reference 13). The test valve had a Limitorque SB-00-15 motor operator, and the plant valves use the same Limitorque operator. During EPRI testing, the 3GM88 block valve fully closed only when the operator produced a torque of 182 ft-lb. Based on Reference 14, TUEC modified Unit 2 block valve operators to close on limit rather than torque to ensure complete valve closure. In this mode of operation, the operator torque output is greater than 182 ft-lb. The test valve is, therefore, representative of the plant valves.

Based on the above, the test valves represent the Comanche Peak, Unit 2, valves and fulfill the requirements of Items 1 and 7 of NUREG-0737 regarding applicability of the test valves.

4.2 Test Conditions

As stated earlier, Westinghouse Electric Corp. designed Comanche Peak, Unit 2. Reference 9 lists the valve inlet fluid conditions that bound the inlet conditions for overpressure transients in Westinghouse plants. In Reference 14, TUEC stated they verified that the inlet conditions in the Westinghouse report are still applicable to Comanche Peak, Unit 2. The applicable inlet conditions in Reference 9 are those identified for four-loop plants. The transients considered in this report include FSAR, extended high pressure injection, and low temperature overpressurization events. This section discusses the expected inlet conditions for each of these events and the applicable EPRI tests.

4.2.1 FSAR Steam Transients

For Comanche Peak, Unit 2, the limiting FSAR steam discharge transients when only the safety valves open are the loss of load event and the locked rotor event. These same events are limiting for steam discharge when both the safety valves and PORVs open. The loss of load event gave the maximum pressurizer pressure and the locked rotor event gave the maximum pressurization rate.

When the safety valves open alone the predicted maximum pressurizer pressure and maximum pressurization rate are 2555 psia and 144 psi/s, respectively. The maximum developed backpressure in the outlet piping is less than 515 psia (Reference 14). Texas Utilities Electric Company insulated the loop seal so the valve inlet temperature is 300°F (Reference 13).

The insulation used to maintain the loop seal temperature in Unit 2 is the same as that in Unit 1 (Reference 14). In Reference 14, the applicant stated that it field measured the Unit 1 loop seal temperature as 314°F. Because both units have the same loop seal insulation, the staff concluded the Unit 2 loop seal temperature should also exceed 300°F.

For steam flow conditions, four loop seal discharge tests on the Crosby 6M6 valve (Test Nos. 929, 1406, 1415, 1419) are applicable to Comanche Peak, Unit 2. These tests used valve ring settings representative of those used in Westinghouse PWRs including Comanche Peak, Unit 2. The ring settings used in these tests were (-71, -18) or (-77, -18). These represent the upper and lower ring positions measured from the level position referenced to the bottom of the disc ring. In Reference 13, TUEC stated the ring settings used at Comanche Peak, Unit 2 are -82 to -103 (upper ring), and -18 (lower ring) relative to the level position. Also in Reference 13, TUEC stated Crosby Valve and Gage Co. determined both the test and in-plant ring settings using similar methods and standard of performance. Therefore, the staff considers these ring settings comparable.

The loop seal temperature measured in the tests ranged from 90 to 350°F at the valve inlet. The maximum test (tank 1) pressures were in the range of 2675 to 2760 psia and the pressurization rate was 90 to 360 psi/s. The backpressures developed in the tests were 245 to 710 psia. The above data show that the test conditions envelope the corresponding data for the Comanche Peak, Unit 2, safety valves. Table 4.2.1 summarizes this comparison.

When both the safety valves and PORVs open, the maximum predicted pressurizer pressure is 2532 psia and the maximum pressurization rate is 130 psi/s. The loop seal temperature is 150°F at the PORV inlet.

