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

Mike Blevins
Senior Vice President &
Chief Nuclear Officer

Ref: 10CFR50.90

CPSES-200700146
Log # TXX-07012
File # 00236

January 18, 2007

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) 06-007
REVISION TO TECHNICAL SPECIFICATION (TS) 3.8.1, "AC SOURCES – OPERATING," EXTENSION OF COMPLETION TIMES FOR OFFSITE CIRCUITS

REF: 1. TXU Power letter, logged TXX-06172, from Mike Blevins to the U.S. Nuclear Regulatory Commission, dated October 31, 2006.

Dear Sir or Madam:

On December 11, 2006, during a conference call between the NRC and TXU Power staff, the NRC suggested that CPSES withdraw License Amendment Request (LAR) 06-007, "Revision to Technical Specifications (TS) 3.8.1, 'AC Sources – Operating,' Extension of Completion Times for Offsite Circuits." The NRC suggested that CPSES revise the LAR submitted in Reference 1 to more fully address the treatment of external events, i.e., fires and floods, in addition to other PRA issues. As suggested, CPSES withdrew the LAR and agreed to resubmit it by January 19, 2007 with revised PRA analysis. The present submittal replaces Reference 1 above.

Pursuant to 10CFR50.90, TXU Generation Company LP (TXU Power) 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 (TS). This change request applies to both units.

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The proposed changes will revise TS 3.8.1 for "AC Sources – Operating" to extend the allowable Completion Time (CT) associated with restoration of an inoperable offsite circuit (i.e., Startup Transformer (ST)). The extended CT establishes a 30 day allowable out of service time when one ST is inoperable. The 30 day CT is based on a plant specific risk analysis performed to establish the out of service time. This change is needed to ensure the continued long term reliability of 345 kV and 138 kV offsite circuit STs which are common to both CPSES units. NRC approval of this request would allow sufficient time to perform maintenance on one ST while both units remain at power.

TXU Power's evaluation of the proposed changes includes traditional engineering analyses as well as a risk informed approach as set forth in the guidance of Regulatory Guide (RG) 1.174, "An Approach for Using Probabilistic Risk Assessment In Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis," and RG 1.177, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications."

The risk increase associated with this proposed CT extension is considered small according to the guidelines contained in RG 1.177. In addition, based on the risk graphs in RG 1.174, the change in core damage probability and the change in large early release probability are not considered significant when ST maintenance is completed while both CPSES units remain at power. The requested CT extension for maintenance on the STs is supported by probabilistic evaluations presented in Section 4.2 of Attachment 1.

The justification for these changes is based upon a risk-informed, deterministic evaluation consisting of three main elements: (1) the reliability and availability of offsite power via separate and physically independent offsite circuit startup transformers, (2) an assessment of risk that shows an acceptably small increase in risk (as indicated by Core Damage Frequency (CDF) and Large Early Release Frequency (LERF)), and (3) continued implementation of a Configuration Risk Management Program (CRMP). These elements provide the basis for the requested TS changes 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 CT.

Attachment 1 provides a detailed description of the proposed changes, a technical analysis of the proposed changes, TXU Power'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 2 provides the affected TS pages marked-up to reflect the proposed changes. Attachment 3 provides proposed changes to the TS Bases for information only. These changes will be processed per CPSES site procedures. Attachment 4 provides retyped TS pages which incorporate the requested changes. Attachment 5 provides retyped TS Bases pages which incorporate the proposed changes.

TXU Power requests approval of the proposed License Amendment by September 1, 2007, to be implemented within 120 days. The plant does not require this amendment to allow continued safe full power operations although approval is required to support planned transformer maintenance in the fall of 2007.

In accordance with 10CFR50.91(b), TXU Power is providing the State of Texas with a copy of this proposed amendment.

This communication contains no new or revised commitments.

Should you have any questions, please contact Ms. Tamera J. Ervin at (254) 897-6902.

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

Executed on January 18, 2007.

Sincerely,

TXU Generation Company LP

By: TXU Generation Management Company LLC
Its General Partner

Mike Blevins

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

TJE

Attachments

1. Description and Assessment
2. Markup of Technical Specifications Pages
3. Markup of Technical Specifications Bases Pages (for information)
4. Retyped Technical Specification Pages
5. Retyped Technical Specification Bases Pages (for information)
6. Comanche Peak Switchyards and Distribution Subsystem Figures (for information)

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

Ms. Alice Rogers
Environmental & Consumer Safety Section
Texas Department of State Health Services
1100 West 49th Street
Austin, Texas 78756-31

ATTACHMENT 1 to TXX-07012

DESCRIPTION AND ASSESSMENT

LICENSEE'S EVALUATION

1.0 DESCRIPTION

By this letter, TXU Generation Company LP (TXU Power) requests a License 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 (TS).

The proposed changes will revise Technical Specification 3.8.1 for "AC Sources – Operating" Required Action A.3 to extend the allowable Completion Time (CT) associated with restoration of an inoperable offsite source (i.e., startup transformer (ST)) from 72 hours to 30 days. The proposed 30 day CT is based on a plant specific risk analysis performed to establish the out of service time.

The license amendment request also proposes to revise the second CT for Required Actions A.3 and B.4 from 6 days to 33 days to reflect the ST CT extension. The second CT establishes a limit on the maximum time allowed for any combination of required AC electrical sources to be inoperable during any single contiguous occurrence of failing to meet the Limiting Condition for Operation (LCO).

The requested changes are based upon CPSES plant specific risk-informed and deterministic evaluations performed in a manner consistent with the risk-informed approaches endorsed by Regulatory Guides 1.174 (Reference 8.1) and 1.177 (Reference 8.2). The proposed changes would increase operational flexibility and provide additional allowances for performance of testing, repairs, and periodic maintenance while at power.

2.0 PROPOSED CHANGE

TXU Power's requested changes to Technical Specifications (TS) 3.8.1 are summarized below. The proposed changes to TS 3.8.1 are shown in Attachment 2.

On page 3.8-2 of TS 3.8.1 "AC Sources – Operating," the Completion Time (CT) for Required Action A.3 reads, "72 hours AND 6 days from discovery of failure to meet LCO." The proposed change will revise the CT to read, "30 days AND 33 days from discovery of failure to meet LCO."

On Page 3.8-4 of TS 3.8.1, the Required Action B.4 reads, "72 hours AND 6 days from discover of failure to meet LCO." The proposed change will revise the CT to read, "72 hours AND 33 days from discovery of failure to meet LCO."

For information only, this LAR includes markups in Attachment 3 indicating proposed associated changes to the Bases for TS 3.8.1, "AC Sources – Operating." Retyped TS pages and TS Bases pages which incorporate the proposed changes are provided in Attachments 4 and 5, respectively.

In summary, the proposed changes will revise TS 3.8.1 for "AC Sources – Operating" Required Action to extend the CT for an inoperable offsite circuit from 72 hours to 30 days. Furthermore, the second CTs for Required Actions A.3 and B.4 will be revised to reflect the CT extension.

3.0 BACKGROUND

The Completion Time (CT) extension for the offsite circuit startup transformers (STs) is expected to be used for performing maintenance activities. In order to perform maintenance on either ST, XST1 or XST2, that would exceed the current CT of 72 hours, both CPSES units would be required to be in cold shutdown (Mode 5) simultaneously. This is due to the fact that each ST provides one of the two required offsite power sources to both Unit 1 and Unit 2 and both units are required to maintain two offsite power sources when in Modes 1-4. Based on experience with similar transformers, preventive maintenance could not be completed in the relatively short duration currently allowed by TS 3.8.1 Required Actions.

TXU Power does not anticipate planned outage schedules to include overlapping or simultaneous shutdowns of both units of sufficient duration to perform the recommended ST preventive maintenance. Given the importance of offsite power sources, it is prudent to maintain them in a reliable condition while minimizing their unavailability.

3.1 System Description

The offsite AC power circuits for CPSES consist of two physically independent circuits from separate switchyards with startup transformers sized to simultaneously carry essential plant loads for both units. Two independent emergency diesel generators (DGs) per unit supply onsite AC power.

Reliability and Availability of the Offsite Power System

The transmission lines of TXU Electric Delivery (ED) (also known as CPSES' Transmission and or Distribution Service Provider (TDSP)) comprise an integrated system with operations coordinated by the System Dispatcher so as to maintain system reliability. Transmission systems consist of 345 kilovolts (kV) lines for bulk supply and 138 kV and 69 kV lines to transmit power to load-serving substations. Generation sources connected to ED's transmission system include fossil fuel plants (lignite, gas/oil, and combustion turbines) and the CPSES nuclear plant. Direct ties to other utilities in Texas are maintained by the Electric Reliability Council of Texas (ERCOT), creating a highly reliable integrated system.

The CPSES output is connected to the 345 kV transmission system via the CPSES switchyard. Startup and shutdown power for the units is derived from the 138 kV and 345 kV systems. Separate connections to the 138 kV switchyard and the 345 kV switchyard provide independent and reliable offsite power sources to the Class 1E systems for both units. The highly reliable network interconnections are made through five 345 kV and two 138 kV transmission lines as shown on the figures in Attachment 6.

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 via startup transformer (ST) XST2; the preferred source to Unit 2 is the 138 kV offsite supply from the 138 kV switchyard via ST XST1. Each of the STs (XST1 and XST2) normally energizes its related 6.9 kV AC Class 1E buses as a preferred source; i.e., XST1 normally energizes Unit 2 Class 1E buses and XST2 normally energizes Unit 1 Class 1E buses.

The preferred power sources supply power to the Class 1E buses during plant startup, normal operation, emergency shutdown, and upon a unit trip. This eliminates the need for automatic transfer of safety-related loads in the event of a unit trip.

Each ST has the capacity to supply the required Class 1E loads of both units during all modes of plant operation. In the event one ST (e.g., XST1, a preferred source) becomes unavailable to its Class 1E buses, power is made available from the other ST (e.g., XST2, an alternate source) by an automatic transfer scheme. For the loss of a ST, the load transfer only takes place in the unit for which the transformer was the preferred source. If it becomes necessary to safely shutdown both units simultaneously, 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 although the design criteria require consideration of a Design Basis Accident (DBA) on one unit only.

Reliability and Availability of the Onsite Standby 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 power when the preferred and the alternate offsite power sources are not available. Four independent diesel generator (DG) sets, two per unit, are provided.

Loads important to plant safety are divided into redundant divisions. Each division is provided with standby power from a dedicated DG. Each DG is directly connected to its dedicated bus. The DGs are physically and electrically independent. With this arrangement, redundant components of all engineered safety feature (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 DGs, the loss of any one of the DGs will not prevent the safe shutdown of the unit. The total standby power system, including DGs and electrical power distribution equipment, satisfies the single failure criterion.

A DG is automatically started by a safety injection signal or an under-voltage condition on the 6.9 kV ESF bus served by the DG. 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 DGs and close its output breaker. Sequential loading of the DG is automatically performed as a result of sequential loading of its dedicated bus.

The DG output breaker will close to its dedicated 6.9 kV Class 1E bus automatically only if the other source feeder breakers to the bus are open. When the DG output breaker is closed, no other source feeder breaker will close automatically. Design and procedural controls ensure that no means exist for connecting redundant buses with each other.

The design basis for the DGs is that the loss of one DG will not result in the inability to perform a safety function. With two DGs available per unit, the system is capable of performing its intended safety function with an assumed single failure of one DG.

Station Blackout (SBO)

Comanche Peak Steam Electric Station (CPSES) 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 8.4) as discussed in Section 4.

FSAR References

Related background in the CPSES FSAR (Reference 8.3) is found primarily in Section 1A(B) and Section 8. Compliance with NRC design criteria is described in detail in FSAR Section 8.1, "INTRODUCTION" and in FSAR Appendix 1A(B) "APPLICATION OF NRC REGULATORY GUIDES." Onsite power systems are described in FSAR Section 8.3 and Station Blackout is described in Appendix 8B of the FSAR.

