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CPSES-200100771
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April 25, 2001

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
LICENSE AMENDMENT REQUEST (LAR) 01-06
REVISION TO TECHNICAL SPECIFICATION,
EXTENSION OF ALLOWABLE COMPLETION TIMES AND
SURVEILLANCE REQUIREMENT CHANGE FOR EMERGENCY
DIESEL GENERATORS, QUALIFIED OFFSITE CIRCUITS, AND AC
ELECTRICAL POWER DISTRIBUTION SUBSYSTEM

Gentlemen:

Pursuant to 10CFR50.90, TXU Electric hereby requests an amendment to the CPSES Unit 1 Operating License (NPF-87) and CPSES Unit 2 Operating License (NPF-89) by incorporating the attached changes into the CPSES Unit 1 and 2 Technical Specifications. This change request applies to both units.

The proposed changes will revise Technical Specification (TS) 3.8.1 for AC Sources Operating to extend the allowable Completion Times for the Required Actions associated with restoration of an inoperable Emergency Diesel Generator (EDG) and an inoperable offsite circuit (i.e., startup transformer). In addition, the TS Surveillance Requirement (SR) corresponding to the 24-hour EDG endurance run (i.e., SR 3.8.1.14) will be revised to allow the SR to be performed during Modes 1 and 2. The proposed changes will also revise Technical Specification (TS) 3.8.9 for Distribution Systems - Operating to extend the allowable Completion Times for the Required Actions associated with restoration of an inoperable AC electrical power distribution system (i.e., 6.9 kV AC safety bus).

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These proposed changes will provide operational flexibility by allowing more efficient application of plant resources to safety significant activities. These proposed changes will (1) allow performance of periodic EDG overhauls and testing on-line, improving EDG availability during shutdown, (2) allow maintenance of the startup transformers at power, and (3) allow repairs of the 6.9 kV AC safety bus at power.

The justification for the change to the EDG Completion Time is based upon a risk-informed, deterministic evaluation consisting of three main elements: (1) the availability of offsite power via separate and physically independent offsite circuit startup transformers, (2) assessment of risk that shows an overall risk reduction (as indicated by Core Damage Frequency (CDF) and Large Early Release Frequency (LERF)) by moving the EDG overhaul and offsite circuit startup transformer maintenance from shutdown to operating states, (3) continued implementation of a Configuration Risk Management Program (CRMP) while the EDG, startup transformer, or safety bus is in an extended Completion Time. These elements provide the basis for the requested TS change by providing a high degree of assurance of the capability to provide power to the safety related 6.9 kV AC Engineered Safety Features (ESF) buses during the extended Completion Times.

Attachment 1 is the required affidavit. Attachment 2 provides a detailed description of the proposed changes, a technical analysis of the proposed changes, TXU Electric's determination that the proposed changes do not involve a significant hazard consideration, a regulatory analysis of the proposed changes and an environmental evaluation. Attachment 3 provides the affected Technical Specification pages marked-up to reflect the proposed changes. Attachment 4 provides proposed changes to the Technical Specification Bases for information only. These changes will be processed per CPSES site procedures. Attachment 5 provides retyped Technical Specification pages which incorporate the requested changes. Attachment 6 provides retyped Technical Specification Bases pages which incorporate the proposed changes.

TXU Electric requests approval of the proposed License Amendment Request by September 30, 2001, to be implemented within 60 days. This proposed schedule supports offsite circuit startup transformer maintenance in late 2001 or early 2002.

TXU

In accordance with 10CFR50.91(b), TXU Electric is providing the State of Texas with a copy of this proposed License Amendment Request.

Should you have any questions, please contact Mr. Carl B. Corbin at (254) 897-0121.

Sincerely,

C. L. Terry

By: Roger D. Walker

Roger D. Walker
Regulatory Affairs Manager

CBC/cbc

Attachments
1. Affidavit
2. Description and Assessment
3. Markup of Technical Specifications pages
4. Markup of Technical Specifications Bases pages (for information)
5. Retyped Technical Specification Pages
6. Retyped Technical Specification Bases Pages (for information)
7. Commitments
8. Figures

c - E. W. Merschoff, Region IV
J. I. Tapia, Region IV
D. H. Jaffe, NRR
Resident Inspectors, CPSES

Mr. Authur C. Tate
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Texas Department of Public Health
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Austin, Texas 78704

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

In the Matter of	)	
	)	
TXU Electric	)	Docket Nos. 50-445
	)	50-446
(Comanche Peak Steam Electric Station,	)	License Nos. NPF-87
Units 1 & 2)	)	NPF-89

AFFIDAVIT

Roger D. Walker, being duly sworn, hereby deposes and says that he is the Regulatory Affairs Manager of TXU Electric, the licensee herein; that he is duly authorized to sign and file with the Nuclear Regulatory Commission this License Amendment Request 01-06; that he is familiar with the content thereof; and that the matters set forth therein are true and correct to the best of his knowledge, information and belief.

Roger D. Walker

Roger D. Walker
Regulatory Affairs Manager

STATE OF TEXAS)
)
COUNTY OF Somervell)

Subscribed and sworn to before me, on this 25th day of April, 2001.

Gayle R. Peck Jespersen
Notary Public, State of Texas
My Comm. Expires 03/16/02

Dayle R. Peck Jespersen
Notary Public

ATTACHMENT 2 to TXX-01077

DESCRIPTION AND ASSESSMENT

Description and Assessment

1.0 INTRODUCTION

1.1 LAR 01-06 is a request to revise Technical Specifications (TS) 3.8.1, "AC Sources – Operating," and TS 3.8.9, "Distribution Systems – Operating," for Comanche Peak Steam Electric Station (CPSES) Units 1 and 2. These changes extend the allowed Completion Time (also previously known as Allowed Outage Time) for the 6.9 kV AC components. These components consisted of the Diesel Generators (EDG), offsite circuit startup transformers, and 6.9 kV AC safety buses. The risks associated with extending the allowed Completion Times for these components during power operations (Mode 1) and the risks associated with removing these components during shutdown were determined and compared. The changes were also evaluated using deterministic measures.

1.2 FINAL SAFETY ANALYSIS REPORT (FSAR) SECTION

The CPSES Final Safety Analysis Report (Sections 1A(B) and 8) (Reference 1) will be updated as required to reflect this License Amendment Request. The FSAR will be updated after the License Amendment Request has been approved and implemented.

2.0 DESCRIPTION

These changes revise the specifications for AC Sources Operating to extend the allowable Completion Times for the Required Actions associated with restoration of an inoperable Emergency Diesel Generator (EDG). In addition, the TS Surveillance Requirement (SR) corresponding to the 24-hour EDG endurance run (i.e., SR 3.8.1.14) will be revised to allow the SR to be performed during MODES 1 and 2. The proposed changes will also revise Technical Specification (TS) 3.8.9 for Distribution Systems - Operating to extend the allowable Completion Times for the Required Actions associated with restoration of an inoperable AC electrical power distribution system (i.e., 6.9 kV AC safety bus).

The changes to TS 3.8.1 and 3.8.9 are marked-up (Attachment 3) on the Technical Specification pages.

TXU Electric's requested changes to TS Sections 3.8.1 and 3.8.9 are summarized below.

<u>Technical Specification (TS) 3.8.1, AC Sources - Operating</u>

TS 3.8.1, "AC Sources – Operating," Actions, Page 3.8-2, Action A.3, Completion Time: change "72 hours <u>AND</u> 6 days from discovery of failure to meet LCO" to "14 days <u>AND</u> 17 days from discovery of failure to meet

LCO."

TS 3.8.1, "AC Sources – Operating," Actions, Page 3.8-4, Action B.4, Completion Time: change "72 hours AND 6 days from discover of failure to meet LCO" to "14 days AND 17 days from discovery of failure to meet LCO."

TS 3.8.1, "AC Sources – Operating," Surveillance Requirements, Page 3.8-12, Surveillance (SR) 3.8.1.14, Note 2, change the heading from "NOTES" to "NOTE", delete the label "1.", and delete "2. Verify requirement during MODES 3, 4, 5, 6 or with core off-loaded."

Technical Specification (TS) 3.8.9, Distribution Systems - Operating

TS 3.8.9, "Distribution Systems – Operating," Actions, Page 3.8-38, Action A.1, Completion Time: change "8 hours AND 16 hours from discovery of failure to meet LCO" to "72 hours AND 80 hours from discovery of failure to meet LCO."

TS 3.8.9, "Distribution Systems – Operating," Actions, Page 3.8-38, Action B.1, Completion Time: change "16 hours from discovery of failure to meet LCO" to "80 hours from discovery of failure to meet LCO."

TS 3.8.9, "Distribution Systems – Operating," Actions, Page 3.8-38, Action C.1, Completion Time: change "16 hours from discovery of failure to meet LCO" to "80 hours from discovery of failure to meet LCO."

In summary, (1) the specifications for AC Sources Operating are revised to permit an Emergency Diesel Generator (EDG) TS Action Completion Time of up to 14 days and allow performance of the EDG 24 hour TS Surveillance Requirement test in MODES 1 and 2, (2) the specifications for AC Sources Operating have been revised to permit an offsite circuit inoperable TS Action Completion Time of up to 14 days, and (3) the specifications for Distribution Systems – Operating have been revised to permit a 6.9 kV AC safety bus TS Action Completion Time of up to 72 hours.

For information only, this LAR includes proposed associated changes to the TS Bases 3.8.1, "AC Sources – Operating," and TS Bases 3.8.9, "Distribution Systems – Operating."

The changes to TS Bases 3.8.1 and 3.8.9 are marked-up (Attachment 4) on the TS Bases pages.

Technical Specification (TS) Bases 3.8.1, "AC Sources – Operating"

Revises Bases information to reflect the updated Completion Times and

Surveillance NOTES.

Technical Specification (TS) Bases 3.8.9, "Distribution Systems – Operating"

Revises Bases information to reflect the updated Completion Times.

Retyped Technical Specification pages and Technical Specification Bases pages which incorporate the proposed changes, are provided in Attachments 5 and 6, respectively.

3.0 BACKGROUND

The Completion Time extensions for the Emergency Diesel Generators (EDGs) and the offsite circuit Startup Transformers (STs) are expected to be used for performing maintenance activities. The extension for the 6.9 kV AC safety buses is expected to be used in the event maintenance is required.

The current Completion Times associated with inoperable AC power source(s) are intended to minimize the time an operating plant is exposed to a reduction in the number of available AC power sources. NRC Regulatory Guide (RG) 1.93, "Availability of Electric Power Sources," December 1974, (Reference 2) is referenced in the TS Bases for Actions associated with TS Section 3.8.1. RG 1.93 provides operating restrictions (i.e., Completion Times) that the NRC considers acceptable if the number of available AC power sources are less than the LCO. Specifically, "if the available ac power sources are one less than the number required by the TS LCO, power operation may continue for a period that should not exceed 72 hours if the system stability and reserves are such that a subsequent single failure (including a trip of the unit's generator, but excluding an unrelated failure of the remaining offsite circuit if this degraded state was caused by the loss of an offsite source) would not cause total loss of offsite power." Regulatory Guide 1.93 also states the following: "The operating time limits delineated in regulatory positions C.1 through C.5 are explicitly for corrective maintenance activities only. These operating time limits should not be construed to include preventive maintenance activities that require the incapacitation of any required electric power source. Therefore, per this guide, preventive maintenance should be scheduled for performance during cold shutdown and/or refueling periods."

The 72-hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a Design Basis Accident (DBA) occurring during this period. The six-day Completion Time establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the TS LCO.

As described in the bases for SR 3.8.1.14, the reason for Note 2 is that during operation with the reactor critical, performance of the 24-hour EDG endurance run could cause perturbations to the electrical distribution systems that could challenge continued steady state operation and, as a result, plant safety systems.

The proposed changes will continue to provide adequate protection of public health and safety and common defense and security as described below. The changes advance the objectives of the NRC's Probabilistic Risk Assessment (PRA) Policy Statement (Reference 3), for enhanced decision-making and result in a more efficient use of resources and reduction of unnecessary burden. Implementation of this proposed Completion Time extension and removal of the Mode restriction from performance of the SR will provide the following benefits.

- Allow increased flexibility in the scheduling and performance of EDG or startup transformer (ST) maintenance.
- Allow better control and allocation of resources. Allowing on-line maintenance, including overhauls, provides the flexibility to focus more quality resources on any required or elected EDG or ST maintenance.
- Avert unplanned plant shutdowns and minimize the potential need for requests for Notice of Enforcement Discretion (NOED). Risks incurred by unexpected plant shutdowns can be comparable to and often exceed those associated with continued power operation.
- Improve EDG, ST, or 6.9 kV AC safety bus availability during shutdown Modes or Conditions. This will reduce the risk associated with EDG maintenance and the synergistic effects on risk due to EDG unavailability occurring at the same time as other various activities and equipment outages that occur during a refueling outage.
- Permit scheduling of EDG or ST overhauls within the requested 14-day Completion Time extension period.
- Permit emergency repair of 6.9 kV AC safety bus at power

The results of TXU probabilistic evaluations support extension of the existing Completion Time for all affected components. The Completion Time for the Diesel Generators may be extended to 14 days. The Completion Time for the offsite circuit startup transformers may be extended to 14 days. The Completion Time for the 6.9 kV AC safety buses may be extended to 72 hours. Details of the analysis are contained in Section 4.0 of this report.

The proposed Completion Time of 14 days is adequate to perform normal EDG inspections and maintenance requiring disassembly of the EDG and to perform post-maintenance and operability tests required to return the EDG to operable status.

Comanche Peak intends to use the proposed 14-day Completion Time extension for performing a planned major overhaul at a frequency of no more than once per EDG per operating cycle. Comanche Peak intends to use the proposed 14-day Completion Time extension for performing a planned overhaul at a frequency of no more than once per startup transformer per operating cycle. Beyond that, Comanche Peak shall continue to minimize the time periods to complete any unplanned maintenance. Plant configuration changes for planned and unplanned maintenance of the EDGs, STs, or 6.9 kV AC safety bus as well as the maintenance of equipment having risk significance is managed by the Configuration Risk Management Program (CRMP). The CRMP helps ensure that these maintenance activities are carried out with no significant increase in the consequences of a severe accident.

Related background in the CPSES FSAR is found primarily in Section 1A(B) and Section 8.

To allow for planned outages of the EDGs in MODES 1 and 2, maintenance of startup transformers, and maintenance of the 6.9 kV AC safety bus, TXU Electric is submitting the proposed Technical Specification changes described in Section 2.

4.0 TECHNICAL ANALYSIS

The proposed changes have been evaluated to determine that current regulations and applicable requirements continue to be met, that adequate defense-in-depth and sufficient safety margins are maintained, and that any increases in core damage frequency (CDF) and large early release frequency (LERF) are small and consistent with the NRC Safety Goal Policy Statement (Reference 3), and the acceptance criteria in Regulatory Guide 1.174, "An Approach for Using Probabilistic Risk Assessment In Risk-Informed Decisions On Plant-Specific Changes to the Licensing Basis," July 1998, (Reference 4) and Regulatory Guide 1.177, "An Approach for Plant-Specific, Risk-Informed Decision making: Technical Specifications," August 1999 (Reference 5).

The justification for the use of an EDG extended Completion Time is based upon a risk-informed and deterministic evaluation consisting of three main elements: 1) the availability of the "preferred" and "alternate" offsite power sources via the startup transformers (STs), 2) an assessment that moving the extended EDG outage from shutdown operation to power operation will provide an overall risk reduction, as indicated by CDF and LERF, and 3) the implementation of the CRMP while an EDG is in an extended Completion Time. The CRMP is used for EDG as well as other work and helps ensure that there is no significant increase in the risk of a severe accident while any EDG maintenance is performed. These elements provide the bases for the proposed TS change by providing a high degree of assurance that power can be provided to the ESF buses during all Design Basis Accidents (DBAs) during the EDG extended Completion Time.

The performance of the 24 hour EDG endurance test during power operations is consistent with the design features of the plant. The remaining EDG is available to respond to an EDG start signal and a single EDG per unit has the capacity to mitigate the consequences of a design basis accident (DBA).

The unavailability of one startup transformer or one safety related (Class 1E) 6.9 kV AC bus are already considered in the plant design. The increased outage time for a startup transformer has no affect on the capability of each transformer to supply the required safety-related loads of both units if it becomes necessary to safely shut down both units simultaneously. The increased Completion Time for a safety related bus has no affect on the capability of each safety related bus to supply the required safety-related loads of both units if it becomes necessary to safely shut down both units simultaneously, although the design criteria require consideration of a Design Basis Accident on one unit only.

4.1 Traditional Engineering Considerations

4.1.1 Emergency Diesel Generator Completion Time Extension

4.1.1.1 Defense-in-depth

The impact of the proposed TS changes were evaluated and determined to be consistent with the defense-in-depth philosophy. The defense-in-depth philosophy in reactor design and operation results in multiple means to accomplish safety functions and prevent release of radioactive material.

Comanche Peak Station is designed and operated consistent with the defense-in-depth philosophy. The units have diverse power sources available (e.g., EDGs and STs) to cope with a loss of the preferred AC source (i.e., offsite power). The overall availability of the AC power sources to the ESF buses will not be reduced significantly as a result of increased on-line maintenance activities. It is therefore, acceptable, under certain controlled conditions, to extend the Completion Time and perform on-line maintenance intended to maintain the reliability of the onsite emergency power systems.

While the proposed change does increase the length of time an EDG can be out of service during unit operation, it will increase the availability of the EDGs while the unit is shutdown, which will provide a significant overall risk reduction throughout the operating cycle. The increased availability of the EDG while shutdown will increase the systems defense-in-depth during outages. Even with one EDG out of service there are multiple means to accomplish safety functions and prevent release of radioactive material. The CPSES PRA evaluation confirms the results of the deterministic analysis, i.e., the adequacy of defense-in-depth and that protection of the public health and safety are ensured.
System redundancy, independence, and diversity are maintained commensurate with the expected frequency and consequences of challenges to the system. As demonstrated in Section 4.2 below there are no risk outliers. Implementation of the proposed changes will be done in a manner consistent with the defense-in-depth philosophy. Station procedures will ensure consideration of prevailing conditions, including other equipment out of service, and implementation of compensatory actions to assure adequate defense-in-depth whenever the EDGs are out of service. In addition, appropriate personnel are trained on the operation and maintenance of the EDGs.

No new potential common cause failure modes are introduced by these proposed changes and protection against common cause failure modes previously considered is not compromised.

Independence of physical barriers to radionuclide release is not affected by these proposed changes.

Adequate defenses against human errors are maintained. These proposed changes do not require any new operator response or introduce any new opportunities for human errors not previously considered. Qualified personnel will continue to perform EDG maintenance and overhauls whether they are performed on-line or during shutdown. The maintenance activities are not affected by this change with the exception that the 24-hour EDG endurance run will be performed on-line. No other new actions are necessary because the overhaul will be performed on-line.

