TXU Power
Comanche Peak Steam
Electric Station
P. O. Box 1002 (E01)
Glen Rose, TX 76043
Tel: 254 897 5209
Fax: 254 897 6652
mike.blevins@txu.com

Mike Blevins
Senior Vice President &
Chief Nuclear Officer

Ref: 10CFR50.90

CPSES-200601814
Log # TXX-06152

September 12, 2006

U. S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, DC 20555

SUBJECT: COMANCHE PEAK STEAM ELECTRIC STATION (CPSES)
DOCKET NOS. 50-445 AND 50-446
RESPONSE TO REQUEST FOR ADDITIONAL INFORMATION TO LICENSE AMENDMENT REQUEST (LAR) 06-003: REVISION TO TECHNICAL SPECIFICATION (TS) 3.8.1, "AC SOURCES – OPERATING" (TAC NOS. MD0932, MD0933)

REF:
1) TXU Energy letter logged TXX-06058 from Mike Blevins to the NRC dated March 22, 2006.
2) NRC memorandum from Allen G. Howe to David Terao (no date) forwarded via email from Mohan C. Thadani to Dennis E. Buschbaum.

Gentlemen:

In reference 1 above, TXU Generation Company LP (TXU Power) transmitted an application for amendment (Reference 1) to Facility Operating License Number NPF-87 and NPF-89 for CPSES Unit 1 and Unit 2. The proposed amendment would revise the Completion Time for TS 3.8.1, Condition F, Required Action F.1 from 12 hours to 24 hours.

After reviewing the proposed license amendment, the NRC staff requested additional information in Reference 2 to support the amendment application. A telephone conference call was conducted on August 22, 2006 to discuss the requested information during which TXU Power agreed to provide the attached responses to the Staff's request for additional information in support of TXU Power's amendment application.

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The additional information provided in the attachment does not impact the conclusions of the No Significant Hazards Consideration provided in Reference 1. In accordance with 10 CFR 50.91, a copy of this submittal is being provided to the designated Texas State official.

This communication contains no new licensing basis commitments regarding CPSES Units 1 and 2.

Should you have any questions, please contact Robert A. Slough at (254) 897-5727.

I state under penalty of perjury that the foregoing is true and correct.

Executed on September 12, 2006.

Sincerely,

TXU Generation Company LP

By: TXU Generation Management Company LLC
Its General Partner

Mike Blevins

By: Fred W. Madden
Fred W. Madden
Director, Regulatory Affairs

RAS
Attachment

c - B. S. Mallett, Region IV
M. C. Thadani, NRR
Resident Inspectors, CPSES

Ms. Alice Rogers
Bureau of Radiation Control
Texas Department of Public Health
1100 West 49th Street
Austin, Texas 78756-3189

REQUEST FOR ADDITIONAL INFORMATION

RE: THE REVIEW OF REQUEST FOR REVISION OF TECHNICAL SPECIFICATION 3.8.1 (TAC NOS. MD0932 AND MD0933)

Question 1:

The currently allowed 12 hours to restore one inoperable SI sequencer to an operable status (condition F) is consistent with the required action completion time for an inoperable required offsite circuit coincident with an inoperable DG (condition D). Both of these conditions have similar impact on the operation of the ESF systems.

In section 4.0 of the submittal, TXU power stated that the proposed change to increase the action completion time from the current 12 hours to 24 hours will provide more time to complete the necessary repairs and required post-work testing to restore an inoperable SI sequencer to operable status prior to commencing a plant shutdown to MODE 3. TXU power did not identify any additional hardship in restoring an inoperable sequencer that will need more than the current allowed time as compared to restoring an inoperable offsite source or a DG.

Question 1 Response:

As stated in the question, Technical Specification 3.8.1, Condition D does provide required actions and completion times to address the condition when a required offsite circuit is inoperable while a required Diesel Generator (DG) is also inoperable at the same time. However, the statement that this condition is similar to or has a similar impact on operation of the ESF systems as would an inoperable SI Sequencer is incorrect.

CPSES has two qualified offsite AC sources. Each offsite source serves as the normal source for the class 1E onsite distribution system for one Unit and as the alternate source for the class 1E onsite distribution system for the other Unit. Additionally, each onsite 1E AC vital bus is capable of being powered by an Emergency Diesel Generator (EDG). The offsite AC sources are more fully described in FSAR Chapter 8.2 and Figure 8.2-4 while the Onsite AC Power Systems are described in FSAR Chapter 8.3 and Figure 8.3-1. The method and sequence of automatic transfer between the two offsite sources and between the offsite sources and the onsite EDG for each 1E bus is described in FSAR Chapter 8.3, section 8.3.1.1.5.2, paragraph 4.

Each onsite 1E bus for each Unit is equipped with a Blackout Sequencer and a Safety Injection Sequencer which, respectively, function to start the required ESF equipment in a predetermined sequence in the event of a blackout or LOCA. These sequencers are more fully described in FSAR Chapter 8.3, section 8.3.1.1.5.3, paragraph 1. Paragraph 2 of the same FSAR section describes sequencer operation in the event of a safety injection, in the event of a blackout, and in the event of a simultaneous or sequential safety injection with blackout.