3.2 Purpose of Amendment

This proposed amendment request changes the CPSES TS to extend the required CT for restoration of an inoperable offsite circuit from 72 hours to 30 days. The proposed change is needed to ensure the continued long term reliability of the offsite circuit STs. CPSES intends to use the proposed CT to perform corrective and preventive maintenance on the STs. Thirty days has been requested to ensure the CT can be met even with emergent issues and to minimize the potential for a required shutdown of both units to cold shutdown conditions simultaneously. The proposed CT of 30 days is adequate to perform the proposed preventive maintenance requiring disassembly of the transformer and to perform post-maintenance and operability tests required to return the offsite circuit to operable status.

In order to perform maintenance on a ST, both CPSES units would need to be in the cold shutdown state simultaneously for an extended period of time. This is due to the fact that each ST provides one of the two required offsite power sources to both Unit 1 and Unit 2 and both units are required to maintain two offsite power sources when in Modes 1-4. Based on experience with similar transformers, the preventive maintenance could not be completed in the relatively short duration currently allowed by TS 3.8.1 Required Actions. As will be discussed below, little preventive maintenance could be performed in such a short period of time.

TXU Power does not anticipate planned outage schedules to include overlapping or simultaneous shutdown of both units of sufficient duration to perform the recommended ST preventive maintenance. Given the importance of offsite power sources, it is prudent to maintain them in a reliable condition while minimizing their unavailability. ED has gained experience with similar type transformers installed in their transmission system and has identified the need to perform preventive maintenance on CPSES' offsite circuit STs. Additionally, ED has performed similar maintenance on other like transformers at CPSES within approximately 22 days and less. Moreover, ED has successfully performed the maintenance on similar transformers in the TXU ED transmission system.

XST1 and XST2 are forced oil and air (FOA), 58.33 MVA transformers, tapped at 138 kV/6.9 kV and 345 kV/6.9 kV, respectively. Routine preventive maintenance has been performed on these transformers approximately every three years. The routine preventive maintenance can be performed during power or shutdown operation of either unit. The routine preventive maintenance does not expose the transformer internals to outside air and typically requires approximately 36 hours to complete from the time the transformer is taken out of service until the time the safety related buses are restored to operable.

Any preventive maintenance that removes transformer oil could allow air and moisture to be admitted to the transformer internals, thus this type of maintenance is typically scheduled every ten years, or as determined necessary by gas analysis. Maintenance of this nature requires subsequent oil processing and consequently longer outage times to restore the transformer to operating conditions. The typical time to process transformer oil is 14 days.

Table 1 details the proposed preventive maintenance activities for the STs. The activities listed in this table envelope the routine maintenance performed every three years. These activities add no additional length to the estimated duration of the transformer outage. The estimated hours for each set of activities assume that work is performed around the clock, 24 hours a day and 7 days a week, as applicable, with some exceptions. Twenty four hour coverage will be possible for all activities except for removing and regasketing coolers, pumps, and bushings, cleaning and inspecting the transformer, and bus work and diagnostic testing.

MAINTENANCE ACTIVITY	ESTIMATED DURATION
Remove transformer from service and danger tag	1/2 day
Drain oil and calibrate instrumentation and relaying	1 day
Remove and regasket coolers and pumps* Replace and regasket bushings* Clean and inspect transformer*	5 days
Place transformer on vacuum for moisture removal Hot oil circulation and evacuate oil under vacuum Vacuum processing Process oil (Degassing) and oil fill	14 days
Bus work and diagnostic testing*	1 day
Trip test, deluge, and restore to power	1/2 day
TOTAL	**22 DAYS**

Table 1. Startup Transformer Maintenance Activity

* These activities should be performed during daylight hours only due to the high possibility of foreign material entering the ST when it is opened, the hazards to personnel and equipment safety, and the close proximity to transformer 1ST and other equipment.

The routine maintenance activities incorporated within the activities listed in Table 1 include:

- Relay and metering calibrations
- Instrumentation calibrations
- External cleaning and inspection
- Cleaning and inspection of affected breaker cubicle
- Cleaning and inspection of grounding resistor bank

In addition, the following provision will help to minimize the transformer outage time:

- Service and support equipment will be pre-staged
- Replacement parts will be pre-staged
- Experienced personnel will be available
- Pre-job briefs will be conducted with affected departments

Therefore, TXU Power requests a CT of 30 days in order to provide time, with sufficient margin for unforeseen or unpredictable circumstances, to complete extensive pre-planned preventive or corrective transformer maintenance activities.

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 United States Nuclear Regulatory Commission (NRC) Safety Goal Policy Statement (Reference 8.5), and the acceptance criteria in Regulatory Guide (RG) 1.174, "An Approach for Using Probabilistic Risk Assessment In Risk-Informed Decisions On Plant-Specific Changes to the Licensing Basis," July 1998, (Reference 8.1) and RG 1.177, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications," August 1998 (Reference 8.2) are met.

The justification for the use of a 30 day Completion Time (CT) for the offsite sources is based upon a risk-informed deterministic evaluation consisting of three main elements: (1) the reliability and availability of offsite power via separate and physically independent offsite circuit startup transformers, (2) assessment of risk that shows an acceptable small increase in risk (as indicated by Core Damage Frequency (CDF) and Large Early Release Frequency (LERF)), and (3) continued implementation of a Configuration Risk Management Program (CRMP) when a Startup Transformer (ST) is removed from service. The CRMP is used to assess the risk impact due to taking a ST out of service (as it is similarly applied to other maintenance and testing work) and helps ensure that there is no significant increase in the risk of a severe accident while the transformer is out of service. These elements provide the bases for the proposed TS change by providing a high degree of assurance that power can be provided to the engineered safety feature (ESF) buses should a design basis accident (DBA) occur while the ST is out of service.

4.1 Traditional Engineering Considerations

Defense-in-depth

The impacts 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.

The unavailability of one ST is already considered in the plant design and is allowed by the current Comanche Peak Steam Electric Station (CPSES) TS. The increased outage time for a ST has no effect 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.

CPSES is designed and operated consistent with the defense-in-depth philosophy. The units have diverse power sources available (e.g., diesel generators (DGs) and STs) to cope with a loss of the preferred alternating current (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 ST maintenance activities and the ST planned preventive maintenance will further ensure the continued long term reliability of the transformers. It is therefore, acceptable, under certain controlled conditions, to extend the CT and perform on-line maintenance intended to maintain the reliability of the onsite emergency power systems.

Even with one ST out of service there are multiple means to accomplish safety functions and prevent release of radioactive material. The CPSES probabilistic risk assessment (PRA) (see Section 4.2 below) 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, the risk increase associated with this proposed CT extension is considered small, according to the guidelines contained in RG 1.177. In addition, based on the risk graphs in RG 1.174, these values indicate that the change in CDF and LERF is not considered significant when maintenance on one ST is completed at power. 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 administrative controls to assure adequate defense-in-depth whenever a ST is out of service. 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 ST maintenance activities whether they are performed on-line or during shutdown. The maintenance activities are not affected by this change with the exception that sufficient time will be available to perform the ST maintenançe while both units remain on-line. No other new actions are necessary.

- **Station Blackout (SBO)**

  CPSES is able to withstand, and recover from, a SBO event of a 4 hour duration in accordance with the guidelines of RG 1.155, "Station Blackout," dated August 1988 (Reference 8.4). The 4 hour coping duration was determined by approved methods based on the redundancy and reliability of onsite emergency AC power sources, the expected frequency of loss of offsite power, and the probable time needed to restore offsite power.

  Assumptions relevant to the proposed changes and used in the SBO analysis include:

  1. One unit at the CPSES site is assumed to be in a station blackout condition. The other unit is assumed to have one emergency DG available.
  2. One emergency DG is capable of powering one train of those safety-related systems which are common to both Units 1 and 2.
  3. Per NUMARC 87-00 (Reference 8.6), NRC Staff analysis reports the median AC power restoration time for all LOOP events to be about 1/2 hour, with offsite power restored in approximately 3 hours for 90% of all events.
  4. As stated in NUMARC 87-00, since a number of failures must occur to result in a station blackout event, additional independent failures are of secondary importance.
  5. Following the loss of all AC power, the reactor will shutdown automatically since the control rod drive mechanism rod drive motor generator sets will lose power.

  The proposed changes are bounded by these assumptions. Therefore, the assumptions used in the SBO analysis are unaffected by this proposed change. The results of the SBO analysis are also unaffected by this proposed 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" and in FSAR Appendix 1A(B) "APPLICATION OF NRC REGULATORY GUIDES." 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 8.7) as discussed in Appendix 1A(B) of the FSAR is not affected by this change.

These proposed changes do not add any loads to the DGs; therefore, the selection of the capacity of the DGs 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 8.8) are not affected by this change.

CPSES conformance with Regulatory Guide 1.81, Revision 1, dated January 1975, titled "Shared Emergency and Shutdown Electric Systems for Multi-unit Nuclear Power Plants," (Reference 8.9) is described in detail in Appendix 1A(B) to the FSAR.

CPSES conformance with RG 1.93, Revision 0, dated December 1974, titled "Availability of Electric Power Sources," (Reference 8.10) is described in Appendix 1A(B) to the FSAR. The station currently conforms to RG 1.93, specifically the 72 hour CT and the proviso that the operating time limits are explicitly for corrective maintenance activities only. If the proposed changes are approved, the station will continue to conform to RG 1.93 with the exceptions that the CT for Required Actions associated with the restoration of an offsite AC circuit will be 30 days and the CT may be used for all ST maintenance.

CPSES commitments to conformance with other key design criteria applicable to onsite electrical systems are unaffected by these proposed changes. These commitments include: RG 1.53, dated June 1973, titled, "Application of Single-Failure Criterion to Nuclear Power Plant Protection Systems," (Reference 8.11); RG 1.62, dated October, 1973, titled "Manual Initiation of Protective Actions," (Reference 8.12); and RG 1.75, Revision 1, dated January 1975, titled "Physical Independence of Electrical Systems" (Reference 8.13).

Application of the Configuration Risk Management Program

Methodologies (Configuration Risk Management Program (CRMP)) associated with risk monitoring and contingency action planning currently exist at CPSES and provide an acceptable risk profile during periods of equipment inoperability. The CRMP will be applied throughout the duration of the extended outage per TS 5.5.18.

Plant procedures require management approval for entry into a limiting condition for operation (LCO) for planned maintenance activities that would exceed 50% of the required LCO CT. Thus if the planned ST maintenance activity requires greater than 50% of the requested CT, existing plant procedures would ensure specific management attention and heightened plant awareness in support of the planned activity.

Operator, maintenance, and management focus will be maximized by scheduling performance of this maintenance on-line when no other significant activities are taking place (as opposed to an outage, for example, where many competing tasks are occurring at the same time). The ST outage would be scheduled to ensure the availability of experienced manpower and technical support personnel, as well as to reduce the potential for distraction due to competing job demands.

Station procedure STA-604, "Configuration Risk Management and Work Scheduling" implements the requirements of TS 5.5.18, "Configuration Risk Management Program (CRMP)." Procedure STA-604, along with other station procedures, provides the administrative controls to ensure that equipment important to accident mitigation remains operable and available for the duration of a planned ST maintenance outage. For example, to minimize risk during a planned maintenance outage of a ST, maintenance and testing of the other unit ST would not be conducted. During the time that the ST is out of service, the only equipment that will be allowed to be unavailable for planned test and/or maintenance is the emergency DGs. The reason that the emergency DGs were excluded from the restriction on maintenance is due to the required monthly TS Surveillance Requirements 3.8.1.2 and 3.8.1.3. One of the four independent DG becomes unavailable each week for a short period of time due to the required surveillance test.