Section 3.1, "Conformance with NRC General Design Criteria," of the Final Safety Analysis Report (FSAR) (Reference 1) provides the basis for concluding that the stations fully satisfy and are in compliance with the NRC General Design Criteria (GDC) in Appendix A to 10 CFR Part 50. These proposed changes do not affect the basis for this conclusion and does not affect compliance with NRC GDC.

4.1.1.1.1 Availability of the Off-Site Power System

The transmission lines of TXU Electric are an integrated system with operations coordinated by the system dispatcher so as to maintain system reliability. Transmission systems consist of 345-kV lines for bulk supply and 138-kV and 69-kV lines to transmit power to load-serving substations. Composition of TXU Electric's generation sources include fossil fuel plants (lignite, gas/oil, and combustion turbines) and the CPSES nuclear plant (interconnected). Direct ties to other utilities in Texas are maintained, creating a highly reliable integrated system.

The CPSES output is connected to the 345-kV transmission system via the CPSES Switchyard. The startup and shutdown power for the units are derived from the 138-kV and 345-kV system. Separate connections to the 138-kV Switchyard and the 345-kV Switchyard provide independent and reliable offsite power sources to the Class 1E systems. The highly reliable network interconnections are made through five 345-kV and two 138-kV transmission lines to the TXU Electric grid as shown on the figures in Attachment 8.

Two physically independent and redundant sources of offsite power are available on an immediate basis for the safe shutdown of either unit. The preferred source to Unit 1 is the 345-kV offsite supply from the 345-kV Switchyard and the startup transformer, XST2; the preferred source to Unit 2 is the 138-kV offsite supply from the 138-kV Switchyard and the startup transformer, XST1. Each of the startup transformers (XST1 and XST2) normally energizes its related 6.9 kV AC Class 1E buses; i.e., XST1 normally energizes Unit 2 Class

1E buses and XST2 normally energizes Unit 1 Class 1E buses. This eliminates the need for automatic transfer of safety-related loads in the event of unit trips. In the event one startup transformer (e.g., XST1, a preferred source) becomes unavailable to its normally fed class 1E buses, power is made available from the other startup transformer (e.g., XST2, an alternate source) by an automatic transfer scheme.

The preferred power sources supply power to the Class 1E buses during plant startup, normal operation, emergency shutdown, and upon a unit trip.

Each startup transformer has the capacity to carry the required Class 1E loads of both units during all modes of plant operation.

The Class 1E buses of each unit can be supplied by two independent and reliable immediate-access offsite power sources. Sharing of these offsite power sources between the two units has no effect on the station electrical system reliability because each transformer is capable of supplying the required safety-related loads of both units if it becomes necessary to safely shut down both units simultaneously, although the design criteria require consideration of a Design Basis Accident on one unit only.

4.1.1.1.2 Availability of the On-Site Power System

The standby AC Power System is an independent, onsite, automatically starting system designed to furnish reliable and adequate power for Class 1E loads to ensure safe plant shutdown and standby when preferred and alternate power sources are not available. Four independent diesel generator sets, two per unit, are provided.

Loads important to plant safety are divided into redundant divisions. Each division is supplied standby power from an individual EDG. Each EDG is completely independent of any auxiliary transformer in the performance of its required function. The EDGs are physically and electrically independent. With this arrangement, redundant components of all ESF systems are supplied from a separate ESF bus so that no single failure can jeopardize the proper functioning of redundant ESF loads. Due to the redundancy of the unit's ESF divisions and EDGs, the loss of any one of the EDGs will not prevent the safe shutdown of the unit. The total standby power system, including EDGs and electrical power distribution equipment, satisfies the single failure criterion.

The purpose of the EDGs is to provide an onsite standby power source upon the loss of preferred and alternate offsite power sources. An EDG is automatically started by a safety injection signal or an under-voltage signal on the 6.9 kV ESF bus served by the EDG. Upon loss of voltage on a 6.9 kV ESF bus due to a Loss of Offsite Power (LOOP) with no safety injection signal present, under-voltage relays automatically start the EDGs. Sequential loading of the EDG is automatically performed.

The EDG feeder breaker will close to its associated load group automatically only if the other source feeder breakers to the load group are open. When the EDG feeder breaker is closed, no other source feeder breaker will close automatically. Design and procedural controls ensure that no means exist for connecting redundant load groups with each other. The design basis for the EDGs is that loss of one EDG will not result in the loss of safety function. With two EDGs available per unit, the system is capable of performing its intended safety function with an assumed single failure of one EDG.

Station Blackout (SBO) EDG Capacity

Comanche Peak Station is able to withstand and recover from a SBO event of 4 hours in accordance with the guidelines of RG 1.155, "Station Blackout," dated August 1988 (Reference 6).

The assumptions used in the SBO analysis regarding the availability and reliability of the EDGs are unaffected by this proposed change. The results of the SBO analysis are also unaffected by this change.

The impact of a SBO event on plant risk is discussed in Section 4.2, "Evaluation of Risk Impact."

Onsite Power System Design Criteria

Compliance with NRC design criteria is described in detail in FSAR Section 8.1, "INTRODUCTION," (Reference 1) and in FSAR Appendix 1A(B) "APPLICATION OF NRC REGULATORY GUIDES" (Reference 1). Safety-related systems and components that require electrical power to perform their safety-related function are defined as Class 1E loads. These proposed changes do not add or reclassify any safety-related systems or equipment; therefore, conformance with Safety Guide 6, dated March 10, 1971, titled "Independence Between Redundant Standby (onsite) Power Sources and Between Their Distribution Systems," (Reference 7) as discussed in Appendix 1A(B) of the FSAR (Reference 1) is not affected by this change. These proposed changes do not add any loads to the EDGs; therefore, the selection of the capacity of the EDGs for standby power systems and conformance to the applicable Sections of Safety Guide 9, dated March 10, 1971, titled "Selection of Diesel Generator Set Capacity for Standby Power Supplies," (Reference 8) are not affected by this change.

Comanche Peak Station conformance with Regulatory Guide 1.81, Revision 1, dated January 1975, titled "Shared Emergency and Shutdown Electric Systems for Multi-unit Nuclear Power Plants," is described in detail in Appendix 1A(B) to the FSAR (Reference 1). The Regulatory Guide guidance is to disallow "normal" sharing of systems such that "a reduction in the number and capacity of the on-site power sources to levels below those required for the same number of units located at separate sites," would not result.

Comanche Peak Station conformance with Regulatory Guide 1.93, Revision 0, dated December 1974, titled "Availability of Electric Power Sources," (Reference 2) is described in Appendix 1A(B) to the FSAR (Reference 1).

Conformance with Regulatory Guide 1.93 is affected by these proposed changes. Aside from the exception discussed above, the stations currently conform to the RG and specifically the position that the 72-hour Completion Time will not be entered for preventative maintenance of the EDGs. If the proposed changes are approved, the stations will continue to conform to RG 1.93 with the exception that the allowed Completion Time for restoration of an EDG will be increased to 14 days and will be used for EDG preventative maintenance.

Commitments to other key design criteria applicable to onsite electrical systems that would be unaffected by these proposed changes include: Regulatory Guide 1.53, dated June 1973, titled, "Application of Single-Failure Criterion to Nuclear Power Plant Protection Systems," (Reference 10) Regulatory Guide 1.62, dated October, 1973, titled "Manual Initiation of Protective Actions," (Reference 11) and Regulatory Guide 1.75, Revision 1, dated January 1975, titled "Physical Independence of Electrical Systems" (Reference 12).

4.1.1.2 Other Considerations

As discussed in the previous section, conformance with relevant regulatory guidance is not affected by this proposed change, with the exception of Regulatory Guide (RG) 1.93. The RGs cited in the previous section endorse industry standards. For example, Safety Guide 1.9 endorses Institute of Electrical and Electronic Engineers (IEEE) Standard 387-1984, "IEEE Standard for Diesel Generator Units Applied as Standby Power Supplies for Nuclear Generating Stations" (Reference 13).

Safety analysis acceptance criteria in the FSAR continue to be met. The proposed changes do not affect any assumptions or inputs to the safety analyses.

Unavailability of a single EDG due to maintenance does not reduce the number of EDGs below the minimum required to mitigate all DBAs. In addition, the proposed changes have no impact on the availability of the two off-site sources of power. The effect on FSAR acceptance criteria has been assessed assuming that one EDG is out of service and no additional failures on the maintenance unit occur. All safety functions continue to be available and acceptance criteria are met.

4.1.2 24 hour EDG Endurance Run On-Line

The SR specifying the 24-hour EDG endurance run (i.e., SR 3.8.1.14) is proposed to be revised to allow the SR to be performed during Modes 1 and 2. In addition, once the SR is revised, the 24-hour endurance run can also be performed on an operable diesel in Modes 1 and 2.

The justification for the proposed change to allow performance of the 24-hour run on-line is that the surveillance does not render any additional safety system or component inoperable. This SR is performed by paralleling the EDG being tested to offsite power similar to the requirements of SR 3.8.1.3, which is typically a four-hour EDG run performed during plant operation. Performing a 24-hour EDG endurance run, instead of a four-hour monthly load run, increases the amount of time the EDGs are paralleled with offsite power. The EDGs were designed for parallel testing and as such, design features, such as protective devices, were included. The change does not affect parallel testing design features, the consequences of postulated failures during parallel testing, and postulated interactions with offsite power during parallel testing. If problems are encountered during testing, the EDG will separate from the bus allowing the offsite circuit to continue to supply the bus. Failure to meet the SR when performed at power will result in an inoperable EDG, which in itself does not result in a challenge to plant safety systems.

Only one EDG per unit will be in parallel with the offsite source at a time in order to prevent any grid disturbances from potentially affecting more than one EDG. During the test, the remaining EDG will be available to respond normally to a start signal. The unit's remaining EDG is capable of supplying power to mitigate all DBAs. This test configuration is consistent with the configuration used during the monthly EDG tests.

The EDG system design includes emergency override of the test mode for both accident conditions (safety injection) and loss of offsite power (LOOP) to permit response to bona fide emergency signals and return control of the EDG to the automatic control system. The diesel generator breaker controls trip the breaker upon receipt of a safety injection signal concurrent with the EDG operating in the test mode.

Further justification is provided in that the amount of time that the EDGs will be inoperable will be reduced by improved maintenance scheduling permitted by the more flexible SR. The flexibility allows performing the 24-hour EDG endurance run in other than shutdown conditions when heavy and complex maintenance activities occur resulting in unavailability of equipment. In addition, the capability to safely complete emergency shutdown procedures following a DBA coincident with a single failure is maintained throughout the performance of the surveillance.

No actions will be taken to affect the operability of the unit's remaining EDG and its support systems throughout the surveillance test, and no actions will be taken to affect the capability of the onsite Class 1E AC electrical distribution system and its support systems to complete plant shutdown and maintain safe shutdown conditions following a DBA. If the EDG fails the 24-hour endurance test, it will be inoperable and the appropriate TS Required Actions will be taken.

Based on the above, although performance of the 24-hour EDG endurance test during power operation deviates from the ISTS (Reference 14), the performance of this test during power operation is consistent with the robust design features of the plant and is therefore acceptable. The conclusion is based on 1) the remaining EDG is available to respond to an EDG start signal and 2) a single EDG per unit has the capacity to mitigate the consequences of a DBA.

4.1.3 Offsite circuit (offsite circuit Startup Transformer) Completion Time Extension

As stated above in Section 4.1.1, two physically independent and redundant sources of offsite power are available on an immediate basis for the safe shutdown of either unit. The preferred source to Unit 1 is the 345-kV offsite supply from the 345-kV Switchyard and the startup transformer, XST2; the preferred source to Unit 2 is the 138-kV offsite supply from the 138-kV Switchyard and the startup transformer, XST1. Each of the startup transformers (XST1 and XST2) normally energizes its related 6.9 kV AC Class 1E buses; i.e., XST1 normally energizes Unit 2 Class 1E buses and XST2 normally energizes Unit 1 Class 1E buses. This eliminates the need for automatic transfer of safety-related loads in the event of unit trips. In the event one startup transformer (e.g., XST1, a preferred source) becomes unavailable to its normally fed class 1E buses, power is made available from the other startup transformer (e.g., XST2, an alternate source) by an automatic transfer scheme.

The unavailability of one startup transformer is already considered in the design. The increased outage time for a startup transformer has no affect on the capability of each transformer to supply the required safety-related loads of both units if it becomes necessary to safety shut down both units simultaneously, although the design criteria require consideration of a Design Basis Accident on one unit only.

4.1.4 AC Electrical Power Distribution Subsystem (6.9 kV AC safety bus) Completion Time Extension

Two independent and redundant 6.9 kV AC Class 1E buses are provided for each unit, each capable of supplying the required safety-related loads to safely shut down the unit following a DBA. Each Class 1E bus can be fed from two independent offsite power sources or the diesel generator assigned to the bus. Redundant safety-related loads are divided between Trains A and B so that loss of either train does not impair fulfillment of the minimum shutdown safety requirements. There are no manual or automatic connections between Class 1E buses and loads of redundant trains.

Safety-related (Class 1E) 6.9 kV AC buses 1EA1 and 1EA2 for Unit 1 and 2EA1 and 2EA2 for Unit 2 are fed directly from dedicated startup transformers XST1 and XST2. There are no interconnections between safety-related and non-safety-related 6.9 kV AC buses

All Class 1E buses are arranged in such a way that train A buses are electrically and physically isolated from train B buses to satisfy the single failure criteria.

The unavailability of one safety-related (Class 1E) 6.9 kV AC bus is already considered in the design. The increased outage time for a safety-related bus has no affect on the capability of each safety-related bus to supply the required safety-related loads of both units if it becomes necessary to safety shut down both units simultaneously, although the design criteria require consideration of a Design Basis Accident on one unit only.

4.1.5 Summary of Results and Conclusions of Deterministic Evaluation

For the increase Completion Times, for the EDG;s, startup transformers and the AC distribution buses, the plant remains in a condition for which the plant has already been analyzed: therefore, from a deterministic aspect, these changes are acceptable.

For the allowance to perform the EDG endurance test during power operations, the plant remains in a configuration for which the plant has already been analyzed except for EDG loading. The current Technical Specifications allow EDG loading while at power and connected to the offsite grid up to 7000kw for performance operability testing. This increase in loading has been found acceptable with respect to the offsite grid since the level of loading is currently allowed when the unit is shut down. Because of the robust nature of the EDG and its support systems this load level increase is also deterministically acceptable.

4.2 Evaluation of Risk Impact

The purpose of this section is to document the Probabilistic Safety Assessment (PRA) conducted in support of the Comanche Peak submittal of an allowed Completion Time extension request for 6.9 kV AC components. These components consist of the Diesel Generators (1EDG1, 1EDG2, 2EDG1, 2EDG2), offsite circuit startup transformers (XST1, XST2) and 6.9 kV AC safety buses (1EA1, 1EA2, 2EA1, 2EA2). Risk-informed changes to a nuclear power plant's licensing basis consist of both deterministic and probabilistic evaluations, as required by NRC Regulatory Guides 1.174 (Reference 4) and 1.177 (Reference 5). This Section documents the probabilistic evaluation and is intended to supplement the deterministic engineering evaluations described in Section 4.1

The risks associated with extending the Completion Time for these components during power operations (MODE 1) and the risks associated with these components being unavailable during shutdown were determined and compared. The Completion Time extensions for the Diesel Generators and the startup transformers are expected to be used to support maintenance activities. The extension for the 6.9 kV AC safety buses are expected to be used in the event maintenance is required.

This analysis evaluated extending the Diesel Generator Completion Time from 72 hours to 14 days. The EDG Completion Time will continue to be entered for the purpose of routine surveillance testing and other minor maintenance activities. It is anticipated that the EDG Completion Time will also be entered once a cycle for a longer period of time (greater than 72 hours) to support major EDG maintenance activities.

This analysis also evaluated extending the offsite circuit startup transformer Completion Time from 72 hours to 14 days. It is anticipated that the offsite circuit startup transformer Completion Time will be entered once per cycle to allow for testing or maintenance activities. The amount of time spent in the LCO is expected to last longer than 72 hours when major maintenance activities are required.

A 72 hour Completion Time extension was assessed for the 6.9 kV AC safety buses from the current 8-hour limit (Technical Specification 3.8.9). It is anticipated that this Completion Time will be entered to support maintenance activities.

The probabilistic evaluations presented in the following sections support the allowed Completion Time extension request for 6.9 kV AC components (Emergency Diesel Generators, offsite circuit startup transformers, and 6.9 kV AC safety buses). The results of the evaluations presented herein justify extending the allowed Completion Times for these components. The risk methods employed are detailed in Section 4.2.1, followed by a discussion on PRA quality in Section 4.3. The analysis tasks and results are presented in Sections 4.2.1 and 4.2.2, respectively.

4.2.1 Overall Methodology

This section describes the CPSES PRA model for internal events and provides a description of the overall methodology that was used for the PRA analysis in support of this submittal and the features of the CPSES PRA model that were used in the analysis are also described. In general, the overall methodology is designed to address the considerations described in the Regulatory Guides 1.174 and 1.177.

Description of the CPSES PRA Model

The CPSES PRA model for internal events is an all-modes model that allows quantification of configurations to determine core damage frequency and large early release frequency at power (mode 1), in transition (modes 2 through 4) and shutdown (modes 5 and 6, shutdown address only CDF). The CPSES PRA model for internal events also includes spent fuel pool modeling for core-off load configurations. A description of the CPSES PRA model pedigree is provided in section 4.3.

Data Review and Model Evaluation

In general, PRA and deterministic data related to the affected components were reviewed. For the probabilistic portion, this consisted of PRA elements that directly model the component and also related supporting documents that implicitly impact how the PRA was constructed or developed. Consideration was given to each of the PRA tasks in order to define what documents to be reviewed in more detail.

Information collected and reviewed in support of the 6.9 kV AC component Completion Time evaluation are listed below.

- Comanche Peak Full Power & Shutdown PRA analysis files and computer model.
- Reactor Coolant Pump Seal LOCA model.
- EDG common cause failure modeling data and techniques.
- Loss of Offsite Power Initiating Event Frequency and post-initiator plant response.
- Station Blackout Initiating Event Frequency and post-initiator plant response.
- Emergency Operating Procedures.
- Maintenance Rule data for the EDG.
- Maintenance Rule data for the affected components (with historical outage times).
- Detailed refueling outage schedule.

The scope of the existing PRA was compared with the intended application. For the 6.9 kV AC components, there are two key areas: (1) review aspects of the PRA model related to 6.9 kV AC electrical power to ensure high quality standards for the submittal; and (2) review the RCP seal LOCA model to ensure integrity and completeness. The 6.9 kV AC system fault tree models and reliability data for the EDGs were reviewed. This review included common cause failure parameters, unavailability parameters, failure rates, and level of detail of the system models. Similarly, the CPSES Loss of Offsite Power (LOOP) and Station Blackout (SBO) models were reviewed.