TABLE 4.2.1 SUMMARY OF TEST DATA FOR CROSBY 6M6 SAFETY VALVE AND COMPARISON WITH COMANCHE PEAK, UNIT 2, REQUIREMENTS

Valve	Test Number/ Conditions	Inlet Conditions	Initial Fluid Temperature at Valve Inlet (°F)	Safety Valve Ring Settings[1]	Pressure at Valve Opening[2] (psia)	Peak Tank Pressure (psia)	Peak Back-pressure (psia)	Percent Blowdown	Peak Pressurization Rate (psi/s)	Valve Stability	Inlet Press. Drop (psi)
6M6-Plant Valve (FSAR Steam Transient Test)		Hot loop seal	300	-82, -18 -103, -18	2500	2555	515	Nominally 5.0	144.0	---	269.0
6M6-Loop seal internals	929/Steam	Cold loop	90	-71, -18	2600	2726	710	5.1	319.0	Stable	263.0
	1406/Steam	Cold loop	147	-77, -18	2530	2703	250	9.4	325.0	Stable	263.0
	1415/Steam	Hot loop	290	-77, -18	2555	2760	255	6.2	360.0	Stable	263.0
	1419/Steam	Hot loop	350	-77, -18	2464	2675	245	---	360.0	Chatter[3]	263.0
6M6-Plant Valve[4] (FSAR Liquid Transient Test)			Sat	-82, -18 -103, -18	2500	2503	515	Nominally 5.0	5.0	---	269.0
6M6-Loop seal internals	931a[5]/LS	Trans	117	-77, -18	2570	2578	725	12.7	2.5	Stable	263.0
	931b/Water		635	-77, -18	2475	2475	700	4.8	2.5	Chatter[6]	263.0

1. The plant and test valve ring settings are relative to the level position. The plant guide ring settings, -82 and -103, represent the range of guide ring settings for the plant valves.
2. The set pressure of the test valves was 2485 psig.
3. This test was terminated because of valve chatter.
4. The maximum liquid surge rate during a feedwater line break is 1109.5 gpm.
5. The maximum liquid flow rate during test 931a was 2355 gpm.
6. The valve chattered during opening but then stabilized.

In the EPRI tests on the Copes-Vulcan PORV, the maximum steam pressureat valve opening was 2715 psia. This bounds the predicted pressure at Comanche Peak, Unit 2. In the loop seal test, the temperature at the valve inlet was 134°F. The backpressure developed at the outlet of the PORVs is not an important consideration for Comanche Peak, Unit 2. This is because the air operated PORVs used at Comanche Peak, Unit 2, are not sensitive to backpressure (Reference 6). Therefore, the EPRI test inlet fluid conditions for the PORV with steam discharge represent the plant specific transient conditions.

4.2.2 FSAR Liquid Transients

The limiting FSAR transient resulting in liquid discharge through the PORVs and safety valves is the main feedline break accident (Reference 9). In a feedline break accident at Comanche Peak, Unit 2, the calculated safety valve inlet conditions during water discharge are maximum pressure, 2503 psia, pressurization rate, 5 psi/s, and maximum pressurizer surge rate, 1109.5 gpm (~369,000 lbm/hr) liquid at 608-615°F. In a feedline break accident resulting in safety valve actuation, steam and steam to water transition flows always precede water discharge.

Tests 931a and 931b on the 6M6 valve included loop seal/steam, steam to water transition, and water discharge conditions. The valve ring settings and inlet pipe configuration used in these tests are representative of the in-plant safety valves. In Test No. 931a, the maximum inlet pressure was 2578 psia. The pressurization rate was 2.5 psi/s, the inlet loop seal fluid temperature was 117°F and the tank fluid temperature was 635°F. After the valve closed in Test 931a, the system repressurized and the valve cycled on approximately 635°F water for Test 931b. The inlet temperature and pressure of these tests bound the predicted in-plant condition. Therefore, the staff considers these tests representative of the Comanche Peak, Unit 2, safety valve inlet conditions. Table 4.2.1 also summarizes the inlet fluid conditions and corresponding test data for liquid discharge.

Westinghouse based the expected safety valve inlet fluid conditions on an analysis that assumed the PORVs did not open during the feedline break transient. If the PORVs open, however, the same fluid conditions postulated for the safety valve inlet will occur at the PORV inlet (Reference 6). In the tests, EPRI performed high temperature water discharge and steam to water transition tests with the Copes-Vulcan PORV. In the water discharge test, Test No. 76-CV-316-2W, the maximum valve inlet pressure was 2535 psia and the temperature was 647°F. In the transition test, Test No. 77-CV-316-7S/W, the maximum inlet pressure was 2532 psia and the water temperature was 657°F. The inlet fluid conditions for these tests bound the expected inlet conditions for Comanche Peak, Unit 2. Therefore, the staff considers these tests adequate to represent the in-plant PORV performance in the feedline break event.

4.2.3 Extended High Pressure Injection Event

The limiting extended high pressure injection event is the spurious actuation of the safety injection system at power (Reference 9). For a four-loop plant, an extended high pressure injection event challenges both the safety valves and PORVs. Valve inlet conditions include both steam and water discharge. In this event, however, the safety valves or PORVs open on steam, and liquid discharge would not occur until the pressurizer becomes water solid. According to Reference 9, this would not occur until at least 20 minutes into the event which allows ample time for operator action. Thus, the staff disregarded the potential for liquid discharge in extended HPI events.