The steam driven emergency feedwater pumps (one per unit and called the Turbine Driven Auxiliary Feedwater pumps) at CPSES are protected from elective maintenance activities since they are relied upon for mitigation of station blackout conditions when the electric motor-driven auxiliary feedwater pumps would be unavailable. Surveillance testing of any such "protected" equipment that might become due during the period that a ST is out of service would be performed prior to removing the ST from service. Limiting testing in this way protects the availability of equipment during the ST maintenance window. This does not imply that surveillance testing requirements will not be performed on key equipment as required, but only that surveillance testing will be shifted as allowed by TS.

Routine testing and preventive maintenance activities are normally scheduled to be performed on a 12 week rotating basis. Work schedules can be adjusted to ensure that surveillance testing of equipment, identified as important to LOOP and SBO considerations, is demonstrated current prior to the start of the ST outage work window and will not be required for the duration of the planned ST outage. As mentioned above, normal test and maintenance activities for the DGs are allowed when the ST CT extension is exercised.

Risk management strategies and maintenance practices at CPSES ensure that extensive work planning is performed. Important aspects of this planning not already mentioned include pre-job briefs and consideration of overall station operating configuration which includes the effect of the planned activities on operation of the opposite unit.

When scheduling, to minimize grid loading and weather related impacts, the prospective schedule for any proposed on-line ST outage will be implemented during the time of the year when weather conditions at CPSES have historically not been severe or threatening to offsite power. Times of peak tornado and thunderstorm frequency or likelihood of winter ice storms will be avoided. In addition, times of optimum grid conditions outside the summer peak electric demands will be considered in selecting the on-line ST maintenance window. Other weather-related considerations include equipment protection, minimal job interruptions, and good worker conditions. Therefore, the CT extension will not be entered if weather conditions are not conducive to performance of planned on-line ST maintenance.

Station procedure STA-629, "Switchyard Control," is part of the Generation Interconnect Agreement for CPSES and defines responsibilities for the design, maintenance, control, and operation of the CPSES switchyards. STA-629 establishes the necessary interfaces between CPSES and the transmission grid system operators. This procedure also provides guidance for the timely exchange of necessary and pertinent information. This guidance has been summarized and is added to the procedure in the form of Attachments 8.F, "Communication Protocol," Attachment 8.G, "CPSES – Plant Condition Communication Guideline," and is also supported by Attachment 8.H, "CPSES Offsite Power System Performance Characteristics," Attachment 8.I, "CPSES Generator and Transformer Performance Characteristics," and Attachment 8J, "Switchyard Work Description." STA-629 ensures (1) activities in the switchyards are closely monitored and controlled, (2) all switchyard maintenance is reviewed to ensure that the increase in probability of loss of offsite power is minimized, and (3) switchyard access is strictly controlled to minimize the potential for offsite power transients. Therefore, the ST extended CT will not be entered if switchyard and grid conditions are not conducive to perform on-line maintenance of the ST.

In summary, CPSES has a robust design which retains desired design features such as defense-in-depth (i.e., the ability to mitigate design basis accidents when a ST is out of service). The risk-informed CT will be implemented consistent with the CRMP, STA-629, and other station procedures. When utilizing the 30 day CT, the requirements of the CRMP per TS 5.5.18 call for the consideration of other measures to mitigate consequences of an accident occurring while a ST is inoperable. Furthermore, the provisions of STA-629 will be applied when exercising the 30 day ST CT extension and are sufficient to maintain adequate defense-in-depth and existing safety margins.

The following administrative controls will be applicable upon entry into plant conditions which rely on the extended CT:

1. The Configuration Risk Management Program (CRMP) (TS 5.5.18) will be applied per 10CFR50.65(a)(4).

2. Weather conditions must be conducive to perform planned maintenance on the offsite circuits.

3. The offsite power supply and switchyard conditions must be conducive to perform maintenance on the offsite circuits.

4. Switchyard access will be monitored and controlled per procedures.

The license amendment request also proposes to revise the second CTs for Required Actions A.3, "Restore required offsite circuit to OPERABLE status" and B.4, "Restore DG to OPERABLE status" to reflect the ST proposed CT extension. These second CTs establish a limit on the maximum time allowed for any combination of required AC electrical sources to be inoperable during any single contiguous occurrence of failing to meet the Limiting Condition for Operation (LCO).

4.2 Evaluation of Risk Impact

The requested CT extension for the ST is expected to be used to support maintenance activities as discussed in Section 4.1. The probabilistic evaluations presented in the following sections support and justify the allowed CT extension request for the ST. The risk analysis methods employed are described 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 and PRA Model Considerations in Support of the Evaluation

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. 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 RGs 1.174 and 1.177 (References 8.1 and 8.2, respectively).

4.2.1.1 Review 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 (CDF) and large early release frequency (LERF) at power (MODE 1), in transition (MODES 2 through 4) and while shutdown (MODES 5 and 6). The CPSES PRA model for internal events also includes spent fuel pool modeling for core-off load configurations; however, only MODE 1 was considered in this evaluation.

The following review shows that the PRA model is sufficiently developed with a scope capable of providing appropriate risk insights for this CT extension. The following sections address data, modeling, and truncation.

Data Review and Model Evaluation

The PRA model has been updated three times since the individual plant examination (IPE) and the work has been peer reviewed. With these updates, a number of areas of the PRA model have been strengthened. Notably for this work, the generic equipment failure probabilities were updated with plant specific data using Bayesian techniques, the RCP seal model was updated as described below, plant specific thermal-hydraulic timing studies for LOOP recovery and human error probabilities (HEP) were performed, and LOOP frequencies were updated using EPRI data. The PRA model was updated to include separate branches for the components of LOOP (plant-centered, weather-centered, grid-centered and grid SBO-centered). The PRA quality considerations are addressed in Section 4.3 below.

PRA and deterministic data related to the affected components, e.g. ST, were reviewed. For the probabilistic portion, this consisted of a detailed review of PRA elements that directly model the component and related supporting documents that impacted this evaluation. Consideration was given to each of the PRA tasks in order to define what documents needed to be reviewed in more detail.

Information collected and reviewed in support of extending the ST CT evaluation is listed below.

- CPSES Full Power PRA analysis files and computer model
- Reactor Coolant Pump (RCP) Seal loss of coolant accident (LOCA) model
- Startup Transformer common cause failure modeling data and techniques
- LOOP Initiating Event Frequency and post-initiator plant response
- SBO Initiating Event Frequency and post-initiator plant response
- Emergency Operating Procedures
- Maintenance Rule data for the Startup Transformer with historical outage times

The scope of the existing PRA was reviewed to ensure that it is adequate to evaluate the impact of the proposed CT extension. Two key areas were identified for review: (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 of the RCP Seal LOCA model to ensure integrity and completeness.

The 6.9 kV AC system fault tree models and ST reliability data were reviewed. This review included unavailability parameters, failure rates, and level of detail of these system models. Similarly, the CPSES LOOP and SBO models were reviewed. The LOOP frequency, LOOP recovery models, and the LOOP/SBO event trees were reviewed. It was concluded that the 6.9 kV AC system, LOOP and SBO modeling are detailed and appropriate for this analysis.

The RCP seal LOCA modeling was reviewed. The CPSES model of record uses the WOG 2000 RCP seal LOCA modeling described in WCAP-15603 Revision 1-A (Reference 8.24), with the modifications proposed by the NRC Safety Evaluation. It was confirmed that the existing RCP Seal LOCA model contains all of the failure modes identified in the United States Nuclear Regulatory Commission (USNRC)-approved Brookhaven RCP Seal LOCA model. The impact of using the Brookhaven RCP Seal LOCA model was examined as a sensitivity analysis. This sensitivity analysis was performed on the model of record as part of the most recent model update. The analysis shows that if the Brookhaven RCP Seal LOCA model was used, there would be a small increase in the baseline risk. These results show that the CPSES PRA model compares very favorably with the Brookhaven model. Thus, the conclusions of this study remain unchanged and the proposed CT analysis is supported.

Truncation

The following describes the methodology and results of the CPSES evaluation on truncation levels done in support of the current model update.

A curve generated from the results of quantifying the model at different truncation limits provides the basis for this evaluation. The curve is typically asymptotic such that successive changes in truncation level will result in smaller and smaller changes in results. A general guideline is that the truncation level should be low enough such that 95% of the total result is captured. Using this guideline a change in the results of less than 5% should be acceptable. This allows the analyst to have confidence that the result is in the flat portion of the curve and that the truncation level will be low enough to capture 95% of the total results.

To support the analysis of the truncation level, several quantifications were performed with different truncation levels. A best-fit curve was developed and analyzed. The curve is asymptotic in nature as expected. The slope of the curve decreases in change at about 2E-11. The increase in risk from 5E-11 to 2E-11 is 3.18%. Since the increase for the truncation levels is less than 5%, the truncation level of 1E-11, which was used for ease of calculation, is considered acceptable.

The truncation level is unaffected by recoveries. This is due to the fact that the recoveries are added after the cutsets have been truncated. In conclusion, the use of the current CPSES PRA model with a truncation level set at 1.0 E-11 is considered adequate for this evaluation.

4.2.1.2 PRA Model Modifications to Support this Evaluation

Certain modifications to the CPSES PRA model were made for this evaluation. The principal modification is discussed below. The others are related to such things as ordinary adjustments for equipment out of service and temporary changes to probabilities for sensitivities.

Reduced LOOP

At CPSES, the LOOP is modeled as it constituent parts; plant-, weather-, grid-, and grid-SBO centered events. For this analysis, sensitivities were performed using reduced LOOP frequencies. The reduced LOOP is based only on the plant-centered and weather-centered frequencies.

A review of the plant-centered events was performed to remove events caused by human interaction. Removal of events caused by human interaction was justified because during the proposed CT, work which could affect offsite power components or work in the switchyard would not be allowed. This resulted in a reduced plant-centered LOOP frequency from 1.37E-02 to 7.72E-03.

The weather-centered component of the LOOP calculation was reviewed relative to severe weather. A review of the National Severe Storm Laboratory website produced several graphs showing the occurrences of severe weather for the last twenty years (1980 through 1999). The graph is characterized by periods of distinct peaks. By choosing a maintenance period away from the peaks, the weather-centered frequency was reduced by 70%. This resulted in a reduced weather-centered LOOP frequency from 8.4E-03 to 2.52E-03.

A table summarizing the LOOP constituent frequencies is provided below:

Constituent	Baseline	Analysis Frequency
Plant-Centered	1.37E-02	7.72E-03
Weather-Center	8.40E-03	2.52E-03
Grid-Centered	5.04E-03	5.04e-03
Grid SBO-Centered	7.79E-03	7.79E-03
Total	**3.49E-02**	**2.31E-02**

Table 2. LOOP Frequencies

4.2.1.3 Inputs and Analysis Assumptions and Methods

For this evaluation, a number of inputs, analysis assumptions and methods were used. These are described in the following paragraphs.

Incremental Conditional Core Damage Probability (ICCDP) and Incremental Conditional Large Early Release Probability (ICLERP) and Delta CDF and Delta LERF

The Incremental Conditional Core Damage Probability (ICCDP) and Incremental Conditional Large Early Release Probability (ICLERP) were calculated by assuming the ST is in maintenance with the administrative controls described earlier in place (e.g., no switchyard work resulting in a reduced LOOP frequency) for the entire CT duration and other conditions as noted in the cases below.

The delta CDF and delta LERF were calculated by assuming the ST is in maintenance with the specified administrative controls in place (e.g., no switchyard work resulting in a reduced LOOP frequency) for the proposed 30 day CT duration and then adding the baseline CDF/LERF for the remainder of the year. The basis for this approach is that the risk reduction measures (administrative controls) would not be in affect during the remainder of the year. This approach is similar to the approach used in the NRC Inspection Manual Chapter 0609 "Significance Determination Process" (SDP).