The review of the PRA model to ensure high quality standards is required for all risk-informed submittals under Regulatory Guide 1.174. The review of the RCP Seal LOCA model is required when the utility has not incorporated the Brookhaven RCP Seal LOCA model. For this submittal, TXU reviewed the EDG reliability data, the Loss of Offsite Power and Station Blackout sequences, and the RCP seal LOCA model using the Westinghouse Owners Group certification guidelines. The key areas reviewed are summarized below.

1. The 6.9 kV AC system fault tree models and reliability data for the EDGs were reviewed against the WOG review criteria. Minor modifications to the models and enhancements to the documentation needed to meet the PRA quality review criteria described later in this section.

2. The CPSES Loss of Offsite Power (LOOP) and Station Blackout (SBO) models were also reviewed. Specifically, the LOOP frequency, LOOP recovery models, and the LOOP/SBO event trees were reviewed against the WOG review criteria. It was concluded that the LOOP and SBO modeling are detailed and appropriate. Additionally, the impact of a higher LOOP initiating event frequency was evaluated and it was concluded that although the risk of both full power and shutdown will increase linearly (with an increase in initiating event frequency), the delta between power and shutdown will remain constant. Therefore, the increased LOOP initiating event frequency does not change the conclusion of the evaluation and the proposed Completion Time extension.

3. It was confirmed that the existing RCP seal LOCA model contains all of the failure modes identified in the USNRC-approved Brookhaven RCP Seal LOCA model. The impact of using the Brookhaven RCP Seal LOCA model was then examined as a sensitivity analysis. This sensitivity analysis showed an increase in the baseline risk if the Brookhaven RCP Seal LOCA model is used. The use of the revised RCP seal LOCA model would cause an increase in risk for the full power plant state but would have no impact on the cold shutdown (Modes 5 and 6) plant states. While the delta risk decreases, it is still less than the change in CDF due to shifting the major EDG maintenance activities from shutdown to full power. Thus, the conclusions of this study remain unchanged and the proposed Completion Time extensions are supported.

PRA Model Modifications

The following modifications to the CPSES PRA model were identified during the supporting document review process. The modified CPSES PRA model and its associated databases were imported into the Safety Monitor™ computer program to allow for easier quantification of various configurations required to support this submittal. Baseline comparisons of the Safety Monitor model baseline results and the CPSES PRA model (evaluated using the EPRI- CAFTA™ code) baseline results were completed and indicated good correlation between the two quantification methods.

During the evaluation process, the quantification runs that were performed to calculate CDF and LERF values were based on average test and maintenance values. In addition, to support the analysis, the data associated with certain basic events in the shutdown model were revised to allow the model to evaluate only the risk associated with damage to the fuel in the reactor vessel and to not consider the fuel in the fuel pool. The plant response modeling for the Spent Fuel Pool is bounded by the CPSES PRA internal events model since the Loss of Offsite Power and Station Blackout modeling contains the same progression.

Minor fault tree logic modifications were made to allow evaluation of an electrical cross-tie to the 6.9kV AC bus on the opposite unit if needed to meet the Regulatory Guides acceptance criteria. This modeling has been implemented as a single basic event in order to provide a bounding calculation on the maximum benefit that such a cross-tie could potentially achieve. The actual benefit would be somewhat less using a more detailed model that addressed dependencies with the EDGs on the unaffected unit.

The CPSES PRA internal events model does not include contributions from internal fires, internal floods, seismic events and other external events. However, due to the common cause nature of these events and the fact that increased allowed Completion Times only impact the risk contributions of independent component unavailabilities, inclusion of floods, fires and external events would not impact the conclusions of this evaluation. While such contributions, if added would make small contributions to the base CDF, the change in CDF or LERF due to the increased allowed Completion Times would be unaffected.

Analysis Assumptions

The following assumptions were used in performing the analysis:

1. The incremental CDF and LERF are calculated by assuming the affected component is in maintenance for the entire Completion Time duration. Component outage in the opposite train is not allowed (this would generally lead to Technical Specification 3.0.3 condition). However component outage in the affected train is allowed and thus two cases are considered as described in Section 4.2.2.

2. The evaluation is based on the assumption that the extended allowed Completion Time would be applied to only one major maintenance activity per EDG per refueling cycle. The cycle time is based on the current 18-month fuel cycle and an assumed total planned and unplanned outage duration of 30 days, which yields $T_{CYCLE} = 518$ days.

3. The Completion Time extensions for the startup transformers are expected to be used only for major maintenance activities. Therefore, the extended Completion Time should be used no more than once per year. The increase in CDF and LERF as a result of the change is therefore the ICCDP and ICLERP for the configuration calculated below. The Completion Time extension for the 6.9 kV AC buses is expected to be used only for maintenance activities and again is not anticipated to be used more frequently than once per year.

4. The CPSES Loss of Offsite Power and RCP seal LOCA model will be considered as the base case. It was confirmed that the existing RCP seal LOCA model contains all of the failure modes identified in the USNRC-approved Brookhaven RCP Seal LOCA model. Sensitivity studies will examine the impact of implementing the Brookhaven RCP seal LOCA model and evaluating the impact of varying Loss of Offsite Power initiating event frequency.

5. The impact of the proposed Completion Time changes will be evaluated by the CPSES PRA internal events model. Basic events in the shutdown model were revised to allow the model to evaluate only the risk associated with damage to the fuel in the reactor vessel and to not consider the fuel in the fuel pool. The plant response modeling for the Spent Fuel Pool is bounded by the CPSES PRA internal events model since the Loss of Offsite Power and Station Blackout modeling contains the same progression.

6. The planned outage schedule from the 7th Unit 1 refueling outage is representative of future outages and thus provides the baseline for expected mode durations.

7. It was confirmed that the design basis of the plant is based on two safety-related diesel generators. Even though CPSES has in the past made the conservative decision to bring

in a non-safety related temporary diesel generator during a refueling outage, for the purpose of this analysis it was not credited since the analysis compares the design bases at power versus shutdown. Some of the refueling outages conducted to date have been conducted using only the two safety-related diesels.

Evaluation Criteria

To determine the effect of the proposed allowed Completion Time for restoration of an inoperable EDG, the guidance suggested in Regulatory Guides 1.174 and 1.177 (References 4 and 5) was used. Thus, the following risk metrics were used to evaluate the risk impacts of extending the EDG allowed Completion Time (similar risk metrics were used for the other 6.9 kV AC Components).

ΔCDF_{AVE} = The change in the annual average CDF due to any increase in on-line maintenance unavailability of the EDGs that could result from the increased allowed Completion Time. This risk metric is used to compare against the criteria of RG 1.174 to determine whether a change in CDF is regarded as risk significant. These criteria are a function of the baseline annual average core damage frequency, $CDF_{BASE.}$

$\Delta LERF_{AVE}$ = The change in the annual average LERF due to any increase in on-line maintenance unavailability of the EDGs that could result from the increased allowed Completion Time. RG 1.174 criteria are also applied to judge the significance of changes in this risk metric.

$ICCDP\{EDGxY\}$ = The incremental conditional core damage probability with EDG Y for Unit X out-of-service for a period equal to the proposed new allowed Completion Time. This risk metric is used as suggested in RG 1.177 to determine whether a proposed increase in allowed Completion Time has an acceptable risk impact.

$ICLERP\{EDGxY\}$ = The incremental conditional large early release probability with EDG Y for Unit X out-of-service for a period equal to the proposed new allowed Completion Time. RG 1.177 criteria are also applied to judge the significance of changes in this risk metric.

The evaluation was based on the assumption that the extended allowed Completion Time would be applied to only one major overhaul per EDG per refueling cycle. The cycle time was based on the current 18-month fuel cycle and an assumed total planned and unplanned outage duration of 30 days, which yields T_{CYCLE} = 518 days.

The incremental conditional core damage probability (ICCDP) and incremental conditional large early release probability (ICLERP) are computed per the definitions from RG 1.177 (Reference 5). In terms of the parameters defined above, the definition of ICCDP is as follows:

$$ICCDP_{xA} = (CDF_{xAOOS} - CDF_{xBASE})T_{CT}$$
$$ICCDP_{xA} = (CDF_{xAOOS} - CDF_{xBASE}) * (14 days) * (365 days / year)^{-1}$$
$$ICCDP_{xA} = (CDF_{xAOOS} - CDF_{xBASE}) * 3.84x10^{-2} / year$$

Note that in the above formula 365 days/year is merely a conversion factor to make the units for allowed Completion Time consistent with the units for CDF frequency. The ICCDP values are dimensionless incremental probabilities of a core damage event over a period of time equal to the extended allowed Completion Time. This should not be confused with the evaluation of ΔCDF_{xAVE} in which the CDF is averaged over an 18-month refueling cycle.

Similarly, ICLERP is defined as follows.

$$ICLERP_{xA} = (LERF_{xAOOS} - LERF_{xBASE}) * 3.84x10^{-2} / year$$

4.2.2 Evaluation

The CPSES PRA internal events model was used to evaluate the Diesel Generator Completion Time extension. A similar set of runs was then conducted for the offsite circuit transformers and safety buses, with any differences described below. All of the runs were quantified using the Safety Monitor™ computer program.

- Baseline CDF with average unavailabilities for all components before and after the proposed EDG Completion Time.
- Baseline LERF with average unavailabilities for all components before and after the proposed EDG Completion Time.
- Conditional Core Damage Probability with each of components to be evaluated out of service for the proposed Completion Time, in this case a 14 day Completion Time.
- Conditional Large Early Release Probability with each of components to be evaluated out of service for the proposed Completion Time, in this case a 14 day Completion Time.

If the initial analysis of the change in core damage frequency, change in large early release frequency, incremental conditional core damage probability, and incremental conditional large early release probability show a decrease or minimal risk increase, then no additional runs were performed. If any of these parameters shows a significant risk increase, then additional runs were performed as described below. The acceptance criteria for the changes in risk come from Regulatory Guide 1.174.

The Core Damage Frequency (CDF) and Large Early Release Frequency (LERF) with average Test and Maintenance probabilities were calculated for the subject components. The incremental CDF and LERF were calculated while exercising the requested Completion Time. This was done with the Safety Monitor™ computer program. The initial PRA analysis followed the steps listed below. Each step included calculation of the overall change in CDF and LERF as well as the incremental change in CDF and LERF. That is, there were four risk numbers calculated for each step. The overall CDF and LERF are calculated using the average unavailabilities for all components including the EDGs. For this calculation, test and maintenance combinations disallowed by Technical Specifications were deleted from the results. The incremental CDF and LERF were calculated by assuming an EDG was in maintenance for the entire Completion Time duration. Component outage in the opposite train was not allowed (this would generally lead to Technical Specification 3.0.3 condition). However component outage in the affected train was allowed and thus two cases were considered. The desirable case is to allow component outage in the affected train and this was the first case analyzed. If this risk was unacceptable, then a second calculation was done with only the EDG out for maintenance.

1. Quantitative Full Power Internal Events and Qualitative External Events/Shutdown Check. The Completion Time submittal development initially examined a submittal based on a quantitative analysis of Full Power internal events only. The general argument to be examined for shutdown is that the risk can only improve because the maintenance of the affected component will be moved out of shutdown, thereby increasing the redundancy of available safety equipment for all of shutdown. If the increase in risk due to the increased Completion Time is acceptable based only on the analysis in this step, no further analysis was necessary. If the risk is unacceptable, the following steps were considered.

2. Quantitative Check of Transition Risk to/from Shutdown. The transition risk model used to support this analysis evaluated the impact of corrective maintenance at power requiring shutdown to cold plant conditions to correct. Then the risk associated with on-line maintenance while the corrective action is being performed can be compared with the risk associated with the transition to shutdown with the component being unavailable, plus the risk associated with conducting the maintenance while in cold shutdown, and the risk associated with the transition back to full power.

3. Quantitative Full Power and Shutdown Internal Events and Qualitative External Events. If the Full Power quantitative data (alone) shows a large risk increase, then the shutdown model was quantified for the modes in which the major EDG maintenance activities would have been done. The decrease in risk during shutdown is then quantified to show there is an overall decrease in risk by moving the major EDG maintenance activities from shutdown to power operation. As with step 1, this case is analyzed with and without component outage in the affected train.

A similar analysis was performed for removal of a startup transformer from service (14 day) and for removal of a 6.9 kV AC emergency bus (72 hour). The risk increase for all of the 6.9 kV AC components was found to be acceptable, accounting for the shutdown operation, therefore it was unnecessary to develop an alternate power source such as implementing an EDG cross-tie from the other unit.

Evaluation of EDG Completion Time

The proposed Completion Time evaluated for the diesel generators is 14 days. This evaluation was done using the methodology described above. The equations defined under section 4.2.1 were used for the evaluation cases described below. A shutdown schedule was evaluated using the appropriate time duration for the plant operating states during which major EDG maintenance activities are normally conducted. The shutdown model (Modes 5 and 6) does not evaluate LERF because industry shutdown models do not normally include a calculation of LERF. Little is known for the physics or the dynamics of scenarios resulting in a Large Early Release following shutdown initiating events. The containment is either closed, or can be closed prior to boiling.

The EDG Completion Time will continue to be entered for the purpose of routine surveillance testing and other minor maintenance activities. It is anticipated that the EDG Completion Time will also be entered once a cycle for a longer period of time (greater than 72 hours) to support major EDG maintenance activities. The increase in CDF and LERF as a result of the change is therefore the ICCDP and ICLERP for the configuration calculated below.

The Diesel Generator evaluation includes a comparison of the risk associated with a 14-day EDG unavailability at power with a 14-day EDG unavailability during a normal refueling outage. The refueling outage evaluation assumes that the EDG is removed from service upon reaching Mode 5. The schedule used for the evaluation is taken from the 7^{th} Unit 1 refueling outage (1RF07) which is representative of a typical outage. The subscripts for ICCDP and ICLERP shown below represent the case numbers from Table 1, located at the end of this section.

At Power,
$ICCDP_{102A}$ = 3.74E-06 and $ICLERP_{102A}$ = 4.88E-7 Mode 1 Power

During a Refueling Outage,
$ICCDP_{132}$ = 8.25E-6 Mode 5 Cold Shutdown
$ICCDP_{133}$ = 6.09E-5 Mode 5 1' below Flange
$ICCDP_{134}$ = 3.78E-5 Mode 5 Midloop
$ICCDP_{135}$ = 1.77E-7 Mode 6 Refueling Basin Flooded for Core Unload
$ICCDP_{\Sigma 132-135}$ = 1.07E-4

During a Forced Maintenance Shutdown,

$ICCDP_{150}$ = 5.44E-7	$ICLERP_{150}$ = 7.10E-8	Mode 1 Power
$ICCDP_{151}$ = 1.45E-7	$ICLERP_{151}$ = 1.88E-8	Mode 3 Hot Standby (Early)
$ICCDP_{152}$ = 4.04E-8	$ICLERP_{152}$ = 5.30E-9	Mode 4 Hot Shutdown (Early)
$ICCDP_{153}$ = 8.70E-7		Mode 5 Cold Shutdown
$ICCDP_{154}$ = 4.64E-9	$ICLERP_{154}$ = 1.41E-9	Mode 4 Hot Shutdown (Late)
$ICCDP_{155}$ = 8.82E-8	$ICLERP_{155}$ = 9.89E-9	Mode 3 Hot Standby (Late)

$ICCDP_{156}$ = 1.21E-8 $ICLERP_{156}$ =1.73E-9 Mode 2 Reactor Startup
$ICCDP_{\Sigma 150\text{-}156} = ICCDP_{MAINTOUT}$
$ICCDP_{MAINTOUT}$ = 1.7E-6 $ICLERP_{MAINTOUT}$ = 1.08E-7 (not including Mode 5)

As shown in the above calculation, the risk of performing a 14-day diesel generator unavailability with the plant at power (ICCDP = 3.74E-06) is less than the risk of performing the same work with the plant in the early stages of a refueling outage as it is presently performed (ICCDP = 1.07E-4). The risk associated with a plant shutdown to perform emergent corrective maintenance (ICCDP = 1.7E-6) is of the same order of magnitude as keeping the plant at power to perform the maintenance. The outage ICCDP and ICLERP values above represent the results for the configurations at various stages of the outage. The final ICCDP and ICLERP represent the summation of the states during the outage and is the total risk associated with the component being out of service. The example above is based on the A Train EDG, comparable results were concluded for the Train B EDG.

The results of these analyses allow a comparison of the change in risk for conducting a 14 day EDG maintenance at power with the risk of conducting the same EDG maintenance during a refueling outage and a forced maintenance. It indicates that the net change in core damage probability is reduced when the diesel generator maintenance is moved from the outage to power.

Evaluation of XST1/XST2 Completion Time

The proposed Completion Time evaluated for the startup transformers is 14 days. This evaluation was done using the methodology described above. The equations defined under section 4.2.1 were used for the evaluations cases described below.

It is anticipated that the offsite circuit startup transformer Completion Time will be entered once per cycle to allow for testing or maintenance activities. The amount of time spent in the LCO is expected to last longer than 72 hours when major maintenance activities are required. The increase in CDF and LERF as a result of the change is therefore the ICCDP and ICLERP for the configuration calculated below.

An evaluation of risk associated with a startup transformer outage with the plant in a shutdown condition was not performed. The startup transformers feed both Unit 1 and Unit 2; therefore, simultaneous outages on both units are not normally scheduled.

If the XST1 startup transformer is taken out of service for maintenance, it affects both units since transformer XST1 functions as a back-up to XST2. The increase in risk results in an additional CDF contribution of approximately 3.63E-08/year and an additional LERF contribution of approximately 4.37E-09/year. The at power ICCDP and ICLERP values calculated are shown below. The subscripts for ICCDP and ICLERP shown below represent the case numbers from Table 1, located at the end of this section.

$ICCDP_{104A} = 9.48E\text{-}7$
$ICLERP_{104A} = 1.14E\text{-}7$

The risk increase associated with this proposed Completion Time extension is considered small, according to the guidelines contained in Regulatory Guide 1.174. Based on the risk graphs in Regulatory Guide 1.174, these values indicate that the change in core damage probability and large early release probability is not considered significant when startup transformer maintenance is completed at power. The example above is based on the XST1 transformer, results for the XST2 transformer are comparable.

Evaluation of 1EA1/1EA2 and 2EA1/2EA2

The proposed Completion Time evaluated for the 6.9 kV AC buses 1EA1 and 1EA2 is 72 hours. This evaluation was done using the methodology described above. The equations defined under section 4.2.1 were used for the evaluations cases described below.

A 72 hour Completion Time extension was assessed for the 6.9 kV AC safety buses from the current 8-hour limit (Technical Specification 3.8.9). It is anticipated that this Completion Time will be entered to support maintenance activities.