4.2.4 Low Temperature Overpressurization (LTOP) Transient

Texas Utilities Electric Company uses the PORV for overpressure protection during low temperature reactor startup and shutdown operations. The PORV low pressure setpoint varies with valve inlet temperature. The setpoint ranges from 445 to 2350 psig for inlet temperatures of 70 to 450°F (Reference 13). Reference 9 identified the expected inlet fluid conditions for LTOP transients, and they range from cold water to steam.

For steam discharge through the PORV, the high pressure steam tests discussed in Section 4.2.1 would cover the low pressure steam conditions predicted for LTOP transients. For water discharge conditions, EPRI performed two low pressure and low temperature water tests on the Copes-Vulcan PORV with stellited plug and 17-4 PH cage. The tests had an inlet pressure of 675 psia and water temperatures of 105°F and 442°F, respectively. The staff considers these conditions representative of those at Comanche Peak, Unit 2. Therefore, the staff will use the EPRI tests to evaluate the performance of the Comanche Peak, Unit 2, PORV for LTOP transients.

4.2.5 Block Valve Inlet Conditions

The block valves operate over a range of fluid conditions (steam, steam-to-water, water) similar to those of the relief valves. However, EPRI tested the block valves only under full pressure steam conditions (to 2420 psia). For Westinghouse manufactured valves, EPRI performed additional water flow tests as documented in Reference 8. The WEMD test conditions ranged from 60 to 600 gpm and 1500 to 2600 psi differential pressure. Based on Reference 8, Westinghouse made four observations concerning valves with similar internal materials. Westinghouse found that under full pressure steam conditions the required torque to open or close the valve:

(1) Depends almost entirely on the differential pressure across the valve disk.
(2) Is rather insensitive to momentum loading.
(3) Is nearly the same for water or steam.
(4) Is nearly independent of the flow.

Thus, full pressure steam tests are adequate to show valve operability for steam and water conditions.

4.2.6 Other Transients

Two additional transient conditions are anticipated transients without scram (ATWS) and feed and bleed decay heat removal. This review did not consider the response of the overpressure protection system to these two transient conditions. Because these conditions are not part of the design basis, neither the Applicant nor the NRC have evaluated the performance of the system for these events.

4.2.7 Inlet Conditions Summary

The staff has determined that the applicant has demonstrated that the test conditions bounded the conditions for the plant valves. Therefore, the applicant has met Items 2 and 4 of NUREG-0737 item II.D.1. That is, the applicant determined conditions for operational occurrences and chose the highest predicted pressures for the tests. The staff has also verified that TUEC has met the portion of Item 7 that requires demonstrating that the test conditions are equivalent to those prescribed in the FSAR.

4.3 Operability

4.3.1 Safety Valves

The steam discharge tests representative of the Comanche Peak, Unit 2, conditions are loop seal tests, Test Nos. 929, 1406, 1415, 1419, on the Crosby 6M6 valve. In these tests (except Test No. 1415), the valve fluttered or chattered during loop seal discharge and stabilized when steam flow started. The valve opened within ±4% of the design set pressure and closed with 5.1 to 9.4% blowdown. The valve achieved up to 111% of rated flow at 3% accumulation with valve lift positions at 92 to 94% of rated lift. As discussed below, these tests demonstrated that the valve performed adequately in spite of the initial chatter during loop seal discharge.

In Test 1419, the valve chattered on closing and the operators ended the test by manually opening the valve to stop the chatter. This result does not indicate a valve closing problem for the Comanche Peak, Unit 2, safety valve. This is because a similar test (Test 1415) had already demonstrated that the valve performed satisfactorily and exhibited no sign of instability. The closing chatter in Test 1419 may be a result of the repeated actuation of the valve in loop seal and water discharge tests. As shown in Table 4.3.1, EPRI performed seventeen steam, water, and transition tests on the 6M6 valve. In the first four or five tests, the valve fluttered and chattered during loop seal discharge but stabilized and closed successfully. After Test 913, there were four instances in which the operators stopped the test due to chatter on closing. EPRI found galled guiding surfaces and damaged internal parts during inspection. They refurbished or replaced the damaged parts before the next test started. After each repair, the valve performed well, but the closing chatter recurred in the subsequent test. EPRI performed Test 1415 immediately after valve maintenance and the valve performed stably. The next test (Test 1419) chattered on closing even though it was a repeat of Test 1415 at similar fluid conditions. This suggests that inspection and maintenance are important to the continued operability of the valves. This recommendation was documented in SER Supplement 21, Appendix AA. The applicant stated that it had developed a procedure for both units that requires inspection and maintenance of the safety valves after each actuation to refurbish or replace damaged parts.