LOOP and Time of Year Considerations

The assumption was made that CPSES will not plan maintenance that would lead to the ST being unavailable when work is being performed in the switchyard. Also, CPSES would not plan ST maintenance during the time of the year when the weather at CPSES has historically been severe (i.e., likelihood of tornado or thunderstorms is high). Therefore, to account for these administrative controls the LOOP frequency was recalculated as discussed above. For the sensitivity studies, a new CDF and LERF were calculated using new LOOP frequencies.

This new CDF was then multiplied by the period of time it was in effect (30 days) and combined with the baseline CDF multiplied by the time it was in effect (365 – 30 = 335 days) to determine the ST out of service CDF. This combination of new CDF (reduced LOOP frequency) with baseline CDF (baseline LOOP frequency) allows credit for administrative controls during the 30 day CT, but does not take credit for the administrative controls for the whole year. If credit were taken for administrative controls for the whole year (i.e., using only the reduced LOOP frequency) the calculated risk results would be non-conservative.

Common Cause Considerations

The baseline CPSES model does not include common cause considerations for the STs since they are of different design and different voltages (i.e., 138kV and 345kV). All remaining components have their normal common cause values. There are no new common cause events that bear on the risk impact of the proposed extended CT.

Discussion of Repair-type Activities and Expected Frequency of Use of Extended CT

Whereas repair-type activities could occur at any time, whether as a part of a scheduled or unscheduled activity, typically, repair activities will be identified as part of a planned or scheduled activity. Historically, at CPSES, the majority of the unavailability for the STs is due to planned maintenance rather than an emergent condition. A review of the maintenance rule data since 1999 shows no unplanned maintenance events for the STs in that period. The planned maintenance activities typically occur at 3 year intervals and average about 25 hours unavailability per activity.

The LCO action and associated CT may be entered more than once a year for emergent repair-type activities. As noted, there have has been no such entries during the recent seven years. If necessary, TXU Power will use the full CT to do the repairs. This will be tracked by the requirements of the Maintenance Rule and any actions required will be instituted.

These considerations are fully accounted for in the risk assessment supporting this evaluation. The PRA analysis addresses the extended interval and other expected test and maintenance (including planned and unplanned maintenance) activities and risks in two ways. First the risk for the extended interval is assessed with appropriate adjustments to the LOOP frequencies using the no test and maintenance model. Second, the risk for times other than the extended interval is assessed using the normal LOOP frequencies and the full test and maintenance model. This second analysis includes all the ST unavailability modes and failure modes and other system out of service combinations that are in the current model of record.

4.2.1.4 Evaluation Criteria and Methodology

The criteria and guidance in RGs 1.174 and 1.177 (References 8.1 and 8.2, respectively) were used in this evaluation. The following provides a discussion of the risk metrics used to evaluate the risk impacts of the extended ST CT.

ΔCDF_{AVE} = The change in the annual average CDF due to any increase in on-line maintenance unavailability of the ST that could result from the increased allowed CT. This risk metric is used to compare against the criteria of RG 1.174 (Reference 8.1) 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 ST that could result from the increased CT extension. This risk metric is used to compare against the criteria of RG 1.174 (Reference 8.1) to determine whether a change in LERF is regarded as risk significant. These criteria are a function of the baseline annual average core damage frequency, $LERF_{base}$.

$ICCDP_{\{STxY\}}$ = The incremental conditional core damage probability with ST Y for Unit X out of service for a period equal to the proposed new allowed CT. This risk metric is used as suggested in RG 1.177 (Reference 8.2) to determine whether a proposed increase in allowed CT will have an acceptable risk impact.

$ICLERP_{\{STxY\}}$ = The incremental conditional large early release probability with ST Y for Unit X out of service for a period equal to the proposed new allowed CT. This risk metric is used as suggested in RG 1.177 (Reference 8.2) to determine whether a proposed increase in allowed CT will have an acceptable risk impact.

The change in core damage frequency (ΔCDF) and the change in conditional large early release frequency (ΔLERF) are computed per the definitions from RG 1.174 (Reference 8.1). In terms of the parameters defined above, the definitions are as follows:

$\Delta CDF = [(CDF_{tmbase} * B/365) + (CDF_{reducedLOOP} * CT/365)] - CDF_{tmbase}$

and

$\Delta LERF = (LERF_{tmbase} * B/365) + (LERF_{reducedLOOP} * CT/365) - LERF_{tmbase}$

where:

CDF_{tmbase} = CDF (Model of Record, test and maintenance model)

$B = 365 - CT$

CT = Completion Time

$CDF_{reducedLOOP}$ = CDF with reduced LOOP and ST out of service (no test or maintenance model)

$LERF_{tmbase}$ = LERF (Model of Record, test and maintenance model)

$LERF_{reducedLOOP}$ = LERF with reduced LOOP and ST out of service (no test or maintenance model)

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 8.2). In terms of the parameters defined above, the definitions are as follows:

$ICCDP = (CDF_{CT} - CDF_{base}) * (CT/365)$

and

$ICLERP = (LERF_{CT} - LERF_{base}) * (CT/365)$

where:

CDF_{CT} = The CDF with the equipment out of service (no test or maintenance model)

CDF_{base} = Baseline CDF (Model of Record, no test or maintenance model)

$LERF_{CT}$ = The LERF with the equipment out of service (no test or maintenance model)

$LERF_{base}$ = Baseline LERF (Model of Record, no test or maintenance model)

CT = Completion Time

Note that in the above formula 365 days/year is merely a conversion factor to make the units for allowed CT 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 CT.

4.2.1.5 Evaluation and Results

The CPSES PRA internal events model was used to evaluate the ST CT extension using the methodology and assumptions presented above. The results were obtained and compared to the acceptance criteria in RG 1.174 and 1.177.

A discussion of the cases evaluated and the results are presented below. Several cases were evaluated to determine if plant configuration would affect the conclusions in this CT evaluation. The results of these analyses also formed the bases for the high risk equipment listed in Section 4.2.3. The Computer Aided Fault Tree Analysis (CAFTA) suite of PRA tools were used for this evaluation.

Cases considered:

Case 1: Base NTM (No Test and Maintenance) - This case is the Full Power Internal Events Model with no equipment in test or maintenance (baseline case). For this case, both CDF and LERF were calculated. This is the baseline case to which other no test and maintenance cases are compared.

Case 2: Base TM (Average Test and Maintenance) - This case is the Full Power Internal Events Model with average test or maintenance (TM baseline case). This is the baseline case to which other test and maintenance cases are compared.

Case 3: XST1 OOS (Out of Service) NTM RPC (Reduced Plant Centered) – For this case XST1 is assumed unavailable and XST2 is supplying both Unit 1 and Unit 2 during power operation with the no test and maintenance model. Also a reduction in plant-centered LOOP frequency is applied. This case shows the effect on CDF and LERF when certain administrative controls are applied with respect to LOOP and maintenance.

Case 4: XST1 OOS TM 1 RPC – For this case XST1 is assumed unavailable and XST2 is supplying both Unit 1 and Unit 2 during power operation with the test and maintenance model. Also a reduction in plant-centered LOOP frequency is applied. This case shows the effect on CDF and LERF on Unit 1 when administrative controls are applied with respect to LOOP and limited controls are applied to maintenance. As shown in Table 3, for this case, the metrics for Unit 1 do not meet the criteria, hence the additional cases.

Case 5: XST1 OOS TM 2 RPC – For this case, XST1 is assumed unavailable and XST2 is supplying both Unit 1 and Unit 2 during power operation with the test and maintenance model. Also a reduction in plant-centered frequency is applied. This case shows the effect on CDF and LERF on

Unit 2 when administrative controls are applied with respect to LOOP and limited controls are applied to maintenance. A comparison of the results for Cases 4 and 5, shown in Table 3, shows that using the metrics for Unit 1 is conservative compared to Unit 2.

Case 6: XST1 OOS U1 RPC DGTM only – For this case XST1 is assumed unavailable and XST2 is supplying both Unit 1 and Unit 2 during power operation with the test and maintenance on a single train of Unit 1 DG only. Also a reduction in plant-centered LOOP frequency is applied. This case shows the effect on CDF and LERF for Unit 1 when administrative controls are applied with respect to LOOP and with Unit 1 Train B DG in test and maintenance. The reason that the DGs were excluded from the restriction on maintenance is due to the required monthly surveillance tests. During the monthly surveillance tests, which are staggered (one emergency diesel generator is tested per week); the equipment becomes unavailable for a short period of time. To be conservative, the DG test and maintenance unavailability was not adjusted in the model even though it is much longer than would normally be attributed to the surveillance testing that would be done during the extended ST CT.

Case 7: XST1 OOS U2 RPC DGTM only – For this case XST1 is assumed unavailable and XST2 is supplying both Unit 1 and Unit 2 during power operation with the test and maintenance on a single train of Unit 2 DG only. Also, reduction in plant-centered LOOP frequency is applied. This case shows the effect on CDF and LERF for Unit 2 when administrative controls are applied with respect to LOOP and with Unit 2 Train B DG in test and maintenance. Again for this case, to be conservative, the DG test and maintenance unavailability was not adjusted in the model even though it is much longer than would normally be attributed to the surveillance testing that would be done during the extended ST CT.

Case 8: XST1 OOS U1 RPC RWC DGTM only – For this case XST1 is assumed unavailable and XST2 is supplying both Unit 1 and Unit 2 during power operation with the test and maintenance on a single train of Unit 1 DG only. Also reductions in both plant–centered and weather-centered LOOP frequencies are applied. This case shows the effect on

CDF and LERF when administrative controls are applied with respect to LOOP and with Unit 1 Train B DG in test and maintenance.

Results

The risk evaluation of performing a 30 day CT maintenance activity at power meets the requirements for a permanent TS change in accordance with RG 1.174 and RG 1.177 (References 8.1 and 8.2, respectively). The requirement of RG 1.174 (Reference 8.1) is a ΔCDF less than 1E-06 and a ΔLERF less than 1E-07. The requirement of RG 1.177 (Reference 8.2) is an ICCDP less than 5E-07 and ICLERP less than 5E-08.

Cases 6 and 7 were used as the basis for the CT extension evaluation. Case 6, which is the Unit 1 case and is bounding for the Unit 2 Case 7, demonstrates the acceptability of increasing the ST CT with credit taken for plant-centered LOOP compensatory actions while allowing for DG test and maintenance. The reason that the emergency DGs were excluded from the restriction on maintenance is due to the required monthly surveillance tests during which the DG becomes unavailable for a short period of time.

Case 6 indicates that even if this extended CT were used for an emergent condition or if the weather is not predictable, which it may not be over the full 30 days, the calculated risk metrics will still meet the requirements of RG 1.174 and 1.177. The additional CDF contribution is 4.99E-07 per year and an additional LERF contribution of approximately 9.38E-09 per year. The ICCDP and ICLERP calculated values are 4.99E-07 and 9.38E-09, respectively. This case restricts the work allowed in the switchyard and allows test and maintenance on a DG train.

As a practical matter, Case 8, which shows a risk reduction over Case 6, is the anticipated risk for planned ST maintenance using this extended CT. Since implementing the extended CT will be a planned evolution, administrative controls allow taking credit for the reduction in both plant-centered and weather-centered LOOP frequency. As Case 8 shows, if test and maintenance is restricted on all PRA components except the DGs, the risk results show an additional CDF contribution of approximately 3.91E-07 and an additional LERF contribution of approximately 6.15E-9 per year for Unit 1. The Unit 1 at power ICCDP and ICLERP calculated values are 3.91E-07 and 6.15E-09, respectively.

All cases except Case 4 meet all the criteria. Case 4 was analyzed with the full test and maintenance model and it was treated as a sensitivity case and not the basis for the CT extension. All of the cases offer some insight into the risk associated with emergent ST conditions in that the marginal risk is generally not large. Even Case 4 is not significantly above the metrics

For emergent conditions, the risk of each case is offset to some degree by the non-quantified considerations, namely the avoided transition and shutdown risk. Currently, without the extended CT, an emergent condition lasting greater than three days requires shutdown of both units with commensurate risk of two shutdowns and two startups and the associated shutdown risk. These cases show collectively that the risk of the extended CT is acceptably low; the avoided risk enhances that conclusion.