The 6.9 kV AC bus evaluation includes a comparison of a 72-hour bus outage at power with the transition and shutdown risk associated with a forced shutdown to perform repairs to the bus. The forced outage evaluation includes evaluation of the shutdown with the bus inoperable and also includes the transition risk associated with plant restart to power.

As shown below, the risk associated with a plant shutdown to perform emergent corrective maintenance is an order of magnitude higher than keeping the plant at power to perform the maintenance. The forced outage ICCDP and ICLERP values below represent the results for the configurations at various stages of the outage. The final ICCDP and ICLERP represent the summation of the states during the outage and are the total risk associated with the component being out of service. The subscripts for ICCDP and ICLERP shown below represent the case numbers from Table 1, located at the end of this section.

At Power,
$ICCDP_{106A}$ = 1.93E-6 and $ICLERP_{106A}$ = 2.15E-7

During a Forced Maintenance Shutdown the following plant states,

$ICCDP_{160}$ = 3.74E-7	$ICLERP_{160}$ = 4.19E-8	Mode 1 Power
$ICCDP_{161}$ = 4.32E-7	$ICLERP_{161}$ = 4.75E-8	Mode 3 Hot Standby (Early)
$ICCDP_{162}$ = 2.85E-7	$ICLERP_{162}$ = 3.34E-8	Mode 4 Hot Shutdown (Early)
$ICCDP_{163}$ = 5.66E-5		Mode 5 Cold Shutdown
$ICCDP_{154}$ = 4.64E-9	$ICLERP_{154}$ = 1.41E-9	Mode 4 Hot Shutdown (Late)
$ICCDP_{155}$ = 8.82E-8	$ICLERP_{155}$ = 9.89E-9	Mode 3 Hot Standby (Late)
$ICCDP_{156}$ = 1.21E-8	$ICLERP_{156}$ =1.73E-9	Mode 2 Reactor Startup

$ICCDP_{\Sigma 160\text{-}163+\Sigma 154\text{-}156}$= $ICCDP_{MAINTOUT}$
$ICCDP_{MAINTOUT}$ = 5.78E-5 $ICLERP_{MAINTOUT}$ = 1.36E-7(not including Mode 5)

The results of these analyses allow a comparison of the change in risk for conducting a 72 hour maintenance outage on 6.9kV bus at power with the risk of conducting the same maintenance during a forced maintenance outage. It indicates that the net change in core damage probability is reduced when the 6.9kV bus maintenance is completed at power rather than during a forced shutdown and therefore presents a lower overall risk.

4.2.3 Sensitivity Studies

For this submittal, TXU reviewed the Loss of Offsite Power and Station Blackout sequences, and the RCP seal LOCA modeling using the Westinghouse Owners Group certification guidelines. The associated sensitivity studies are summarized below.

Sensitivity Cases 110A and 110B

Sensitivity cases 110A and 110B were run to determine the effect of a higher Loss of Offsite Power initiating event frequency. The normal value for INIT-X3 is 0.0395/year and for the sensitivity analysis, this value was changed to0.052/year. The value used for the sensitivity is the frequency used by another plant in this region and is on the higher end of the Loss of Offsite Power initiating event frequencies cited in NUREG/CR-5496, Evaluation of Loss of Offsite Power Events at Nuclear Power Plants: 1980-1996, November 1998. The results of this sensitivity show that the CDF rises as the Loss of Offsite Power initiator frequency is increased. A higher loss of offsite power initiating event frequency affects both full power and shutdown. Since both the full power and shutdown risk increase linearly, the delta between full power and shutdown risk remains constant. Thus, an increased loss of offsite power initiating event frequency does not change the conclusions of this analysis and the proposed Completion Time extensions are supported.

Sensitivity Cases 111A and 111B

Sensitivity cases 111A and 111B were run to determine the effect of implementing the Brookhaven RCP Seal LOCA model. The nominal value of the basic events associated with various seal failure modes were change to reflect the values defined in Brookhaven RCP Seal LOCA model. This sensitivity shows an increase in the baseline risk if the Brookhaven RCP Seal LOCA model is used. A revised RCP seal LOCA model would cause an increase in risk for the full power plant state but have no impact on the cold shutdown (Modes 5 and 6) plant states. While the delta risk decreases, it is still less than the change in CDF due to shifting the major EDG maintenance activities from shutdown to full power. Thus, the conclusions of this study remain unchanged and the proposed Completion Time extensions are supported.

Sensitivity Cases 101BX5, 102CX5, and 103DX5

Sensitivity cases 101BX5, 102CX5, and 103DX5 were run to assess the potential benefit of having an electrical cross- tie between Unit 1 and Unit 2 that could be used to supply power from a Unit 2 emergency switchgear to a Unit 1 emergency switchgear. For these cases, the probability of failure to successfully establish the cross-tie was set to a value of 0.5 (basic event XTIEFAILS). For all other runs, this basic event was set to a failure probability of 1.0. This sensitivity was conducted to evaluate the change in risk if a plant modification to install a diesel cross-tie was implemented. Each of the runs showed a 30% to 50% reduction in risk with the cross-tie installed. It should be noted that this is the largest change in risk that could be reasonably achieved since the simplified modeling of the sensitivity case does not include dual unit diesel dependencies, and does not evaluate the mechanical failures associated with the cross-tie itself. While the electrical cross-tie shows a potentially significant risk decrease, the risk benefit of extending the Completion Time without crediting the currently non-existent cross-tie is still significant. The analysis shows a decrease in CDF when the major EDG maintenance activities are shifted from shutdown to full power, with or without the cross-tie capability. Thus, the conclusions of this study remain unchanged and the proposed Completion Time extensions are supported.

4.2.4 Restriction on High Risk Configuration

To avoid or reduce the potential for risk-significant configurations from either emergent or planned work, CPSES has put in place a set of administrative guidelines that go beyond the limitations set forth in the plant Technical Specifications. These guidelines control configuration risk by assessing the risk impact of equipment out-of-service during all modes of operation to assure that the plant is always being operated within acceptable risk guidelines.

CPSES employs a conservative approach to at power maintenance. The weekly schedules are train/channel based and prohibit the scheduling of opposite train activities without additional review, approvals and/or compensatory actions. The assessment process further minimizes risk by restricting the number and combination of systems/trains allowed to be simultaneously unavailable for scheduled work.

Unplanned or emergent work activities are factored into the plant's actual and projected condition, and the level of risk is evaluated. Based on the result of this evaluation, decisions pertaining to what action, if any, are required to achieve an acceptable level of risk (component restoration or invoking compensatory measures) are made. The unplanned or emergent work activities are also evaluated to determine impact on planned activities and the affect the combinations would have on risk.

Technical Specification 5.5.18, "Configuration Risk Management Program (CRMP)," will apply to this license amendment request and is repeated below for information:

> The Configuration Risk Management Program (CRMP) provides a proceduralized risk-informed assessment to manage the risk associated with equipment inoperability. The program applies to technical specification structures, systems, or components for which a risk-informed allowed Completion Time has been granted. The program shall include the following elements:
>
> a. Provisions for the control and implementation of a Level 1, at-power, internal events PRA-informed methodology. The assessment shall be capable of evaluating the applicable plant configuration.
>
> b. Provisions for performing an assessment prior to entering the LCO Action for preplanned activities.
>
> c. Provisions for performing an assessment after entering the LCO Action for unplanned entry into the LCO Action.
>
> d. Provisions for assessing the need for additional actions after the discovery of additional equipment out of service conditions while in the LCO Action.
>
> e. Provisions for considering other applicable risk significant contributors such as Level 2 issues, and external events, qualitatively or quantitatively.

<u>Risk-Significant Components Given A 6.9kv AC Component Is Out Of Service</u>

This list of risk significant components associated with each of the associated of the 6.9kV components being considered for Completion Time extension was obtained by using the Safety Monitor™ "Important Operable Components" option. This option identifies those components whose risk values contribute the most to the overall risk of the configuration. The category of components are summarized below, rather than presenting a long list of individual components identifiers.

Risk Significant Components Given a Diesel Generator is out of Service

The following provides a list of the risk significant components and /or systems given that a Diesel Generator is out of service. The list provides those components and / or systems whose simultaneous unavailability would likely place the plant in a high-risk configuration, based upon their Risk Achievement Worth (RAW) value (i.e., the increase in risk if the component is assumed to be failed at all times, expressed as a ratio of assumed risk to baseline risk). These are not necessarily in ranked order.

- Electric Power - opposite train motive and control power
- Refueling Water Storage Tank - Tank and its associated discharge valves
- Service Water - opposite train
- Emergency Diesel Generator - opposite train

Risk Significant Components Given a Startup Transformer is out of Service

The following provides a list of the risk significant components and /or systems given that a Startup Transformer is out of service. The list provides those components and / or systems whose simultaneous unavailability would likely place the plant in a high-risk configuration, based upon their RAW value. These are not necessarily in ranked order.

- Electric Power – AC and DC power distribution, both trains
- The redundant Startup Transformer
- Service Water - Both trains
- Emergency Diesel Generators

Risk Significant Components Given a 6.9kV Bus is out of Service

The following provides a list of the risk significant components and /or systems given that a 6.9 kV bus is out of service. The list provides those components and / or systems whose simultaneous unavailability would likely place the plant in a high-risk configuration, based upon their RAW value. These are not necessarily in ranked order.

- Electric Power - opposite train motive and control power
- Refueling Water Storage Tank - Tank and its associated discharge valves
- Service Water - opposite train
- Emergency Diesel Generator - opposite train
- Component Cooling Water – opposite train
- Charging System – Opposite Train
- Turbine Driven AFW Pump
- RHR System – Opposite Train

4.2.5 Summary of Results and Conclusions of Risk Evaluation

The probabilistic evaluations presented above support the allowed Completion Time extension request for 6.9 kV AC components including the Emergency Diesel Generators (EDGs), offsite circuit startup transformers, and 6.9 kV AC safety buses. The results of the evaluations presented herein justify extending the allowed Completion Times for these components.

Specifically, the risk of performing a 14-day diesel generator maintenance activity at power is less than the risk of performing the same work with the plant in the early stages of a refueling outage (as it is presently performed). The risk associated with a plant shutdown to perform emergent corrective maintenance on the EDG is of the same order of magnitude as keeping the plant at power to perform the maintenance.

If a startup transformer is taken out of service for maintenance, it affects both units since transformer XST1 functions as a back-up to XST2. The increase in risk results in an additional CDF contribution of approximately 3.63E-08/year and an additional LERF contribution of approximately 4.37E-09/year. The risk increase associated with this proposed Completion Time extension is considered small, according to the guidelines contained in Regulatory Guide 1.174. Based on the risk graphs in Regulatory Guide 1.174, these values indicate that the change in core damage probability and large early release probability is not considered significant when startup transformer maintenance is completed at power.

Finally, the risk associated with a plant shutdown to perform emergent corrective maintenance is an order of magnitude higher than keeping the plant at power to perform the maintenance. The results of the analyses allow a comparison of the change in risk for conducting a 72 hour maintenance outage on 6.9kV bus at power with the risk of conducting the same maintenance during a forced maintenance outage. It indicates that the net change in core damage probability is reduced when the 6.9kV bus maintenance is completed at power rather than during a forced shutdown and therefore presents a lower overall risk.

<u>Summary</u>

TXU Electric has concluded, based on the considerations discussed above, that: (1) there is reasonable assurance that the health and safety of the public will not be endangered by operation in the proposed manner; (2) such activities will be conducted in compliance with the Commission's regulations; and (3) the issuance of the amendments will not be inimical to the common defense and security or to the health and safety of the public.

Table 1 – Comanche Peak 6.9 kV AC Completion Time PRA Results Summary

CASE ID	COMPONENT	ICCDP	ICLERP	ΔCDF (per yr.)	ΔLERF (per yr.)	COMMENTS
101A	(Baseline-all equipment operable, TM=0)					Baseline CDF=1.17E-5/yr, Baseline LERF=1.59E-6/yr.
102A	"A" Train EDG: 1EDG1, 2EDG1 with 14 day Completion Time	3.74E-6	4.88E-7	9.73E-5	1.27E-5	Full Power calculated with 1EA1 EDG inoperable. All TM events 0.
132-135		1.07E-4	N/A		N/A	Refueling Outage calculated with 1EA1 EDG inoperable when Mode 5 starts.
150-156		1.70E-6	1.08E-7			Forced Maintenance Outage to Cold Shutdown calculated with 1EA1 EDG inoperable.
"A" EDG		Performing the maintenance at power (Mode 1) rather than during shutdown (refueling outage) presents a lower overall risk and thus shifting the EDG-A maintenance to online is acceptable.				
103A	"B" Train EDG: 1EDG2, 2EDG2 with 14 day Completion Time	3.74E-6	4.88E-7	9.73E-5	1.27E-5	Full Power calculated with 1EA2 EDG inoperable. All TM events 0.
142-145		3.91E-6	N/A		N/A	Refueling calculated with 1EA2 EDG inoperable when Mode 5 starts.
250-253 & 154-156		9.82E-6	1.08E-7			Forced Maintenance Outage to Cold Shutdown calculated with 1EA2 EDG inoperable.
"B" EDG		Performing the maintenance at power (Mode 1) rather than during shutdown (refueling outage) presents a lower overall risk and thus shifting the EDG-A maintenance to online is acceptable.				
104A	XST1 Transformer with 14 day Completion Time	9.48E-7	1.14E-7	2.47E-5	2.98E-6	Full Power calculated with XST1 Transformer inoperable, all TM events 0, switchyard work indirect effect. The risk increase is considered small, according to Reg Guide 1.174, within Region II of the acceptance guidelines charts.
105A	XST2 Transformer with 14 day Completion Time	1 24E-6	1.46E-7	3.24E-5	3.81E-6	Full Power calculated with XST2 Transformer inoperable, all TM events 0, switchyard work indirect effect. The risk increase is considered small, according to Reg Guide 1.174, within Region II of the acceptance guidelines charts.
106A	6.9 kV AC Bus 1EA1, 2EA1 with 72 hour Completion Time	1.93E-6	2.15E-7	2.34E-4	2.62E-5	Full Power calculated with 6.9kv bus 1EA1 inoperable, all TM events 0.
160-163 & 154-156		5.78E-5	1.36E-7			Forced Maintenance Outage to Cold Shutdown calculated with 1EA1 6.9 kV AC bus inoperable.
"A" Bus		Performing the maintenance at power rather than during shutdown presents a lower overall risk.				
107A	6.9 kV AC Bus 1EA2, 2EA2 with 72 hour Completion Time	2.02E-6	2.28E-7	2.45E-4	2.77E-5	Full Power calculated with 6.9kv bus 1EA2 inoperable, all TM events 0.
260-263 & 154-156		7.10E-5	1.38E-7			Forced Maintenance Outage to Cold Shutdown calculated with 1EA2 6.9 kV AC bus inoperable.
"B" Bus		Performing the maintenance at power rather than during shutdown presents a lower overall risk.				

Sensitivity Cases						
101BX5	(Baseline CDF & LERF Sensitivity)	CDF= 1.34E-5 per yr	LERF= 1.69E-6 per yr			Sensitivity = Baseline CDF with Electrical Cross-Tie. All equipment operable, average TM. With unit electrical cross-tie capability w/ .5 cross-tie fail rate.
102C	"A" Train EDG CDF & LERF Sensitivity	CDF= 1.12E-4 Per yr	LERF= 1.47E-5 per yr	9.83E-5	1.29E-5	Sensitivity = Full Power with "A" Train EDG inoperable. "A" Train average TM, "B" Train all TM 0.
102CX5	"A" Train EDG CDF & LERF Sensitivity	CDF= 5.75E-5 per yr	LERF= 7.57E-6 Per yr			Sensitivity = Full Power with "A" Train EDG inoperable. "A" Train average TM, "B" Train all TM 0. With unit electrical cross-tie capability w/ .5 cross-tie fail rate.
103D	"B Train EDG CDF & LERF Sensitivity	CDF= 1.22E-4 per yr	LERF= 1.60E-5 per yr	1.09E-4	1.42E-5	Sensitivity = Full Power with "B" Train EDG inoperable., "A" train all TM 0, "B" Train average TM.
103DX5	"B Train EDG CDF & LERF Sensitivity	CDF= 6.25E-5 per yr	LERF= 8.22E-6 per yr			Sensitivity = Full Power with "B" Train EDG inoperable. "B" Train average TM, "A" Train all TM 0. With unit electrical cross-tie capability w/ .5 cross-tie fail rate.
104B	"XST1" Transformer CDF & LERF Sensitivity	CDF= 6.36E-5 per yr	LERF= 7.69E-6 per yr	4.34E-5	5.17E-6	Sensitivity = Full Power with "XST1" Transformer inoperable., average TM, with switchyard work environmental factor in effect.
105B	"XST2" Transformer CDF & LERF Sensitivity	CDF= 7.18E-5 per yr	LERF= 8.57E-6 per yr	5.16E-5	6.05E-6	Sensitivity = Full Power with "XST2" Transformer inoperable., average TM, with switchyard work environmental factor in effect.
110A	(Baseline CDF & LERF Sensitivity)	CDF= 1.46E-5 per yr	LERF = 1.96E-6 per yr			Sensitivity= Full Power Baseline with higher LOOP value (INIT-X3 set to .052). All Equipment operable, all TM events 0. 25% increase in CDF and 23% increase in LERF.
110B	(Baseline CDF & LERF Sensitivity)	CDF= 2.54E-5 per yr	LERF = 3.18E-6 per yr			Sensitivity= Full Power Baseline with higher LOOP value (INIT-X3 set to .052). All equipment operable, average TM. 26% increase in CDF and 26% increase in LERF.
111A	(Baseline CDF & LERF Sensitivity)	CDF= 1.79E-5 per yr	LERF= 2.38E-6 per yr			Sensitivity= Full Power Baseline with BNL RCP Seal LOCA model. All Equipment operable, all TM events 0. GSFSMALL set to 0.2. 53% increase in CDF and 50% increase in LERF for higher GSFSMALL value.
111B	(Baseline CDF & LERF Sensitivity)	3.08E-5	3.89E-6			Sensitivity= Full Power Baseline with BNL RCP Seal LOCA model. All equipment operable, average TM. GSFSMALL set to 0.2. 52% increase in CDF and 54% increase in LERF for higher GSFSMALL value.

4.3 PRA Quality

The following milestones in the development of the CPSES PRA assure the analysis is sufficient to adequately provide risk insights in support of regulatory applications. The results of this history and the current evaluation for suitability in this application show that the CPSES PRA is appropriate for use in the CPSES Risk-Informed extension of allowed Completion Times for 6.9 kV AC components.