The applicant provided calculated values for the inlet pressure drop on valve opening and closing and compared the plant specific values to the test values in Reference 13. The plant opening and closing pressure differences were 255-269 psi and 152-158 psi, respectively. The corresponding test pressure differences were 263 psi (valve opening) and 181 psi (valve closing). Based on this information, the staff determined that the plant valves are as stable as the test valves.

TABLE 4.3.1 EPRI TESTS ON CROSBY HB-BP-86 6M6 SAFETY VALVE

Seqn. No.	Test No.	Ring Setting	Test Type	Actions Taken Between Tests	Stability	Leakage Pre (gpm)	Leakage Post (gpm)
1	903	1	Steam		Stable	0	0
				Inspection/repair			
2	906a,b,c	1	L.S.		Stable	0	0
3	908	1	L.S.		f/c	0	0
4	910	1	L.S.		f/c	0	0
				Inspection/repair			
5	913	2	L.S.		f/c	0	1.0
6	914a,b,c	2	L.S. Transition		Terminated	0	Large
				Inspection/repair			
7	917	3	L.S.		f/c	0	0
8	920	3	L.S.		Terminated	0	0
				Inspection/repair			
9	923	3	L.S.		f/c	0	0
10	926a,b,c,d	3	Transition		Stable	0.36	0.08
				Inspection/repair			
11	929	4	L.S.		f/c	0	0
12	931a,b	4	L.S. Transition		c	0	0
13	932	4	Water		Terminated	0	--
				Inspection/repair			
14	1406	4	L.S.		f/c	0	0.63
				Inspection/repair			
15	1411	4	Steam		Stable	0.76	0.37
				Inspection/repair			
16	1415	4	L.S.		Stable	0	0
17	1419	4	L.S.		Terminated	0	1.5
				Inspection/repair			

c--chatter
f/c--flutter/chatter
L.S.--loop seal
Ring setting--four different ring settings were tested. Actual ring settings not shown.
Terminated--Test terminated after valve manually opened to stop chatter.

As discussed in Section 4.2.2 of this appendix, the limiting FSAR transient resulting in liquid discharge is the main feedline break accident. Tests 931a and 931b represent Comanche Peak, Unit 2, feedwater line break conditions. Test 931a was a loop seal/steam/water transition test. The test valve opened, fluttered or chattered with partial lift during loop seal discharge, then popped open and stabilized on steam. The valve closed with 12.7% blowdown. Test 931b was a saturated water test. The 6M6 valve opened on 640°F water, chattered, and then stabilized. The valve closed with 4.8% blowdown. For these tests, the valve opened within -1% and +3% of the set pressure. The maximum calculated surge rate at Comanche Peak, Unit 2, during the feedline break transient is 1109.5 gpm. The EPRI 6M6 test valve passed 2355 gpm at 2415 psia and 641°F. This flow is much higher than the predicted liquid surge rate for Comanche Peak, Unit 2. The above results demonstrate that the Crosby 6M6 safety valves would adequately perform the required water relief function at CPSES Unit 2.

From the above steam and water results, the maximum observed blowdown in the applicable EPRI tests was 12.7%. Since this observed blowdown exceeded the design value of 5%, TUEC was requested to demonstrate that extended blowdown will not impact plant safety and valve operability. They provided this information in Reference 15. Texas Utilities Electric Company stated they evaluated the impact of 13% blowdowns on the Comanche Peak, Unit 2, licensing basis safety analyses. They noted:

1. Extended safety valve blowdown of up to 13% will not cause the pressurizer to fill in any licensing basis event where the pressurizer does not already become water solid.

2. Extended safety valve blowdown of up to 13% will not challenge any safety systems which were not previously challenged in the licensing basis safety analyses.

3. Extended blowdown of up to 13% will not cause voiding of the primary system in any licensing basis event.

Therefore, the extended blowdown observed in the EPRI tests does not impact plant safety or valve operability.

The loads induced on the safety valve tested by EPRI exceed the loads for Comanche Peak, Unit 2. The maximum bending moment on the 6M6 test valve discharge flange was 298,750 in-lb during Test 908. Application of this bending moment did not affect test valve performance. The largest moment predicted for the safety valve inlet or outlet at Comanche Peak, Unit 2, is 172,428 in-lb. All valve nozzle loads are evaluated for the combined effects of deadweight, thermal expansion, safe shutdown earthquake (SSE), and valve actuation loads. Based on this, the staff expects the plant valve to operate satisfactorily with the maximum expected plant bending moment.