In conclusion, these results support having one ST removed from service for maintenance for 30 days while both units remain operating at power. Further, the risk increase associated with this proposed CT extension is considered small and is acceptable according to the guidelines contained in RG 1.177 and RG 1.174.

Table 3. PRA Study Results

DESCRIPTION OF ASSUMPTIONS	CDF	LERF	ΔCDF	ΔLERF	ICCDP	ICLERP	CCDP	CLERP	MEETS RG 1.174	MEETS RG 1.177
Case 1: BASE NTM	6.58E-06	5.05E-07							-	-
Case 2: BASE TM	9.30E-06	6.31E-07							-	-
Case 3: XST1 OOS NTM RPC	1.22E-05	6.38E-07	4.61E-07	1.09E-08	4.61E-07	1.09E-08	1.00E-06	5.24E-08	YES	YES
Case 4: XST1 OOS TM 1 RPC	1.84E-05	8.56E-07	7.47E-07	1.85E-08	7.47E-07	1.85E-08	1.51E-06	7.03E-08	YES	NO
Case 5: XST1 OOS TM 2 RPC	1.31E-05	7.37E-07	3.16E-07	8.74E-09	3.16E-07	8.74E-09	1.08E-06	6.06E-08	YES	YES
Case 6: XST1 OOS U1 RPC DGTM only	1.54E-05	7.45E-07	4.99E-07	9.38E-09	4.99E-07	9.38E-09	1.26E-06	6.12E-08	YES	YES
Case 7: XST1 OOS U2 RPC DGTM only	1.10E-05	6.40E-07	1.39E-07	7.24E-10	1.39E-07	7.24E-10	9.03E-07	5.26E-08	YES	YES
Case 8: XST1 OOS U1 RPC RWC DGTM only	1.41E-05	7.06E-07	3.91E-07	6.15E-09	3.91E-07	6.15E-09	1.16E-06	5.80E-08	YES	YES

NTM - NO TEST AND MAINTENANCE
TM1 - TEST AND MAINTENANCE - ANALYSIS PERFORMED WITH TEST AND MAINTENANCE FOR UNIT 1
TM2- TEST AND MAINTENANCE - ANALYSIS PERFORMED WITH TEST AND MAINTENANCE FOR UNIT 2
OOS - OUT OF SERVICE
RPC – REDUCED PLANT CENTERED FAILURE PROBABILITY
RWC – REDUCED WEATHER CENTERED FAILURE PROBABILITY
DGTM- EMERGENCY DIESEL GENERATOR AVERAGE TEST AND MAINTENANCE
CDF - CORE DAMAGE FREQUENCY
LERF – LARGE EARLY RELEASE FREQUENCY
ΔCDF – THE CHANGE IN CDF
ΔLERF – THE CHANGE IN LERF
ICCDP – THE INCREMENTAL CONDITIONAL CORE DAMAGE PROBABILITY
ICLERP - THE INCREMENTAL CONDITIONAL LARGE EARLY RELEASE PROBABILITY
CCDP - CONDITIONAL CORE DAMAGE PROBABILITY
CLERP - CONDITIONAL LARGE EARLY RELEASE PROBABILITY
1.174 REQUIREMENTS - ΔCDF < 1E-06 AND ΔLERF < 1E-07
1.177 REQUIREMENTS - ICCDP < 5E-07 AND ICLERP < 5E-08

4.2.2 External Events Considerations

The CPSES PRA internal events model does not include contributions from internal fires, internal floods, seismic events, and other external events. A qualitative evaluation of these events is provided below. The conclusion of this qualitative assessment is that external events have only a minor impact on the results of the internal events evaluation.

External events of interest in this assessment are those that could directly or indirectly cause the loss of the operating ST but which would not have simultaneously affected the ST which is in maintenance for the extended CT. The added risk is that associated with the increased fault exposure time, i.e., for 3 days to 30 days. LOOP events other than those caused by the loss of the operating ST during the extended CT are ruled out because such events render both STs inoperable. In other words, the risk of the extended CT is independent of LOOP events that simultaneously affect both STs. Therefore, for many external event scenarios, an extended Startup Transformer completion time will not impact the plant risk.

The following discusses the potential impact of each external event on the conclusions of this study for the plant requesting the CT change.

External Events - Seismic

The CPSES Individual Plant Examination of External Events (IPEEE) (Reference 8.27) is the basis for the review of the impact of a seismic event. The CPSES IPEEE used the seismic margins approach which assumes a LOOP occurs due to the seismic event. As noted above, for events that cause a LOOP, whether the STs are available or unavailable due to maintenance is immaterial since the external event would have caused both of the STs to be inoperable.

Even assuming that seismic failure of the STs is the sole cause of the seismic-induced LOOP and that one ST may survive the seismic event, the risk is very small since the frequency of such seismic events is approximately two orders of magnitude less than the internal events LOOP frequency and the increased fault exposure time is a small fraction of the year. Therefore, the seismic events do not impact the conclusions of this analysis.

External Events - Fire

The CPSES IPEEE is the basis for review of the impact of fire events. The STs were not identified as important fire contributors for that study. The fire event of interest is one that can cause loss of the available ST while the other is in maintenance. Because of the extended CT and the increased fault exposure time, this could be more significant. Thus, it is reviewed in more detail below.

There have been fire events in transformers which bear on this risk assessment. If it is assumed that the operating ST could experience a fire during the period of the extended CT thereby causing a LOOP, the risk can be inferred by comparing the transformer fire ignition frequency to the internal event LOOP frequency.

Appendix C of NUREG/CR-6850, "EPRI/NRC-RES Fire PRA Methodology for Nuclear Power Facilities, Volume 2: Detailed Methodology," (Reference 8.25) provides initiating event frequency for yard transformers. The mean, 5th and 95th values are provided for three cases: catastrophic, non-catastrophic and other transformer fires. If the sum of means of all yard transformer fire frequencies from Appendix C is used as the mean frequency for this comparison, then for the 27 day (i.e., from 3 to 30 days) extension of the CT, a transformer fire poses a marginally significant increase in risk for this evaluation, or approximately 5% increase in LOOP frequency.

However, there are several factors that lead to the conclusion that the mean fire frequency used for this evaluation is closer to the 5^{th} than the mean frequency. (The 5^{th} is typically about one-tenth of the mean.)

- The extended CT will be taken at a time when the grid stress is low and environmental stress on the operating ST is low. The higher grid and environmental stresses generally occur in the summer months when the extended CT is not anticipated to be used.
- Thermography is performed to identify whether hot spots exist and oil analysis is routinely performed.
- There has not been a transformer fire event at CPSES during the operating lifetime of the units. A Bayesian update would show a smaller plant specific value than the generic value.
- The purpose of the CT extension is to provide for on-line maintenance that will enhance the overall state and reliability of the transformers. This should further reduce the likelihood of transformer fires.

Given the above risk management actions and other considerations, the fire risk can be minimized during the extended CT. Therefore, the impact of fire events on plant risk with respect to changes to ST CTs does not impact the conclusions of this analysis.

External Events - High Winds

The CPSES IPEEE is the basis for review of the impact of a high wind event. The CPSES IPEEE assumed a LOOP occurs due to a high wind event. As noted earlier, for events which cause a LOOP at the switchyard or grid, whether the STs are available or unavailable due to maintenance is immaterial since the external event would have caused the ST to be inoperable.

Even assuming that tornado-induced failure of the operating STs is the sole cause of the LOOP (i.e., there is no switchyard or grid LOOP resulting from the tornado) and that one ST might have survived the event, the risk is very small since the frequency of such tornado events is approximately two orders of magnitude less than the internal events LOOP frequency. Therefore, the high wind and tornado events do not impact the conclusions of this analysis.

External Events - Floods

The occurrence of floods that can cause plant damage is location specific. The CPSES IPEEE concludes that the plant is not under a threat from external flooding, even in the worst conditions of probable maximum precipitation or potential dam failures. Consequently, the contribution of such events to the total CDF at CPSES is concluded to be insignificant.

Other External Events

Other external events include transportation and nearby facility accidents and the other external events listed in Table 4.1 of NUREG-1742 (Reference 8.26). As concluded in the NUREG, these events do not account for a significant risk contribution in any of the CPSES IPEEE submittals. This conclusion is consistent with the conclusions and insights from the CPSES IPEEE.

4.2.3 Restriction on High Risk Configuration

This section addresses the Tier 2 and Tier 3 considerations related to avoidance and control and management of high risk considerations.

Tier 2: Avoidance of Risk-Significant Plant Conditions

In addition to the administrative controls proposed by this license amendment, CPSES has existing administrative guidelines to avoid or reduce the potential for risk-significant configurations from either emergent or planned work. These guidelines control configuration risk by assessing the risk impact due to out of service equipment during all modes of operation to ensure that the plant is always operated within acceptable risk guidelines.

CPSES employs a conservative approach to performing maintenance during power operations. The weekly schedules are train/channel based and prohibit the scheduling of opposite train activities without additional review, approvals, and/or administrative controls. 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 re-evaluated. Based on the result of this re-evaluation, decisions are made concerning further actions required to achieve an acceptable level of risk. Unplanned or emergent work activities are also evaluated to determine the impact on other, already planned activities and the affect the combinations would have on risk.

Risk Significant Components Given a Startup Transformer is out of Service

The following components and/or systems become risk-significant when a ST is out of service. The list provides those components and/or systems whose unavailability simultaneous with an out of service ST would likely place the plant in a high-risk configuration, based upon quantitative and deterministic analysis. These are not necessarily in ranked order.

- Electric power – AC and DC power distribution, both trains
- The redundant ST
- All switchyard work
- Service water - both trains
- Emergency DGs
- Turbine Driven Auxiliary Feedwater Pump and the appropriate portions of the Auxiliary Feedwater System

Tier 3 Risk Informed Plant Configuration Control and Management

The objective of the third tier is to ensure that the risk impact of out of service equipment is evaluated prior to performing any maintenance activity. As stated in Section 2.3 of Regulatory Guide 1.177, "a viable program would be one that is able to uncover risk significant plant equipment outage configurations in a timely manner during normal plant operation." The third tier requirement is an extension of the second tier requirement, but addresses the limitation of not being able to identify all possible risk significant plant configurations in the second tier evaluation.

The risk impact associated with performance of maintenance and testing activities is evaluated in accordance with the CPSES Work Scheduling Process (Work Control Instruction WCI-203). A risk assessment is performed for activities with a weekly schedule. Compensatory measures are addressed for activities deemed to be risk significant. The weekly scheduled activities and associated risk assessment are reviewed by the CPSES PRA Group. The Work Scheduling Process also addresses the impact on the risk assessment due to added or emergent activities and activities which have slipped from the scheduled completion time.

4.3 PRA Quality

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 conducted internally by TXU Power staff, and the other review was performed 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. Further, 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. This process has been continued since the IPE with the Westinghouse Owners Group (WOG) peer review and the external peer review of our updated models. A discussion of the WOG and other subsequent peer review is provided below.

WOG and Other Peer Reviews

A WOG peer review of the CPSES PRA model was performed during the spring of 2002. The conclusion of the peer assessment is that the CPSES PRA can be effectively used to support risk significance evaluations with deterministic input, subject to addressing the items identified as significant in the technical element summary and Facts & Observations (F&O) sheets. There were three level A F&Os.

Two Level A F&Os involved steam generator (SG) tube rupture and the application of the 24 hour mission time concept for both CDF and LERF considerations. The basis and success paths for the SG tube rupture model were clarified to provide for actions beyond the 24 hour mission time to assure that plant is in a stable condition. To address this, it was determined that changes to the PRA event and fault trees were needed for long term cooling after a SG tube rupture. These changes were incorporated into and are part of the current PRA model.