PRA Model Update History

To ensure a high-quality PRA and to provide quality control to the PRA Process, two types of independent reviews were conducted during the development of the PRA model used to support the Individual Plant Examination (IPE) submittal. One was done internally by TXU staff, and the other was done externally by outside PRA experts. In general, both reviews were applied to the entire examination process except when it was not possible due to the availability of resources or required skills. In those few cases, as a minimum, each task was reviewed thoroughly by either an internal or external independent reviewer. Furthermore, a final independent review was performed after the IPE study was completed. A team of PRA experts was selected from the industry to independently review the entire IPE study and its supporting analyses. The review team spent one week at the TXU offices where documents, procedures and supporting calculations and analyses were available for use. The results of all independent review activities performed by internal and external reviewers were well documented as part of the IPE documentation requirements.

As mentioned above, one of the main objectives of the original CPSES PRA development was to be able to utilize its results and insights toward the 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. In order to use the PRA 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. In order 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 several times since the original IPE submittal. The current PRA model includes modeling enhancements that were identified as part of an overall model update, and insights gained when using the PRA model in support of several previous risk-informed initiatives. The first major update to the PRA was performed in 1996 and 1997 when the original IPE model was revised to support a linked fault tree model. By revising the top logic (event tree/fault tree interface) to support a linked fault tree model, the effort required to requantify the PRA was reduced substantially. Subsequently, the usefulness of the PRA rose dramatically.

A second major revision to the PRA model occurred when the model was modified to allow it to be used by the Safety Monitor software for on-line risk monitoring. Although the modeling changes made to support the development of a Safety Monitor™ compatible model were primarily "cosmetic" in nature, some modeling inconsistencies and system alignment issues were identified and the model was revised to address these issues.

In 1998, a massive effort was undertaken to ensure the PRA system level models were done consistently, and that the models were symmetric between trains. The focus of this effort was to ensure consistency between the PRA system level models, including ensuring the newly developed system models were adequate to support upcoming risk informed activities. In addition, this update included reviewing plant-specific operational data in order to update component failure rates, initiating event frequencies, human error probabilities, and recovery probabilities. An initial update to the PRA model was completed in February 2000; however, additional modeling enhancements were identified when the PRA model was used to support risk-informed activities in the first and second quarters of 2000. The current PRA model includes the modeling updates performed to support each of the efforts mentioned above, and also includes modifying the models to include the enhancements identified during the risk-informed application process.

In each of these efforts, there was a significant amount of work done to enhance the fault tree modeling, both at the system level and in the top logic. These enhancements include changes that:

- Updating the PRA model to reflect as-built changes since 1992
- Updating the Thermal-Hydraulics analysis used to develop accident sequences, including using MAAP 4.0 vs. MAAP 3.0 to evaluate the postulated scenarios
- Updating component failure rates and unavailabilities with plant-specific data where available
- Updating the initiating event frequencies with plant-specific data where available
- Updating the model to reflect updated industry initiating events, in particular LOCA frequencies
- Updating the model to reflect more systematic recovery analysis and application
- Revising the model structure to represent a linked fault tree for linked model quantification
- Integrating ISLOCA sequences directly into the fault tree logic
- Updating the latent human error analysis, including a detailed review and resulting reduction in human error probabilities
- Updating the dynamic and recovery analysis, including a detail review and resulting reduction in human error probabilities
- Updating the model to reflect changes to RCP seal modeling, including crediting high temperature seal leak rates and treatment of small end leakage rates as covered by normal charging
- Enhancing the documentation and level of detail associated with the 6 systems not fully developed under the original IPE effort

Current PRA Model

The CPSES PRA model is controlled and archived on the CPSES LAN and is downloaded for maintenance and applications on business computers. The model can be readily manipulated to evaluate risk impact or individual system reliability due to modifications, procedure changes, or equipment status. The model is routinely updated to ensure plant changes (including modifications, procedure changes, etc.) are accurately reflected in the PRA.

Use of PRA for RI-IST Submittal

In November 1995, CPSES submitted a request for an exemption from the requirements (testing frequency) of 10CFR50.55a(f)(4)(I) and (ii). This request is commonly referred to the Risk Informed In-Service Testing (RI-IST) submittal. Specifically, CPSES requested approval to utilize a risk-based in-service testing program to determined in-service test frequencies for valves and pumps that are identified as less safety significant, in lieu of testing those components per the frequencies specified by the AMSE code. As part of this effort the PRA model of record at that time was reviewed using the EPRI PRA Applications Guide and found to be suitable for a Risk-Informed In-Service Testing application. This review evaluated the questions posed in the EPRI PRA Applications Guide (text and Appendix B). These questions included problem definition, scope, figures of merit, analysis, decision criteria, initiating events, success criteria, event trees, system reliability models, parameter databases, dependent failure analysis, human reliability analysis, quantification, analysis of results, plant damage state classification, containment analysis, external events PRA hazards analysis, and shutdown PRA considerations.

In August 1998, the USNRC provided a Safety Evaluation Report to CPSES with respect to the RI-IST request, and approved the request. As part of their review of the RI-IST submittal, the NRC performed an in-depth review of the CPSES PRA model of record at that time, the original IPE and IPEEE submittals. The focus of the NRCs review was to establish that the CPSES PRA appropriately reflected the plant's design and actual operating conditions and practices, and that there was a suitable technical basis to support the PRA-related findings made to support the Safety Evaluation Report (SER).

To reach specific findings regarding the quality of the PRA, a focused-scope evaluation was performed that 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. As a result of their in-depth evaluation, the USNRC found the quality of the Comanche Peak PRA acceptable for the 1998 RI-IST submittal. Since that time, the PRA has been updated and improved further, by means of an update process that incorporates review steps.

5.0 REGULATORY ANALYSIS

5.1 No significant Hazards Determination

TXU Electric has evaluated whether or not a significant hazards consideration is involved with the proposed changes by focusing on the three standards set forth in 10CFR50.92 as discussed below:

1. Do the proposed changes involve a significant increase in the probability or consequences of an accident previously evaluated?

   Response: No

   The proposed Technical Specification changes do not significantly increase the probability of occurrence of a previously evaluated accident because the 6.9 kV AC components (i.e., Emergency Diesel Generators (EDGs), startup transformers (STs), and safety-related (Class 1E) busses) are not initiators of previously evaluated accidents involving a loss of offsite power. The proposed changes to the Technical Specification Action Completion Times do not affect any of the assumptions used in the deterministic or the Probabilistic Safety Assessment (PSA) analysis

   The proposed Technical Specification changes will continue to ensure the 6.9 kV AC components perform their function when called upon. Extending the Technical Specification Completion Times to 14 days and allowing the performance of the EDG 24-hour run test in either MODES 1 or 2 does not affect the design of the EDGs, the operational characteristics of the EDGs, the interfaces between the EDGs and other plant systems, the function, or the reliability of the EDGs. Thus, the EDGs will be capable of performing either accident mitigation function and there is no impact to the radiological consequences of any accident analysis.

   To fully evaluate the effect of the changes to the 6.9 kV AC components, Probabilistic Safety Analysis (PSA) methods and deterministic analysis were utilized. The results of this analysis show no significant increase in the Core Damage Frequency.

   The Configuration Risk Management Program (CRMP) in Technical Specification 5.5.18 is an administrative program that assesses risk based on plant status. Adding the requirement to implement the CRMP for Technical Specification 3.8.1 and 3.8.9 requires the consideration of other measures to mitigate consequences of an accident occurring while a 6.9 kV AC component is inoperable.

The proposed changes do not alter the operation of any plant equipment assumed to function in response to an analyzed event or otherwise increase its failure probability. Therefore, these changes do not involve a significant increase in the probability or consequences of any accident previously evaluated.

2. Do the proposed changes create the possibility of a new or different kind of accident from any accident previously evaluated?

   Response: No

   These proposed changes do not change the design, configuration, or method of operation of the plant. The proposed activities involves a change to the allowed plant mode for the performance of specific Technical Specification surveillance requirements. No physical or operational change to the 6.9 kV AC components or supporting systems are made by this activity. Since the proposed changes do not involve a change to the plant design or operation, no new system interactions are created by this change. The proposed Technical Specification changes do not produce any parameters or conditions that could contribute to the initiation of accidents different from those already evaluated in the Final Safety Analysis Report.

   The proposed changes only address the time allowed to restore the operability of the 6.9 kV AC components. Thus the proposed Technical Specification changes do not create the possibility of a new or different kind of accident from any accident previously evaluated.

3. Do the proposed changes involve a significant reduction in a margin of safety?

   Response: No

   The proposed changes do not affect the Limiting Conditions for Operation or their Bases that are used in the deterministic analysis to establish any margin of safety. PSA evaluations were used to evaluate these changes, and these evaluations determined that the net changes are either risk neutral or risk beneficial. The proposed activities involves changes to certain Completion Times and to the allowed plant mode for the performance of specific Technical Specification Requirements. The proposed changes remain bounded by the existing Surveillance Requirement Completion Times and therefore have no impact to the margins of safety.

   The proposed change does not involve a change to the plant design or operation and thus does not affect the design of the 6.9 kV AC components, the operation characteristics of the 6.9 kV AC components, the interfaces between the 6.9 kV AC components and other plant systems, or the function or reliability of the 6.9 kV AC components. Because 6.9 kV AC components performance and reliability will continue to be ensured by the proposed Technical Specification changes, the proposed changes do not result in a reduction in the margin of safety.

Therefore the proposed change does not involve a reduction in a margin of safety.

Based on the above evaluations, TXU Electric concludes that the activities associated with the above described changes present no significant hazards consideration under the standards set forth in 10CFR50.92 and accordingly, a finding by the NRC of no significant hazards consideration is justified.

5.2 Regulatory Safety Analysis

Applicable Regulatory Requirements / Criteria

USNRC, "Final Policy Statement on Technical Specification Improvements for Nuclear Power Reactors," Federal Register, 58 FR 39132, July 22, 1993.

USNRC, 10 CFR 50.36, "Technical Specifications," Federal Register, 60 FR 36953, July 19, 1995.

NUREG 1431, "Standard Technical Specifications Westinghouse Plants, Rev. 1, April 1995)

GDC 5 - Sharing of Structures, Systems, and Components, "Structures, systems, and components important to safety shall not be shared between nuclear power units unless it can be shown that such sharing will not significantly impair their ability to perform their safety functions including, in the event of an accident in one unit, an orderly shutdown and cooldown of the remaining unit."

GDC 17 - An onsite electric power system and an offsite electric power system shall be provided to permit functioning of structures, systems, and components important to safety. The safety function for each system (assuming the other system is not functioning) shall be to provide sufficient capacity and capability to assure that (1) specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded as a result of anticipated operational occurrences, and (2) the core is cooled and containment integrity and other vital functions are maintained in the event of postulated accidents. The onsite electric power sources, including the batteries, and the onsite electrical distribution system, shall have sufficient independence, redundancy, and testability to perform their safety functions, assuming a single failure. Electric power from the transmission

network to the onsite electric distribution system shall be supplied by two physically independent circuits (not necessarily on separate rights of way) designed and located so as to minimize to the extent practical the likelihood of their simultaneous failure under operating and postulated accident and environmental conditions. A switchyard common to both circuits is acceptable. Each of these circuits shall be designed to be available in sufficient time following a loss of all onsite alternating current power supplies and the other offsite electrical power circuit, to assure that specified acceptable fuel design limits and design conditions of the reactor coolant pressure boundary are not exceeded. One of these circuits shall be designed to be available within a few seconds following a-loss-of-coolant accident to assure that core cooling, containment integrity, and other vital safety functions are maintained.
Provisions shall be included to minimize the probability of losing electric power from any of the remaining supplies as a result of, or coincident with, the loss of power generated by the nuclear power unit, the loss of power from the transmission network, or the loss of power from the onsite electrical power supplies.

GDC 18 – Inspection and Testing of Electric Power System, Electric power systems important to safety shall be designed to permit appropriate periodic inspection and testing of important areas and features, such as wiring, insulation, connections, and switchboards, to assess the continuity of the systems and the condition of their components. The systems shall be designed with a capability to test periodically (1) the operability and functional performance of the components of the systems, such as onsite power sources, relays, switches, and buses and (2) the operability of the systems as a whole and, under conditions as close to design as practical, the full operational sequence that brings the systems into operation, including operation of applicable portions of the protection system and the transfer of power among the nuclear power unit, the offsite power system, and the onsite power system [1]."

NRC Safety Guide 6, dated March 10, 1971, titled "Independence Between Redundant Standby (onsite) Power Sources and Between Their Distribution Systems."

NRC Safety Guide 9, dated March 10, 1971, titled "Selection of Diesel Generator Set Capacity for Standby Power Supplies."

NRC Regulatory Guide 1.53, dated June 1973, "Applicability of Single-Failure Criterion to Nuclear Power Plant Protection Systems."

NRC Regulatory Guide 1.62, dated October, 1973, titled "Manual Initiation of Protective Actions."

NRC Regulatory Guide 1.75, Revision 1, dated January 1975, titled "Physical Independence of Electrical Systems."

NRC Regulatory Guide 1.81, Revision 1, dated January 1975, titled "Shared Emergency and Shutdown Electric Systems for Multi-unit Nuclear Power Plants."

NRC Regulatory Guide 1.93, "Availability of Electric Power Sources," December 1974

NRC Regulatory Guide 1.108, "Periodic Testing of Diesel Generators Used as Onsite Electric Power Systems at Nuclear Power Plants," Revision 1 (8/77)

NRC Regulatory Guide 1.155, "Station Blackout," dated August 1988

Analysis

The primary requirement of concern is GDC 17.

Compliance With GDC 17:

The safety-related systems are designed with sufficient capacity, independence, and redundancy to ensure performance of their safety functions assuming a single failure. The offsite electrical power system also provides independence and redundancy to ensure an available source of power to the safety-related loads.

Upon loss of the preferred power source to any 6.9 kV Class 1E bus, the alternate power source is automatically connected to the bus and the diesel generator starts should the alternate source not return power to the Class 1E buses. Loss of both offsite power sources to any 6.9 kV Class 1E bus, although highly unlikely, results in the diesel generator providing power to the Class 1E bus.

Two independent diesel generators and their distribution systems are provided for each unit to supply power to the redundant onsite AC Power System. Each diesel generator and its distribution system is designed and installed to provide a reliable source of redundant onsite-generated (standby) AC power and is capable of supplying the Class 1E loads connected to the Class 1E bus which it serves.

Redundant parts within the AC and DC systems are physically and electrically independent to the extent that a single event or single electrical fault can not cause a loss of power to both Class 1E load groups.

The proposed extended Completion Times and revised Surveillance Requirement Notes related to the 6.9 kV AC components do not change the compliance with the above general design criteria and regulatory requirement, other than the deviations from Regulatory Guide 1.93 and NUREG 1431 discussed in Section 4, "Technical Analysis," above.

Conclusion

The technical analysis performed by TXU Electric in Section 4, "Technical Analysis," demonstrates the ability of the 6.9 kV AC components (emergency diesel generator, startup transformer, and safety bus) to perform their safety function. The increased Completion Times continue to comply with the above regulatory requirements.

6.0 ENVIRONMENTAL EVALUATION

TXU Electric has determined that the proposed amendment would change requirements with respect to the installation or use of a facility component located within the restricted area, as defined in 10CFR20, or would change an inspection or surveillance requirement. TXU Electric has evaluated the proposed changes and has determined that the changes do not involve (1) a significant hazards consideration, (2) a significant change in the types or significant increase in the amounts of any effluent that may be released offsite, or (3) a significant increase in individual or cumulative occupational radiation exposure. Accordingly, the proposed changes meet the eligibility criterion for categorical exclusion set forth in 10CFR51.22(c)(9). Therefore, pursuant to 10CFR51.22(b), an environmental assessment of the proposed change is not required.

7.0. REFERENCES

1. Comanche Peak Steam Electric Station Final Safety Analysis Report, Docket Nos. 50-445 and 50-446.

2. NRC Regulatory Guide (RG) 1.93, "Availability of Electric Power Sources," December 1974.

3. NRC's Probabilistic Risk Assessment (PRA) Policy Statement, "Use of Probabilistic Risk Assessment Methods in Nuclear Activities: Final Policy Statement," Federal Register, Volume 60, p.42622, August 16, 1995.

4. NRC Regulatory Guide 1.174, "An Approach for Using Probabilistic Risk Assessment In Risk-Informed Decisions On Plant-Specific Changes to the Licensing Basis," July 1998.

5. NRC Regulatory Guide 1.177, "An Approach for Plant-Specific, Risk-Informed Decision making: Technical Specifications," August 1999.

6. NRC Regulatory Guide 1.155, "Station Blackout," dated August 1988

7. NRC Safety Guide 6, dated March 10, 1971, titled "Independence Between Redundant Standby (onsite) Power Sources and Between Their Distribution Systems."

8. NRC Safety Guide 9, dated March 10, 1971, titled "Selection of Diesel Generator Set Capacity for Standby Power Supplies."

9. NRC Regulatory Guide 1.81, Revision 1, dated January 1975, titled "Shared Emergency and Shutdown Electric Systems for Multi-unit Nuclear Power Plants."

10. NRC Regulatory Guide 1.53, dated June 1973, "Applicability of Single-Failure Criterion to Nuclear Power Plant Protection Systems."

11. NRC Regulatory Guide 1.62, dated October, 1973, titled "Manual Initiation of Protective Actions."

12. NRC Regulatory Guide 1.75, Revision 1, dated January 1975, titled "Physical Independence of Electrical Systems."

13. Institute of Electrical and Electronic Engineers (IEEE) Standard 387-1984, "IEEE Standard for Diesel Generator Units Applied as Standby Power Supplies for Nuclear Generating Stations."

14. NUREG 1431, "Standard Technical Specifications Westinghouse Plants, Rev. 1, April 1995)

15. Individual Plant Examination for the Comanche Peak Steam Electric Station, (Full Power PRA), RXE-92-01A TU Electric, August 1992

16. Review of the CPSES IPE for Applicability to Risk-Based IST, Comanche Peak, 1996

17. Safety Evaluation By The Office Of Nuclear Reactor Regulation Related To The TU Electric Request To Implement A Risk-Informed Inservice Testing Program At Comanche Peak Steam Electric Station (CPSES), Units 1 And 2 Docket Numbers 50-445 And 50-446, USNRC

8.0. PRECEDENTS

There have been several other Nuclear Power Plants who have requested and received a similar extension for the Allowed Completion Time for the Emergency Diesel Generator and a change to allow the 24 hour EDG endurance run in MODES 1 and 2 (e.g., Byron and Braidwood, Issuance of Amendments (TAC NOS. MA8027, MA8028, MA8025, and MA8026) September 1, 2000)).

ATTACHMENT 3 to TXX-01077

MARKUP OF TECHNICAL SPECIFICATION PAGES

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INFORMATION ONLY

3.8 ELECTRICAL POWER SYSTEMS

3.8.1 AC Sources — Operating

LCO 3.8.1 The following AC electrical sources shall be OPERABLE:

a. Two qualified circuits between the offsite transmission network and the onsite Class 1E AC Electrical Power Distribution System;

b. Two diesel generators (DGs) capable of supplying the onsite Class 1E power distribution subsystem(s); and

c. Automatic load sequencers for Train A and Train B.