4.3.2 Power Operated Relief Valves

The EPRI tests on the Copes-Vulcan PORV with 316 SS stellited plug and 17-4 PH cage demonstrated that the valve had opened and closed on demand under the full range of inlet conditions. The opening and closing times were within the 2.0 second opening and closing times normally required for Westinghouse PWRs. The lowest steam flow rate observed in the tests was 232,000 lb/hr. This flow exceeds the rated flow of 210,000 lb/hr for the Comanche Peak, Unit 2 PORVs.

During testing, EPRI induced a bending moment of 43,000 in-lb on the Copes-Vulcan PORV test valve in Test 64-CV-174-2S. Application of this bending moment did not affect test valve performance. The largest moment predicted for the PORV inlet or outlet at Comanche Peak, Unit 2, is 21,625 in-lb. All valve nozzle loads are evaluated for the combined effects of deadweight, thermal expansion, safe shutdown earthquake (SSE), and valve actuation loads. Therefore, the bending moment imposed during valve discharge transients will not affect plant valve performance.

4.3.3 PORV Control Circuit Qualification

NUREG-0737, Item II.D.1, requires the qualification of the PORVs and their associated control circuitry for design basis accidents and transients. The EPRI test program included the PORV control circuitry attached directly to the valve (Reference 16). It did not include the circuits away from the valve such as pressure sensing devices, cables, transmitters, etc. The individual utilities still need to meet the NUREG-0737, Item II.D.1, requirements for the circuits away from the valve. Based on Reference 11, the NRC concluded that applicants could meet the NUREG requirement for environmental qualification of those circuits by including them in their 10 CFR 50.49 program. If an applicant includes the PORV control circuits in the 10 CFR 50.49 program, specific testing to meet the NUREG-0737 requirements is not necessary. Texas Utilities Electric Company included the PORV controls in the Comanche Peak, Unit 2, environmental qualification program (References 13 and 14). This meets the environmental qualification requirements for the control circuitry. Regarding control circuit qualification for normal operation, the applicant (Reference 14) included the PORV control circuits in its Generic Letter 90-06 (Reference 17) program. The generic letter required Applicants to include the PORVs in the inservice test program. This meets the requirement to qualify the PORV control circuitry during normal operation.

4.3.4 PORV Block Valves

The Westinghouse 3-inch Model 3GM88 block valves used in Comanche Peak, Unit 2, are the same design as the model tested by EPRI. Texas Utilities Electric Company modified the block valves/operators as recommended by Westinghouse. The valve/operators now close on limit rather than torque (Reference 14). The plant valve operator will supply greater than 182 ft-lb of torque in this mode of operation. The test valve opened and closed fully under the full range of operating conditions with the operator set to produce 182 ft-lb of torque. Therefore, the tests demonstrated acceptable valve operation.

4.3.5 Operability Summary

The facts presented above demonstrate that the applicant met Item 1 (conducting tests for valve qualification) and Item 7 (considering the affects of discharge piping on operability) of Section 1.2 in this report. Meeting the requirements of 10 CFR 50.49 and including the PORV in the GL 90-06 program satisfy Item 5 of Section 1.2 in this report regarding the PORV control circuitry.

4.4 PIPING AND SUPPORT EVALUATION

This evaluation covers the piping and supports from the pressurizer nozzles to the pressurizer relief tank. The Applicant designed the piping for dead weight, internal pressure, thermal expansion, earthquake, and safety and relief valve discharge conditions. This section discusses the calculation of the hydraulic force time histories due to valve discharge, structural analysis methods, and the load combinations and stress evaluation.

4.4.1 Thermal Hydraulic Analysis

Texas Utilities Electric Company used pressurizer fluid conditions in the thermal hydraulic analysis such that the calculated pipe discharge forces bounded the forces for the FSAR, HPI, and cold pressurization events, including the single failure that would maximize the forces on the valve.

The forcing functions from the Comanche Peak, Unit 1, thermal hydraulic analysis were used for Unit 2. Texas Utilities Electric Company justified this approach in References 14 and 15. They stated (Reference 14) that the Unit 1 and Unit 2 discharge piping layouts are mirror images of each other within the tolerances allowed by NCIG-05 (Reference 18). In Reference 15, the applicant stated these differences are approximately 6 inches or less. These differences, the applicant stated, are small enough not to affect the hydraulic forcing functions calculated for Unit 1 as applied to Unit 2. Based on this information, the staff concluded that the applicant's approach is adequate.