As stated in the Bases for TS 3.8.1, Conditon I, "A blackout sequencer is an essential support system to the DG associated with a given ESF bus. The sequencer is required to provide the system response to a loss of or degraded ESF bus voltage signal." If a blackout sequencer is

inoperable while one of the required offsite AC sources is also inoperable, then a subsequent station blackout condition would result in only one available EDG capable of providing power to one 1E bus and its train-related ESF equipment within the times assumed in the Station Blackout analysis. Therefore, Condition I of TS 3.8.1 requires that an associated EDG be immediately declared inoperable whenever a blackout sequencer is inoperable. If one required offsite source is already inoperable, Condition D of TS 3.8.1 becomes applicable and requires restoration of either the offsite source or the EDG (e.g., the blackout sequencer) to OPERABLE status within 12 hours rather than the 72 hours allowed by Conditions A or B when an offsite source or a EDG separately is inoperable.

The CPSES LOCA analysis does not assume a coincidental station blackout. The blackout sequencer, and its associated EDG, is not required to function for a LOCA since both 1E busses, and the train associated ESF equipment, would remain powered from either the normal or the alternate offsite AC source. A LOCA occurring while one Safety Injection Sequencer is already inoperable would result in one train of ESF equipment not being automatically started and sequenced onto the 1E bus. However, since the 1E bus would remain energized from either of the two offsite sources, the ESF loads could be manually started. This is acceptable since the CPSES LOCA analysis assumes that one train of ECCS equipment fails to actuate.

During the last four years CPSES has experienced two failures of the Unit 1 Train A Safety Injection Sequencer and two failures of the Unit 1 Train B Safety Injection Sequencer as shown in the table below.

Affected SI Sequencer	Cause	Resolution	LCO 3.8.1, Condition F Date/Time		
			Entered	Exited	Total Time
Unit 1, Train A	Loose connector wire	Replaced card frame	01/13/03, 1004	01/13/03, 1307	3 hours, 3 minutes
Unit 1, Train A	Output relay failure	Replaced relay	04/25/04	04/25/04	Unknown*
Unit 1, Train B	Faulty relay driver card	Replaced card	08/30/05, 0015	08/30/05, 0328	3 hours, 13 minutes
Unit 1, Train B	Failed power supply	Replaced power supply	09/07/05, 1700	09/08/05, 0121	8 hours, 21 minutes

* This failure occurred during an outage when the SI Sequencer was not required to be OPERABLE.

Question 2:

Comanche Peak Units SI sequencers are actuated by an Automatic Actuation Logic and Actuation Relays. Amendment 114, issued by the NRC in 2005, allowed an increase in restoration time of an inoperable train of Safety Injection Automatic Actuation Logic and Actuation Relays from six hours to 24 hours. Amendment 114 was based on the staff approved Topical Reports WCAP-14333-P-A," Probabilistic Risk Analysis of the RPS and ESFAS Test and Completion Times," and WCAP-15376-P-A,"Risk Informed Assessment of the RTS and

ESFAS Surveillance Test Intervals and Reactor Trip Breaker Test and Completion Times." The licensee stated that an inoperable SI sequencer presents no greater risk and has the same impact upon accident mitigation capability as an inoperable train of Safety Injection Automatic Actuation Logic and Actuation Relays. This condition was evaluated in amendment 114 and formed the basis for the licensee's statement that it is reasonable to allow 24 hours to restore an inoperable SI sequencer to operable status. These statements are qualitative and analogical and do not provide sufficient basis, especially in the absence of a probabilistic risk assessment, for deviation from the consistency identified in item 1.

Question 2 Response:

A probabilistic evaluation of the proposed Completion Time extension was performed using Regulatory Guides 1.174 and 1.177 and resulted in the plant condition not being considered risk significant. The results from the evaluation were: baseline CDF of 6.50E-06, CDF with one train of the SI sequencer out of service was 6.77E-06. This resulted in a ΔCDF of 2.70E-07. This is below the threshold of 1E-06 at which the change in CDF would be considered risk significant per Regulatory Guide 1.174. The ICCDP was calculated for the proposed extension period and was found to be 7.40E-10. This is below the threshold of 5E-07 at which the ICCDP would be considered to be risk significant per Regulatory Guide 1.177.

The evaluation results for LERF also indicated an acceptable change in risk. Specifically, ΔLERF was 2.97E-08, below the Regulatory Guide 1.174 threshold of 1E-07. ICLERP was 8.14E-11, well below the Regulatory Guide 1.177 threshold of 5E-08.

Evaluation of the proposed change relative to both CDF and LERF demonstrate a small increase in calculated risk. The evaluation indicates that extending the Completion Time for the SI Sequencer from 12 hours to 24 hours is not risk significant.