APPLICABILITY: MODES 1, 2, 3, and 4

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One required offsite circuit inoperable.	A.1	Perform SR 3.8.1.1 for required OPERABLE offsite circuit.	1 hour AND Once per 8 hours thereafter
	AND		
		----------NOTE---------- In MODES 1, 2 and 3, the TDAFW pump is considered a required redundant feature. ------------------------------	
	A.2	Declare required feature(s) with no offsite power available inoperable when its redundant required feature(s) is inoperable.	24 hours from discovery of no offsite power to one train concurrent with inoperability of redundant required feature(s)
	AND		
	A.3	Restore required offsite circuit to OPERABLE status.	14 days 72 hours AND 28 6 days from discovery of failure to meet LCO

(continued)

INFORMATION ONLY

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. One DG inoperable.	B.1	Perform SR 3.8.1.1 for the required offsite circuit(s).	1 hour AND Once per 8 hours thereafter
	AND		
		------------NOTE--------- In MODES 1, 2 and 3, the TDAFW pump is considered a required redundant feature. -------------------------------	
	B.2	Declare required feature(s) supported by the inoperable DG inoperable when its required redundant feature(s) is inoperable.	4 hours from discovery of Condition B concurrent with inoperability of redundant required feature(s)
	AND		
	B.3.1	Determine OPERABLE DG(s) is not inoperable due to common cause failure.	24 hours
	OR		
		-----------NOTE----------- The SR need not be performed if the DG is already operating and loaded. -------------------------------	
	B.3.2	Perform SR 3.8.1.2 for OPERABLE DG(s).	24 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. (continued)	AND B.4 Restore DG to OPERABLE status.	14 days 72 hours AND 28 6 days from discover of failure to meet LCO
C. Two required offsite circuits inoperable.	-----------NOTE----------- In MODES 1, 2 and 3, the TDAFW pump is considered a required redundant feature. -------------------------------	
	C.1 Declare required feature(s) inoperable when its redundant required feature(s) is inoperable.	12 hours from discovery of Condition C concurrent with inoperability of redundant required features
	AND C.2 Restore one required offsite circuit to OPERABLE status.	24 hours

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
D. One required offsite circuit inoperable. AND One DG inoperable.	----------------NOTE---------------- Enter applicable Conditions and Required Actions of LCO 3.8.9, "Distribution Systems - Operating," when Condition D is entered with no AC power source to any train. --	
	D.1 Restore required offsite circuit to OPERABLE status.	12 hours
	OR	
	D.2 Restore DG to OPERABLE status.	12 hours
E. Two DGs inoperable.	E.1 Restore one DG to OPERABLE status.	2 hours
F. One SI sequencer inoperable.	----------------NOTE---------------- One required SI sequencer channel may be bypassed for up to 4 hours for surveillance testing provided the other channel is operable. --	
	F.1 Restore SI sequencer to OPERABLE status.	12 hours

(continued)

INFORMATION ONLY

ACTIONS (continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
G. Required Action and associated Completion Time of Condition A, B, C, D, E, or F not met.	G.1 Be in MODE 3. AND G.2 Be in MODE 5.	6 hours 36 hours
H. Three or more required AC sources inoperable.	H.1 Enter LCO 3.0.3.	Immediately
I. One Blackout Sequencer inoperable	I.1 Declare associated DG inoperable	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.1.1	Verify correct breaker alignment and indicated power availability for each required offsite circuit.	7 days

(continued)

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.8.1.14	-----NOTES----- 1. Momentary transients outside the load and power factor ranges do not invalidate this test. 2. Verify requirement during MODES 3, 4, 5, 6 or with core off-loaded. ---------- Verify each DG operates for ≥ 24 hours: a. For ≥ 2 hours loaded ≥ 6900 kW and ≤ 7700 kW; and b. For the remaining hours of the test loaded ≥ 6300 kW and ≤ 7000 kW.	18 months
SR 3.8.1.15	-----NOTES----- 1. This Surveillance shall be performed within 5 minutes of shutting down the DG after the DG has operated ≥ 2 hours loaded ≥ 6300 kW and ≤ 7000 kW. Momentary transients outside of load range do not invalidate this test. 2. All DG starts may be preceded by an engine prelube period. ---------- Verify each DG starts and achieves: a. in ≤ 10 seconds, voltage ≥ 6480 V and frequency ≥ 58.8 Hz; and b. steady state, voltage ≥ 6480 V, and ≤ 7150 V and frequency ≥ 58.8 Hz and ≤ 61.2 Hz.	18 months 66

(continued)

3.8 ELECTRICAL POWER SYSTEMS

3.8.9 Distribution Systems — Operating

LCO 3.8.9 Train A and Train B AC, DC, and AC vital bus electrical power distribution subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One AC electrical power distribution subsystem inoperable.	A.1	Restore AC electrical power distribution subsystem to OPERABLE status.	72 8 hours <u>AND</u> 80 16 hours from discovery of failure to meet LCO
B. One AC vital bus subsystem inoperable.	B.1	Restore AC vital bus subsystem to OPERABLE status.	2 hours <u>AND</u> 80 16 hours from discovery of failure to meet LCO

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. One DC electrical power distribution subsystem inoperable.	C.1	Restore DC electrical power distribution subsystem to OPERABLE status.	2 hours <u>AND</u> 80 16 hours from discovery of failure to meet LCO
D. Required Action and associated Completion Time not met.	D.1	Be in MODE 3.	6 hours
	<u>AND</u>		
	D.2	Be in MODE 5.	36 hours
E. Two trains with inoperable distribution subsystems that result in a loss of safety function.	E.1	Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.9.1	Verify correct breaker alignments and voltage to required AC, DC, and AC vital bus electrical power distribution subsystems.	7 days

INFORMATION ONLY

5.5.17 Technical Requirements Manual (TRM)

The TRM contains selected requirements which do not meet the criteria for inclusion in the Technical Specification but are important to the operation of CPSES. Much of the information in the TRM was relocated from the TS.

Changes to the TRM shall be made under appropriate administrative controls and reviews. Changes may be made to the TRM without prior NRC approval provided the changes do not involve either a change to the TS or an unreviewed safety question as defined by 10 CFR 50.59. TRM changes require approval of the Plant Manager*.

5.5.18 Configuration Risk Management Program (CRMP)

The Configuration Risk Management Program (CRMP) provides a proceduralized risk-informed assessment to manage the risk associated with equipment inoperability. The program applies to technical specification structures, systems, or components for which a risk-informed Completion Time has been granted. The program shall include the following elements:

a. Provisions for the control and implementation of a Level 1, at-power, internal events PRA-informed methodology. The assessment shall be capable of evaluating the applicable plant configuration.

b. Provisions for performing an assessment prior to entering the LCO Action for preplanned activities.

c. Provisions for performing an assessment after entering the LCO Action for unplanned entry into the LCO Action.

d. Provisions for assessing the need for additional actions after the discovery of additional equipment out of service conditions while in the LCO Action.

e. Provisions for considering other applicable risk significant contributors such as Level 2 issues, and external events, qualitatively or quantitatively.

* Duties may be performed by the Vice President of Nuclear Operations if that organizational position is assigned.

ATTACHMENT 4 to TXX-01077

MARKUP OF TECHNICAL SPECIFICATION BASES PAGES
(For Information Only)

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	B 3.8-81
	B 3.8.82
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	B 3.8.85

BASES

ACTIONS (continued)

A.3

Reference 16

14 days

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition A for a period that should not exceed 72 hours. With one offsite circuit inoperable, the reliability of the offsite system is degraded, and the potential for a loss of offsite power is increased, with attendant potential for a challenge to the unit safety systems. In this Condition, however, the remaining OPERABLE offsite circuit and DGs are adequate to supply electrical power to the onsite Class 1E Distribution System.

14 day

The 72 hour Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

14 days

28 days

42

28

28

The second Completion Time for Required Action A.3 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition A is entered while, for instance, a DG is inoperable and that DG is subsequently returned OPERABLE, the LCO may already have been not met for up to 72 hours. This could lead to a total of 144 hours, since initial failure to meet the LCO, to restore the offsite circuit. At this time, a DG could again become inoperable, the circuit restored OPERABLE, and an additional 72 hours (for a total of 9 days) allowed prior to complete restoration of the LCO. The 6 day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the 72 hour and 6 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

14 day

As in Required Action A.2, the Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This will result in establishing the "time zero" at the time that the LCO was initially not met, instead of at the time Condition A was entered.

(continued)

The 14 day Completion Time is based on a risk-informed assessment to manage the risk associated with the equipment in accordance with the Configuration Risk Management Program (TS 5.5.18)

BASES

ACTIONS (continued)

B.4

Reference 16

According to Regulatory Guide 1.93 (Ref. 6), operation may continue in Condition B for a period that should not exceed ~~72 hours~~ 14 days.

In Condition B, the remaining OPERABLE DG and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. The ~~72 hour~~ 14 day Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

The second Completion Time for Required Action B.4 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition B is entered while, for instance, an offsite circuit is inoperable and that circuit is subsequently restored OPERABLE, the LCO may already have been not met for up to ~~72 hours.~~ 14 days. This could lead to a total of ~~144 hours~~ 28 days, since initial failure to meet the LCO, to restore the DG. At this time, an offsite circuit could again become inoperable, the DG restored OPERABLE, and an additional ~~72 hours~~ 14 days (for a total of ~~9~~ 42 days) allowed prior to complete restoration of the LCO. The ~~6~~ 28 day Completion Time provides a limit on time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the ~~72 hour~~ 14 day and ~~6~~ 28 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

As in Required Action B.2, the Completion Time allows for an exception to the normal "time zero" for beginning the allowed time "clock." This will result in establishing the "time zero" at the time that the LCO was initially not met, instead of at the time Condition B was entered.

C.1 and C.2

Required Action C.1, which applies when two offsite circuits are inoperable, is intended to provide assurance that an event with a coincident single failure will not result in a complete loss of redundant required safety functions. The Completion Time for this failure of redundant required features is reduced to 12 hours from that allowed for

(continued)

The 14 day Completion Time is based on a risk-informed assessment to manage the risk associated with the equipment in accordance with the Configuration Risk Management Program (TS 5.5.18).

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.14

Regulatory Guide 1.9 (Ref. 3), requires demonstration once per 18 months that the DGs can start and run continuously at full load capability for an interval of not less than 24 hours, ≥ 2 hours of which is at a load equivalent to approximately 110% of the continuous duty rating and the remainder of the time at a load equivalent to 90% to 100% of the continuous duty rating of the DG. For the purposes of the 2 hour run, the minimum load is approximately 110% of the 6300 kW maximum design load in lieu of the 7000 kW continuous rating. The DG start for this 4
Surveillance can be performed either from ambient or hot conditions. The provisions for prelubricating and warmup, discussed in SR 3.8.1.2, and for gradual loading, discussed in SR 3.8.1.3, are applicable to this SR.

The load band is provided to avoid routine overloading of the DG. Routine overloading may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY.

The 18 month Frequency is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3), takes into consideration unit conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

a which

This Surveillance is modified by two Notes. Note 1 states that momentary transients due to changing bus loads do not invalidate this test. Note 2 says to verify the requirement during MODES 3, 4, 5, 6 or with the core off-loaded.

SR 3.8.1.15

This Surveillance demonstrates that the diesel engine can restart from a hot condition, such as subsequent to shutdown from normal Surveillances, and achieve the required voltage and frequency within 10 seconds. The 10 second time is derived from the requirements of the accident analysis to respond to a design basis large break LOCA. The 18 month Frequency is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3).

(continued)

BASES (continued)

REFERENCES

1. 10 CFR 50, Appendix A, GDC 17.
2. FSAR, Chapter 8.
3. Regulatory Guide 1.9 Rev 3, July 1993.
4. FSAR, Chapter 6.
5. FSAR, Chapter 15.
6. Regulatory Guide 1.93, Rev. 0, December 1974.
7. Generic Letter 84-15, "Proposed Staff Actions to Improve and Maintain Diesel Generator Reliability," July 2, 1984.
8. 10 CFR 50, Appendix A, GDC 18.
9. Regulatory Guide 1.108, Rev. 1, August 1977.
10. Regulatory Guide 1.137, January 1978.
11. ASME, Boiler and Pressure Vessel Code, Section XI.
12. IEEE Standard 308-1974.
13. IEEE Standard 387-1977
14. Generic Letter 94-01, "Removal of Accelerated Testing and Special Reporting Requirements for Emergency Diesel Generators," May 31, 1994.
15. ANSI C84.1
16. License Amendment Request (LAR) 01-06, Revision To Technical Specification, Extension Of Allowable Completion Times And Surveillance Requirement Change For Emergency Diesel Generators, Qualified Offsite Circuits, And AC Electrical Power Distribution Subsystem, Docket Nos. 50-445 and 50-446, CPSES.

BASES

LCO
(continued)

OPERABLE AC electrical power distribution subsystems require the associated buses, and load centers, to be energized to their proper voltages. OPERABLE DC electrical power distribution subsystems require the associated buses to be energized to their proper voltage from either the associated battery or charger. OPERABLE vital bus electrical power distribution subsystems require the associated buses to be energized to their proper voltage from either the associated inverter via 7
inverted DC voltage or the alternate bypass power supply via Class 1E transformers.

APPLICABILITY

The electrical power distribution subsystems are required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure that:

a. Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of AOOs or abnormal transients; and

b. Adequate core cooling is provided, and containment OPERABILITY and other vital functions are maintained in the event of a postulated DBA.

Electrical power distribution subsystem requirements for MODES 5 and 6 are covered in the Bases for LCO 3.8.10, "Distribution Systems — Shutdown."

ACTIONS

A.1

With one or more required AC buses or load centers except AC vital buses, in one train inoperable the remaining AC electrical power distribution subsystem in the other train is capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure. The overall reliability is reduced, however, because a single failure in the remaining power distribution subsystem could result in the minimum required ESF functions not being supported. Therefore, the required AC buses, and load centers, must be restored to OPERABLE status within 8 hours.

72

(continued)

BASES

ACTIONS

A.1 (continued)

Condition A worst scenario is one train without AC power (i.e., no offsite power to the train and the associated DG inoperable). In this Condition, the unit is more vulnerable to a complete loss of AC power. It is, therefore, imperative that the unit operator's attention be focused on minimizing the potential for loss of power to the remaining train by stabilizing the unit, and on restoring power to the affected train. The ~~8~~ 72 hour time limit before requiring a unit shutdown in this Condition is acceptable because of:

a. The potential for decreased safety if the unit operator's attention is diverted from the evaluations and actions necessary to restore power to the affected train, to the actions associated with taking the unit to shutdown within this time limit; and

b. The potential for an event in conjunction with a single failure of a redundant component in the train with AC power.

The 72 hour Completion Time is based on a risk-informed assessment to manage the risk associated with the equipment in accordance with the Configuration Risk Management Program (TS 5.5.18) (Reference 4).

The second Completion Time for Required Action A.1 establishes a limit on the maximum time allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition A is entered while, for instance, a DC bus is inoperable and subsequently restored OPERABLE, the LCO may already have been not met for up to 2 hours. This could lead to a total of ~~10~~ 74 hours, since initial failure of the LCO, to restore the AC distribution system. At this time, a DC circuit could again become inoperable, and AC distribution restored OPERABLE. This could continue indefinitely.

The Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This will result in establishing the "time zero" at the time the LCO was initially not met, instead of the time Condition A was entered. The ~~16~~ 80 hour Completion Time is an acceptable limitation on this potential to fail to meet the LCO indefinitely.

(continued)

INFORMATION ONLY

BASES

ACTIONS (continued)

B.1

With one AC vital bus inoperable the remaining OPERABLE AC vital buses are capable of supporting the minimum safety functions necessary to shut down the unit and maintain it in the safe shutdown condition. Overall reliability is reduced, however, since an additional single failure could result in the minimum required ESF functions not being supported. Therefore, the required AC vital bus must be restored to OPERABLE status within 2 hours by powering the bus from the associated inverter via inverted DC.

Condition B represents one AC vital bus without non-interruptible inverted DC power. In this situation, the unit is significantly more vulnerable to a complete loss of all non-interruptible power. It is, therefore, imperative that the operator's attention focus on stabilizing the unit, minimizing the potential for loss of non-interruptible power to the remaining vital buses and restoring non-interruptible power to the affected vital bus subsystems.

This 2 hour limit is more conservative than Completion Times allowed for the vast majority of components that are without adequate vital AC power. Taking exception to LCO 3.0.2 for components without adequate vital AC power, that would have the Required Action Completion Times shorter than 2 hours if declared inoperable, is acceptable because of:

a. The potential for decreased safety by requiring a change in unit conditions (i.e., requiring a shutdown) and not allowing stable operations to continue;

b. The potential for decreased safety by requiring entry into numerous Applicable Conditions and Required Actions for components without adequate vital AC power and not providing sufficient time for the operators to perform the necessary evaluations and actions for restoring power to the affected train; and

c. The potential for an event in conjunction with a single failure of a redundant component.

(continued)

BASES

ACTIONS

B.1 (continued)

The 2 hour Completion Time takes into account the importance to safety of restoring the AC vital bus to OPERABLE status, the redundant capability afforded by the other OPERABLE vital buses, and the low probability of a DBA occurring during this period.

The second Completion Time for Required Action B.1 establishes a limit on the maximum allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition B is entered while, for instance, an AC bus is inoperable and subsequently returned OPERABLE, the LCO may already have been not met for up to 4 hours. This could lead to a total of 6 hours, since initial failure of the LCO, to restore the vital bus distribution system. At this time, an AC train could again become inoperable, and vital bus distribution restored OPERABLE. This could continue indefinitely.

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This Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This will result in establishing the "time zero" at the time the LCO was initially not met, instead of the time Condition B was entered. The 16 hour Completion Time is an acceptable limitation on this potential to fail to meet the LCO indefinitely.

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C.1

With DC bus(es) in one train inoperable the remaining DC electrical power distribution subsystems are capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure. The overall reliability is reduced, however, because a single failure in the remaining DC electrical power distribution subsystems could result in the minimum required ESF functions not being supported. Therefore, the required DC buses must be restored to OPERABLE status within 2 hours by powering the bus from the associated battery or charger.

(continued)

INFORMATION ONLY

BASES

ACTIONS

C.1 (continued)

Condition C represents one or more electrical power distribution subsystems without adequate DC power; potentially both with the battery significantly degraded and the associated charger nonfunctioning for the affected bus(es). In this situation, the unit is significantly more vulnerable to a complete loss of all DC power. It is, therefore, imperative that the operator's attention focus on stabilizing the unit, minimizing the potential for loss of power to the remaining bus(es) and restoring power to the affected bus(es) .