In the analysis, the applicant treated the safety valve and PORV discharge transients as two separate events (Reference 13). That is, the safety valves opened simultaneously with the PORVs closed, and the PORVs opened simultaneously with the safety valves closed. This approach is acceptable, because the safety valves and PORVs have different setpoints.

A valve operating condition more likely to occur would be a PORV discharge followed by a safety valve discharge. Because the PORVs have a lower setpoint, they will open first. When the openings are treated as one transient, the PORV piping loads would be the same as those calculated from the PORV actuation case above. However, this sequence reduces the safety valve discharge forces due to the build-up of backpressure in the discharge piping from the preceding PORV actuation. Because the resulting safety valve piping loads are lower in this case than in the analysis above in which the discharge transients are treated as two separate events, the results are bounded by the previous analysis. Therefore, the applicant need not analyze this condition.

Steam discharge transients have the potential to develop the worst loads on the safety valve and PORV piping. Both the safety valves and PORVs at Comanche Peak, Unit 2, have loop seals upstream of the valve inlets. When the safety valve or PORV opens, the loop seal water slug driven by the high steam pressure and flow imposes the highest hydrodynamic loads on the piping and supports.

For the safety valve loop seal, the applicant assumed a temperature of 300°F at the valve inlet. As discussed in Section 4.2.1, the applicant has not measured the Comanche Peak, Unit 2, loop seal temperature to verify the assumed temperature. However, the applicant provided information on the Comanche Peak, Unit 1, loop seal temperature taken by field measurements. The Unit 1 measured loop seal temperature was 314°F. Both Comanche Peak units use the same type of loop seal insulation. Because the Unit 1 measured temperature is greater than 300°F, this verifies the appropriateness of the loop seal temperature used in the Unit 2 thermal hydraulic analysis.

For the PORVs, steam discharge also represents the limiting condition for the pipe loads. The PORV inlet piping has a cold loop seal with 150°F water (Reference 13). The thrust of the cold water slug under high steam pressure and flow generates the highest piping loads of all steam and water discharge transients including cold overpressurization events.

In the thermal hydraulic analysis, the applicant selected fluid conditions to bound all limiting transients discussed in Section 4.2. For the safety valve analysis, the initial pressure of the saturated steam upstream of the loop seals was 2575 psia and the initial downstream pressure was 18 psia. Texas Utilities Electric Company held the pressurizer conditions constant for the entire transient at 2575 psia and 1110 Btu/lb. They assumed the loop seal water temperature was 300°F at the safety valve inlet. For the PORV analysis, the initial upstream pressure of the saturated steam was 2350 psia and the downstream pressure was 18 psia. Texas Utilities Electric Company held the pressurizer conditions constant for the entire transient at 2350 psia and 1162 Btu/lb. They assumed the temperature of the liquid upstream of the PORV to be a constant 150°F.

The pressurizer pressure used in the PORV analysis is lower than the maximum pressure of 2532 psia predicted by Westinghouse for a loss of load event. The pressure used in the PORV piping analysis is the valve opening setpoint. They justified the pressure used in References 14 and 15. Texas Utilities Electric Company noted in some cases the pressurizer pressure will continue to rise above the valve setpoint. In the analyzed loss of load accident the pressure rises to 2532 psia at a rate of 130 psi/sec. Texas Utilities Electric Company also noted that, although the water slug passes through the discharge piping quickly (less than 1.7 sec), it does experience some increase in the driving force of the peak pressure. However, the applicant noted the peak pressure, 2532 psia, is less than 10% above the opening pressure. They also noted the loads on the critically loaded portions of the system (valves and pressurizer nozzle) peak within 0.5 sec. For piping in the common header region, TUEC stated the forces on the header piping decrease rapidly because the water slug breaks up in the large pipe (inside diameter 12 inches). In the common header region, the stresses due to relief valve discharge are small (less than 1000 psi bending, for example). Therefore, the applicant concluded the pressure increase was not significant and did not include it in the analysis. The staff agrees with this conclusion because, during the portion of the valve discharge transient when the critical loadings occur (that is, the first 0.5 sec), the pressure would increase by approximately 65 psi. This pressure increase is not considered significant because the loads are dominated by the water slug discharge. After 0.5 sec, the forces in the common header region are low enough such that the pressure increase would have negligible effect.

Texas Utilities Electric Company does not expect the safety valve and PORV piping loads from water discharge to exceed those from the loop seal slug discharge (Reference 14). Based on discussions with Westinghouse, the applicant noted Westinghouse had previously performed analyses of scenarios other than the loop seal slug discharge case analyzed for Comanche Peak, Unit 2. The results of Westinghouse's analyses indicated the other scenarios were less severe than the loop seal slug discharge. Therefore, the staff agrees that the piping loads from a loop seal slug discharge bounds the forces from all transient conditions expected.