A third Level A F&O was written to address cutsets with multiple human errors and to revise dependency calculations if necessary. This item was found not to adversely affect the technical adequacy of the PRA. To address this, a PRA utility program was used to identify unique combinations of multiple human actions. These combinations were reviewed on a scenario basis to assure that dependencies were identified and handled as appropriate. Changes were made to the model where required to address these dependencies.

There were several Level B F&Os. CPSES addressed each of the Level B F&Os and incorporated those items into the PRA model where appropriate. In summary, all of the level A and B F&Os were fully resolved and, where appropriate, internal PRA guidance was strengthened.

In addition to the above described peer review, a focused, independent industry peer review of the Revision 3 changes was completed in the spring of 2005. The major model features addressed in this review included the RCP seal LOCA model update to WOG 2000 model, thermal-hydraulic (T-H) analyses associated with seal LOCA scenarios, LOOP model changes, and the quantification process This review was completed based on the ASME PRA Standard. No category A or B F&Os were identified by this peer review. All other F&O items were resolved and incorporated into Revision 3B of the model as appropriate.

4.4 Summary of Results and Conclusions of Risk Evaluation

The probabilistic evaluations presented above support and justify the CT extension request for a ST.

If a ST is taken out of service for maintenance, it affects both units since transformer XST1 functions as a back-up to XST2 and XST2 functions as a back-up for XST1. The increase in risk results in an additional CDF contribution of approximately 4.990E-07 per year and an additional LERF contribution of approximately 9.38E-09 per year even without consideration for the reduced weather centered event probability (RWC). The risk increase associated with this proposed CT extension is considered small, according to the guidelines contained in RG 1.177. Based on the risk graphs in RG 1.174, these values indicate that the change in core damage probability and large early release probability is not considered significant when either ST is out of service for planned or corrective maintenance for up to 30 days during continued power operation of both CPSES units.

5.0 REGULATORY ANALYSIS

5.1 No Significant Hazards Consideration

TXU Power has evaluated whether or not a significant hazards consideration is involved with the proposed amendment(s) by focusing on the three standards set forth in 10CFR50.92, "Issuance of amendment," 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 (TS) Completion Time (CT) extension does not significantly increase the probability of occurrence of a previously evaluated accident because the startup transformers (STs) are not initiators of previously evaluated accidents involving a loss of offsite power (LOOP). The proposed changes to the TS Required Actions CTs do not affect any of the assumptions used in the deterministic or the PSA analysis relative to LOOP initiating event frequency. Implementation of the proposed changes does not result in a risk significant impact. The onsite AC power sources will remain highly reliable and the proposed changes will not result in a significant increase in the risk of plant operation. This is demonstrated by showing that the impact on plant safety as measured by the increase in core damage frequency (CDF) is less than

1E-06 per year and the increase in large early release frequency (LERF) is less than 1E-07 per year. In addition, for the CT changes, the incremental conditional core damage probabilities (ICCDP) and incremental conditional large early release probabilities (ICLERP) are less than 5E-07 and 5E-08, respectively. These changes meet the acceptance criteria in Regulatory Guides 1.174 and 1.177. Therefore, since the onsite AC power sources will continue to perform their functions with high reliability as originally assumed and the increase in risk as measured by ΔCDF, ΔLERF, ICCDP, and ICLERP risk metrics is within the acceptance criteria of existing regulatory guidance, there will not be a significant increase in the consequences of any accidents.

The proposed changes do not adversely affect accident initiators or precursors nor alter the design assumptions, conditions, or configuration of the facility or the manner in which the plant is operated and maintained. The proposed changes do not alter or prevent the ability of structures, systems, and components (SSCs) from performing their intended function to mitigate the consequences of an initiating event within the assumed acceptance limits. The proposed changes do not affect the source term, containment isolation, or radiological release assumptions used in evaluating the radiological consequences of an accident previously evaluated. The proposed changes are consistent with safety analysis assumptions and resultant consequences.

The proposed TS CT extension will continue to provide assurance that the sources of power to 6.9 kV AC buses perform their function when called upon. Extending the TS CT to 30 days does not affect the design of the STs, the operational characteristics of the STs, the interfaces between the STs and other plant systems, the function, or the reliability of the STs. Thus, the STs will be capable of performing their accident mitigation functions and there is no impact to the radiological consequences of any accident analysis.

The Configuration Risk Management Program (CRMP) in TS 5.5.18 is an administrative program that assesses risk based on plant status. The risk informed CT will be implemented consistent with the CRMP and approved plant procedures. When utilizing the 30 day extension, requirements of the CRMP per TS 5.5.18 call for the consideration of other measures to mitigate the consequences of an accident occurring while a ST is inoperable. Furthermore, administrative controls will be applied when exercising the 30 day CT extension and are adequate to maintain defense-in-depth and sufficient safety margins.

Therefore, the proposed changes do not involve a significant increase in the probability or consequences of an 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

   The proposed changes do not result in a change in the manner in which the electrical distribution subsystems provide plant protection. There is no design changes associated with the proposed changes. The changes to the CT do not change any existing accident scenarios, nor create any new or different accident scenarios.

   The changes do not involve a physical alteration of the plant (i.e., no new or different type of equipment will be installed) or a change in the methods governing normal plant operation. In addition, the changes do not impose any new or different requirements or eliminate any existing requirements. The changes do not alter any of the assumptions made in the safety analysis. The changes to the CT do not affect the accident analysis directly; the CT is strictly tied to the PRA and the risk associated with the occurrence of a low-probability event during the limited time the component is unavailable.

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

   Response: No

   The proposed changes do not alter the manner in which safety limits, limiting safety system settings or limiting conditions for operation are determined. Neither the safety analyses nor the safety analysis acceptance criteria are impacted by these changes. The proposed changes will not result in plant operation in a configuration outside the current design basis. The proposed activities only involve changes to certain TS CTs.

   The proposed change does not involve a change to the plant design or operation and thus does not affect the design of the STs, the operation characteristics of the STs, the interfaces between the STs and other plant systems, or the function or reliability of the STs. Because the STs performance and reliability will continue to be ensured by the proposed TS change, 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 Power concludes that the proposed amendment presents no significant hazards under the standards set forth in 10CFR50.92(c) and, accordingly, a finding of "no significant hazards consideration" is justified.

5.2 Applicable Regulatory Requirements/Criteria

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." Therefore, the proposed license amendment has no impact on this regulatory requirement.

GDC 17 – Electric Power Systems, "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 ensure 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 ensure 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 ensure 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."

At CPSES, 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 DG 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 DG providing power to the Class 1E bus. Two independent DGs and their distribution systems are provided for each unit to supply power to the redundant onsite alternating current (AC) Power System. Each DG 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. Therefore, the proposed license amendment has no impact on this regulatory requirement.

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." Therefore, this proposed license amendment has no impact on this regulatory requirement.

NRC Regulatory Guide 1.53, dated June 1973, titled "Applicability of Single-Failure Criterion to Nuclear Power Plant Protection Systems." The proposed license amendment has no impact on this regulatory requirement.

NRC regulatory Guide 1.62, dated October 1973, titled "Manual Initiation of Protective Actions." The proposed license amendment has no impact on this regulatory requirement.

NRC Regulatory Guide 1.75, Revision 1, dated January 1975, titled "Physical Independence of Electrical Systems." The proposed license amendment has no impact on this regulatory requirement.

NRC Regulatory Guide 1.81, Revision 1, dated January 1975, titled "Shared Emergency and Shutdown Electric Systems for Multi-unit Nuclear Power Plants." The proposed license amendment has no impact on this regulatory requirement.

NRC Regulatory Guide 1.93, dated December 1974, titled "Availability of Electric Power Sources." The current CT 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 (Reference 8.10) is referenced in the TS Bases for actions associated with TS 3.8.1. RG 1.93 provides operating restrictions (i.e., CT and maintenance limitations) that the NRC considers acceptable if the number of available AC power sources is one less than the LCO. RG 1.93 specifically states, "If the available a.c. power sources are one less than the 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." RG 1.93 additionally states, "The operating time limits delineated above are explicitly for corrective maintenance activities only." Conformance with Regulatory Guide 1.93 is affected by these proposed changes. The station currently conforms to the RG. If the proposed changes are approved, the station will continue to conform to RG 1.93 with the exception that the allowable Required Actions CT for restoration of a ST will be 30 days and the CT may be used for all ST maintenance.

NRC Regulatory Guide 1.155, "Station Blackout," dated August 1988. The proposed license amendment has no impact on this regulatory requirement.

NRC Regulatory Guide 1.174, "An Approach for Using Probabilistic Risk Assessment In Risk-Informed Decisions on Plant-Specific Changes to the Licensing Bases," dated July 1998. The proposed license amendment is consistent with this regulatory requirement.

NRC regulatory Guide 1.177, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications," dated August 1998. The proposed license amendment is consistent with this regulatory requirement.

NRC Safety Guide 6, dated March 10, 1971, titled "Independence Between Redundant Standby (onsite) Power Sources and Between Their Distribution Systems." These proposed changes do not add or reclassify any safety-related systems or equipment; therefore, conformance with Safety Guide 6 (Reference 8.7) as discussed in Appendix 1A(B) of the FSAR (Reference 8.3) is not affected by this change. Redundant parts within the AC and direct current (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 buses.

NRC Safety Guide 9 (Reference 8.8), dated March 10, 1971, titled "Selection of Diesel Generator Set Capacity for Standby Power Supplies." These proposed changes do not add any loads to the DGs; therefore, the selection of the capacity of the DGs for standby power systems and conformance to the applicable sections of Safety Guide is not affected by this change.

The technical analysis performed by TXU Power in Section 4, "Technical Analysis," demonstrates the ability of the STs to perform their safety function. The increased CT continues to comply with the above regulatory requirements with the exception of RG 1.93.

Safety analysis acceptance criteria in the FSAR continue to be met. The proposed changes do not affect any assumptions or inputs to the safety analysis (Reference 8.3).

In conclusion, based on the considerations discussed above, (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 amendment will not be inimical to the common defense and security or to the health and safety of the public.

6.0 ENVIRONMENTAL CONSIDERATION

TXU Power 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 Power 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 PRECEDENTS

7.1 By letter dated April 28, 2000 (Reference 8.22), the NRC issued Amendment No. 206 to Facility Operating License No. DPR-51 and Amendment No. 215 to facility Operating License No. NPF-6 for Arkansas Nuclear One (ANO), Units 1 and 2, respectively. The amendment provided a 30-day allowed outage time for offsite startup transformer No. 2 which is shared by both units. The 30-day completion time will be used not more than once in any 10-year period for the purpose of performing preventive maintenance to increase the reliability of the transformer. Although similar, the proposed CPSES amendment requests a CT of 30 days, based on PRA, and will not be limited to once in any 10-year period.

7.2 A similar license amendment was issued to Oyster Creek Generating Station (Reference 8.23), to delete the 30 day unavailability period restriction for occurrence of the specified 7 day allowed outage durations for the startup transformers. During the allowed outage time of 7 days, the redundant Oyster Creek startup transformer is required to be operable. This license amendment is similar to the proposed CPSES license amendment with the exception that the proposed allowed outage time will be 30 days.

7.3 The CPSES PRA has been used in support of several submittals to the NRC including Risk-Informed Inservice Testing program (Reference 8.16) and Risk-Informed Inservice Inspection program (Reference 8.17). Additionally, the NRC has reviewed and approved CPSES PRA supported License Amendment Requests to (1) remove the mode restrictions on several Technical Specification (TS) 3.8.1 surveillance requirements via amendment 124 (Reference 8.18), (2) revise TS 3.8.1 to allow a one-time only change to extend the Action A.3 Completion Time (CT) for restoration of an inoperable offsite circuit from 72 hours to 21 days via amendment number 88 (Reference 8.19), and (3) increase the allowed outage time for a centrifugal charging pump from 72 hours to 7 days via amendment numbers 62 and 48 (Reference 8.20).