This 2 hour limit is more conservative than Completion Times allowed for the vast majority of components that would be without power. Taking exception to LCO 3.0.2 for components without adequate DC power, which would have Required Action Completion Times shorter than 2 hours, is acceptable because of:

a. The potential for decreased safety by requiring a change in unit conditions (i.e., requiring a shutdown) while allowing stable operations to continue;

b. The potential for decreased safety by requiring entry into numerous applicable Conditions and Required Actions for components without DC power and not providing sufficient time for the operators to perform the necessary evaluations and actions for restoring power to the affected train; and

c. The potential for an event in conjunction with a single failure of a redundant component.

The 2 hour Completion Time for DC buses is consistent with Regulatory Guide 1.93 (Ref. 3).

The second Completion Time for Required Action C.1 establishes a limit on the maximum time allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition C is entered while, for instance, an AC bus is inoperable and subsequently returned OPERABLE, the LCO

(continued)

BASES

ACTIONS

C.1 (continued)

72

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may already have been not met for up to 8 hours. This could lead to a total of 10 hours, since initial failure of the LCO, to restore the DC distribution system. At this time, an AC train could again become inoperable, and DC distribution restored OPERABLE. This could continue indefinitely.

This Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This will result in establishing the "time zero" at the time the LCO was initially not met, instead of the time Condition C was entered. The 16 hour Completion Time is an acceptable limitation on this potential to fail to meet the LCO indefinitely.

80

D.1 and D.2

If the inoperable distribution subsystem cannot be restored to OPERABLE status within the required Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging plant systems.

E.1

Condition E corresponds to inoperable distribution subsystems that result in a loss of safety function, adequate core cooling, containment OPERABILITY and other vital functions for DBA mitigation would be compromised, and immediate plant shutdown in accordance with LCO 3.0.3 is required.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.8.9.1

This Surveillance verifies that the required AC, DC, and AC vital bus electrical power distribution systems are functioning properly, with the correct circuit breaker alignment. The correct breaker alignment ensures the appropriate separation and independence of the electrical divisions is maintained, and the appropriate voltage is available to each required bus. The verification of proper voltage availability on the buses ensures that the required voltage is readily available for motive as well as control functions for critical system loads connected to these buses. The 7 day Frequency takes into account the redundant capability of the AC, DC, and AC vital bus electrical power distribution subsystems, and other indications available in the control room that alert the operator to subsystem malfunctions.

REFERENCES

1. FSAR, Chapter 6.

2. FSAR, Chapter 15.

3. Regulatory Guide 1.93, December 1974.

4. License Amendment Request (LAR) 01-06, Revision To Technical Specification, Extension of Allowable Completion Times and Surveillance Requirement Change For Emergency Diesel Generators, Qualified Offsite Circuits, and AC Electrical Power Distribution Subsystem, Docket Nos. 50-445 and 50-446, CPSES.

INFORMATION ONLY

Table B 3.8.9-1 (page 1 of 1)
AC and DC Electrical Power Distribution Systems

TYPE	VOLTAGE	TRAIN A*#	TRAIN B*#
AC safety buses	6900 V 480 V	ESF Bus 1EA1 (2EA1) Load Centers 1EB1, 1EB3 (2EB1, 2EB3)	ESF Bus 1EA2 (2EA2) Load Centers 1EB2, 1EB4 (2EB2, 2EB4)
DC buses	125 V	Bus 1ED1 (2ED1) Bus 1ED3 (2ED3)	Bus 1ED2 (2ED2) Bus 1ED4 (2ED4)
AC vital buses	118 V	Buses 1EC1, 1EC5 (2EC1, 2EC5) Buses 1PC1, 1PC3 (2PC1, 2PC3)	Buses 1EC2, 1EC6 (2EC2, 2EC6) Buses 1PC2, 1PC4 (2PC2, 2PC4)

* Each train of the AC and DC electrical power distribution systems is a subsystem.

The 480 V load centers are fed from the following transformers:

1EB1 - T1EB1
1EB2 - T1EB2
1EB3 - T1EB3
1EB4 - T1EB4
2EB1 - T2EB1
2EB2 - T2EB2
2EB3 - T2EB3
2EB4 - T2EB4

ATTACHMENT 5 to TXX-01077

RETYPED OF TECHNICAL SPECIFICATION PAGES

Pages	**3.8-2**
	3.8-4
	3.8-12
	3.8-38
	3.8-39

ACTIONS

CONDITION	REQUIRED ACTION	COMPLETION TIME
A. One required offsite circuit inoperable.	A.1 Perform SR 3.8.1.1 for required OPERABLE offsite circuit.	1 hour AND Once per 8 hours thereafter
	AND ---------------NOTE----------------- In MODES 1, 2 and 3, the TDAFW pump is considered a required redundant feature. -- A.2 Declare required feature(s) with no offsite power available inoperable when its redundant required feature(s) is inoperable.	24 hours from discovery of no offsite power to one train concurrent with inoperability of redundant required feature(s)
	AND A.3 Restore required offsite circuit to OPERABLE status.	14 days AND 28 days from discovery of failure to meet LCO

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
B. (continued)	AND		
	B.4	Restore DG to OPERABLE status.	14 days AND 28 days from discover of failure to meet LCO
C. Two required offsite circuits inoperable.		------------NOTE------------- In MODES 1, 2 and 3, the TDAFW pump is considered a required redundant feature. ---------------------------------	
	C.1	Declare required feature(s) inoperable when its redundant required feature(s) is inoperable.	12 hours from discovery of Condition C concurrent with inoperability of redundant required features
	AND		
	C.2	Restore one required offsite circuit to OPERABLE status.	24 hours

(continued)

SURVEILLANCE REQUIREMENTS (continued)

	SURVEILLANCE	FREQUENCY
SR 3.8.1.14	-----NOTE----- Momentary transients outside the load and power factor ranges do not invalidate this test. ---------- Verify each DG operates for ≥ 24 hours: a. For ≥ 2 hours loaded ≥ 6900 kW and ≤ 7700 kW; and b. For the remaining hours of the test loaded ≥ 6300 kW and ≤ 7000 kW.	18 months
SR 3.8.1.15	-----NOTES----- 1. This Surveillance shall be performed within 5 minutes of shutting down the DG after the DG has operated ≥ 2 hours loaded ≥ 6300 kW and ≤ 7000 kW. Momentary transients outside of load range do not invalidate this test. 2. All DG starts may be preceded by an engine prelube period. ---------- Verify each DG starts and achieves: a. in ≤ 10 seconds, voltage ≥ 6480 V and frequency ≥ 58.8 Hz; and b. steady state, voltage ≥ 6480 V, and ≤ 7150 V and frequency ≥ 58.8 Hz and ≤ 61.2 Hz.	18 months

(continued)

3.8 ELECTRICAL POWER SYSTEMS

3.8.9 Distribution Systems — Operating

LCO 3.8.9 Train A and Train B AC, DC, and AC vital bus electrical power distribution subsystems shall be OPERABLE.

APPLICABILITY: MODES 1, 2, 3, and 4

ACTIONS

CONDITION	REQUIRED ACTION		COMPLETION TIME
A. One AC electrical power distribution subsystem inoperable.	A.1	Restore AC electrical power distribution subsystem to OPERABLE status.	72 hours AND 80 hours from discovery of failure to meet LCO
B. One AC vital bus subsystem inoperable.	B.1	Restore AC vital bus subsystem to OPERABLE status.	2 hours AND 80 hours from discovery of failure to meet LCO

(continued)

ACTIONS (continued)

CONDITION	REQUIRED ACTION		COMPLETION TIME
C. One DC electrical power distribution subsystem inoperable.	C.1	Restore DC electrical power distribution subsystem to OPERABLE status.	2 hours AND 80 hours from discovery of failure to meet LCO
D. Required Action and associated Completion Time not met.	D.1	Be in MODE 3.	6 hours
	AND		
	D.2	Be in MODE 5.	36 hours
E. Two trains with inoperable distribution subsystems that result in a loss of safety function.	E.1	Enter LCO 3.0.3.	Immediately

SURVEILLANCE REQUIREMENTS

SURVEILLANCE		FREQUENCY
SR 3.8.9.1	Verify correct breaker alignments and voltage to required AC, DC, and AC vital bus electrical power distribution subsystems.	7 days

ATTACHMENT 6 to TXX-01077

RETYPED TECHNICAL SPECIFICATION BASES PAGES
(For Information Only)

Pages	**B 3.8-7**
	B 3.8-10
	B 3.8-24
	B 3.8-29
	B 3.8-78
	B 3.8-79
	B 3.8-81
	B 3.8-83
	B 3.8-84

BASES

ACTIONS (continued)

A.3

According to Reference 16, operation may continue in Condition A for a period that should not exceed 14 days. With one offsite circuit inoperable, the reliability of the offsite system is degraded, and the potential for a loss of offsite power is increased, with attendant potential for a challenge to the unit safety systems. In this Condition, however, the remaining OPERABLE offsite circuit and DGs are adequate to supply electrical power to the onsite Class 1E Distribution System.

The 14 day Completion Time is based on a risk-informed assessment to manage the risk associated with the equipment in accordance with the Configuration Risk Management Program (TS 5.5.18). The 14 day Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

The second Completion Time for Required Action A.3 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition A is entered while, for instance, a DG is inoperable and that DG is subsequently returned OPERABLE, the LCO may already have been not met for up to 14 days. This could lead to a total of 28 days, since initial failure to meet the LCO, to restore the offsite circuit. At this time, a DG could again become inoperable, the circuit restored OPERABLE, and an additional 14 days (for a total of 42 days) allowed prior to complete restoration of the LCO. The 28 day Completion Time provides a limit on the time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the 14 day and 28 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

As in Required Action A.2, the Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This will result in establishing the "time zero" at the time that the LCO was initially not met, instead of at the time Condition A was entered.

(continued)

BASES

ACTIONS (continued)

B.4

According to Reference 16, operation may continue in Condition B for a period that should not exceed 14 days.

In Condition B, the remaining OPERABLE DG and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. The 14 day Completion Time is based on a risk-informed assessment to manage the risk associated with the equipment in accordance with the Configuration Risk Management Program (TS 5.5.18). The 14 day Completion Time takes into account the capacity and capability of the remaining AC sources, a reasonable time for repairs, and the low probability of a DBA occurring during this period.

The second Completion Time for Required Action B.4 establishes a limit on the maximum time allowed for any combination of required AC power sources to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition B is entered while, for instance, an offsite circuit is inoperable and that circuit is subsequently restored OPERABLE, the LCO may already have been not met for up to 14 days. This could lead to a total of 28 days, since initial failure to meet the LCO, to restore the DG. At this time, an offsite circuit could again become inoperable, the DG restored OPERABLE, and an additional 14 days (for a total of 42 days) allowed prior to complete restoration of the LCO. The 28 day Completion Time provides a limit on time allowed in a specified condition after discovery of failure to meet the LCO. This limit is considered reasonable for situations in which Conditions A and B are entered concurrently. The "AND" connector between the 14 day and 28 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

As in Required Action B.2, the Completion Time allows for an exception to the normal "time zero" for beginning the allowed time "clock." This will result in establishing the "time zero" at the time that the LCO was initially not met, instead of at the time Condition B was entered.

C.1 and C.2

Required Action C.1, which applies when two offsite circuits are inoperable, is intended to provide assurance that an event with a coincident single failure will not result in a complete loss of redundant required safety functions. The Completion Time for this failure of redundant required features is reduced to 12 hours from that allowed for

(continued)

BASES

SURVEILLANCE REQUIREMENTS (continued)

SR 3.8.1.14

Regulatory Guide 1.9 (Ref. 3), requires demonstration once per 18 months that the DGs can start and run continuously at full load capability for an interval of not less than 24 hours, ≥ 2 hours of which is at a load equivalent to approximately 110% of the continuous duty rating and the remainder of the time at a load equivalent to 90% to 100% of the continuous duty rating of the DG. For the purposes of the 2 hour run, the minimum load is approximately 110% of the 6300 kW maximum design load in lieu of the 7000 kW continuous rating. The DG start for this Surveillance can be performed either from ambient or hot conditions. The provisions for prelubricating and warmup, discussed in SR 3.8.1.2, and for gradual loading, discussed in SR 3.8.1.3, are applicable to this SR.

The load band is provided to avoid routine overloading of the DG. Routine overloading may result in more frequent teardown inspections in accordance with vendor recommendations in order to maintain DG OPERABILITY.

The 18 month Frequency is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3), takes into consideration unit conditions required to perform the Surveillance, and is intended to be consistent with expected fuel cycle lengths.

This Surveillance is modified by a Note which states that momentary transients due to changing bus loads do not invalidate this test.

SR 3.8.1.15

This Surveillance demonstrates that the diesel engine can restart from a hot condition, such as subsequent to shutdown from normal Surveillances, and achieve the required voltage and frequency within 10 seconds. The 10 second time is derived from the requirements of the accident analysis to respond to a design basis large break LOCA. The 18 month Frequency is consistent with the recommendations of Regulatory Guide 1.9 (Ref. 3).

(continued)

BASES (continued)

REFERENCES

1. 10 CFR 50, Appendix A, GDC 17.
2. FSAR, Chapter 8.
3. Regulatory Guide 1.9 Rev 3, July 1993.
4. FSAR, Chapter 6.
5. FSAR, Chapter 15.
6. Regulatory Guide 1.93, Rev. 0, December 1974.
7. Generic Letter 84-15, "Proposed Staff Actions to Improve and Maintain Diesel Generator Reliability," July 2, 1984.
8. 10 CFR 50, Appendix A, GDC 18.
9. Regulatory Guide 1.108, Rev. 1, August 1977.
10. Regulatory Guide 1.137, January 1978.
11. ASME, Boiler and Pressure Vessel Code, Section XI.
12. IEEE Standard 308-1974.
13. IEEE Standard 387-1977
14. Generic Letter 94-01, "Removal of Accelerated Testing and Special Reporting Requirements for Emergency Diesel Generators," May 31, 1994.
15. ANSI C84.1
16. License Amendment Request (LAR) 01-06, Revision To Technical Specification, Extension Of Allowable Completion Times And Surveillance Requirement Change For Emergency Diesel Generators, Qualified Offsite Circuits, And AC Electrical Power Distribution Subsystem, Docket Nos. 50-445 and 50-446, CPSES.

BASES

LCO (continued)

OPERABLE AC electrical power distribution subsystems require the associated buses, and load centers, to be energized to their proper voltages. OPERABLE DC electrical power distribution subsystems require the associated buses to be energized to their proper voltage from either the associated battery or charger. OPERABLE vital bus electrical power distribution subsystems require the associated buses to be energized to their proper voltage from either the associated inverter via inverted DC voltage or the alternate bypass power supply via Class 1E transformers.

APPLICABILITY

The electrical power distribution subsystems are required to be OPERABLE in MODES 1, 2, 3, and 4 to ensure that:

a. Acceptable fuel design limits and reactor coolant pressure boundary limits are not exceeded as a result of AOOs or abnormal transients; and

b. Adequate core cooling is provided, and containment OPERABILITY and other vital functions are maintained in the event of a postulated DBA.

Electrical power distribution subsystem requirements for MODES 5 and 6 are covered in the Bases for LCO 3.8.10, "Distribution Systems — Shutdown."

ACTIONS

A.1

With one or more required AC buses or load centers except AC vital buses, in one train inoperable the remaining AC electrical power distribution subsystem in the other train is capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure. The overall reliability is reduced, however, because a single failure in the remaining power distribution subsystem could result in the minimum required ESF functions not being supported. Therefore, the required AC buses, and load centers, must be restored to OPERABLE status within 72 hours.

(continued)

BASES

ACTIONS

A.1 (continued)

Condition A worst scenario is one train without AC power (i.e., no offsite power to the train and the associated DG inoperable). In this Condition, the unit is more vulnerable to a complete loss of AC power. It is, therefore, imperative that the unit operator's attention be focused on minimizing the potential for loss of power to the remaining train by stabilizing the unit, and on restoring power to the affected train. The 72 day Completion Time is based on a risk-informed assessment to manage the risk associated with the equipment in accordance with the Configuration Risk Management Program (TS 5.5.18) (Reference 4). The 72 hour time limit before requiring a unit shutdown in this Condition is acceptable because of:

a. The potential for decreased safety if the unit operator's attention is diverted from the evaluations and actions necessary to restore power to the affected train, to the actions associated with taking the unit to shutdown within this time limit; and

b. The potential for an event in conjunction with a single failure of a redundant component in the train with AC power.

The second Completion Time for Required Action A.1 establishes a limit on the maximum time allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition A is entered while, for instance, a DC bus is inoperable and subsequently restored OPERABLE, the LCO may already have been not met for up to 2 hours. This could lead to a total of 74 hours, since initial failure of the LCO, to restore the AC distribution system. At this time, a DC circuit could again become inoperable, and AC distribution restored OPERABLE. This could continue indefinitely.

The Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This will result in establishing the "time zero" at the time the LCO was initially not met, instead of the time Condition A was entered. The 80 hour Completion Time is an acceptable limitation on this potential to fail to meet the LCO indefinitely.

(continued)

BASES

ACTIONS

B.1 (continued)

The 2 hour Completion Time takes into account the importance to safety of restoring the AC vital bus to OPERABLE status, the redundant capability afforded by the other OPERABLE vital buses, and the low probability of a DBA occurring during this period.

The second Completion Time for Required Action B.1 establishes a limit on the maximum allowed for any combination of required distribution subsystems to be inoperable during any single contiguous occurrence of failing to meet the LCO. If Condition B is entered while, for instance, an AC bus is inoperable and subsequently returned OPERABLE, the LCO may already have been not met for up to 72 hours. This could lead to a total of 74 hours, since initial failure of the LCO, to restore the vital bus distribution system. At this time, an AC train could again become inoperable, and vital bus distribution restored OPERABLE. This could continue indefinitely.

This Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This will result in establishing the "time zero" at the time the LCO was initially not met, instead of the time Condition B was entered. The 80 hour Completion Time is an acceptable limitation on this potential to fail to meet the LCO indefinitely.

C.1

With DC bus(es) in one train inoperable the remaining DC electrical power distribution subsystems are capable of supporting the minimum safety functions necessary to shut down the reactor and maintain it in a safe shutdown condition, assuming no single failure. The overall reliability is reduced, however, because a single failure in the remaining DC electrical power distribution subsystems could result in the minimum required ESF functions not being supported. Therefore, the required DC buses must be restored to OPERABLE status within 2 hours by powering the bus from the associated battery or charger.

(continued)

BASES

ACTIONS

C.1 (continued)

may already have been not met for up to 72 hours. This could lead to a total of 74 hours, since initial failure of the LCO, to restore the DC distribution system. At this time, an AC train could again become inoperable, and DC distribution restored OPERABLE. This could continue indefinitely.

This Completion Time allows for an exception to the normal "time zero" for beginning the allowed outage time "clock." This will result in establishing the "time zero" at the time the LCO was initially not met, instead of the time Condition C was entered. The 80 hour Completion Time is an acceptable limitation on this potential to fail to meet the LCO indefinitely.