The thermal hydraulic analysis was performed using the Westinghouse computer code ITCHVALVE. ITCHVALVE calculates the fluid parameters as a function of time. Another Westinghouse program, FORFUN calculates the unbalanced forces or wave forces in the piping segments from the fluid properties obtained from the ITCHVALVE analysis. These calculations provide the forcing functions on the piping system resulting from the fluid transients.

Westinghouse verified the ITCHVALVE/FORFUN programs for use in valve discharge piping analyses by comparing the analytical and test results for two EPRI tests (Test Nos. 908 and 917). In Reference 13, the applicant presented comparisons of the ITCHVALVE predicted force time histories and the EPRI test results. These comparisons show that the maximum forces calculated by the programs are more conservative than the experimental results. The staff considers these comparisons satisfactory.

Westinghouse, TUEC's consultant, performed the thermal hydraulic analysis of the Comanche Peak, Unit 2, safety valve and PORV piping and supports. The staff reviewed a typical Westinghouse analysis for such piping systems in previous submittals for a similar PWR plant (Reference 19). The staff reviewed Westinghouse's methods including analysis assumptions and key computer input parameters (node spacing, time steps, valve opening time, etc.) and found them to be adequate. In addition, the applicant stated in References 13 and 14, the Comanche Peak, Unit 2, piping analysis followed the same approach used in the Westinghouse verification analyses of the EPRI tests for time step, nodalization, and valve opening time. Therefore, the staff considers the Comanche Peak, Unit 2, analysis adequate.

The valve opening times used by the applicant were 0.040 sec for the safety valves and 1.0 sec for the PORVs. During testing, EPRI measured opening times for the safety valve and PORV that were faster than the valve opening times used by the applicant. The opening times measured by EPRI were less than 0.019 sec for the safety valve and 0.66 sec for the PORV. The staff does not consider this difference significant because the resulting loads using 0.04 sec and 1.0 sec were found to be equal to or greater than the actual EPRI test results. Also, Comanche Peak, Unit 2, uses loop seals upstream of both the safety valves and PORVs. Therefore, the valve opening time is not as important in determining peak loads as for plants without loop seals.

The applicant provided the safety valve and PORV flow rates used in the analysis in Reference 13. For the safety valve analysis, the flow rate was 120% of the rated flow for the Crosby 6M6 safety valves. The conservatism in this flow rate accounts for the 10% derating of the safety valve flow rate required by the ASME Code. This flow rate is also greater than the 111% of rated flow at 3% accumulation measured in the EPRI tests. The PORV flow rate used in the analysis was 139% of the rated flow for the Copes-Vulcan valve. This accounts for 10% ASME derating of the valve flow rate. It also exceeds the maximum flow observed in the EPRI tests, 122% of rated flow. Therefore, the staff concludes that the flow rates used by the applicant in the analyses are amply conservative.

4.4.2 Stress Analysis

Westinghouse calculated the structural response of the piping system to the safety valve/PORV discharge transients using normal mode theory. They used the FORFUN calculated fluid force time histories from the thermal hydraulic analysis as the forcing functions on the structural model. Westinghouse used the structural analysis program, WESTDYN, and its subroutines FIXFM3, WESTDYN2, and POSDYN2. Westinghouse used WESTDYN to calculate the piping natural frequencies and normal modes. FIXFM3 calculated the nodal time history displacements, and WESTDYN2 the internal forces and deflections. Westinghouse used POSDYN2 to calculate the maximum forces, moments, and displacements on the piping elements and maximum piping support loads.

The NRC previously reviewed and approved the WESTDYN series of structural programs (Reference 20). Westinghouse further verified these programs for valve discharge piping analysis by comparing calculated results from these programs with EPRI test results (Reference 13).

The staff reviewed the important structural analysis parameters of time step size, lumped mass spacing, cutoff frequency, and damping. The step size was 0.001 sec. This time step size will adequately analyze frequencies up to 100 Hz. Damping of 2% was used for the WESTDYN analysis of the PORV and safety valve discharge piping. The staff considers this damping factor adequate based on Reference 21. Reference 21 indicated damping factors of 2% are more realistic. It also indicated using realistic damping factors, rather than small, overly conservative damping factors, could improve overall piping/support system performance. Texas Utilities Electric Company used the PAGES computer program to develop the mass point spacing. This program bases the mass point spacing on the support locations and the pipe size at Comanche Peak, Unit 2. In Reference 15, TUEC stated this program was also used to develop the mass point spacing in the benchmarks of the EPRI tests. These benchmark results were adequate when compared to the test data. Based on the above, the staff considers the structural analysis parameters adequate for use in the Comanche Peak, Unit 2, analysis.