8.0 REFERENCES

8.1 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.
8.2 NRC Regulatory Guide 1.177, "An Approach for Plant-Specific, Risk-Informed Decisionmaking: Technical Specifications," August 1998.
8.3 Comanche Peak Steam Electric Station Final Safety Analysis Report, Docket Nos. 50-445 and 50-446.
8.4 NRC Regulatory Guide 1.155, "Station Blackout," August 1988.
8.5 NRC 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.
8.6 NUMARC 87-00, "Guidelines and Technical Bases for NUMARC Initiatives Addressing Station Blackout at Light Water Reactors," Rev. 1, August 1991.
8.7 NRC Safety Guide 6, "Independence Between Redundant Standby (Onsite) Power Sources and Between Their Distribution Systems," March 10, 1971.
8.8 NRC Safety Guide 9, "Selection of Diesel Generator Set Capacity for Standby Power Supplies," March 10, 1971.
8.9 NRC Regulatory Guide 1.81, Revision 1, "Shared Emergency and Shutdown Electric Systems for Multi-unit Nuclear Power Plants," January 1975.
8.10 NRC Regulatory Guide (RG) 1.93, "Availability of Electric Power Sources," December 1974.

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

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

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

8.14 EPRI Final Report, "Losses of Off-Site Power at U.S. Nuclear Power Plants-Through 2003," April 2004.

8.15 Generic Letter 88-20, Supplement No. 1, "Initiation of the Individual Plant Examination for Severe Accident Vulnerabilities-10 CFR 50.54(f)," August, 29, 1989.

8.16 Letter to C. Lance Terry (TU Electric) from John H. Hannon (USNRC) dated August 14, 1998, "Approval of Risk-Informed Inservice Testing (RI-IST) Program for Comanche Peak Steam Electric Station, Units 1 and 2 (TAC Nos. M94165, M94166, MA1972, and MA1973)."

8.17 Letter to C. Lance Terry (TXU Electric) from Robert A. Gramm (USNRC) dated September 28, 2001, "Comanche Peak Steam Electric Station (CPSES), Units 1 and 2 – Approval of Relief Request for Application of Risk-Informed Inservice Inspection Program for American Society of Mechanical Engineers Boiler and Pressure Vessel Code Class 1 and 2 Piping (TAC Nos. MB1201 and MB1202)."

8.18 Letter to M. R. Blevins (TXU Power) from Mohan C. Thadani (USNRC) dated March 15, 2006, amendment number 124, "Comanche Peak Steam Electric Station (CPSES), Units 1 and 2 – Issuance of Amendments Re: Technical Specification 3.8.1, "AC Sources – Operating," Mode Restrictions on Emergency Diesel Generator Surveillance (TAC Nos. MC4912 and MC4913)."

8.19 Letter to C. Lance Terry (TXU Electric) from David H. Jaffe (USNRC) dated October 9, 2001, amendment no. 88, "Comanche Peak Steam Electric Station (CPSES), Units 1 and 2 – Issuance of Amendments Re: Extended Outage Time for Off-site Power – Single Occurrence (TAC Nos. MB1823 and MB1824)."

8.20 Letter to C. Lance Terry (TU Electric) from Timothy J. Polich (USNRC) dated December 29, 1998, "Comanche Peak Steam Electric Station, Units 1 and 2 – Amendment Nos. 62 and 48 to Facility Operating License Nos. NPF-87 and NPF-89 (TAC Nos. M97809 and M97810)."

8.21 EPRI-TR-10536, "PSA Applications Guide," August 1995.

8.22 Letter from M. Christopher Nolan (NRC) to Craig G. Anderson (Entergy Operations, Inc.) dated April 28, 2000, "Arkansas Nuclear One, Units 1 and 2 – Issuance of Amendments Re: Startup Transformer No. 2 Allowed Outage Time for Preventative Maintenance (TAC Nos. MA7184 and MA7185)."

8.23 Letter from Peter S. Tam (NRC) to John L Skolds (AmerGen Energy Company) dated November 23, 2003, "Oyster Creek Nuclear Generating Station – Issuance of Amendment Re: Startup Transformer and Emergency Diesel Generator Unavailability Periods (TAC No. MB9144)."

8.24 WCAP-15603 Revision 1-A, "WOG 2000 Reactor Coolant Pump Seal Leakage Model for Westinghouse PWRS," June 2003.
8.25 NRC NUREG/CR-6850, "EPRI/NRC-RES Fire PRA Methodology for Nuclear Power Facilities, Volume 2: Detailed Methodology," September 2005.
8.26 NRC NUREG-1742, "Perspectives Gained From the Individual Plant Examination External Events (IPEEE) Program," April 2002.
8.27 CPSES IPEEE, "IPEEE for Severe Accident Vulnerabilities," June 1995.

ATTACHMENT 2 to TXX-07012

PROPOSED TECHNICAL SPECIFICATION CHANGES (MARK-UP)

Pages 3.8-1
3.8-2
3.8-3
3.8-4

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

--NOTE--
One DG may be synchronized with the offsite power source under administrative controls for the purpose of surveillance testing.

ACTIONS

---NOTE---
LCO 3.0.4.b is not applicable to DGs.

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.	~~72 hours~~ 30 days AND ~~6~~ 33 days from discovery of failure to meet LCO

(continued)

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.	72 hours AND 6 days from discover of failure to meet LCO 33 y
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. AND C.2 Restore one required offsite circuit to OPERABLE status.	12 hours from discovery of Condition C concurrent with inoperability of redundant required features 24 hours

(continued)

ATTACHMENT 3 to TXX-07012

PROPOSED TECHNICAL SPECIFICATIONS BASES CHANGES
(Markup For Information Only)

Pages B 3.8-8
B 3.8-10
B 3.8-11
INSERTS

INSERT A

ACTIONS (continued)

A.3

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.

30 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.

INSERT B

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.

33 days

36

33

30 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.

B.1

To ensure a highly reliable power source remains with an inoperable DG, it is necessary to verify the availability of the offsite circuits on a more frequent basis. Since the Required Action only specifies "perform," a failure of SR 3.8.1.1 acceptance criteria does not result in a Required Action being not

(continued)

ACTIONS

B.2 (continued)

OPERABILITY of the redundant counterpart to the inoperable required feature. Additionally, the 4 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.

B.3.1 and B.3.2

Required Action B.3.1 provides an allowance to avoid unnecessary testing of the OPERABLE DG. If it can be determined that the cause of the inoperable DG does not exist on the OPERABLE DG, SR 3.8.1.2 does not have to be performed. If the cause of inoperability exists on the other DG, the other DG would be declared inoperable upon discovery and Condition E of LCO 3.8.1 would be entered. Once the failure is repaired, the common cause failure no longer exists, and Required Action B.3.1 is satisfied. If the cause of the initial inoperable DG cannot be confirmed not to exist on the remaining DG, performance of SR 3.8.1.2 suffices to provide assurance of continued OPERABILITY of that DG.

In the event the inoperable DG is restored to OPERABLE status prior to completing either B.3.1 or B.3.2, the applicable plant procedures will continue to evaluate the common cause possibility. This continued evaluation, however, is no longer under the 24 hour constraint imposed while in Condition B.

According to Generic Letter 84-15 (Ref. 7), 24 hours is reasonable to confirm that the OPERABLE DG is not affected by the same problem as the inoperable DG.

During performance of surveillance activities as a requirement for ACTION statements, the air-roll test shall not be performed.

INSERT C

B.4

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

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 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.

(continued)

BASES

ACTIONS

B.4 (continued)

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,
33 days 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 30 days
DG. At this time, an offsite circuit could again become inoperable, the DG
restored OPERABLE, and an additional 72 hours (for a total of 9 days)
33 allowed prior to complete restoration of the LCO. The 9 day Completion 63
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 and 6 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 one train without offsite power (Required Action A.2). The rationale for the reduction to 12 hours is that Regulatory Guide 1.93 (Ref. 6) allows a Completion Time of 24 hours for two required offsite circuits inoperable, based upon the assumption that two complete safety trains are OPERABLE. When a concurrent redundant required feature failure exists, this assumption is not the case, and a shorter Completion Time of 12 hours is appropriate. These features are powered from redundant AC safety trains. This includes the motor driven auxiliary feedwater pumps and the TDAFW pump which must be available for mitigation of a Feedwater line break. Single train systems, other than the turbine driven auxiliary feedwater pump, are not included.

The Completion Time for Required Action C.1 is intended to allow the operator time to evaluate and repair any discovered inoperabilities. This

(continued)

INSERTS

INSERT A

In Condition A, the remaining OPERABLE offsite circuit and DGs are adequate to supply electrical power to the onsite Class 1E Distribution System. With an offsite circuit inoperable, the inoperable offsite circuit must be restored to OPERABLE status within the applicable, specified Completion Time.

INSERT B

The 30 day Completion Time is based on a plant specific risk analysis performed to establish the out of service time.

The following administrative controls will be applicable upon entry into plant conditions which rely on the extended CT.

1. The Configuration Risk Management Program (CRMP) (TS 5.5.18) will be applied per 10CFR50.65(a)(4).
2. Weather conditions must be conducive to perform maintenance on the offsite circuits.
3. The offsite power supply and switchyard conditions must be conducive to perform maintenance on the offsite circuits.
4. Switchyard access must be monitored and controlled per procedures.

INSERT C

In Condition B, the remaining OPERABLE DG and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. With a DG inoperable, the inoperable DG must be restored to OPERABLE status within the applicable, specified Completion Time.

ATTACHMENT 4 to TXX-07012

RETYPED TECHNICAL SPECIFICATION PAGES

Pages 3.8-2
3.8-4

ACTIONS

-----NOTE-----
LCO 3.0.4.b is not applicable to DGs.

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 <u>AND</u> Once per 8 hours thereafter
	<u>AND</u>	
	-----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)
	<u>AND</u>	
	A.3 Restore required offsite circuit to OPERABLE status.	30 days <u>AND</u> 33 days from discovery of failure to meet LCO

(continued)

CONDITION	REQUIRED ACTION	COMPLETION TIME
B. (continued)	AND B.4 Restore DG to OPERABLE status.	72 hours AND 33 days from discovery 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)

ATTACHMENT 5 to TXX-07012

RETYPED TECHNICAL SPECIFICATION BASES PAGES

Pages B 3.8-8
B 3.8-11

ACTIONS (continued)

A.3

In Condition A, the remaining OPERABLE offsite circuit and DGs are adequate to supply electrical power to the onsite Class 1E Distribution System. With an offsite circuit inoperable, the inoperable offsite circuit must be restored to OPERABLE status within the applicable, specified Completion Time.

The 30 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 30 day Completion Time is based on a plant specific risk analysis performed to establish the out of service time.

The following administrative controls will be applicable upon entry into plant conditions which rely on the extended CT.

1. The Configuration Risk Management Program (CRMP) (TS 5.5.18) will be applied per 10CFR50.65(a)(4).

2. Weather conditions must be conducive to perform maintenance on the offsite circuits.

3. The offsite power supply and switchyard conditions must be conducive to perform maintenance on the offsite circuits.

4. Switchyard access must be monitored and controlled per procedures.

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 33 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 72 hours (for a total of 36 days) allowed prior to complete restoration of the LCO. The 33 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 30 day and 33 day Completion Times means that both Completion Times apply simultaneously, and the more restrictive Completion Time must be met.

(continued)

ACTIONS (continued)

B.4

In Condition B, the remaining OPERABLE DG and offsite circuits are adequate to supply electrical power to the onsite Class 1E Distribution System. With a DG inoperable, the inoperable DG must be restored to OPERABLE status within the applicable, specified Completion Time.

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.

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 30 days. This could lead to a total of 33 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 30 days (for a total of 63 days) allowed prior to complete restoration of the LCO. The 33 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 and 33 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.