D.1 and D.2

If the inoperable distribution subsystem cannot be restored to OPERABLE status within the required Completion Time, the unit must be brought to a MODE in which the LCO does not apply. To achieve this status, the unit must be brought to at least MODE 3 within 6 hours and to MODE 5 within 36 hours. The allowed Completion Times are reasonable, based on operating experience, to reach the required unit conditions from full power conditions in an orderly manner and without challenging plant systems.

E.1

Condition E corresponds to inoperable distribution subsystems that result in a loss of safety function, adequate core cooling, containment OPERABILITY and other vital functions for DBA mitigation would be compromised, and immediate plant shutdown in accordance with LCO 3.0.3 is required.

(continued)

BASES (continued)

SURVEILLANCE REQUIREMENTS

SR 3.8.9.1

This Surveillance verifies that the required AC, DC, and AC vital bus electrical power distribution systems are functioning properly, with the correct circuit breaker alignment. The correct breaker alignment ensures the appropriate separation and independence of the electrical divisions is maintained, and the appropriate voltage is available to each required bus. The verification of proper voltage availability on the buses ensures that the required voltage is readily available for motive as well as control functions for critical system loads connected to these buses. The 7 day Frequency takes into account the redundant capability of the AC, DC, and AC vital bus electrical power distribution subsystems, and other indications available in the control room that alert the operator to subsystem malfunctions.

REFERENCES

1. FSAR, Chapter 6.
2. FSAR, Chapter 15.
3. Regulatory Guide 1.93, December 1974.
4. License Amendment Request (LAR) 01-06, Revision To Technical Specification, Extension Of Allowable Completion Times And Surveillance Requirement Change For Emergency Diesel Generators, Qualified Offsite Circuits, And AC Electrical Power Distribution Subsystem, Docket Nos. 50-445 and 50-446, CPSES.

ATTACHMENT 7 to TXX-01077

Commitments

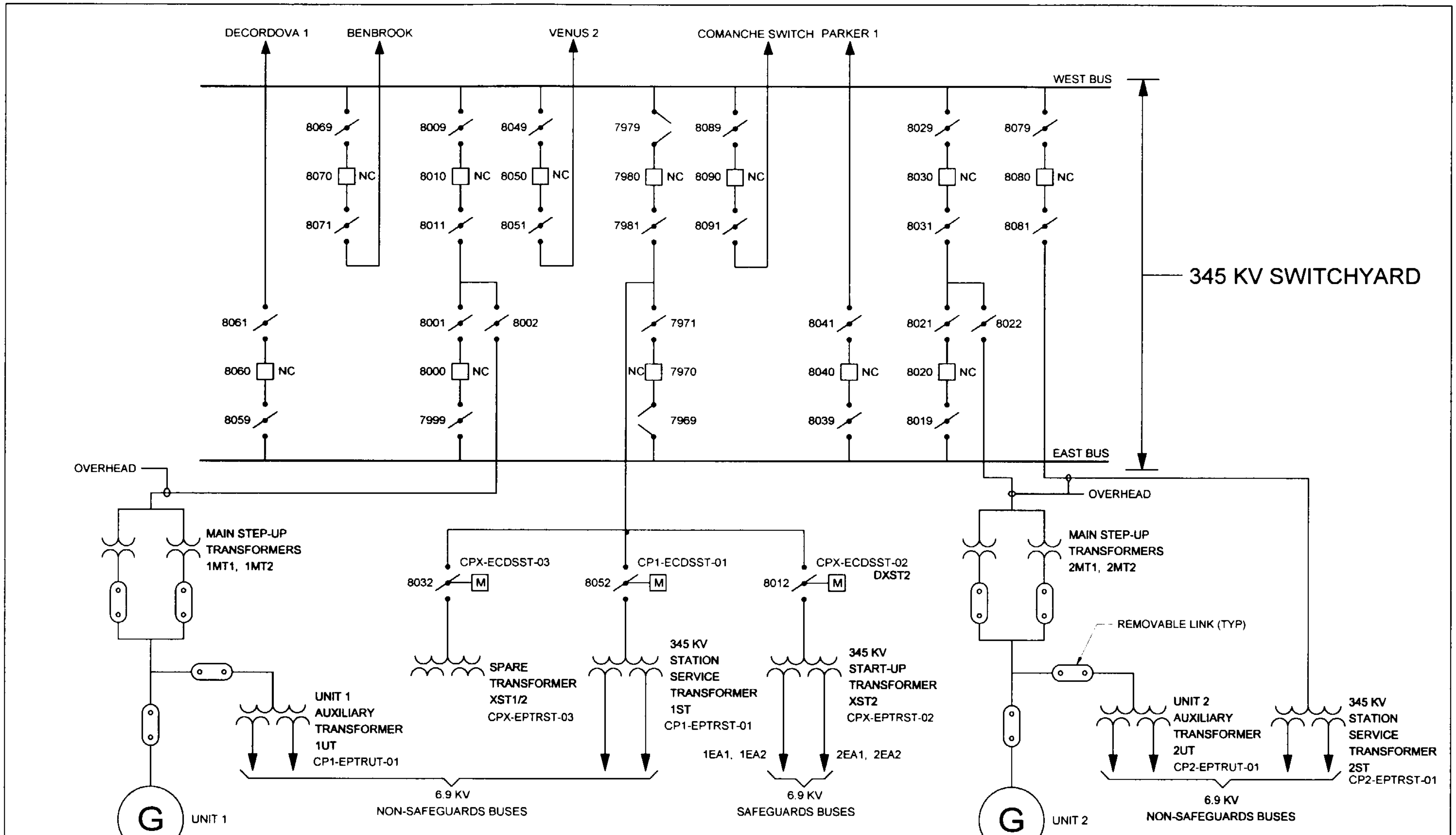
This communication contains the following new commitments which will be completed as noted:

Commitment Number	Commitment
27226	When performing SR 3.8.1.1.14 during MODES 1 or 2, only one EDG per unit will be in parallel with the offsite source at a time in order to prevent any grid disturbances from potentially affecting more than one EDG. (page 12 of Attachment 2 to TXX-01077)
27227	No actions will be taken to affect the operability of the unit's remaining EDG and its support systems throughout the surveillance test (SR 3.8.1.1.14), and no actions will be taken to affect the capability of the onsite Class 1E AC electrical distribution system and its support systems to complete plant shutdown and maintain safe shutdown conditions following a DBA. If the EDG fails the 24-hour endurance test, it will be inoperable and the appropriate TS Required Actions will be taken. (page 12 of Attachment 2 to TXX-01077)

The commitment number is used by TXU Electric for the internal tracking of CPSES commitments.

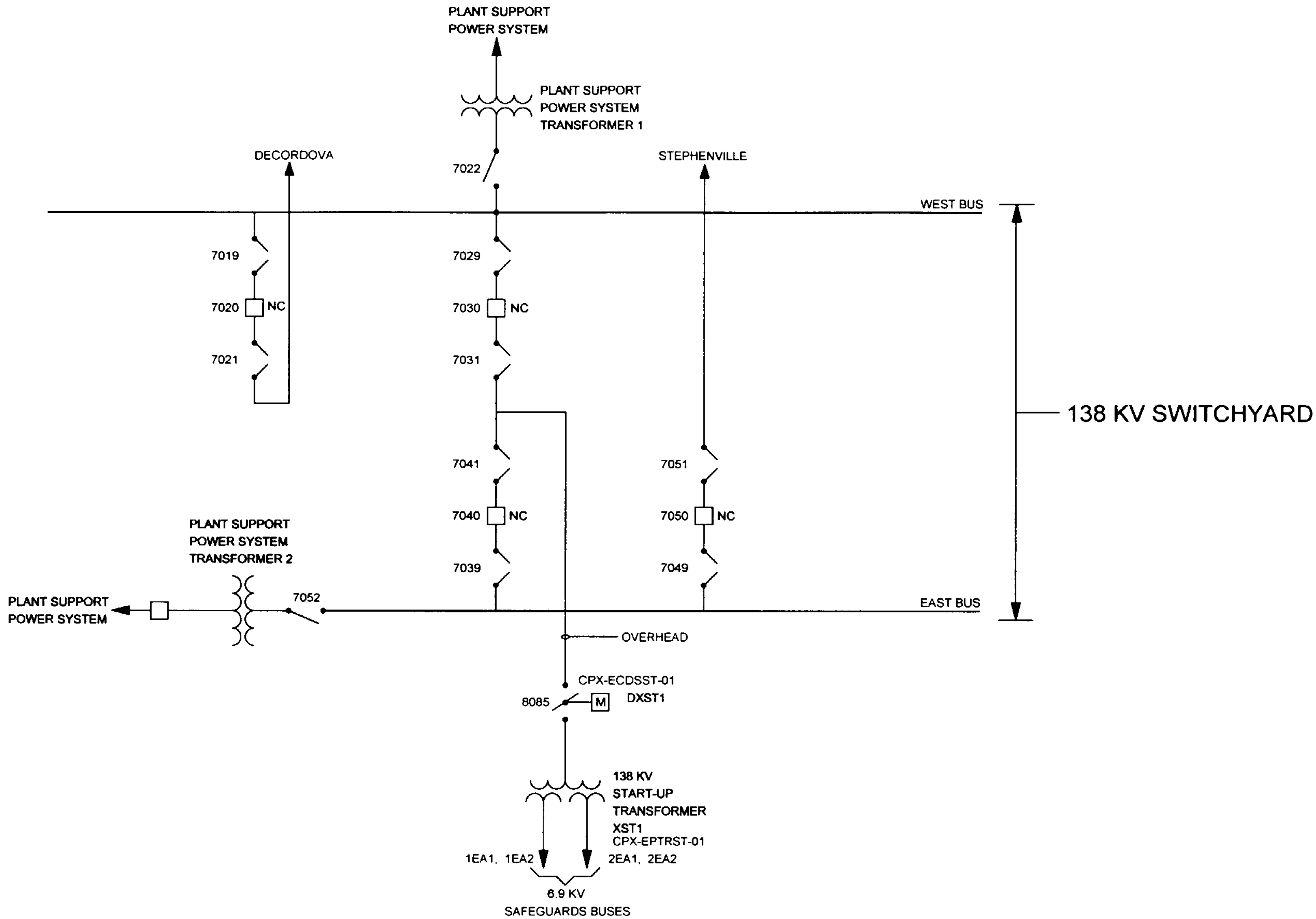
ATTACHMENT 8 to TXX-01077

Figures (4 Figures + this page = 5 pages)



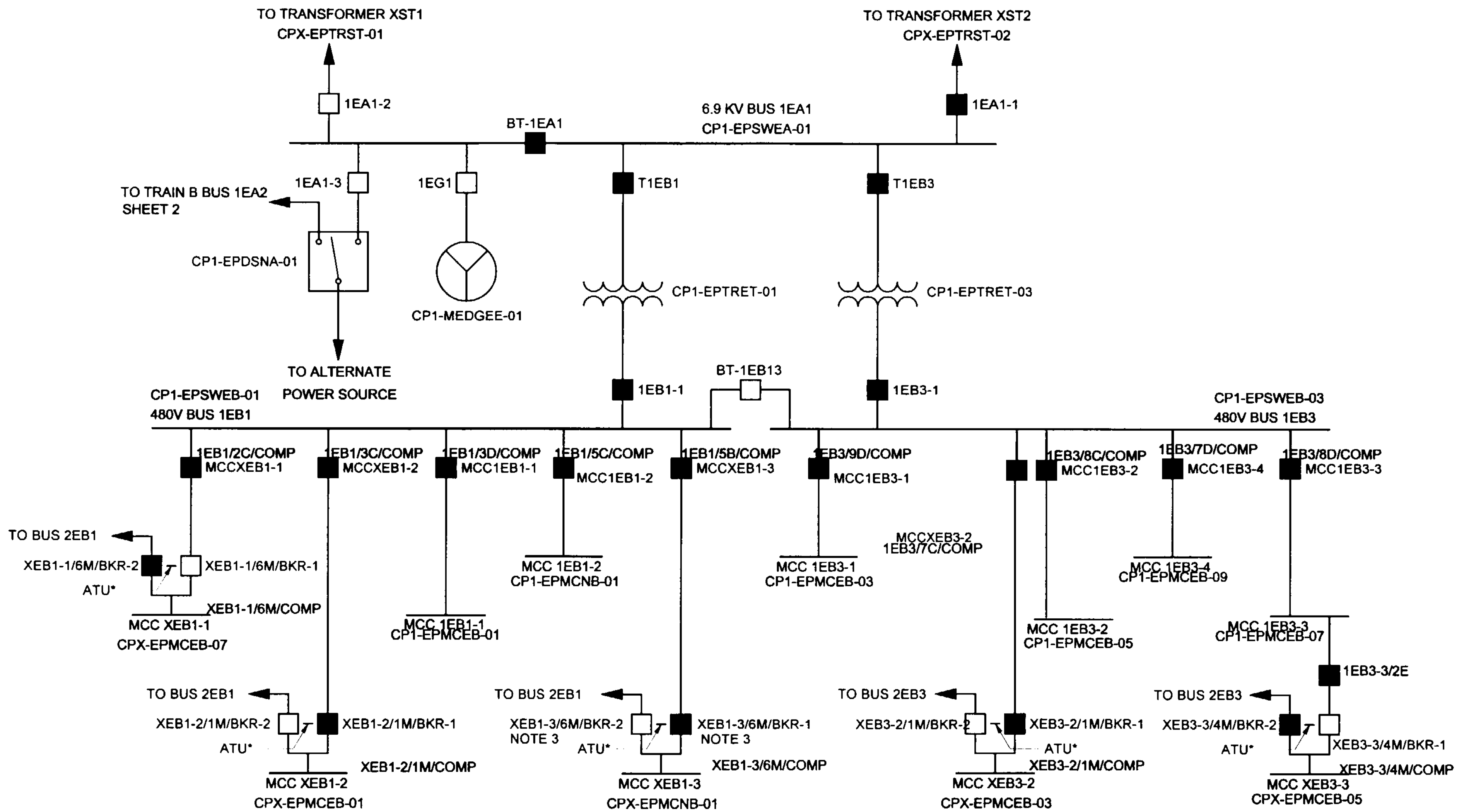
ELECTRIC POWER SYSTEM
HIGH VOLTAGE SWITCHYARDS
SIMPLIFIED SCHEMATIC
SHEET 1 OF 2

This simplified drawing is provided for graphical representation only.



ELECTRIC POWER SYSTEM
HIGH VOLTAGE SWITCHYARDS
SIMPLIFIED SCHEMATIC
SHEET 2 OF 2

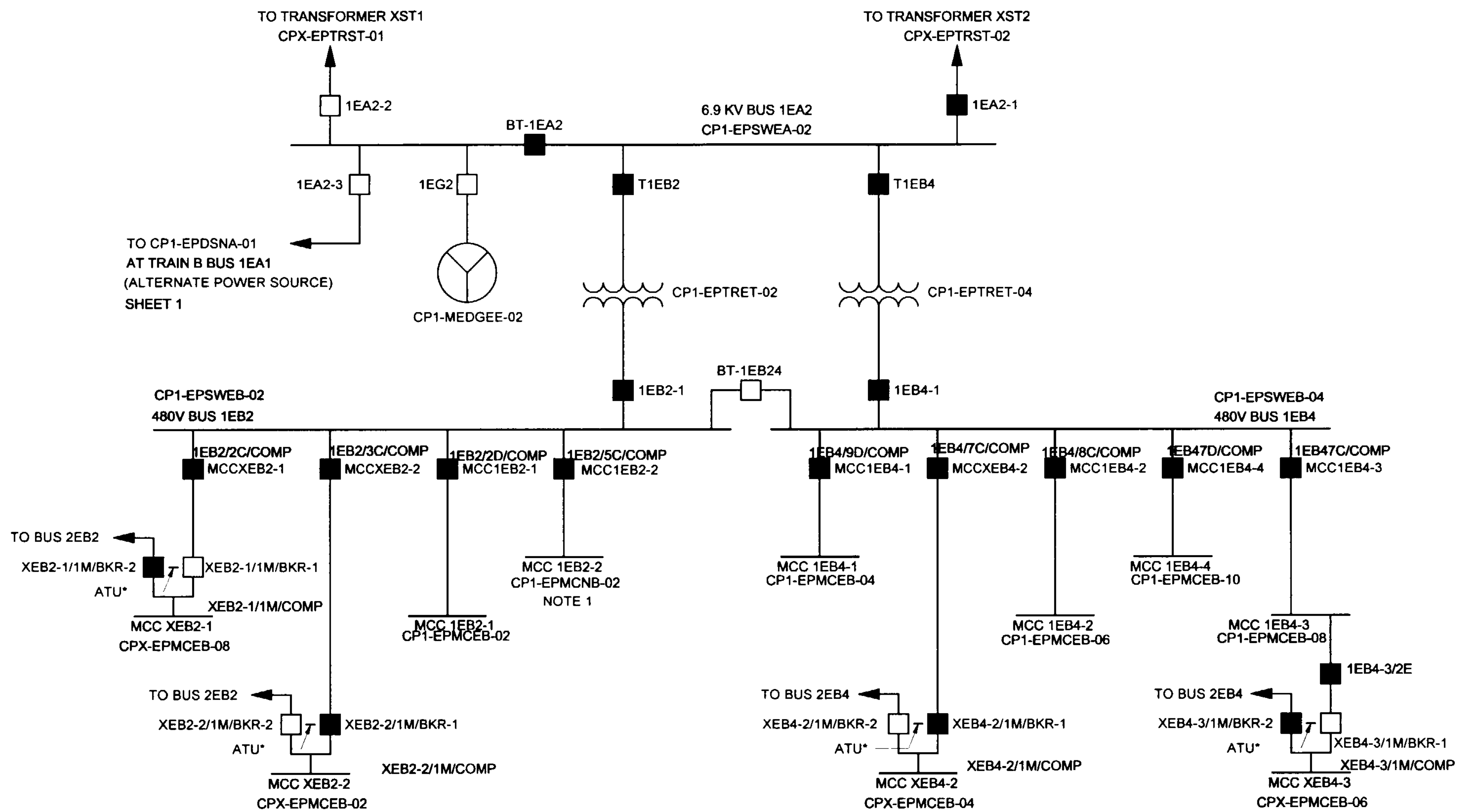
This simplified drawing is provided for graphical representation only.



LEGEND:
* AUTOMATIC TRANSFER UNIT

ELECTRIC POWER SYSTEM
CLASS 1E AC POWER SYSTEM - TRAIN A
SIMPLIFIED SCHEMATIC
SHEET 1 OF 2

This simplified drawing is provided for graphical representation only.



LEGEND:
* AUTOMATIC TRANSFER UNIT

ELECTRIC POWER SYSTEM
CLASS 1E AC POWER SYSTEM - TRAIN B
SIMPLIFIED SCHEMATIC
SHEET 2 OF 2

This simplified drawing is provided for graphical representation only.