The governing code for the piping stress analysis was the ASME Boiler and Pressure Vessel Code, Section III, Subsection NB, 1977 Edition, with addenda to and including Summer 1979. For the piping supports, the governing code was the ASME Boiler and Pressure Vessel Code Section III, Subsection NF, 1974 Edition, with addenda to and including Winter 1979. The load combinations and stress limits used to evaluate the piping and support stresses are the same as those recommended by EPRI (Reference 22).

The piping stress summaries presented by the applicant (Reference 13) compare the highest stresses in the piping with the applicable stress limits. The staff reviewed the piping stress results and found all the stresses were within the applicable stress limits.

During EPRI tests on the Crosby 6M6 safety valve, high frequency pressure oscillations of 170-260 Hz occurred in the piping upstream of the safety valve as the loop seal water slug passed through the valve. This raised a concern that these oscillations could potentially excite high frequency vibration modes in the inlet piping that could contribute to higher bending moments in the piping. The applicant did not account for this phenomenon in the structural analysis of the system. However, the piping between the pressurizer and safety valves in the EPRI tests was 8-in. Schedule 160 and 6-in. Schedule XX. The same piping at Comanche Peak, Unit 2, is 6-in. Schedule 160. A comparison of the intensified bending moments from the stress evaluation and the allowable moments shows that the maximum bending moment calculated for 6-inch Schedule 160 piping was 187.38 in-kips which is below the maximum allowable (516 in-kips). Because the test piping did not sustain any discernible damage during pressure oscillations occurring in the tests, the staff concluded that the plant piping also would not incur damage during similar oscillations. Thus, a specific analysis for these pressure oscillations is not necessary for this plant.

Reference 13 presented the worst case load/stress versus the allowables for representative piping supports. The results showed that the load/stresses were within their respective allowables.

In References 14 and 15, TUEC provided information on the pressurizer nozzle loads. They reviewed the nozzle loads due to valve discharge and found they were acceptable for all load conditions identified in the Comanche Peak, Unit 2, Class 1 stress analysis summary report.

4.4.3 Structural Analysis Summary

The selection of a bounding case for the piping evaluation and the piping and support stress analysis demonstrate that TUEC met the requirements of Items 3 and 8 of NUREG-0737, item II.D.1.

5. EVALUATION SUMMARY

The Applicant for Comanche Peak, Unit 2, provided an acceptable response to the requirements of NUREG-0737, Item II.D.1. Therefore, the applicant confirmed that Comanche Peak, Unit 2, met General Design Criteria 14, 15, and 30 of Appendix A to 10 CFR 50 with regard to the safety valves, PORVs, and block valves. The discussion below provides the rationale for this conclusion.

The Applicant participated in the development and execution of an acceptable test program. The program would qualify the operability of prototypical valves and demonstrate that their operation would not invalidate the integrity of the associated equipment and piping. The Electric Power Research Institute successfully completed the subsequent tests under operating conditions which by analysis bounded the most probable maximum forces expected from anticipated operational occurrences and design basis events. The generic test results and piping analyses demonstrated that the valves which were tested had functioned correctly and safely for all steam and water discharge events in the test program applicable to Comanche Peak, Unit 2. Also, the pressure boundary component design criteria were not exceeded. Analysis and review of the test results and the Applicant's justifications indicated direct applicability of the prototypical valve and valve performance to the in-plant valves and systems covered by the generic test program. The Applicant's analysis of the plant specific piping showed it was acceptable.

Thus, TUEC met the requirements of Item II.D.1 of NUREG-0737 (Items 1-8 of Section 1.2 in this report). Therefore, the Applicant demonstrated by testing and analysis for the subject equipment that: (a) the reactor primary coolant pressure boundary will have a low probability of abnormal leakage (General Design Criterion No. 14), (b) the reactor primary coolant pressure boundary and its associated components (piping, valves, and supports) were designed with sufficient margin such that design conditions are not exceeded during relief/safety valve events (General Design Criterion No. 15), and (c) the valves and associated components were constructed in accordance with high quality standards (General Design Criterion No. 30).

6. REFERENCES

1. TMI-2 Lessons Learned Task Force, TMI-2 Lessons Learned Task Force Status Report and Short-Term Recommendations, NUREG-0578, July 1979.

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