PRA QUALITY

One of the main objectives of the CPSES PRA development was to be able to use its results and insights toward enhancement of plant safety through risk-based applications. With this objective in mind, the PRA elements were developed in detail and integrated in a manner sufficient to satisfy both the NRC Generic Letter 88-20 requirements and support future plant applications. For future plant applications, it was recognized that the PRA had to be of high quality, and that the assumptions within the PRA had to be supportable. To maintain the level of quality needed to support risk-informed applications, significant enhancements to the original IPE work were made.

The PRA model has been updated three times since the original IPE submittal. The current PRA model includes modeling enhancements identified as part of the model update process, and insights gained when using the PRA model in support of several risk-based initiatives.

The PRA analysts have continued to enhance fault tree modeling since the IPE, both at the system level and in the top logic. The major updates have resulted in a number of model

changes. The updates have addressed model maintenance (e.g., data and plant changes) and industry based changes (these include such things as peer review and industry input).

The CPSES PRA has been extensively reviewed by both the PRA staff and outside PRA experts. It is believed that the CPSES PRA meets or exceeds the quality standards subsequently suggested by Industry guidelines. As part of the IPE process, the PRA model was peer reviewed as described in the IPE submittal to ensure that the PRA represented the as-built, as-operated plant. Since that time, the CPSES PRA model has been updated to incorporate plant procedure revisions, plant modifications, and plant specific operational data. Since then the model has been peered reviewed at least twice.

The NRC and its PRA experts, as part of the CPSES RI-IST submittal, reviewed the CPSES PRA in detail. As part of their review of the RI-IST submittal, the NRC performed an in-depth review of the CPSES PRA model. This review concentrated on elements of the PRA affected by the RI-IST application, and on the assumptions and elements of the PRA model which drive the results and conclusions. The NRC's review established that the CPSES PRA appropriately reflected the plant's design and actual operating conditions and practices and was of suitable quality to support the PRA-related findings made to support the RI-IST submittal.

The Westinghouse Owners Group (WOG) peer review was performed during the spring of 2002. The conclusion of the peer assessment was that the Comanche Peak PRA can be effectively used to support risk significance evaluations with deterministic input, subject to addressing the items identified as significant in the technical element summary and Facts & Observations (F&O) sheets. CPSES addressed each of the Categories A and B F&Os and incorporated those items into the PRA model.

Beginning in late 2004 and completed in 2005, CPSES embarked on its third and latest periodic update to the PRA model. This update encompassed data as well as system and top level logic changes. Prior to the start of this update, an internal gap assessment of the CPSES PRA model was completed using the ASME PRA standard as guidance. Items of significance from this assessment were addressed as part of the revision 3 update. The PRA included:

- Updating the PRA model to reflect the plant as-built configuration including all changes made since 2000.
- Updating component failure rates and unavailabilities with plant-specific data where available.
- Updating the initiating event frequencies with plant-specific data where available.
- Loss of Off-site Power (LOOP) initiating event frequencies were modeled as their constituent parts (Grid, Plant and Weather- Centered events). Consequential LOOP and degraded grid conditions were also included in the PRA model. These frequencies were also updated using industry data collected by EPRI.
- Updating the latent, dynamic, and recovery human reliability analysis (HRA) using the EPRI HRA Calculator software.
- Implemented the Westinghouse 2000 RCP seal modeling, including NRC SER recommendations.

- Updating the Thermal-Hydraulics (T-H) analysis used to develop core uncovery times associated with seal LOCA scenarios.
- Updating the model and associated documentation to reflect WOG and Peer review comments. Remaining category A & B F&O's (documentation) from the WOG Peer Review were incorporated into the update documentation as well as other documentation issues identified during that process.

An Independent Industry Peer review of the Revision 3 changes associated with the RCP seal LOCA model, T-H analyses associated with seal LOCA scenarios, LOOP model changes (discussed above) and quantification process was completed. This review was completed based on the ASME PRA Standard. No category A or B F&O's were identified by the peer review and other F&O items were resolved and incorporated in Revision 3B of the model.

This current version of the CPSES model is used in support of the Mitigating Systems Performance Indicators (MSPI) process. There are no outstanding A or B category F&O's from the WOG peer review process or from any of the other third party independent reviews.

As part of the Westinghouse Owners Group (WOG) industry participation in the MSPI, the WOG performed a cross comparison and assessment of monitored components and PRA results used in the implementation of NEI-99-02 for establishing Mitigating Systems Performance Indicators. This cross comparison was to be done across the entire fleet of Westinghouse and Combustion Engineering designed plants. The cross comparison has been given significant importance due to an NEI/NRC agreement to substitute the cross comparison as a vehicle for resolving PRA quality issues relevant to MSPI before implementation. The results of that effort identified Comanche Peak as presenting potential outliers in two areas which were subsequently resolved. Candidate outliers were established based on the plants Birnbaum value being either relatively low or high for those in its "group" and/or the observed presence of large component asymmetries. The information provided to the industry peers and NRC established an understanding of the reasons for those risk importance measure being considered as potential outliers. That information was reviewed and accepted and the technical adequacy of the Comanche Peak PRA was found to be acceptable for generation of risk based MSPI metrics.