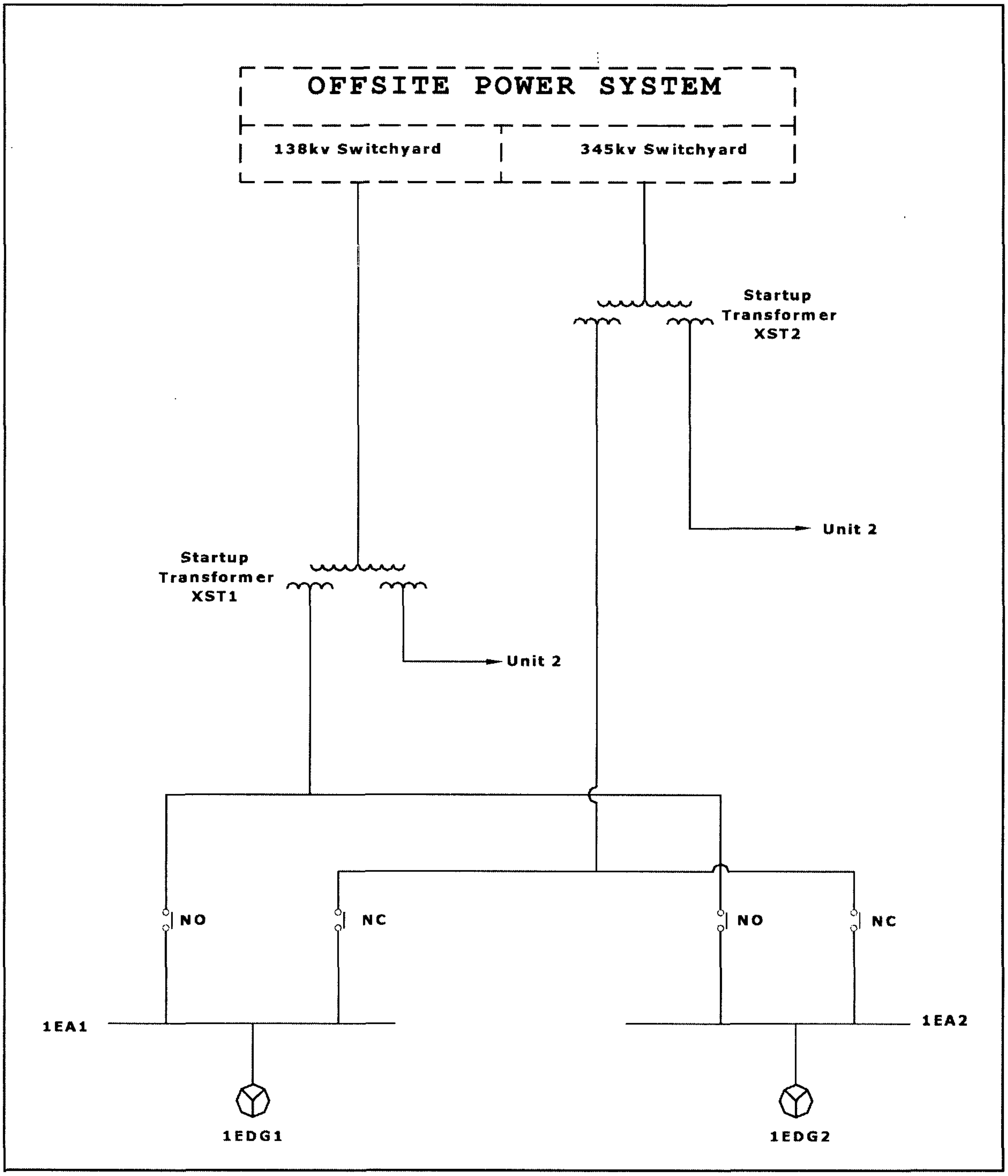
C.1 and C.2

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 one train without offsite power (Required Action A.2). The rationale for the reduction to 12 hours is that Regulatory Guide 1.93 (Ref. 6) allows a Completion Time of 24 hours for two required offsite circuits inoperable, based upon the assumption that two complete

(continued)

ATTACHMENT 6 to TXX-07012

CPSES SWITCHYARDS and DISTRIBUTION SUBSYSTEM FIGURES
(For Information Only)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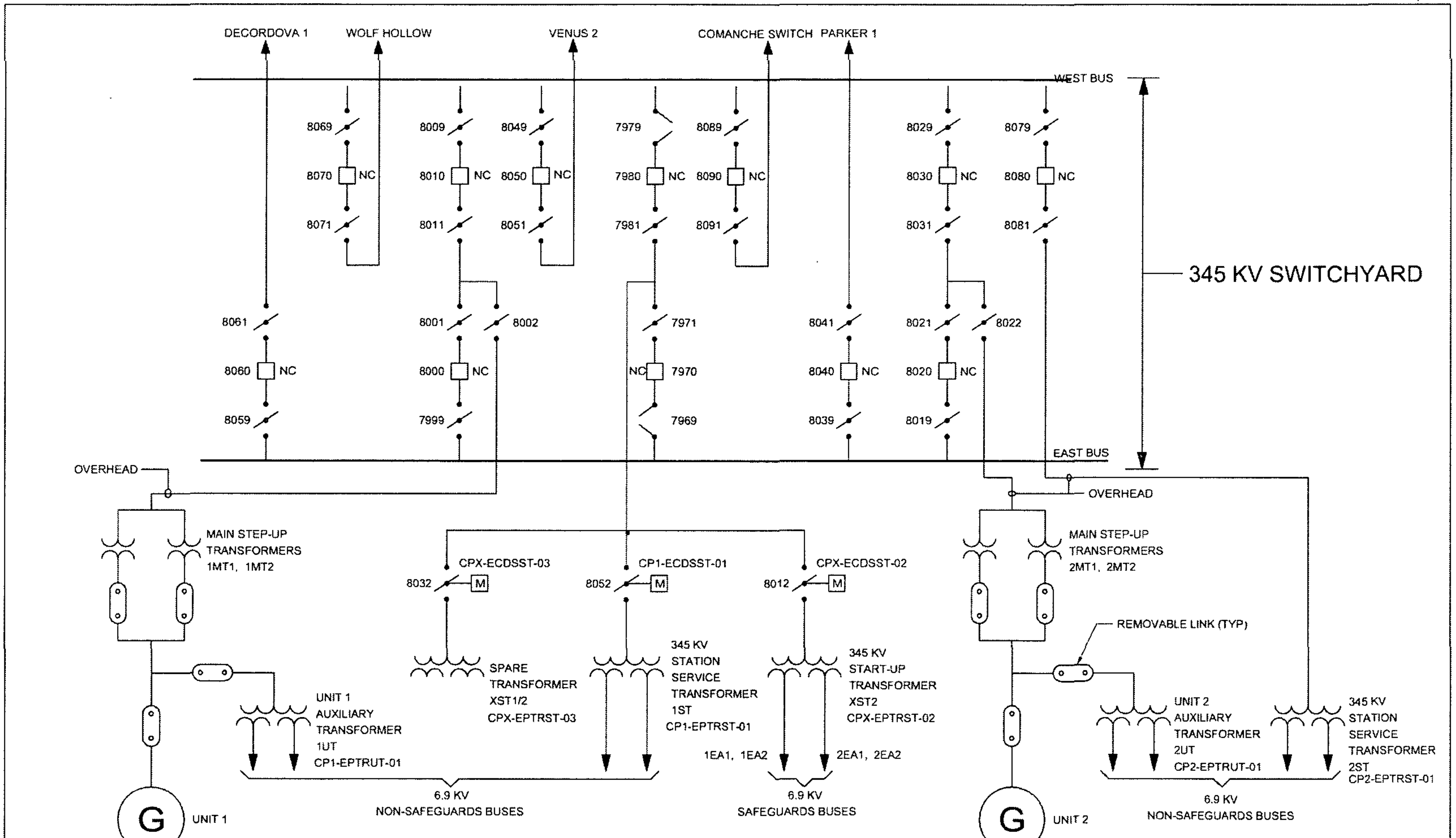
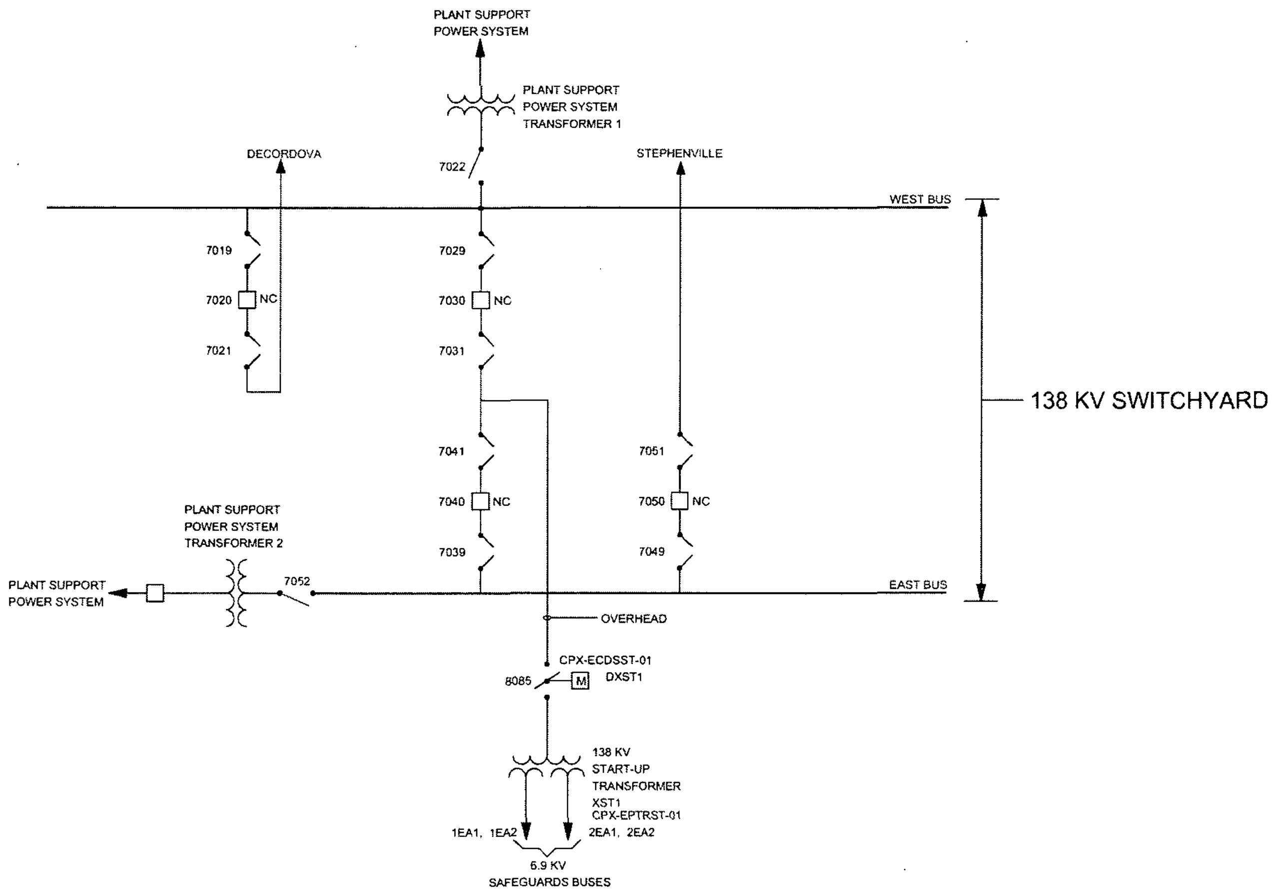
138kv Switchyard
345kv Switchyard
Startup
Transformer
XST2
Unit 2
Startup
Transformer
XST1
Unit 2
NO
NC
NO
NC
1EA1
1EA2
1EDG1
1EDG2



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



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